

APPENDIX

AM-30

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* NCSU DEPARTMENT OF CHEMICAL ENGINEERING
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* ACID GAS REMOVAL SYSTEM
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RUN NUMBER A-M-30
 INTEGRATED
 DATE 5/28/1980

---STREAM COMPOSITION (MOL-%)---

	SOUR GAS	SWEETGAS	FLASHGAS	STRIPN2	ACID GAS	ABSORBOT*	FLASHBOT*	STRIPBOT*
CO2	24.600	1.460	43.200	0.000	71.500	5.918	5.545	0.000
H2S	0.910	0.048	0.634	0.000	2.539	0.220	0.216	0.000
COS	0.042	0.003	0.043	0.000	0.117	0.010	0.010	0.000
MEDH	0.000	0.000	0.000	0.000	0.000	92.764	93.669	99.498
H2	33.170	43.190	15.240	0.000	0.000	0.619	0.473	0.502
CO	21.060	28.480	22.720	0.000	1.020	0.204	0.000	0.000
N2	18.500	24.890	14.750	100.000	24.560	0.202	0.057	0.000
CH4	1.640	1.950	3.400	0.000	0.420	0.064	0.030	0.000

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CALCULATED

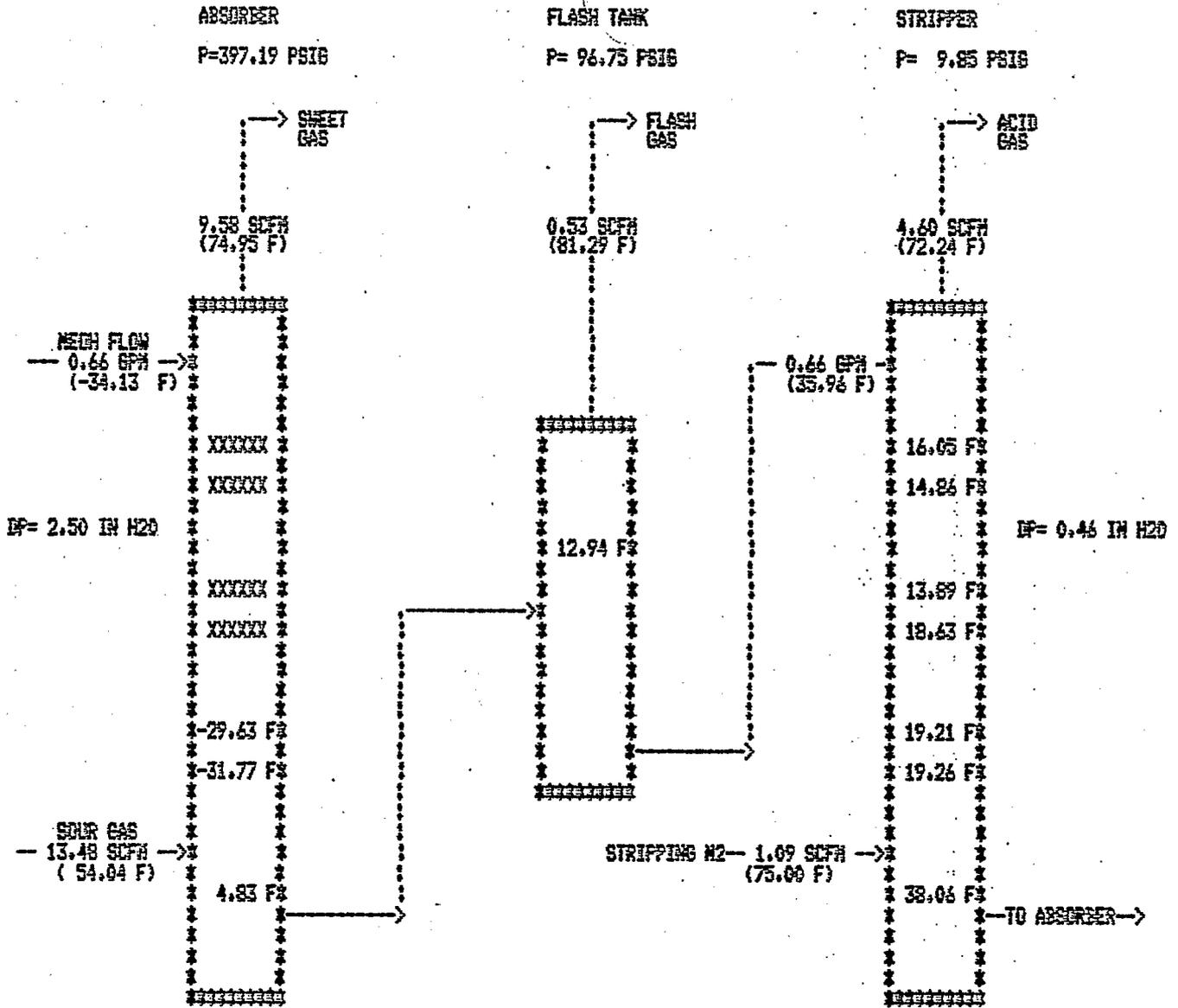
MASS BALANCE (LB-MOLES/HR)

	IN		OUT			TOTAL IN*	TOTAL OUT*	% RECOVERY
	SOUR GAS	STRIP N2	SWEETGAS	FLASHGAS	ACID GAS			
CO2	0.554	0.000	0.023	0.038	0.550	0.554	0.611	110.3
H2S	0.020	0.000	0.001	0.001	0.020	0.020	0.021	101.7
COS	0.001	0.000	0.000	0.000	0.001	0.001	0.001	104.0
MEDH	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.0
H2	0.747	0.000	0.692	0.013	0.000	0.747	0.705	94.4
CO	0.474	0.000	0.456	0.020	0.008	0.474	0.484	102.0
N2	0.417	0.182	0.359	0.013	0.189	0.599	0.601	100.3
CH4	0.037	0.000	0.031	0.003	0.003	0.037	0.037	101.4
TOTAL (LB-MOLES/HR)	2.253	0.182	1.602	0.059	0.769	2.433	2.461	101.130

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METHANOL-FREE BASIS

TOTAL METHANOL LOSS= 0.000 LB-MOLES/HR = 0.000 GALLONS/HR

COLUMN TEMPERATURE PROFILES & MASS BALANCES



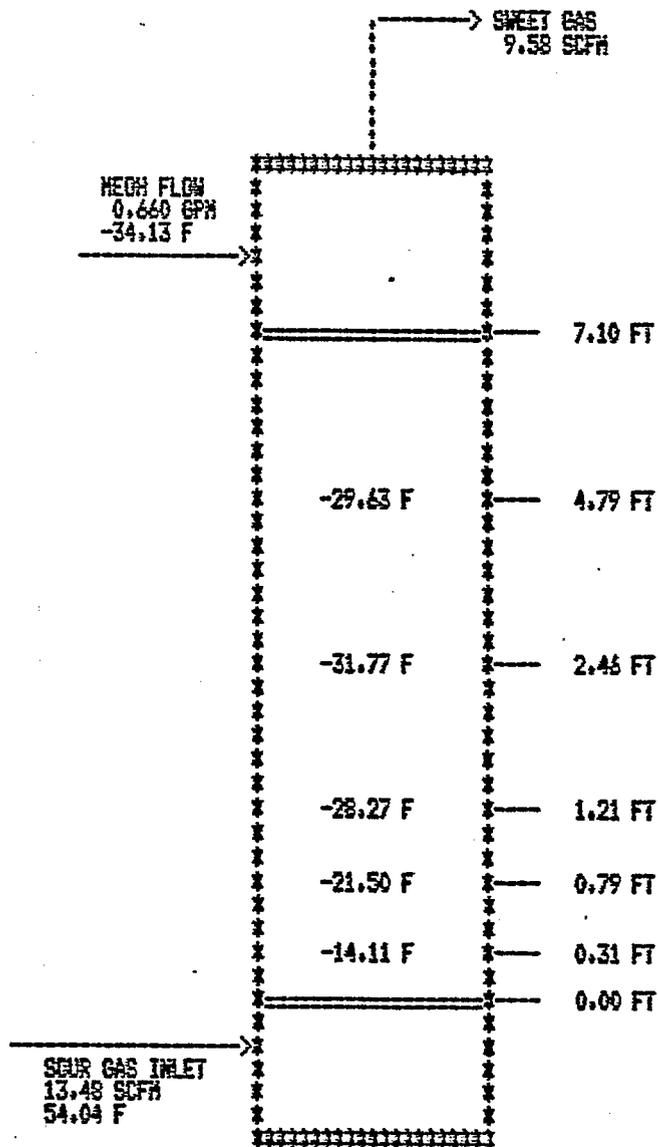
RUN NUMBER A-X-30
 INTEGRATED
 DATE 5/28/1980

COLUMN TEMPERATURE PROFILE

ABSORBER COLUMN PRESSURE = 397.2 PSIG

TOTAL PACKING HEIGHT = 7.10 FEET

PACKING USED = 1/4" CERAMIC INTALOX SADDLES



TRANSMITTER	HEIGHT ABOVE GAS INLET	HEIGHT OF PACKING	TEMPERATURE (F)
TT350	4.79	4.79	-29.63
TT351	2.46	2.46	-31.77
TT352	1.21	1.21	-28.27
TT353	0.31	0.31	-14.11
TT354	0.79	0.79	-21.50

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* NCSU DEPARTMENT OF CHEMICAL ENGINEERING *
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* ACID GAS REMOVAL SYSTEM *
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RUN NUMBER A-H-35
 INTEGRATED RUN
 DATE 6/26/1980

STREAM COMPOSITION (MOL %)

	SOUR GAS	SWEETGAS	FLASHGAS	STRIPN2	ACID GAS	ABSORBOT*	FLASHBOT*	STRIPBOT*
CO2	28.010	0.950	42.450	0.000	71.900	5.674	5.361	0.000
H2S	0.807	0.037	0.526	0.000	1.970	0.162	0.159	0.000
COS	0.045	0.003	0.038	0.000	0.127	0.009	0.007	0.000
MEOH	0.000	0.000	1.310	0.000	2.910	93.934	94.365	99.901
H2	33.190	45.500	4.210	0.000	0.000	0.118	0.085	0.090
CO	20.200	27.850	23.830	0.000	1.630	0.048	0.000	0.000
N2	15.700	23.230	13.490	100.000	20.750	0.000	0.000	0.000
CH4	2.010	2.440	4.110	0.000	0.690	0.054	0.021	0.000

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CALCULATED

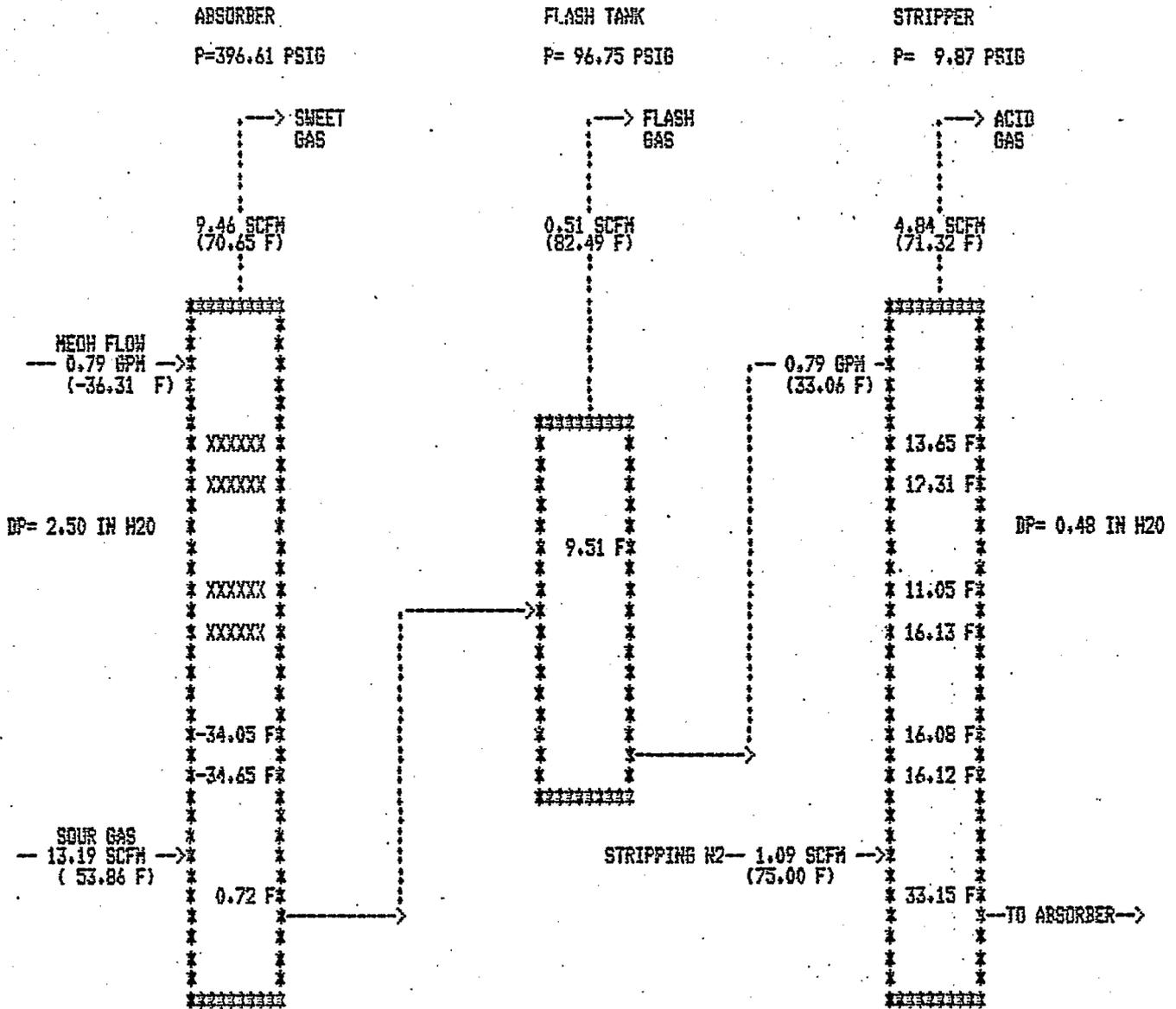
MASS BALANCE (LB-MOLES/HR)

	IN		OUT			TOTAL IN*	TOTAL OUT*	% RECOVERY
	SOUR GAS	STRIP N2	SWEETGAS	FLASHGAS	ACID GAS			
CO2	0.618	0.000	0.015	0.036	0.582	0.618	0.633	102.4
H2S	0.018	0.000	0.001	0.000	0.016	0.018	0.017	95.3
COS	0.001	0.000	0.000	0.000	0.001	0.001	0.001	111.9
MEOH	0.000	0.000	0.000	0.001	0.024	0.000	0.000	0.0
H2	0.732	0.000	0.719	0.004	0.000	0.732	0.723	98.8
CO	0.445	0.000	0.440	0.020	0.013	0.445	0.474	106.3
N2	0.346	0.182	0.367	0.011	0.168	0.528	0.547	103.4
CH4	0.044	0.000	0.039	0.003	0.006	0.044	0.048	107.5
TOTAL	2.205	0.182	1.581	0.085	0.809	2.386	2.441	102.301
(LB-MOLES/HR)								

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METHANOL-FREE BASIS

TOTAL METHANOL LOSS= 0.025 LB-MOLES/HR = 0.117 GALLONS/HR

COLUMN TEMPERATURE PROFILES & MASS BALANCES



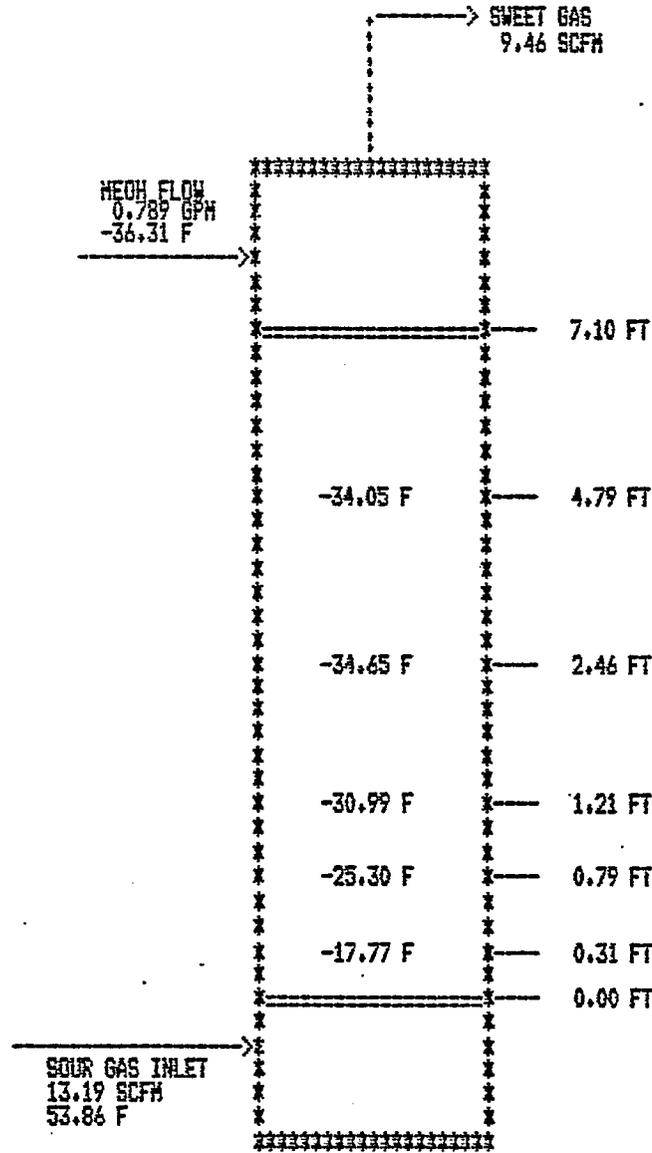
RUN NUMBER A-N-35
 INTEGRATED RUN
 DATE 6/26/1980

COLUMN TEMPERATURE PROFILE

ABSORBER COLUMN PRESSURE = 396.6 PSIG

TOTAL PACKING HEIGHT = 7.10 FEET

PACKING USED = 1/4" CERAMIC INTALOX SADDLES



TRANSMITTER	HEIGHT ABOVE GAS INLET	HEIGHT OF PACKING	TEMPERATURE (F)
TT350	4.79	4.79	-34.05
TT351	2.46	2.46	-34.65
TT352	1.21	1.21	-30.99
TT353	0.31	0.31	-17.77
TT354	0.79	0.79	-25.30

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* MCSU DEPARTMENT OF CHEMICAL ENGINEERING *
*          ACID GAS REMOVAL SYSTEM          *
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RUN NUMBER A-M-36
 INTEGRATED RUN
 DATE 7/18/1980

STREAM COMPOSITION (MOL %)

	SOUR GAS	SWEETGAS	FLASHGAS	STRIPN2	ACID GAS	ABSORBOT*	FLASHBOT*	STRIPBOT*
CO2	20.900	0.420	34.170	0.000	69.770	4.465	4.302	0.000
H2S	0.892	0.068	0.569	0.000	2.225	0.182	0.180	0.023
COS	0.048	0.004	0.038	0.000	0.133	0.010	0.010	0.000
HEDH	0.000	0.000	0.000	0.000	0.000	95.037	95.411	99.947
H2	33.449	44.310	13.870	0.000	0.000	0.000	0.000	0.000
CO	17.030	20.550	22.020	0.000	0.970	0.214	0.098	0.030
N2	26.190	33.040	26.490	100.000	26.500	0.093	0.000	0.000
CHA	1.270	1.680	2.830	0.000	0.360	0.000	0.000	0.000

* CALCULATED

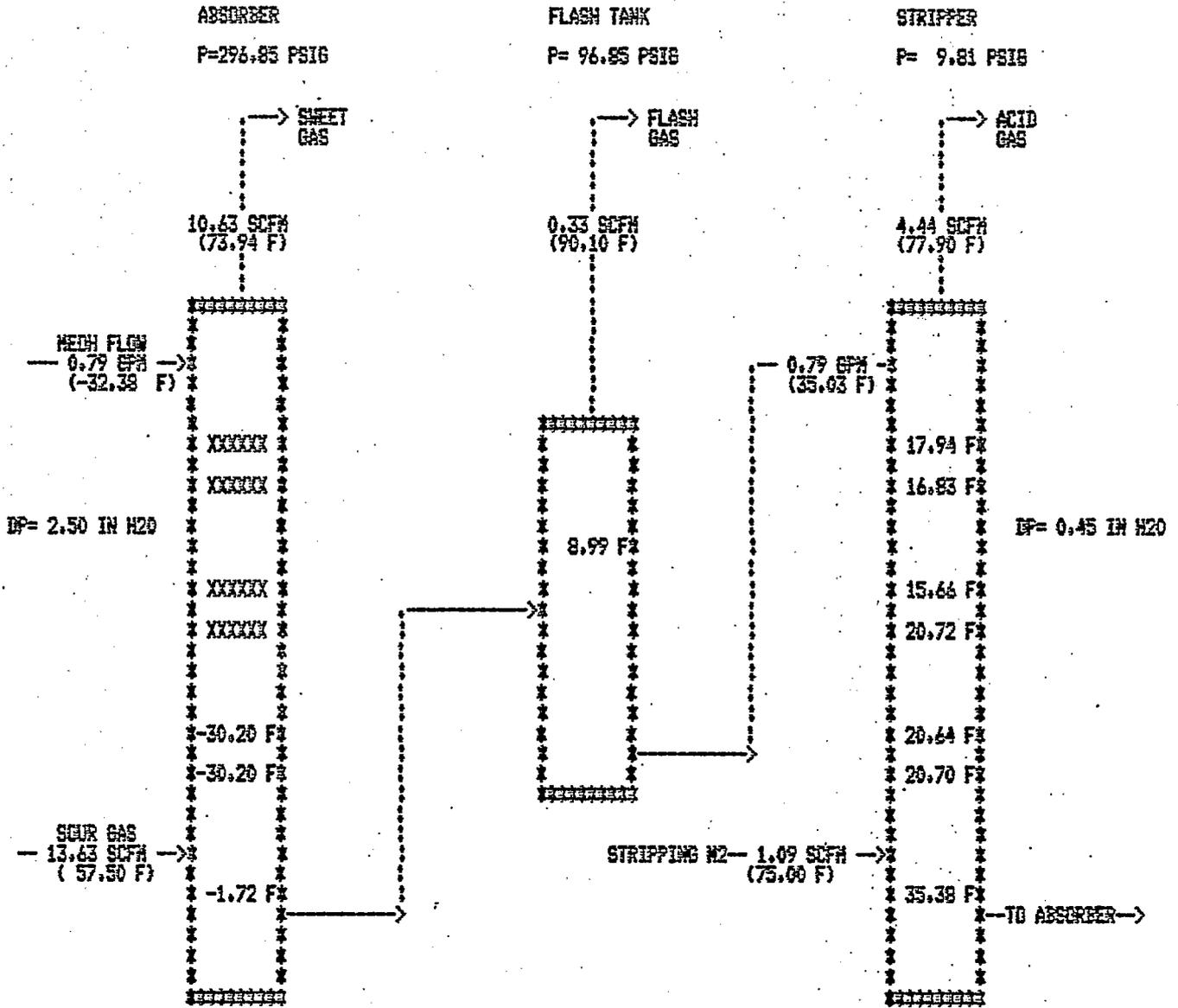
MASS BALANCE (LB-MOLES/HR)

	IN		OUT			TOTAL IN*	TOTAL OUT*	Z RECOVERY
	SOUR GAS	STRIP N2	SWEETGAS	FLASHGAS	ACID GAS			
CO2	0.476	0.000	0.007	0.019	0.518	0.476	0.545	114.4
H2S	0.020	0.000	0.001	0.000	0.017	0.020	0.018	88.9
COS	0.001	0.000	0.000	0.000	0.001	0.001	0.001	99.3
HEDH	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.0
H2	0.762	0.000	0.787	0.008	0.000	0.762	0.755	104.3
CO	0.388	0.000	0.366	0.012	0.007	0.388	0.385	99.2
N2	0.597	0.182	0.587	0.015	0.197	0.779	0.798	102.5
CHA	0.029	0.000	0.030	0.002	0.003	0.029	0.034	117.8
TOTAL (LB-MOLES/HR)	2.278	0.182	1.776	0.055	0.743	2.455	2.576	104.918

* METHANOL-FREE BASIS

TOTAL METHANOL LOSS= 0.000 LB-MOLES/HR = 0.000 GALLONS/HR

COLUMN TEMPERATURE PROFILES & MASS BALANCES



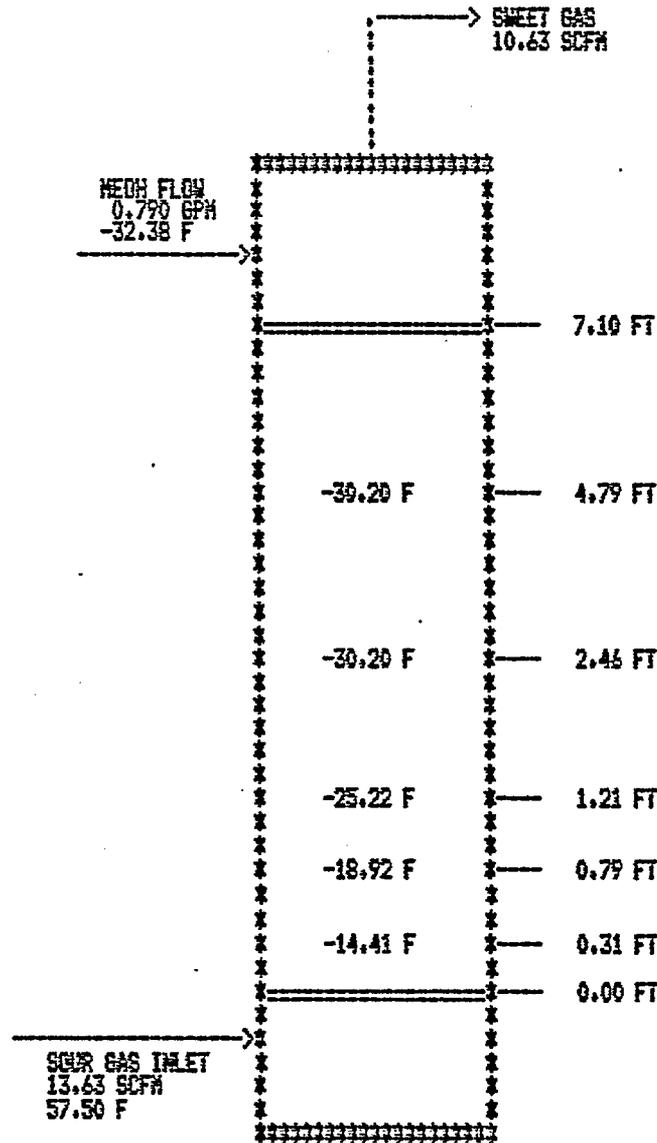
RUN NUMBER A-M-36
 INTEGRATED RUN
 DATE 7/18/1980

COLUMN TEMPERATURE PROFILE

ABSORBER COLUMN PRESSURE = 296.9 PSIG

TOTAL PACKING HEIGHT = 7.10 FEET

PACKING USED = 1/4" CERAMIC INTALOX SADDLES



TRANSMITTER	HEIGHT ABOVE GAS INLET	HEIGHT OF PACKING	TEMPERATURE(F)
TT350	4.79	4.79	-39.20
TT351	2.46	2.46	-30.20
TT352	1.21	1.21	-25.22
TT353	0.31	0.31	-14.41
TT354	0.79	0.79	-18.92

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* HCSU DEPARTMENT OF CHEMICAL ENGINEERING *
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* ACID GAS REMOVAL SYSTEM *
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RUN NUMBER A-H-37
 INTEGRATED RUN
 DATE 7/25/1980

STREAM COMPOSITION (MOL %)

	SOUR GAS	SWEETGAS	FLASHGAS	STRIPN2	ACID GAS	ABSORBENT *	FLASHBOT *	STRIPBOT *
CO2	25.050	0.640	47.820	0.000	71.050	5.406	4.975	0.000
H2S	0.863	0.041	0.628	0.000	2.260	0.183	0.179	0.000
COS	0.047	0.003	0.043	0.000	0.130	0.010	0.010	0.000
MEOH	0.000	0.000	0.870	0.000	4.030	93.853	94.667	99.850
H2	38.930	54.960	11.880	0.000	0.000	0.000	0.000	0.000
CO	18.810	23.920	22.340	0.000	0.940	0.310	0.089	0.015
N2	14.820	19.300	12.940	100.000	21.150	0.171	0.044	0.114
CH4	1.150	1.160	3.140	0.000	0.220	0.067	0.037	0.020

* CALCULATED

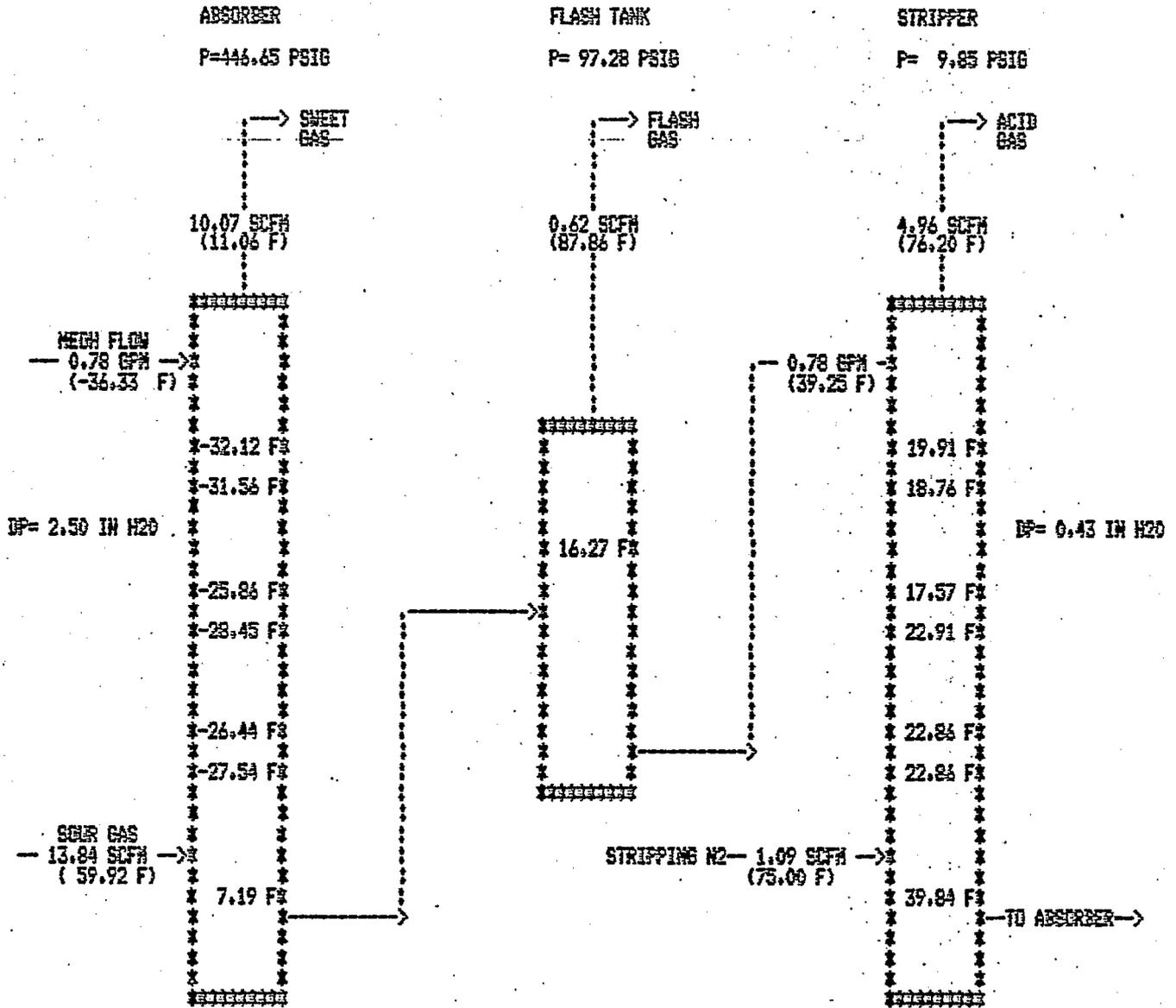
MASS BALANCE (LB-MOLES/HR)

	IN		OUT			TOTAL IN *	TOTAL OUT *	% RECOVERY
	SOUR GAS	STRIP N2	SWEETGAS	FLASHGAS	ACID GAS			
CO2	0.579	0.000	0.011	0.050	0.589	0.579	0.650	112.2
H2S	0.020	0.000	0.001	0.001	0.019	0.020	0.020	100.0
COS	0.001	0.000	0.000	0.000	0.001	0.001	0.001	100.0
MEOH	0.000	0.000	0.000	0.001	0.033	0.000	0.000	0.0
H2	0.900	0.000	0.925	0.012	0.000	0.900	0.937	104.1
CO	0.435	0.000	0.402	0.023	0.008	0.435	0.434	99.7
N2	0.343	0.182	0.325	0.013	0.175	0.525	0.514	97.9
CH4	0.027	0.000	0.020	0.003	0.002	0.027	0.025	92.5
TOTAL (LB-MOLES/HR)	2.313	0.182	1.683	0.104	0.830	2.487	2.580	103.732

* METHANOL-FREE BASIS

TOTAL METHANOL LOSS= 0.034 LB-MOLES/HR = 0.164 GALLONS/HR

COLUMN TEMPERATURE PROFILES & MASS BALANCES



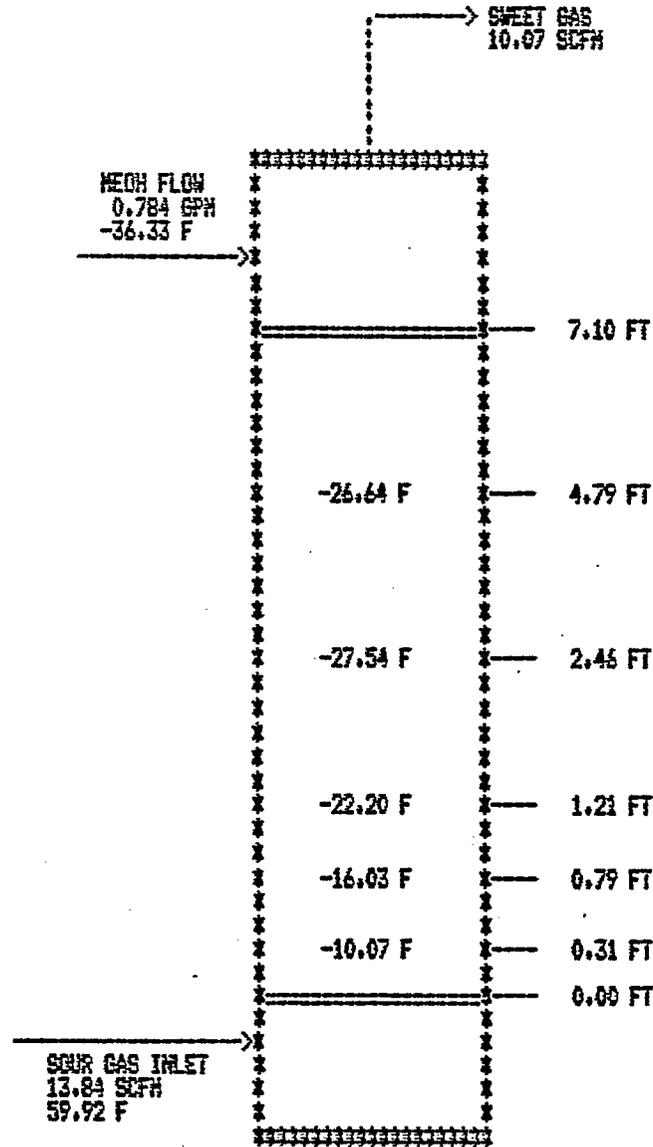
RUN NUMBER A-M-37
 INTEGRATED RIM
 DATE 7/25/1980

COLUMN TEMPERATURE PROFILE

ABSORBER COLUMN PRESSURE = 446.6 PSIG

TOTAL PACKING HEIGHT = 7.10 FEET

PACKING USED = 1/4" CERAMIC INTALOX SADDLES



TRANSMITTER	HEIGHT ABOVE GAS INLET	HEIGHT OF PACKING	TEMPERATURE(F)
TT350	4.79	4.79	-26.64
TT351	2.46	2.46	-27.54
TT352	1.21	1.21	-22.20
TT353	0.31	0.31	-10.07
TT354	0.79	0.79	-16.03

POLLUTION CONTROL GUIDANCE DOCUMENT
FOR
LOW-BTU GASIFICATION TECHNOLOGY:

BACKGROUND STUDIES

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ABSTRACT

The Environmental Protection Agency is currently preparing a Pollution Control Guidance Document (PCGD) for low-Btu gasification (LBG) facilities which use atmospheric pressure, fixed-bed gasifiers. The PCGD is intended to aid industry and government in their efforts to commercialize LBG technology in an environmentally acceptable manner. This paper presents some of the preliminary results of background studies performed to support the development of the LBG PCGD.

A model plant approach was used to assess the environmental control needs for LBG facilities. The plant configuration and coal feed combinations for which pollution controls were identified and evaluated were selected based on existing and proposed plants in the U.S. The major variables examined were coal feed type (anthracite, lignite, and high- and low-sulfur bituminous coals) and degree of product gas purification (production of hot, cooled, and desulfurized low-Btu gas). In all, eleven combinations of these variables, i.e., model plants, were selected for study. Each model plant had a nominal capacity of 45 MJ/s (150×10^6 Btu/hr) of low-Btu gas.

Multimedia pollutant sources and pollutants of potential concern were identified and quantified for each model plant. The bases for these determinations were field test data and calculated emissions projections. The EPA's low-Btu gasification environmental assessment program was the major source of the field test data, but results from other government and industry test programs were also used.

Control/disposal options were identified and evaluated for each discharge stream. Factors that were considered included the need for control, current industry practices, control equipment performance, capital investment requirements, annual operating costs, energy impacts, and secondary environmental discharges.

POLLUTION CONTROL GUIDANCE DOCUMENT
for
LOW-BTU GASIFICATION TECHNOLOGY:

BACKGROUND STUDIES

INTRODUCTION

Over the past several years the United States has moved from a position of energy independence to one of energy dependence. A decade ago this country imported only about ten percent of its crude oil needs and now the figure is around fifty percent. The amount of oil and gas produced in the U.S. has declined slightly over this period despite a doubling of drilling activity. The country's vast coal reserves, however, have not been developed with the same intensity. With the changing energy picture there has been a growing interest on the part of government and industry in the technologies that produce clean fuels and chemical feedstocks from coal. One such technology is low-Btu coal gasification (LBG).

The Environmental Protection Agency is responsible for ensuring that LBG technology and other alternate energy technologies are developed in a manner which protects public health and the environment. As part of that effort, the EPA has initiated programs to assess the environmental impacts of LBG.

The EPA has developed the Pollution Control Guidance Document (PCGD) concept to aid industry and government in their efforts to commercialize low-Btu gasification technology in a manner that will be environmentally acceptable. The primary purposes of a PCGD are to:

- Provide guidance to permit writers on the best control approaches presently available at a reasonable cost for the processes under consideration.
- Provide system developers with an early indication of EPA's assessment of the appropriate multimedia environmental protection needs for each of these processes, considering costs, so that developers can design their facilities to achieve this level of protection (rather than add potentially more costly retrofit controls later).
- Describe to public interest groups EPA's judgment of the best available controls for these processes.
- Provide the regulatory offices in EPA with information useful in developing future regulations.

The low-Btu gasification PCGD will describe the performance capabilities and costs of currently available controls for LBG facilities which use

fixed-bed, atmospheric pressure gasifiers. (This type of gasifier is believed to be the likely candidate for near-term commercial use). The PCGD will provide guidance both for currently regulated pollutants and for sources and/or pollutants not covered by current standards. The guidance will be based on a coordinated evaluation of available data by EPA's research and development, regulatory, and permitting/enforcement offices. In the PCGD, suggested levels of environmental protection considering costs, multimedia tradeoffs, and control system reliability will be specified for all air, water, solid waste, and product/by-product streams. The PCGD will consist of three volumes whose contents can be summarized as follows:

- Volume I will describe the technology, identify applicable existing regulations, and present the control guidance;
- Volume II will summarize all of the data employed and present the baseline engineering design, waste stream characterizations and control option evaluations; and
- Volume III (Appendices) will contain detailed data listings and calculations which support the guidance.

This paper presents some of the preliminary results of background studies being conducted to support the development of the LBG PCGD. Included in this paper are: 1) a description of the technology and an identification and characterization of its multimedia discharges (including flow rates and factors affecting discharge characteristics); 2) an identification and evaluation of available control techniques; and 3) an estimation of the capital and annualized cost impacts of available controls.

Technology Overview

Low-Btu coal gasification technology has been commercially available for over 60 years. In the U.S., there are currently 20 known LBG plants either in operation, under construction, or being planned for construction in the near future. All of the commercially operating plants use fixed-bed, atmospheric pressure gasifiers and are generally located in the industrialized Midwest and Northeast regions of the Country. Feedstocks used at those plants include anthracite, lignite, and low-sulfur (<1%) bituminous coal. No high-sulfur coals are currently in use. The only gas purification process used at most of these plants is a hot gas cyclone for particulate removal. Tar and oil removal using gas quenching/scrubbing is practiced at one plant and is proposed for several future plants. Sulfur compound removal is currently practiced only at one plant. Current end-uses of low-Btu product gas include fuel for brick and lime kilns, process heaters, and steam boilers.

LBG systems featuring fixed-bed, atmospheric pressure gasifiers are most suitable for relatively small applications, with fuel demands ranging from about 8.8 to 88 MW of thermal energy (30-300 million Btu/hr). This would require using from 1 to 10 gasifiers, depending on the coal feed. Energy demands

greater than about 88 MW (300 million Btu/hr) may be better served by gasification systems using gasifiers with larger capacities (for example, pressurized gasifiers).

Applicable Existing Federal Regulations

New low-Btu gasification plants will have to comply with existing Federal regulations for 1) sources within the plant that are already subject to regulation (NSPS); 2) the disposal of solid wastes (RCRA); and 3) ambient-based limitations, such as National Ambient Air Quality Standards (NAAQS), Prevention of Significant Deterioration (PSD) requirements, Water Quality Criteria, and Drinking Water Standards which may indirectly limit the quantities or concentrations of compounds in specific source discharges. However, at the current time there are no Federal regulations which apply to specific air or water discharge sources within an LBG facility. In addition, products and by-products may be subject to restrictions if they contain toxic substances.

New plants will also be required to comply with state and local regulations. The guidance in the PCGD is not intended to supersede the requirements of any of these existing or proposed regulations.

Approach Used For Background Studies

In conducting the background studies, an inventory of waste streams and pollutants generated in model plant facilities was prepared and an assessment of the performance and costs of various control alternatives for those streams and pollutants was made. The approaches used to develop the pollutant inventory and to select and evaluate applicable controls are briefly described below.

Pollutants Considered. A listing of all the currently regulated pollutants which have been found in the gaseous and aqueous wastes from LBG facilities is provided in Table 1. The major pollutants not listed in this table, but which are expected to be present in an LBG system's discharges are polycyclic organic matter (POM), hydrogen cyanide and ammonia in the uncontrolled gaseous emissions, and a number of specific organic compounds which are only covered by gross parameters such as "organic carbon" in the aqueous effluents.

Model Plants. A model plant approach was used to characterize the potential uncontrolled discharges from LBG systems and to evaluate pollution control alternatives for those discharges. The model plants selected represent processing configurations currently in use or proposed for use in the U.S. Each has similar processes in the coal preparation and coal gasification operations. They differ in the areas of coal feedstock used and the degree to which the low-Btu product gas is purified. For the background studies, recommendations were not made as to which model plant should be used, but pollution control information for the discharges from each model plant was developed.

TABLE 1. CONSTITUENTS IN LOW-BTU GASIFICATION PLANT WASTE STREAMS COVERED BY EXISTING AIR AND WATER STANDARDS

Subject Pollutants Found in Discharge Streams from Low-Btu Gasification Facilities

Standard

National Ambient Air Quality Standards	CO, NO ₂ , SO ₂ , Pb, TSP, NMHC
New Source Performance Standards	CO, NO ₂ , SO ₂ , TSP, Total Reduced Sulfur, NMHC
National Emission Standards for Hazardous Air Pollutants	Hg, Be, Inorganic As*, Benzene*, Radionuclides*
Prevention of Significant Deterioration Standards	
Increments	SO ₂ , TSP
De Minimis Levels	CO, NO ₂ , TSP, SO ₂ , Pb, Hg, Se, H ₂ S, CS ₂ , COS
Effluent Limitation Guidelines	
Conventional and nonconventional pollutants	Al, Ammonia, B, Ca, Fluoride, Fe, Mn, Nitrate, Organic Carbon, P, Sulfate, Sulfide, U, BOD ₅ , COD, pH, Total Nitrogen, Total Suspended Solids, Color, Oil and Grease, Settleable Solids
Consent decree pollutants (toxic pollutants)	Sb, As, Be, Cd, Cr, Cu, Cyanides, Pb, Hg, Ni, Phenol and phenolic compounds, Polynuclear aromatic hydrocarbons, Se, Ag, Zn

*Listed as hazardous air pollutants; no regulations promulgated.

The characteristics of the coal being gasified influence the presence, composition and flow rates of the discharges from low-Btu gasification plants. In order to evaluate the impact of coal properties on the discharge streams, four different coals were examined: anthracite, lignite, low-sulfur bituminous coal, and high-sulfur bituminous coal. These feedstocks span the range of coals and coal properties which are or might be used in low-Btu gasification plants.

Using the data sources described below, mass balances were calculated for a basic plant capacity of 45 MW (approximately 150×10^6 Btu/hr) of thermal energy in the product gas (based on the higher heating value of the gas). This capacity is representative of the plant sizes expected to be constructed in the near future. The mass balances provided a consistent basis for calculating "uncontrolled" mass discharge rates.

Based upon the expected characteristics of the waste streams, pollution control processes were identified and evaluated. "Secondary" waste streams resulting from pollution control were also defined and controls for these streams evaluated.

Data Sources. The major source of data used in the background studies is an EPA-sponsored environmental assessment program for low-Btu gasification technology. As part of that program, a series of field test programs are being conducted. To date, three data acquisition programs have been completed, another is on-going and a fifth is planned for the fall of 1980.^{1,2,3} All test sites are either commercially operating or commercial-size demonstration units located in the U.S. Additional data sources are other government and industry sponsored test programs.

Information used to identify and evaluate pollution control alternatives was mainly obtained by technology transfer, i.e., extrapolation from other industries with identical or similar pollution control problems. Additional technical information was obtained from process vendors, process developers, and published literature. Only limited pollution control information was obtained from the field test programs because of the essentially "uncontrolled" nature of the sites tested.

PROCESS DESCRIPTION AND POLLUTANT SOURCES

Low-Btu coal gasification systems can be considered to consist of three basic operations: coal preparation, coal gasification, and gas purification. Each of these operations in turn consists of process modules that are employed to satisfy the functions of the operations.

As mentioned previously, a model plant approach was used to characterize the potential uncontrolled discharges from LBG systems and to evaluate pollution control alternatives for those discharges. Block diagrams of the three model plants examined are shown in Figure 1. These represent all the processing configurations of plants currently operating or proposed in the U.S.

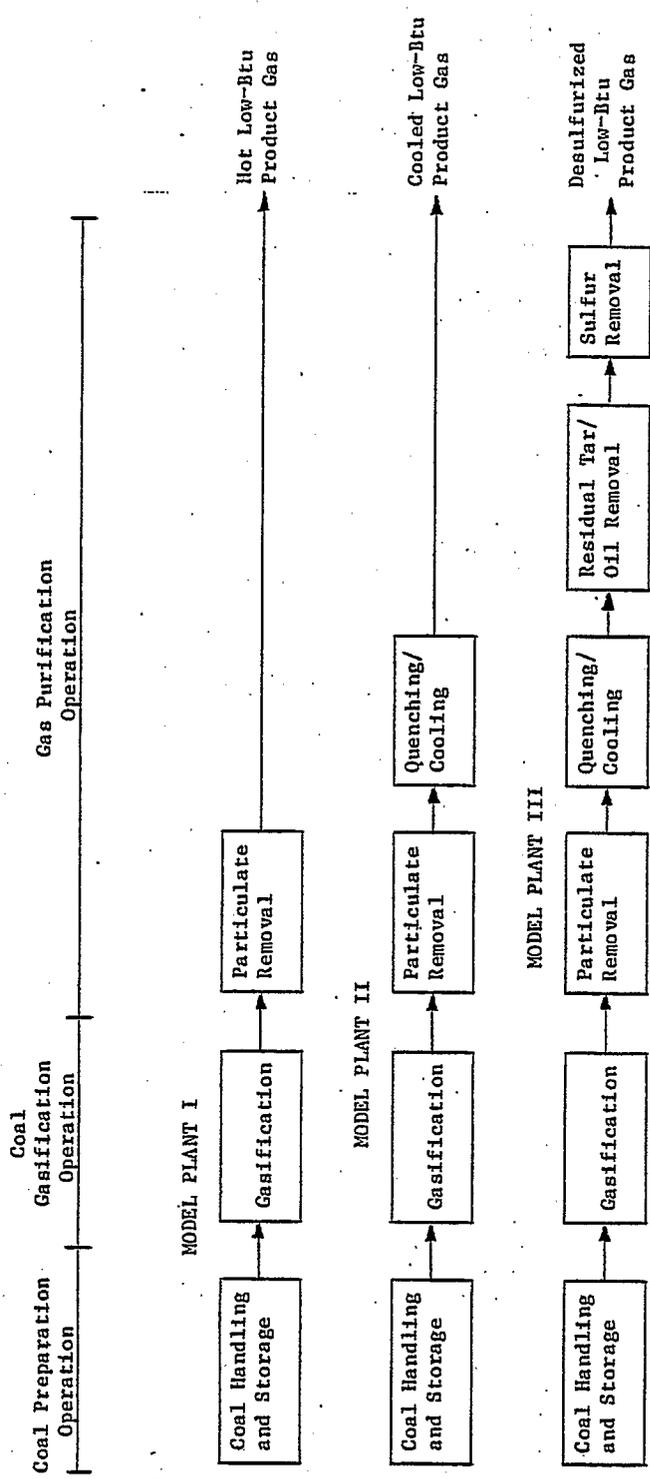


FIGURE 1. LOW-BTU GASIFICATION MODEL PLANTS

The first model plant produces a hot low-Btu product gas. The only gas purification process used is a hot gas cyclone for partial removal of entrained particulate matter. This process configuration is typical of most of the plants currently in operation and several plants which are proposed or under construction.

The second model plant produces a cooled low-Btu product gas. In this plant, a series of wet scrubbers are used to quench and cool the hot gas. This step also removes additional particulate matter and the majority of tars and oils present. This configuration is similar to an existing LBG plant which uses Chapman gasifiers.

The third model plant produces a desulfurized product gas and as a result has the most extensive gas purification scheme. In addition to a hot gas cyclone and quenching/cooling, this model plant uses an electrostatic precipitator for removal of residual tars/oils and a sulfur removal process. Available sulfur removal processes can be broadly classified as 1) those that remove sulfur compounds and directly convert them into elemental sulfur, and 2) those that remove sulfur compounds and produce an off-gas containing the removed sulfur species. An evaluation of these processes, including discussions with process licensors, indicated that the direct oxidation processes are the preferred sulfur removal technique for low-Btu gas derived from fixed-bed, atmospheric pressure gasifiers. While some of the other types of processes (e.g., the monoethanolamine process) could be used, difficulties would be encountered in treating the sulfur species laden off-gas due to its high CO₂ content. This conclusion is supported by the fact that all existing and proposed designs of LBG facilities which remove sulfur species use direct oxidation processes. Thus, for the Model Plant III systems, only direct oxidation processes are examined for sulfur removal. For study purposes, the Stretford process was selected as being representative of commercially available direct oxidation processes.

Descriptions of the three basic operations, the process modules which might be found in them, and the potential discharges from each operation are presented in the following sections.

Description Of The Coal Preparation Operation

Fixed-bed, atmospheric pressure gasifiers require a sized coal feed. Current practice at all commercial LBG facilities in the U.S. is to purchase pre-sized coal, eliminating the need for on-site crushing and sizing equipment. Future LBG facilities are also expected to purchase pre-sized coal. As a result, coal preparation requirements for these facilities will most likely consist only of coal receiving and storage, and means for transporting coal from storage to the gasifier coal feed hoppers. Some facilities though may have to perform final, on-site sizing if fuel size degradation occurs in shipment.

Discharges from the coal preparation operation include airborne coal dust particles from coal handling, rainwater runoff from coal storage piles, and, if final on-site sizing is performed, small amounts of coal fines. No test data are available on the discharges from the coal preparation operation.

However, their physical and chemical characteristics can be estimated from data for similar discharges from the coal mining and coal-fired steam electric industries. Coal pile runoff tends to contain high levels of suspended and dissolved solids (including heavy metals) and can have an acidic or alkaline pH. Dissolved organics tend to be at negligible or non-detectable levels. Dust from coal handling and storage consists of small coal particles.

Description Of The Coal Gasification Operation

There are six commercially available gasifiers that operate in a fixed-bed mode and at atmospheric pressure. They are:

- Chapman (Wilputte),
- Foster-Wheeler/Stoic,
- Riley,
- Wellman-Galusha,
- Wellman Incandescent, and
- Woodall-Duckham/Gas Integrale.

These gasifiers produce low-Btu gas by countercurrent gasification of coal with a mixture of air and steam.

Coal is fed to the top of the gasifier from an overhead bin through a lock hopper and/or a rotary feeder. As the coal gravitates downward through the gasifier, it is contacted by rising hot gases and passes through "zones" of progressively higher temperatures before exiting the bottom of the gasifier as ash. As the coal is heated, it undergoes a series of physical and chemical reactions. Sequentially, these are drying, devolatilization, gasification, and finally combustion. Air saturated with water, i.e., steam, enters at the bottom of the gasifier. The steam absorbs some of the heat released in the combustion zone, which helps to maintain the combustion temperature below the coal ash softening temperature.

With most gasifiers, ash is collected at the bottom of the gasifier in a water sealed ash pan and removed from the unit using an ash plow. The Wellman-Galusha gasifier however, collects the ash in an ash hopper located beneath the gasifier. Ash is removed by adding water to the hopper and draining the ash slurry through a slide valve. The water also serves to seal the gasifier internals from the atmosphere during the ash removal step.

Pokeholes are located on the top of the gasifier. Rods are inserted through the pokeholes to measure the depth and location of the "fire" and ash zones. These rods can also be used to break up any agglomerates formed in the bed.

The Wellman-Galusha, Chapman, and Riley gasifiers produce a single low-Btu gas stream that exits the top of the gasifier. The Foster-Wheeler/Stoic, Wellman Incandescent, and Woodall-Duckham/Gas Integrale gasifiers are two-stage gasifiers that produce two gas streams. A "clear" gas stream,

constituting approximately one-half of the total gas production, is withdrawn from the gasification zone (near the middle of the gasifier). As such, it contains essentially no tars or oils. The remaining gas, which contains tars and oils, is withdrawn from the top of the gasifier where devolatilization of the coal occurs.

At present, very limited environmental characterization data are available for two-stage gasification systems. From a process viewpoint, the two-stage gasification arrangement simplifies the gas purification operation, but it does not appear to alter materially the system's potential environmental impacts. The background study deals specifically with single-stage gasification systems. However, the information developed is felt to also be generally applicable to two-stage gasification systems.

Discharges from the coal gasification operation include:

- Gaseous emissions - pokehole gases
- coal feeder gases
- transient gases
- Liquid effluents - ash sluice water
(from Wellman-Galusha gasifiers only)
- Solid wastes - gasifier ash

Coal feeder gases, pokehole gases, and transient gases generated during start-up, shutdown, and upset conditions are essentially raw low-Btu gas. These discharges contain primarily carbon monoxide, carbon dioxide, hydrogen, nitrogen, and water vapor. Minor components include hydrogen sulfide, carbonyl sulfide, ammonia, hydrogen cyanide, entrained particulates, trace elements, low molecular weight hydrocarbons, and, if the coal feed is lignite, bituminous, or subbituminous, higher molecular weight organics (e.g., tars and oils).

Ash sluice water from Wellman-Galusha gasifiers contains suspended and dissolved solids, including trace elements. Negligible or nondetectable levels of organics have been identified, with most of them being attributable to artifacts of the sampling and analytical procedures. The pH of ash sluice water can vary widely, depending on the characteristics of the ash. An alkaline pH is typical if lignite is the coal feed, while acidic or neutral pH's are typical for other coal feeds.

Ash from the gasifier is similar to bottom ash from a coal-fired boiler although higher levels of residual carbon are present. Data for gasification of several coals indicate that trace elements are not leachable in amounts which would result in classification of gasifier ash as a hazardous waste.

Description Of The Gas Purification Operation

The purpose of the gas purification operation is to remove undesirable constituents such as entrained particulate matter, tars, oils, and sulfur

from the raw low-Btu gas. Depending on the concentrations of these constituents in the raw gas and on the product gas specifications imposed by the end-use (by either process or environmental considerations), none, some, or all of these constituents may need to be controlled. No attempt was made to evaluate systems producing a predefined product gas quality. Instead, systems were selected based on existing or proposed purification configurations, with the assumption that the resulting product gas quality would be sufficient to meet the user's needs.

Particulate Removal. Entrained particulate matter can be removed from the low-Btu gas with cyclones, wet scrubbers, and/or electrostatic precipitators (ESP). Cyclones are currently used in all domestic commercial LBG facilities.

Tars and Oils Removal. The primary means of removing tars and oils from raw low-Btu gas is to use wet scrubbers. These include in-line sprays, wet cyclones, and spray, tray, or packed scrubbers. Most of the commercially available sulfur removal processes have limitations on the concentrations of tars and oils in the gas to be treated. Normally, these levels cannot be achieved using wet scrubbers alone. Detarrers (electrostatic precipitators) have been used with some success for residual tars and oils removal.

Tars/oils-laden water from the scrubbers is directed to a gravity separator. Here, the heavier-than-water tars/oils are separated from the water and recovered as a by-product. The scrubber water is then cooled in indirect heat exchangers and recycled. Some volatile organic and inorganic species are absorbed from the low-Btu gas when it is scrubbed. These species tend to desorb from the scrubber water and fill the separator vapor space. They can be recombined with the low-Btu gas by ducting the vapor space to the low-Btu gas line.

In order to control the buildup of dissolved solids in the recirculating scrubber water and/or to maintain a water balance in the scrubbing loop, a portion of the scrubber water is removed as blowdown. The size of this blowdown depends on such factors as the moisture and chloride content of the coal, the dew point of the hot low-Btu gas and the temperature to which the gas is cooled.

Sulfur Compounds Removal. Commercially available sulfur removal processes include those using physical solvents, chemical solvents, combinations of physical and chemical solvents, and processes featuring removal and direct oxidation of sulfur compounds to produce elemental sulfur.⁴ Physical solvent, combination chemical and physical solvents and some of the chemical solvent processes are not well suited to the removal of sulfur compounds from an atmospheric pressure, low-Btu gas.⁵ Several of the alkanolamine (chemical solvent) processes can be used, but they require moderate pressurization of the gas in order to obtain low residual sulfur levels. Regeneration of the

alkanolamine solvent also produces an off-gas which contains the removed H₂S and CO₂, and which must be further processed for sulfur recovery. Standard means of treating these off-gases (which will contain 70-95% CO₂) is to route them to a Claus unit. The low H₂S/high CO₂ content of these off-gases can limit the recovery efficiency of the Claus unit and prohibit the use of a Claus tail gas treatment process such as the SCOT unit. Thus, while alkanolamine processes appear to be feasible for treating low-Btu gas, technical (and economic) considerations indicate they are a poor choice. In light of the above factors, none of the chemical or physical solvent processes were evaluated in the background studies for the model plant III configurations.

The direct oxidation processes do not have gas pressure limitations and are very effective in removing H₂S. These processes also convert the removed H₂S directly into elemental sulfur, thus eliminating the need for additional treatment of an H₂S-laden off-gas. However, direct oxidation processes do not remove significant amounts of non-H₂S sulfur species such as carbonyl sulfide (COS).⁵ For purposes of analysis, the Stretford process was selected as a representative example of a commercially available direct oxidation type sulfur removal process.

Summary of Discharges from Gas Purification. The existence, quantity, and characteristics of discharges from the gas purification operation depend on the degree of gas purification desired. In general terms, as the low-Btu gas undergoes additional clean-up, additional waste streams are created. These waste streams include:

- collected particulate matter from cyclones (all Model Plants),
- scrubbing liquor blowdown (Model Plants II and III),
- by-product tars and oils (Model Plants II and III except for anthracite feed), and
- vent gas and sulfur cake from direct oxidation sulfur removal processes (Model Plant III).

Collected particulates or cyclone dust has a very high carbon content and resembles devolatilized coal. Leaching tests indicate that cyclone dust is not a toxic waste.

Scrubbing liquor blowdown contains suspended solids, dissolved inorganics (including trace elements and soluble gaseous components such as H₂S and NH₃), and, unless anthracite is the coal feed, dissolved organics. By-product tars/oils derived from gasification of non-anthracite coals are predominantly organic material, but also contain ash and various trace elements. This material has a significant energy content, and represents a fuel resource which should be recovered.

Discharges from the sulfur removal module include vent gases from the Stretford oxidizer and sulfur cake. The oxidizer gases contain primarily nitrogen, oxygen, and water vapor, with minor amounts of ammonia, carbon dioxide, and reduced sulfur compounds. Other components of the low-Btu gas

may also be absorbed by the Stretford scrubbing liquor and released in the oxidizer. However, this is not expected to occur to any significant extent.

Sulfur produced in the Stretford process is initially recovered as a cake containing nominally 50% water. Dissolved in the water are Stretford scrubbing chemicals (sodium vanadates, anthraquinone disulfonic acid, ethylene diamine tetracetic acid, iron, carbonates, and bicarbonates) and high levels of nonregenerable sulfur components such as sulfates, thiosulfates, and thiocyanates.

EVALUATION OF POLLUTION CONTROL TECHNOLOGIES

Evaluations of control technologies for application to individual waste streams were based on considerations of control efficiency, ability to comply with emissions regulations, capital and operating costs, energy and resource consumption, reliability, simplicity, multi-pollutant abatement capability, residue generation and disposal requirements, potential for recovery of by-products, and stage of development. The above criteria were used as a basis for comparison of candidate control technologies either used alone or in combination with in-plant control methods or other add-on controls.

Performance data for applicable control technologies were obtained primarily from the open literature supplemented by vendor supplied data in some cases. The capabilities of various control technologies were not usually assessed on a design-specific basis but rather upon a generalized basis derived from test results and/or engineering studies of the subject technologies.

In many cases performance can only be estimated in terms of control of major constituents (e.g., carbon monoxide) or gross parameters (e.g., TOC) since often no information is available for removal efficiencies for specific substances. Further, even in those cases where substance-specific performance information exists for a control technology, accurate or complete characterization of the waste streams requiring control may be lacking. In the final analysis of course, the capabilities of state-of-the-art controls for LBG facilities can be accurately evaluated only by testing operating facilities. Since these opportunities are generally not available, the performance estimates presented here are believed to reflect the best information currently available based on actual experience and/or engineering analysis.

Air Pollution Control

The uncontrolled gaseous emissions from LBG facilities are summarized in Table 2. The pollutants of potential concern, factors affecting the emission characteristics, and estimated emission flow rates are also summarized in this table. Available control techniques for these emissions are discussed below.

TABLE 2. UNCONTROLLED ATMOSPHERIC EMISSIONS FROM LOW-BTU GASIFICATION FACILITIES

Uncontrolled Atmospheric Emissions	Pollutants of Potential Concern	Factors Affecting Emissions Characteristics	Estimated Flowrate of Uncontrolled Emissions
Airborne particulates from coal handling and storage (All Model Plants)	Particulates	Coal type; gasifier feed size requirements; type and condition of coal handling, crushing and sizing equipment	Not estimated, but believed to be negligible since presized coal is received at the plant site
Coal feeder gases (All Model Plants)	CO, H ₂ S, HCN, trace elements, and other low-Btu gas components	Coal feeder design and conditions; coal composition, feed rate and adsorption characteristics; system pressure	Anthracite: 56 m ³ /hr (32 scfm) Low-sulfur bituminous: 53 m ³ /hr (30 scfm) High-sulfur bituminous: 62 m ³ /hr (35 scfm) Lignite: 110 m ³ /hr (62 scfm)
Pokehole gases (All Model Plants)	CO, H ₂ S, HCN, trace elements, and other low-Btu gas components	Pokehole design and conditions; poking procedures and frequency; system pressure	Anthracite: 38 m ³ /hr (22 scfm) Low-sulfur bituminous: 16 m ³ /hr (9 scfm) High-sulfur bituminous: 16 m ³ /hr (9 scfm) Lignite: 28 m ³ /hr (16 scfm)
Stretford oxidizer vent gases (Model Plant III)	Reduced sulfur compounds, ammonia	Coal Composition; Stretford unit design and operation	Anthracite: 220 m ³ /hr (130 scfm) Low-sulfur bituminous: 280 m ³ /hr (160 scfm) High-sulfur bituminous: 2000 m ³ /hr (1100 scfm) Lignite: 600 m ³ /hr (340 scfm)
Startup, shutdown and upset gases (All Model Plants)	CO, H ₂ S, HCN, trace elements, and other low-Btu gas components	Startup, shutdown and upset procedures; gasifier reliability	Not determined, highly variable

Note: m³/hr flow is relative to 25°C and atmospheric pressure, scfm flow is relative to 60 °F and atmospheric pressure.

Airborne Particulates from Coal Handling and Preparation. Most IBG installations will receive coal that has been crushed and sized. For these installations, no significant particulate emissions are expected and therefore, no control is necessary. If the coal feed is crushed and sized on site, then airborne particulates generated by these operations may be a problem. Control techniques involve enclosing the coal unloading facility, storage bins, crushing and sizing equipment and any conveying devices. These enclosures should be vented by low pressure ducting to a central bag filter collection system. An induced draft fan at the outlet of the bag filters would provide the necessary air flow and ensure that any leakage would be into the system.

Coal Feeder Gases. Low-Btu gas can leak from the gasifier vessel through the coal feeder mechanism and up into the coal bin area by passing countercurrent to the coal flow. One method of reducing the hazards from this emission is to collect it before it enters the coal bin area and then disperse it to the atmosphere through a vent pipe. The top of the coal bin must be sealed (hooded) and a pipe run from there to an elevated outside venting point. An induced draft fan in the vent line would draw air into the coal bin through slots in the side of the bin. Coal feeder gases which pass up through the coal in the bin would then be swept into the vent pipe. While this control option incurs no significant operating costs or energy requirements, it does not decrease the amount of coal feeder gases emitted to the atmosphere.

Another, and more effective means of controlling these emissions is to return them to the process. This strategy can be done in one of two basic ways. One approach is to enclose the coal bin (as with the atmospheric venting option) and run a duct to the intake of the gasifier air blower. To provide continuous sweeping air in the coal bin (to prevent a possible explosive mixture in the bin during very low air rates), a small vent and blow-off valve will be needed in the air blower discharge line for venting during periods of low gasifier air requirements. A second approach involves slightly pressurizing the coal bin with an inert gas. This approach prevents the passage of low-Btu gases into the coal bin. Either of these control options can effect almost complete (99%) control of the coal feeder gases during normal gasifier operations.

Pokehole Gases. Low-Btu gas escapes from pokeholes during and between poking operations. Improved pokehole designs are available with closer tolerances and positive seal valves. While effective in reducing emissions between poking operations, this control method still allows significant quantities of gases to continue to escape during the poking operation.

A second control technology is to combine improved pokehole sealing methods with the injection of an inert gas during poking operations. The inert gas effectively eliminates low-Btu gas leakage. Nitrogen is a possible choice for the inert gas but this may incur operating costs (mainly for the purchase of nitrogen) of up to two percent of the base plant annualized costs. If available, steam might be a more economical choice since the steam requirement would be less than 0.1 percent of the product gas energy.

Stretford Oxidizer Vent Gases. For systems using the Stretford process to produce a desulfurized product gas, an air blown oxidizer is used to convert the reduced Stretford solution back to its oxidized form. A large excess of air is used in the oxidizer and released in the vent. The vent gases consist primarily of oxygen and nitrogen plus water vapor from the Stretford solution. Minor amounts of ammonia and carbon dioxide and other components absorbed from the Stretford solution may also be present. This emission is not expected to pose a significant environmental problem if adequately dispersed to the atmosphere.

Startup, Shutdown and Upset Gases. During gasifier startup, shutdown, and upsets, gases are produced which do not meet product specifications. If the gas is being burned locally and the customer can safely and economically continue to combust the gas (possibly with auxiliary firing), then this is obviously a good option and really represents a "no control required" situation. If this option is not available, then two possible control strategies may be used. One option is to combust these gases in an incinerator or flare. This option requires installing piping, valves, and instrumentation. A second option is to vent the low-Btu product gas line to the atmosphere through a stack. This option could pose localized odor problems. Therefore, its viability could be limited to those areas where adequate dispersion is attainable.

Water Pollution Control

The uncontrolled effluents from LBG facilities are summarized in Table 3. The pollutants requiring control, factors affecting the effluent characteristics, and estimated effluent flow rates are also summarized in this table. Most of the processes considered for treating these effluents have not been applied to the treatment of low-Btu gasification wastewaters. Therefore, decisions related to the applicability, performance capabilities, and costs of controls were based upon experience gained in related industries including the coking, petroleum refining, and electric utility industries.

Coal Pile Runoff and Ash Sluice Water. These two effluents are very similar to their counterparts in coal-fired power plants. They contain suspended solids and dissolved inorganics but negligible dissolved organics. Treatment techniques used in the utility industry include sedimentation, clarification or filtration for suspended solids removal and acid or base addition for pH adjustment. An additional treatment step available is chemical precipitation for removal of selected trace elements. Use of these techniques for coal pile runoff and ash sluice water from LBG facilities should produce an effluent which would meet the NSPS for coal-fired power plants.

Process Condensate. Process condensate contains suspended solids and dissolved gases, organics, and trace elements. Viable treatment techniques for dissolved organics include activated carbon adsorption and biological oxidation. Sour water strippers can be used to remove dissolved gases. Chemical precipitation treatment can be used to reduce the levels of trace elements, although treatment to remove organics will be the key to disposing of this stream in an environmentally acceptable manner.

TABLE 3. UNCONTROLLED EFFLUENTS FROM LOW-BTU GASIFICATION FACILITIES

UNCONTROLLED EFFLUENTS FROM LOW-BTU GASIFICATION FACILITIES	POLLUTANTS OF POTENTIAL CONCERN	FACTORS AFFECTING EFFLUENT CHARACTERISTICS	ESTIMATED EFFLUENT FLOWRATES
Coal Pile Runoff (Model Plants I, II, and III)	Suspended solids (coal fines), inorganics leached from coal, pH	Coal type and conditions of wastewater contact with coal (e.g., residence time) will determine waste stream composition. Rainfall rates and coal storage practices will determine flow.	Flow rate is intermittent and variable. Annual average: 7.5 to 15 kg/min (2 to 4 gpm). Average from 10 year/24 hour rain: 380 to 760 kg/min (100 to 200 gpm).
Ash Sluice Water (Model Plants I, II, and III which use Wellman-Galusha gasifier)	Suspended solids, inorganics and trace elements leached from ash	Characteristics of the ash and contact time between the ash and sluice water will determine waste stream composition. Quantity of ash removed from gasifier and operator practices will determine flow.	Flow rate is intermittent, existing only when ash is removed. This is normally 2 or 3 times per day, per gasifier. Average flow: 20 to 60 kg/min (5 to 16 gpm).
Process Condensate (Model Plants II and III)	Suspended solids, dissolved organics, inorganics, trace elements, and gases	Composition of low-btu gas has major influence on composition. Important factors include H ₂ S, HCN, NH ₃ , and tar/oil content of gas. Chloride content of coal feed and moisture content of gas determine waste flow.	Based on maintaining water balance in quench loop: bituminous coal - 23 kg/min (6 gpm) lignite - 76 kg/min (20 gpm) anthracite - periodic Flows may be as high as 76 kg/min (20 gpm) for all coals in order to control chloride corrosion problems.

Thus two treatment options appear to be available for treating process condensate: one uses carbon adsorption and steam stripping while the other uses biological oxidation and steam stripping. Chemical precipitation could be used with either option. For both of the options, the organics removal unit is required only if the coal feed produces tars and oils when gasified. Since anthracite does not produce tars and oils, the treatment of condensate from an anthracite gasifier may not require dissolved organics removal. Representative performance criteria for two treatment options for process condensate are summarized in Table 4.

TABLE 4. ESTIMATED PERFORMANCE CAPABILITIES OF PROCESS CONDENSATE TREATMENT TECHNOLOGIES

Component	Untreated Effluent	Treated Effluent ^a	Treated Effluent ^b
TSS	140	<10	<30
Oil and Grease	400	<10	<30
BOD	9000	?	<1000
Phenols	2000	<5	<20
TOC	5600	<700	<700
NH ₃	4000	<50	<50
H ₂ S	220	<10	<10
CN ⁻	1100	<10	<10
Trace Elements	Yes	some removal ^c	some removal ^c

Unit: mg/l

^a Treatment using activated carbon adsorption and steam stripping.

^b Treatment using biological oxidation and steam stripping.

^c Increased removals of cationic trace elements can be achieved using chemical precipitation.

Solid Waste Management Alternatives

The solid wastes generated by low-Btu gasification facilities are summarized in Table 5. Included in this table are estimated flow rates, important characteristics (such as physical condition, energy content, potential environmental problems), and expected classification (as hazardous or nonhazardous) for each waste. Management techniques for these wastes should be based on the criteria and guidelines developed by the EPA in response to the Resource Conservation and Recovery Act.

Coal Fines. Generally, coal fines are not expected to be a waste produced by low-Btu gasification facilities. This is because presized coal is normally purchased, eliminating the need for on-site crushing and sizing. However, it is possible that final, on-site sizing may be required if fuel size degradation occurs in shipment and handling. If so, a coal fines stream will be produced. The quantity of fines produced is difficult to estimate but

TABLE 5. UNCONTROLLED WASTES FROM LOW-BTU GASIFICATION FACILITIES

Waste	Flow Rate	Characteristics	Expected Classification
Coal Fines (All Model Plants)	This is not a waste stream unless on-site sizing is employed. Flow rates have not been estimated.	Dry solid; heating value same as coal feed.	Non-hazardous
Gasifier Ash (All Model Plants)	800 to 1800 kg/hr	Damp solid with 20 to 30% H ₂ O; heating value: 1.4 to 8.2 MJ/kg; leachable trace elements.	Non-hazardous
Cyclone Dust (All Model Plants)	6 to 38 kg/hr	Dry solid; heating value: 25 to 28 MJ/kg; leachable trace elements.	Non-hazardous
Stretford Sulfur Cake (Model Plant III)	70 to 620 kg/hr	Wet solid with approximately 50% H ₂ O; contains thiocyanates, thiosulfates, iron, vanadates, ADA, EDTA.	Hazardous
Tars and Oils (Model Plants II and III gasifying non-anthracite coals)	750 to 1220 kg/hr	Viscous liquid; specific gravity greater than one; heating value: 30 to 37 MJ/kg; contains organics and trace elements.	Hazardous

should be very small. Since coal fines have the same energy content as coal, a desirable means of handling them is to recover their energy value. Because of the small quantities involved, this may be practical only if an existing combustor is available on-site or nearby. If resource recovery is not practical, then the coal fines should be disposed of as a nonhazardous waste in a sanitary landfill.

Gasifier Ash. Gasifier ash is the unreacted portion of the coal fed to the gasifier - predominantly mineral matter but also some carbonaceous material. After dewatering, it is a damp solid containing 20 to 30 weight percent water. All available data on gasifier ash indicate that it is a nonhazardous waste. As such, the most reasonable option for disposing of gasifier ash is disposal in a sanitary landfill.

Cyclone Dust. Cyclone dust resembles devolatilized coal. It has a carbon content as high as 90 percent and a heating value of 25 MJ/kg (11,000 Btu/lb) or higher. It is removed from the cyclones as a dry, powdery solid. All available data indicate that cyclone dust is a nonhazardous waste and could be disposed of in a sanitary landfill. Because of its high energy content though, consideration should be given to recovering its fuel value.

Stretford Sulfur Cake. Elemental sulfur is produced by a Stretford unit and recovered as a filter cake containing approximately 50 percent water. No test data are available for this waste. However, it will contain Stretford solution chemicals (vanadates, anthraquinone disulfonic acid salts, EDTA, and iron) and nonregenerable sulfur components such as thiocyanates and thiosulfates. Because of the presence of these contaminants, Stretford sulfur cake is suspected to be a hazardous waste. If so, the management technique for this waste would have to comply with the Subtitle C criteria and guidelines for hazardous waste disposal. Alternatively, the contaminated sulfur can be processed to recover a saleable by-product. This option produces an effluent containing the contaminants originally present in the sulfur cake. Reductive incineration and high temperature hydrolysis are two techniques recently developed for treating Stretford solution effluent, but these approaches are not proven commercially.

Tars and Oils. By-product tars and oils contain a number of toxic organics. However, due to the high specific gravity and viscosity of this material, it is expected to have a low vapor pressure which will minimize the release of volatile organics during storage. Operators and handlers should take precautionary steps to minimize contact with this material. Special note should be taken of the NIOSH proposed criteria for coal gasification plants. Because of its significant fuel value, the logical management technique for by-product tars and oils is resource recovery. This would involve using the material to fire a boiler or furnace.

SUMMARY OF POLLUTION CONTROL COSTS AND ENERGY REQUIREMENTS

In order to compare controls for cost effectiveness and to estimate the impact of pollution control costs on overall plant costs, approximate capital and operating costs for individual control processes/equipment were developed. These costs are based primarily on factored estimates of costs contained in non-proprietary published literature, normalized to a first quarter 1980 basis. In some cases actual vendor quotes have been used but generally, it was beyond the scope and purpose of the background studies to develop the detailed engineering designs necessary for cost estimation at the "firm" (approaching \pm 10 percent) level. Although the accuracy of the cost estimates varies, most are believed to be within 50 percent.

For purposes of presentation in this paper, costs for various pollution control options are given as a percent of the "uncontrolled" plant capital and total annualized costs. This format was selected since it more clearly indicates the magnitude of pollution control costs on overall plant costs than would actual dollar estimates. This approach has the additional benefit of being less sensitive to assumed economic factors such as inflation, interest rates (cost of capital), etc.

Total annualized costs were calculated as the sum of annual operating cost and annualized capital costs. For purposes of annualizing the capital investment, a fixed rate charge factor of 0.175 was calculated. This represents the fraction of the total capital investment that must be assessed as annualized capital charge.

Table 6 summarizes the capital and annualized cost impacts of pollution control for the three model plants examined. The ranges shown reflect differences in control costs as a result of gasifying the four coals studied. They are not intended to reflect the accuracy of the cost impacts. All cost numbers are expressed in terms of a percent of the uncontrolled base plant costs.

As shown in this table, the cost impacts for emission controls are minimal. Capital costs or annualized costs do not exceed 2 percent of the base plant cost for any emission and, most of the control costs are below 1 percent. On a total plant basis, the emission controls are estimated to add approximately 1 to 3 percent to the base plant capital requirements and increase annualized costs by 2 to 5 percent. Energy requirements for air pollution control are negligible.

The cost impacts for controlling a specific liquid effluent are greatest for the hot gas systems and least for the desulfurized gas systems. This reflects an increase in the base plant costs and not a decrease in the control costs. Total plant water treatment costs tend to increase or remain approximately constant as the degree of gas purification increases. This reflects the fact that increases in the base plant costs (the denominator used to calculate the percentage cost impacts shown) are offset by increased treatment costs (the

TABLE 6. SUMMARY OF ESTIMATED POLLUTION CONTROL COST IMPACTS^a

	Control Costs as a Percent of Base Plant Costs					
	Hot Gas		Cooled Gas		Desulfurized Gas	
	Capital	Annualized	Capital	Annualized	Capital	Annualized
GASEOUS EMISSIONS						
Coal Feeder Gases	0.8-1.0	0.9- 1.7	0.6- 0.9	0.8- 1.6	0.3-0.6	0.6- 1.3
Pokehole Gases	1.0-1.2	1.1- 2.0	0.7- 1.0	0.9- 1.9	0.4-0.8	0.7- 1.6
Stretford Oxidizer	-	-	-	-	none	none
Transient Gases	0.8-1.0	1.1- 1.4	0.7	1.0- 1.3	0.4-0.5	0.7- 1.1
TOTAL	2.8-3.0	3.1- 5.1	2.0- 2.6	2.7- 4.8	1.1-1.9	2.0- 4.0
LIQUID EFFLUENTS						
Coal Pile Runoff	2.8-10.3	1.2- 2.6	2.4- 7.3	1.1- 2.3	1.7-4.1	0.9- 1.7
Ash Sluice Water	-	-	1.5- 7.9	1.4- 6.8	1.1-4.4	1.2- 5.1
Process Condensate	2.8-10.3	1.2- 2.6	3.9-15.2	2.5- 9.1	2.8-8.5	2.1- 6.8
TOTAL	-	-	-	-	-	-
SOLID WASTES						
Gasifier Ash	b	4.6- 7.3	b	4.1- 6.7	b	2.8- 5.4
Cyclone Dust	b	<0.1- 0.2	b	<0.1- 0.2	b	<0.1- 0.1
Sulfur Cake	-	-	-	-	b	0.6- 6.2
Tars and Oils	-	-	c	c	c	c
TOTAL	b	4.8- 7.5	b	4.3- 6.8	b	4.5- 9.1
TOTAL POLLUTION CONTROL	5.8-13.1 ^b	9.5-13.9	6.5-17.2 ^b	11.9-18.1	4.6-9.6 ^b	9.5-17.2

^a - Ranges shown reflect differences in control costs for various coal feeds. Totals shown are ranges calculated from totals for each coal feed, which may be different than algebraic sum of component ranges shown.

^b - Data not available for capital costs for solid waste disposal.

^c - No costs are included for controlling tars and oils; recovery of fuel value is expected.

(-) - Discharge does not exist for this model plant.

numerator used to calculate the cost impacts) resulting from the need to treat additional effluents. On a total plant basis, water pollution control costs are estimated to increase the base plant capital costs by 3 to 15 percent and annualized costs by 1 to 9 percent. Energy requirements for water pollution control amount to 0.6 to 2.1 percent of the energy content of the low-Btu product gas. This is almost entirely attributable to the sour water stripper steam requirements for treating process condensate.

Capital cost estimates were not available for the solid waste disposal practices. The waste disposal annualized costs are dominated by the costs of handling gasifier ash, with the only other significant costs being those associated with sulfur cake disposal. (For the high sulfur bituminous coal case, sulfur disposal costs are dominant). Cost factors used for disposal of wastes were \$21 and \$71 per metric ton for nonhazardous and hazardous wastes, respectively. Although \$71 per tonne is a relatively high estimate for hazardous waste disposal, it may not truly reflect the costs associated with disposing of very small quantities of hazardous wastes. For small quantities, the relative impacts of capital costs and administrative costs (in terms of dollars per tonne disposed) can be very large.

Energy requirements for disposing of solid wastes are minimal and are estimated at 0.2% or less of the low-Btu gas energy content. The energy requirements are mainly fuel for haul trucks and earthmoving equipment.

The total plant pollution control cost impacts are estimated to range from approximately 6 to 17 percent of the base plant capital investment and from 9.5 to slightly over 18 percent of the base plant's annualized costs.

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DEVELOPMENT OF A
POLLUTION CONTROL GUIDANCE DOCUMENT
FOR INDIRECT COAL LIQUEFACTION

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ABSTRACT

Synfuels present both an opportunity and a problem for EPA in terms of developing a new environmentally acceptable industry. The opportunity is for EPA to encourage environmental controls to be incorporated/developed as an integral part of the first plant designs rather than as "add on" technology in an existing industry. The problem is that an adequate data base for promulgation of defensible regulations for synfuels plants does not now exist and will likely not exist until after the first plants have been constructed and operated for some period of time. EPA has responded to this situation with the "Pollution Control Guidance Document (PCGD)" concept, in which the best thinking of the various EPA R&D program and regional offices is to be provided to permittees and to industry in the form of "guidance" for an interim period rather than as regulations.

The Indirect Liquefaction (IL) PCGD is one of the first such documents which EPA is preparing with the technical support of various contractors. TRW, Radian, Versar and RTI are involved in the preparation of the data base for the first technical draft of the ILPCGD.

This paper summarizes the technology basis for control levels identified.

DEVELOPMENT OF A POLLUTION CONTROL GUIDANCE DOCUMENT
FOR INDIRECT COAL LIQUEFACTION

The production of transportation fuels from domestic coal to displace fuels derived from imported petroleum has high priority in the overall U.S. energy policy. Since indirect liquefaction (IL) is the only commercially demonstrated means of producing transportation fuels from coal, this technology is likely to be among the first to be employed for synthetic fuels production in the United States.

The Environmental Protection Agency (EPA) is responsible for ensuring that the designs of first generation synthetic fuel technologies provide for adequate protection of the environment. To serve this need and to avoid costly delays in the commercialization of a process due to uncertainties concerning environmental control requirements, EPA developed the Pollution Control Guidance Document (PCGD) approach. This paper summarizes the data base that has been developed for the preparation of the PCGD for Lurgi-based IL technology. EPA's technical support contractors in this effort are TRW, Radian, Versar, and RTI.

The approach for the ILPCGDs was to develop a series of model plants based on Lurgi, Texaco, and Koppers-Totzek (K-T) gasification using methanol, Fischer-Tropsch (F-T), and Mobil M-gasoline synthesis. These technologies are considered commercial or near-commercial. Major and minor constituent material balances were established for integrated model plants using three U.S. coals (Montana Rosebud subbituminous, Illinois No. 6 bituminous, and North Dakota lignite) in order to provide estimates of the volumes and loadings of various waste streams which would be generated. Waste stream constituents covered by the PCGD include both conventional/criteria/consent decree pollutants and currently unregulated substances (e.g., POM).

The PCGD data base includes an identification and evaluation of various pollution control options, based on the expected capabilities of available technologies, for all major gaseous, aqueous, and solid waste streams generated in an integrated facility. This paper presents several of the control

options developed in the data base. The control options are based on considerations of the volume and toxicity of the specific waste stream, costs, safety, reliability, degree to which controls have been demonstrated, intra- and intermedia tradeoffs, and site specific factors.

The major sources of data used in the Lurgi data base for defining the types and characteristics of uncontrolled indirect liquefaction plant waste streams are (1) data obtained as part of an EPA sponsored environmental test program of a Lurgi gasification facility at Kosovo, Yugoslavia; (2) data obtained as part of an Energy Research and Development Administration (ERDA, now DOE) sponsored program involving the gasification of American coals in a Lurgi gasifier at Westfield, Scotland; (3) data obtained as part of an American Natural Gas, Inc. sponsored program involving gasification of North Dakota lignite at the SASOL plant in South Africa; (4) data provided to EPA by South African Coal and Gas Corp. Ltd. (SASOL); and (5) data contained in various permit filings and environmental impact statements for proposed Lurgi-based SNG and indirect liquefaction facilities in the U.S.

Data sources employed for development of model plant/process configurations were primarily engineering studies of the technology sponsored by DOE, EPA, and EPRI. Data sources which served as the basis for the analysis of pollution control applicability and costs include the above engineering studies, studies conducted by TVA, various permit filings, technical information obtained from pollution control equipment vendors and process developers, and published literature. Much of the information on controls is derived from applications in related industries such as petroleum refining, natural gas processing, by-product coke production, electric utilities, and coal preparation.

The configurations of the model plants were based on designs of Lurgi plants which are either proposed or currently in operation. Auxiliary processes considered were those which would render a facility essentially self-sufficient in energy (one which would need only run-of-mine coal, raw water, and various chemicals and catalysts as inputs). A plant size corresponding to 1×10^{11} Btu/day (2.5×10^{10} kcal/day) of total product was selected as representative of the first plant(s) which may be built. This corresponds to about 7000 bbls/day ($1200 \text{ Nm}^3/\text{day}$) gasoline plus 50×10^6 SCF ($1.3 \times 10^6 \text{ Nm}^3$) of substitute natural gas per day (co-produced in the case of Lurgi

gasification). This is approximately the size of the first phase facility planned by American Natural Resources for their North Dakota SNG project.

Figures 1 and 2 are simplified flow diagrams of the main process train and auxiliary operations associated with integrated Lurgi IL facilities. System operations include coal preparation, coal gasification, gas purification and upgrading, crude product synthesis and separation, and product upgrading. Nonpollution control auxiliary processes include process cooling, product storage, raw water treatment, steam and power generation, and oxygen production. The major waste streams identified for facilities depicted in the figures are listed in Table 1 along with the primary constituents/parameters of concern for each waste. The remainder of this paper will focus on control options for these major streams in Lurgi-based facilities. Note that no fundamentally new problems are believed to apply to K-T or Texaco gasification which do not also apply to Lurgi gasification, although differences do exist in the relative quantities of wastes/waste constituents which are generated. Indeed, K-T and Texaco gasification may be somewhat less complicated than Lurgi since the former gasifiers generate fewer organics (other than methane and formic acid) which would eventually become components of waste streams. The organics in Lurgi wastes present some of the more difficult pollution control problems.

Gaseous Waste Streams

Figure 3 summarizes the primary control options for Lurgi acid gases. Indicated in the figure are both selective and nonselective Rectisol* acid gas removal (AGR); that is, separate removal of CO_2 and H_2S from product gas generating an H_2S -rich stream and a CO_2 -rich stream or combined removal generating only one dilute H_2S stream. The primary goal of selective AGR is to produce a more concentrated sulfur-bearing stream for sulfur recovery allowing either the use of Claus technology or the reduction in a Stretford plant size (and thus reduced cost). Since selective AGR is significantly more expensive than nonselective AGR, it is economically justified only if cost savings are realized in sulfur recovery/pollution control. If, for environmental reasons, the CO_2 -rich stream from selective AGR cannot be directly discharged to the atmosphere (with perhaps incineration), then treatment

*Rectisol is a Lurgi-licensed acid gas removal (AGR) process and would be used with all Lurgi gasifiers in the U.S.

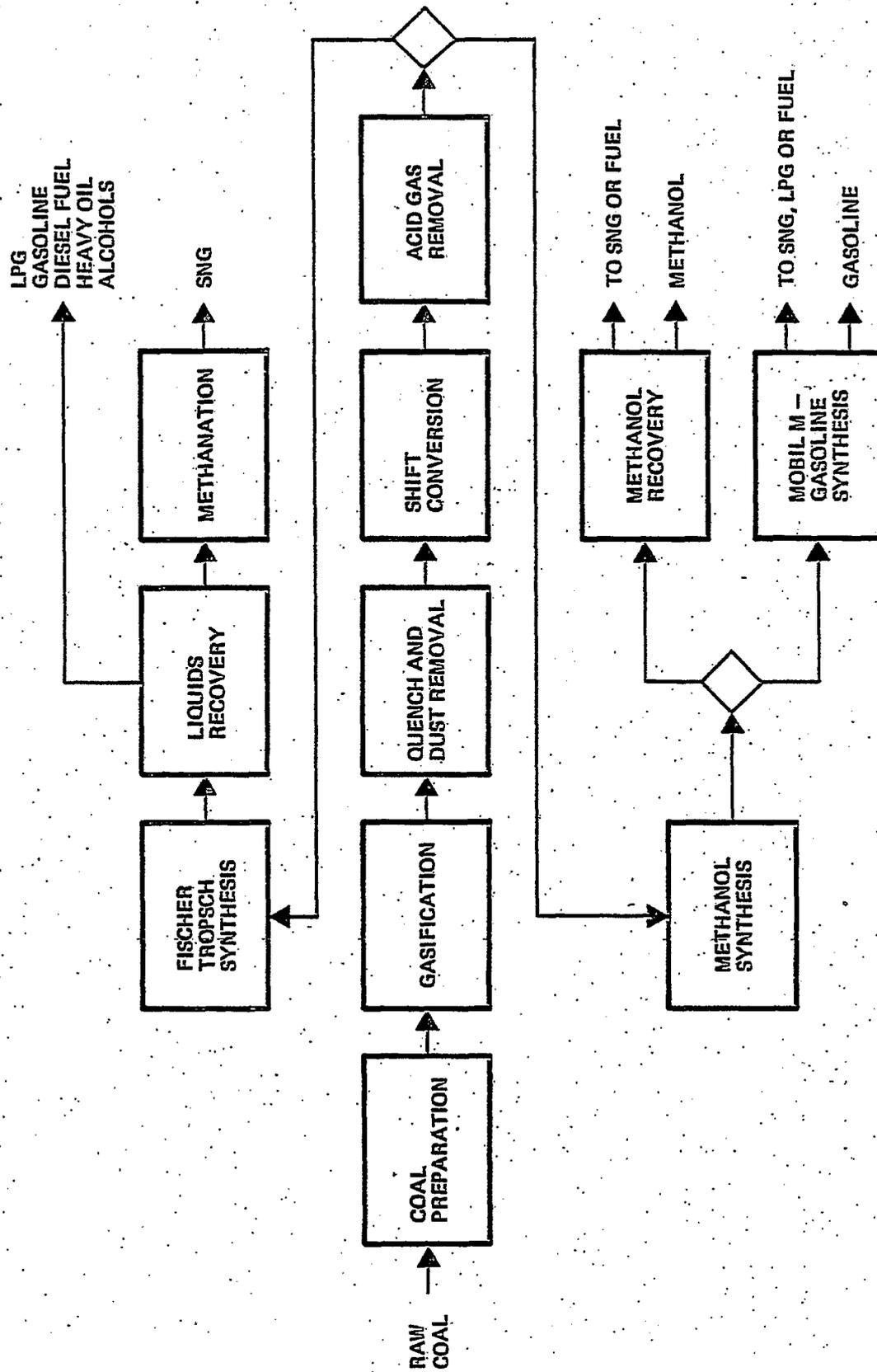


Figure 1. Simplified Flow Diagram of Indirect Coal Liquefaction Facilities

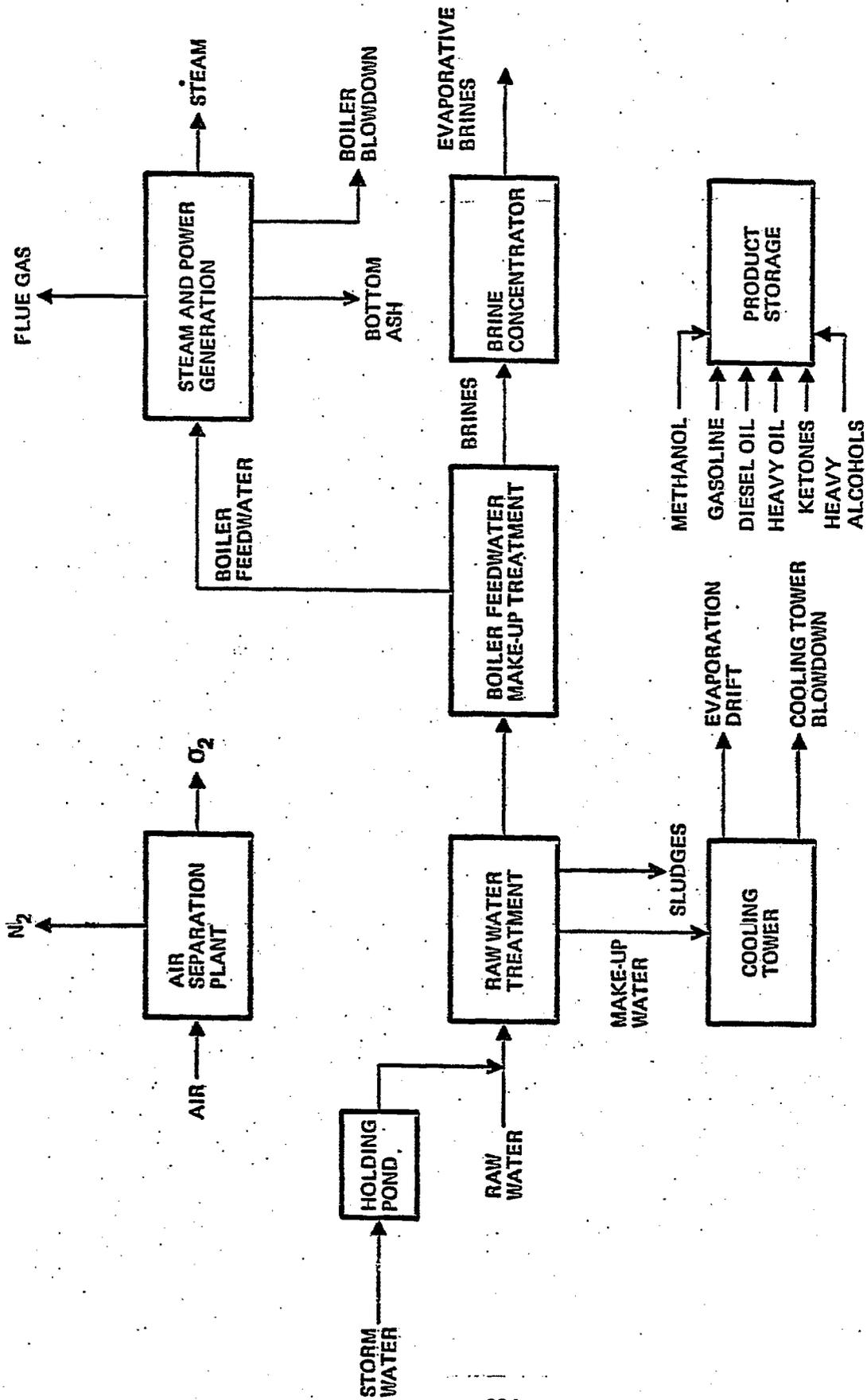


Figure 2. Auxiliary Operations Associated with an Indirect Coal Liquefaction Facility

TABLE 1. MAJOR WASTE STREAMS IN AN INTEGRATED INDIRECT LIQUEFACTION FACILITY

<u>WASTE STREAMS</u>	<u>PRIMARY CONSTITUENTS/PARAMETERS OF CONCERN</u>
<p><u>GASEOUS STREAMS</u></p> <ul style="list-style-type: none"> • ACID GASES (INCLUDING STRIPPING AND DEPRESSURIZATION GASES) • BOILER FLUE GASES • TRANSIENT WASTE GASES • FEED LOCKHOPPER VENT GASES • CATALYST REGENERATION/DECOMMISSIONING OFFGASES 	<p><u>GASEOUS STREAMS</u></p> <ul style="list-style-type: none"> • REDUCED SULFUR AND NITROGEN COMPOUNDS, HYDROCARBONS • SULFUR DIOXIDE, PARTICULATES, NITROGEN OXIDES • REDUCED SULFUR AND NITROGEN COMPOUNDS, HYDROCARBONS, CARBON MONOXIDE, PARTICULATES, POLYCYCLIC ORGANIC MATERIAL • SULFUR DIOXIDE, PARTICULATES, CARBON MONOXIDE, TRACE ELEMENTS
<p><u>AQUEOUS STREAMS</u></p> <ul style="list-style-type: none"> • RAW GAS QUENCH AND ACID GAS REMOVAL CONDENSATES • ASH QUENCH BLOWDOWN • SYNTHESIS WASTEWATERS • WASTEWATER TREATMENT BRINES 	<p><u>AQUEOUS STREAMS</u></p> <ul style="list-style-type: none"> • ORGANIC COMPOUNDS, SUSPENDED SOLIDS, CYANIDES AND THIOCYANATES, AMMONIA, TRACE ELEMENTS • DISSOLVED AND SUSPENDED SOLIDS, TRACE ELEMENTS • ORGANIC COMPOUNDS • DISSOLVED AND SUSPENDED SOLIDS, TRACE ELEMENTS
<p><u>SOLID WASTES/SLUDGES</u></p> <ul style="list-style-type: none"> • GASIFIER ASH • BOILER ASH • FGD SLUDGES AND BRINES • WASTEWATER TREATMENT BRINES • BIOSLUDGES • SPENT CATALYSTS 	<p><u>SOLID WASTES/SLUDGES</u></p> <ul style="list-style-type: none"> • SOLUBLE SALTS, TRACE ELEMENTS • SOLUBLE SALTS, TRACE ELEMENTS • SOLUBLE SALTS, TRACE ELEMENTS • SOLUBLE SALTS AND ORGANICS, TRACE ELEMENTS • SOLUBLE ORGANICS, TRACE ELEMENTS • TRACE ELEMENTS

costs for this stream would likely make the selective AGR option unattractive and designers may revert to nonselective modes.

Option I in Figure 3 consists of Stretford or Claus sulfur recovery followed by tail gas treatment (TGT) for residual sulfur removal and hydrocarbon control. In the Claus cases, enrichment of the H_2S feed stream may be required or desired and an amine (ADIP) system is indicated in the figure. The ADIP offgas and the Claus offgas both receive TGT prior to atmospheric discharge; the CO_2 rich gas from selective AGR is directly discharged to the atmosphere. TGT technologies include incineration/FGD (e.g., Wellman-Lord) and catalytic reduction H_2S recycle (e.g., Beavon).

The Option II alternatives consist of either Stretford sulfur recovery followed by incineration for hydrocarbon control or Claus sulfur recovery followed by SCOT TGT. Neither Claus without sulfur TGT nor direct incineration followed by flue gas desulfurization is considered adequate under Option II since neither of these controls achieves the same levels of total sulfur emissions compared to Stretford or Claus/SCOT. Note that the alternatives in Figure 3 represent the range of controls envisioned by all conceptual and proposed Lurgi gasification projects in the U.S. which have been identified to date.

Table 2 summarizes the estimated costs and energy requirements for control of acid gas in integrated facilities. The cost data represent the least expensive system in each option but assume no credit for energy recovery from incineration of Lurgi gases. Total annualized costs range from 3.8 to 5.7% of base plant costs for sulfur recovery with TGT compared to 2.3 to 4.0 for sulfur removal only (Stretford). Energy requirements of control of acid gases vary from essentially zero to 1.9% of plant input energy, depending primarily on the extent of heat recovery practiced during incineration. Recovered energy could exceed that required to operate the sulfur control systems.

Options for the control of boiler flue gas emissions correspond to the levels defined by electric utility NSPS (Option I) and large industrial boiler NSPS (Option II). Table 3 summarizes the SO_2 , particulates, and NO_x options. For gaseous and liquid fuels derived from coal (e.g., tars, oils, phenols, naphtha, low Btu gas), the same limits apply as to the petroleum or natural gas fuels.

TABLE 2. RELATIVE COSTS AND ENERGY REQUIREMENTS FOR CONTROL OF ACID GASES
(AS PERCENT OF BASE PLANT COST OR ENERGY INPUT)

	Low Sulfur Coal			High Sulfur Coal		
	Capital	Total Annual	Energy	Capital	Total Annual	Energy
Option I (Sulfur removal plus tail gas treatment)	3.2	3.8	0 - 0.84	5.3	5.7	0 - 1.9
Option II (Sulfur removal, minimum or no tail gas treatment)	1.6	2.3	0 - 0.8	3.0	4.0	0 - 1.8

TABLE 3. CONTROL OPTIONS FOR COAL BOILER SO₂, PARTICULATE, AND NO_x EMISSIONS

	Option I g/10 ⁶ cal (lb/10 ⁶ Btu)	Option II g/10 ⁶ cal (lb/10 ⁶ Btu)
SO ₂	2.16 (1.2) and 90% control unless emissions less than 1.09 (0.6) in which case 70% required	2.16 (1.2)
Particulates	0.054 (0.03)	0.18 (0.10)
NO _x Lignite & bituminous coals	1.1 (0.6)	
Subbituminous coals	0.88 (0.5)	1.26 (0.7)
Lurgi byproducts	1.1 (0.6)	

Costs associated with a representative FGD system (Wellman-Lord) applied to a coal- and Lurgi-byproduct-fired boiler are estimated in Table 4. Annualized costs of the FGD systems amount to 2.4 - 3.9% of base plant costs, depending on the boiler size, coal sulfur content, and degree of SO₂ removal attained. Energy requirements for the example FGD units range from 2.9 to 5.8% of the boiler heat input, or 0.4 to 0.6% of total plant input energy. Note that incremental costs for FGD sulfur removal are about \$11-15/lb (\$24-33/kg) while incremental costs for sulfur recovery FGD sulfur removal are about \$20-30/lb (\$44-66/kg). Thus, it may be less expensive to design for lower emissions at the boiler rather than lower emissions from sulfur recovery operations if minimum overall sulfur emissions control at least cost is a defined goal and is environmentally acceptable.

Table 5 summarizes the control options for smaller volume waste streams in Lurgi indirect liquefaction facilities. Generally, the controls for these streams consist of incineration with or without additional SO₂ and/or particulate control.

Aqueous Waste Streams

Figure 4 presents the major options evaluated for control of gasification and synthesis wastewaters. Lurgi wastewaters (gas liquors) are treated for tar/oil separation, phenol removal (Phenosolvan), and ammonia removal as basic steps in all cases. Further treatment would consist of biological or chemical oxidation for bulk organics removal and chemical precipitation and carbon absorption for trace elements and refractory organics removal when discharge to surface waters is the wastewater disposal method (Option I). When "zero discharge" to surface waters is to be practiced, treatment would consist of volume reduction via use of cooling towers, evaporators, and/or incinerators. Biological oxidation may precede the cooling tower concentration step. Ultimate disposal of residual brines may be via underground injection (Option II), surface impoundment (Option III), and ash quenching (Option IV).

The "zero discharge" options involve various tradeoffs with air emissions (cooling tower evaporation/drift) or solid waste disposal (leaching of organics or trace elements in surface impoundments or landfills). In the case of codisposal of brines with ash, the combined waste may be rendered hazardous due to the residual organics or trace elements contained in the brine.

TABLE 4. SO₂ EMISSIONS, COSTS, AND ENERGY REQUIREMENTS ASSOCIATED WITH BOILER/WELLMAN-LORD FGD SYSTEMS

	Sulfur Removal (%)	SO ₂ Emissions (kg/10 ⁶ kcal)	Costs		Energy*** Requirements (%)
			Capital (%)**	Annual (\$/kg S Removed) (%)**	
Low Sulfur (Rosebud)	70	0.88	2.6	2.7 9.7	2.9
	80	0.58	4.0	3.9 12.0	3.2
High Sulfur (Illinois No. 6)	80	0.98	2.5	2.4 9.2	5.2
	90	0.51	3.2	3.6 12.0	5.8

*Coal to boiler

**Percentage of uncontrolled base plant costs.

***As percentage of coal fed to boiler

TABLE 5. CONTROL OPTIONS FOR SMALL VOLUME LURGI WASTE GASES

	Feed Lock Vent Gases	Transient Waste Gases	Catalyst Decommissioning Offgases
Option I	Recompression/recycle or use as fuel for high pressure gases, incineration of low pressure residuals	Incineration with SO ₂ and particulate control	Incineration with SO ₂ and particulate control
Option II	Discharge of residuals via low energy scrubber	Incineration, short term discharge of high oxygen content waste gases	Incineration

Table 6 summarizes the estimated costs and energy requirements for the water pollution control technologies depicted in Figure 4. Although treatment costs are highly coal-, gasifier-, and synthesis-case specific, these estimates indicate the relative contribution of various unit processes to overall costs. The basic treatment steps, phenol removal, ammonia removal, and biological oxidation, constitute 40 to 80% of total treatment costs (or about 3.1% of the base plant annualized costs). Carbon absorption/chemical precipitation is seen as a less expensive route than forced evaporation or surface impoundment for further treatment. The data also indicate that the basic treatment processes also contribute a large fraction of the total energy requirement for water pollution control, with further treatment contributing heavily only with incineration. The use of the cooling tower as a "preconcentration" step has been assumed in the estimates in Table 6; hence treatment of wastewaters by forced evaporation, incineration, or surface impoundment without prior volume reduction could dramatically increase the costs of water pollution control.

Solid/Hazardous Wastes

Options for the disposal of solid wastes generated by the subject facilities are determined both by the characteristics of the waste and by the local environment providing candidate disposal sites. The general operation performance standards for various hazardous waste disposal methods are currently being drafted by EPA's Office of Solid Waste. These standards, based on "best engineering judgment," are expected to largely define the practices for and site-specific factors to be considered in the treatment/disposal of hazardous (and in many cases nonhazardous) wastes. Thus, for purposes of PCGD development, the focus has been on providing a data base for the classification of indirect liquefaction wastes based on their characteristics.

Perhaps the most important waste from the standpoint of volume in the subject facilities is gasifier ash. Several papers presented at this symposium have provided data on the leaching characteristics of ash from a variety of gasifiers and coal types. Generally, these data suggest that gasifier ash is not expected to be hazardous based upon the RCRA Extraction Procedure* test. Thus, this material will likely be handled in a manner

*Refers to the Extraction Procedure defined in 40 CFR 261.

TABLE 6. TYPICAL COSTS AND ENERGY REQUIREMENTS OF WATER POLLUTION CONTROL TECHNOLOGIES

	Cost*		Energy** Requirements
	Capital	Annual	
Phenosolvan	1.2	1.4	1.3
NH ₃ Stripping	0.9	0.6	2.9
Biological oxidation	1.4	1.1	0.1
Chemical precipitation	0.5	0.4	0.04
Carbon adsorption	0.3	0.2	0.01
Forced evaporation	1.3	1.1	0.2
Incineration	0.3	0.3	0.9
Deep well injection	0.2	-	-
Evaporation ponds	7.1	4.3	-

*As percentage of uncontrolled base plant costs

**As percentage of total base plant coal energy input

similar to boiler bottom ash and FGD sludges in the electric utility industry. Limited data indicate that when such wastes are to be disposed of in surface mines that placement should be in "V-notch" areas of the spoil pile rather than in the pit bottom to minimize leaching.

Two important wastes are potentially generated by wastewater treatment (WWT) brines from evaporators or incinerator scrubbers and sludges from biological treatment. In the case of the former, codisposal with gasifier or boiler ash is commonly proposed (codisposal with some type of solid material would be required in any case since RCRA guidelines prohibit the disposal of free flowing liquids in landfills). Codisposal of WWT brines with ash is believed to render the ash hazardous if the organics are not previously destroyed by incineration or wet oxidation. However, if the organics in the brine are destroyed prior to codisposal, available data indicate that the ash/brine mixture would be classified as nonhazardous according to the RCRA Extraction Procedure test. Thus, a tradeoff may exist between WWT costs for organics destruction and solid (hazardous) waste disposal costs for hazardous vs. non-hazardous disposal. WWT brines may also be disposed of in surface impoundments or by underground injection consistent with RCRA requirements. In the later case, organics in the waste may have to be destroyed prior to injection to prevent plugging of the accepting formation.

Biosludges from WWT would likely be considered a hazardous waste under RCRA. Options for disposal include landfarming, incineration with air pollution control, landfill or mine disposal, and surface impoundment. Dewatered sludges may be beneficially utilized by landfarming in conjunction with revegetation of surface mine spoil overburden.

Several types of spent catalyst wastes are generated in indirect liquefaction facilities, including those from shift synthesis (methanol, F-T, Mobil), methanation, and air pollution control (Claus, Beavon). Wastes such as spent shift catalyst are expected to be hazardous due to their inherent metal content as well as other toxic elements derived from coal. Wastes such as Mobil-M (a zeolite material) and Claus (Bauxite) spent catalysts are not believed to be hazardous, but data are lacking on RCRA leach characteristics or other toxicity information. Many of the catalyst materials can be economically recycled for their metal values, particularly when the costs of disposal as hazardous waste are set as the point of reference.

Table 7 summarizes the total estimated costs and energy impact of pollution control for the options presented. The data indicate that air pollution control can add up to 14% of base plant annualized costs, water pollution control up to about 9%, and solid/hazardous waste disposal up to 3.3%, or up to 26% for controls in all media.

Energy requirements for pollution control range from 4.4 to almost 11% of plant input energy, with water pollution control contributing over 60% of the requirement. The differences in energy requirements between the control options are not especially large.

TABLE 7. SUMMARY OF TOTAL COSTS AND ENERGY IMPACTS FOR POLLUTION CONTROL IN AN INTEGRATED FACILITY

Pollution Control Technology	% of Total Annualized Costs		% of Plant Energy Reqmts.	
	Option I	Option II	Option I	Option II
Air	9.1 - 14.1	5.8 - 11.7	1.6 - 2.8	1.4 - 2.5
Water	3.7 - 8.5	3.1 - 7.5	3.0 - 8.0	3.0 - 7.9
Solid Waste	2.6 - 3.3	1.8 - 2.3	0.06 - 0.08	0.04 - 0.06
Total Percent of Base Plant	15.4 - 25.9	10.7 - 21.5	4.7 - 10.9	4.4 - 10.5

INITIAL EFFORT ON A POLLUTION CONTROL
GUIDANCE DOCUMENT; DIRECT LIQUEFACTION

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(ABSTRACT)

Development of the pollution control guidance document (PCGD) for direct coal liquefaction is preceding in parallel with the permitting and construction of the first demonstration-size liquefaction plant, the SRC-II unit in Ft. Martin W.V. In addition to the SRC-II process, the PCGD will provide guidance for the other major liquefaction technologies: SRC-I, H-Coal, and Exxon Donor Solvent.

The control technology guidance will be related to baseline designs prepared for each of the four liquefaction processes, sized at 100,000 bbls/day production. The baseline designs are composed of material balance flowsheets and uncontrolled waste stream calculations, using plant configurations which are most likely to occur in future commercial size plants. Variations of the baseline designs will be considered if they affect control decisions. A range of feed coals have been selected for the baseline cases, with at least one common coal type that could be used by all four processes. The present effort is focused on identification of the pollutants of concern using pilot-plant test data from coal liquefaction developers, DOE, and EPA sponsored testing programs. These data will be evaluated with a variety of engineering analysis methodologies, so that the subsequent examination of control options can be carried out.

The range of control options--air, water, solid waste--will be selected from those methods that have a known track record in related industrial applications, such as petroleum refining, coke ovens, and mining.

The control technologies will be characterized parametrically according to the inlet stream compositions and quantities, and their percentage release of specific pollutants. Finally, the cost of control will be developed according to the same parameters, with a range of costs obtained depending on the complexity and efficiency of control.

INITIAL EFFORT ON A POLLUTION CONTROL
GUIDANCE DOCUMENT; DIRECT LIQUEFACTION

DIRECT COAL LIQUEFACTION PROCESSES

The Direct Liquefaction PCGD will be based on those liquefaction processes that are the closest to commercialization. The SRC-I, SRC-II, H-Coal and Exxon Donor Solvent (EDS) processes are all at an advanced stage of pilot-plant development, and the SRC-I and SRC-II processes will be expanded to demonstration size units in the next few years. Although other "second generation" direct liquefaction processes are in bench-scale development, they will not be ready for commercialization until the early 1900's. The current status of the advanced development processes are:

- The SRC-I process is being tested in a 50 tons/day pilot plant at Fort Lewis, Washington, and in a 6 tons/day process development unit at Wilsonville, Alabama. Preliminary designs for a demonstration plant, to be located near Newman, Kentucky, were completed on July 1979. The demonstration plant is designed to produce the equivalent of 20,000 barrels of oil per day, and is scheduled to be completed by 1984. Current plans call for enlargement of the facility to produce the equivalent of 100,000 barrels of oil per day in 1990.
- The SRC-II process is also being tested in the pilot plant at Fort Lewis, Washington. Preliminary designs for a SRC-II demonstration plant, to be located at Fort Martin, West Virginia, were completed in July 1979. The demonstration plant is designed to process 6,000 tons of coal per day to produce the equivalent of 20,000 barrels of oil per day. Completion of the plant is scheduled for 1984.
- The EDS pilot plant at Baytown, Texas, started up on June 24, 1980. This plant has a capacity of 250 tons per day of coal feed to produce approximately 600 barrels per day of synthetic liquid fuel. A 70 tons per day Flexicoking unit at the same site is planned to be completed in the second quarter of 1982. The design of a demonstration plant could begin as early as the fourth quarter of 1982, leading to a start-up date of about 1988.
- The H-Coal pilot plant at Catlettsburg, Kentucky, has been operational since June 1980. This plant has a capacity of 600 tons per day of coal feed. Support work in a 3 tons per day process development unit is also continuing. Groundbreaking for a commercial plant in Breckinridge, Kentucky, is planned for 1983. The commercial plant is expected to start production as early as 1987.

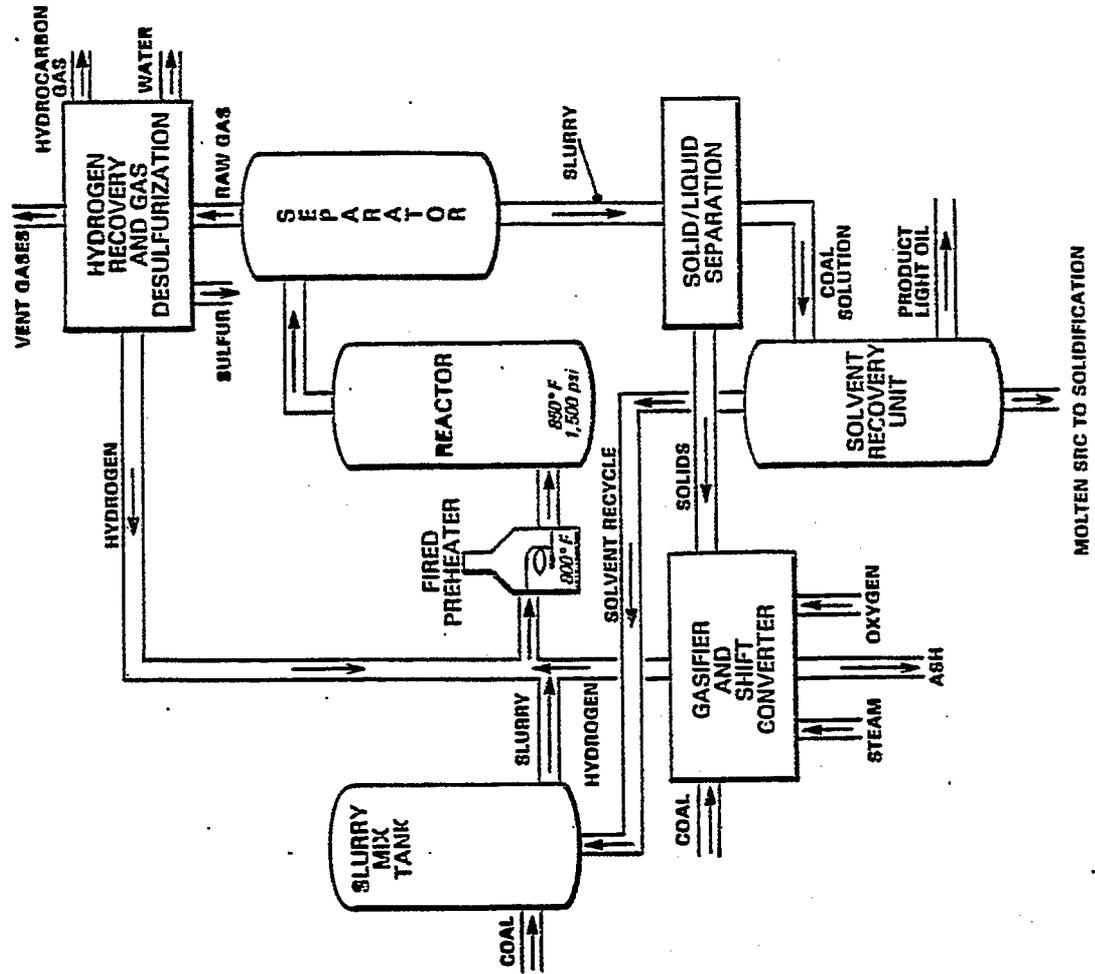
SRC-I PROCESS⁽¹⁾

The SRC-I is a process for converting high-sulfur, high-ash coals to a low-sulfur and substantially ash-free solid fuel. In the SRC-I process (Figure 1), feed coal is pulverized and slurried in a process-derived solvent. This slurry is then pumped to reaction pressure (2000 psig), mixed with hydrogen-rich recycle gas, and then heated to reaction temperature in a fired-heater. Within the fired-heater, coal dissolution is accomplished and hydrogenation reactions begin. At the exit of the fired-heater, hot hydrogen makeup gas from a hydrogen makeup area is added to the slurry, and the mixture is sent to the dissolver.

The dissolver effluent is flashed. The raw gas is sent to gas purification, and the slurry containing unconverted coal and ash from the low-pressure flash is sent to a vacuum column, where process solvent and lighter components are removed from the SRC slurry. The SRC ash slurry is then sent to solvent deashing unit, where it is separated into SRC and ash concentrates. The ash concentrate, consisting of ash and unreacted coal, and some residual SRC, is gasified with steam and oxygen. The syngas produced, after shift conversion and acid gas removal, is converted to hydrogen and sent to the dissolver unit as makeup. The major portion of the SRC concentrate is solidified into the primary final product, solvent refined coal.

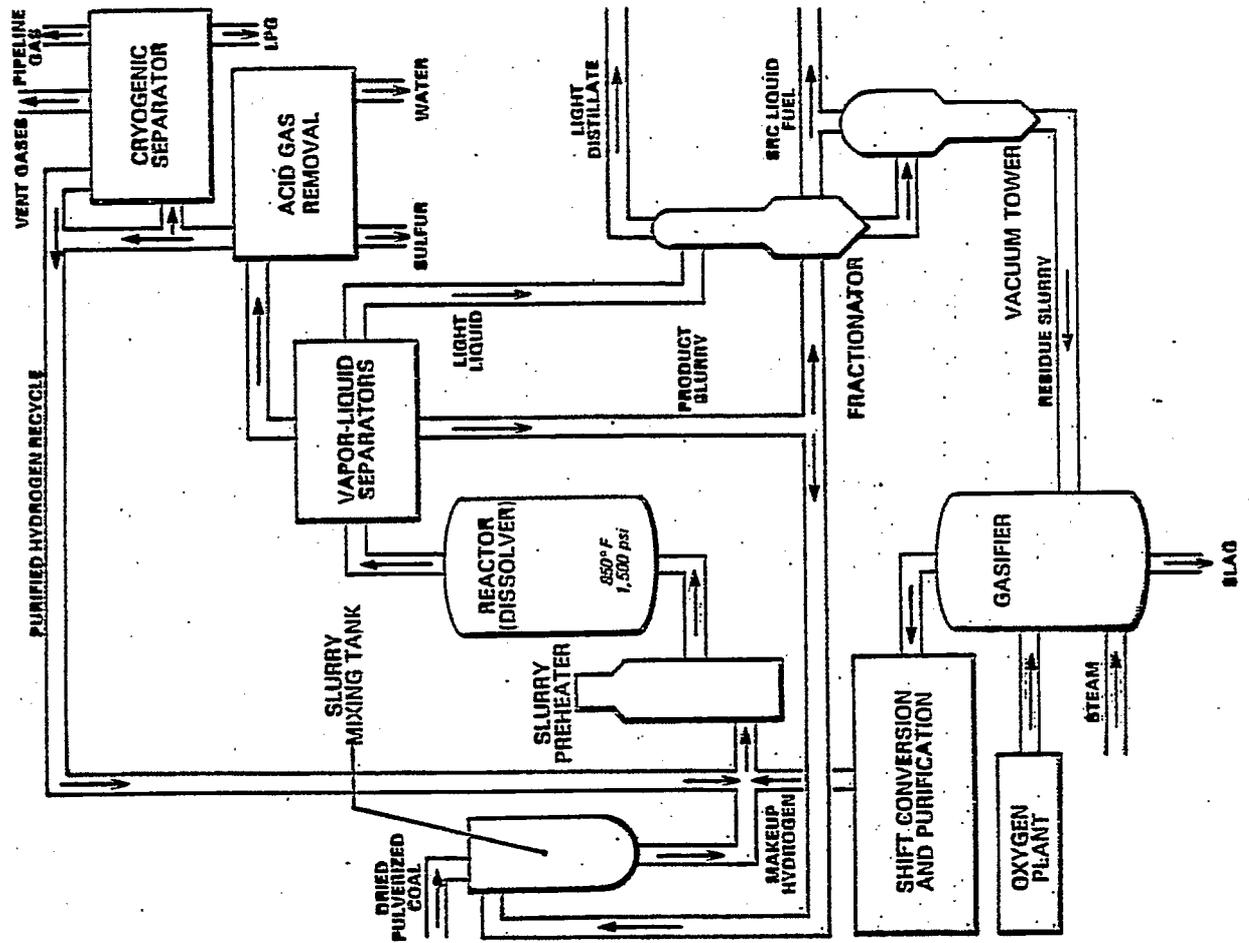
SRC-II PROCESS⁽²⁾

The SRC-II process is designed to produce low-sulfur liquid fuel from high-sulfur bituminous coals. As shown in Figure 2, raw coal is pulverized, mixed with a recycle slurry stream from the process, and then pumped together with recycle and makeup hydrogen through a preheater to a dissolver operated at high temperature and pressure. The coal is first dissolved in the liquid portion of the recycle slurry and then largely hydrocracked to liquids and gases. Much of the sulfur, oxygen, and nitrogen in the original coal is hydrogenated to hydrogen sulfide, water, and ammonia, respectively. The rates of these reactions are increased by the catalytic activity of the undissolved mineral residues. The recycle of a portion of the product slurry contributes substantially to the process by increasing the concentration of catalytic mineral residue in the reactor.



SRC-I PROCESS

Figure 1.



SRC-II PROCESS

The dissolver effluent is separated into gas, light hydrocarbon liquid and slurry streams using conventional flashing and fractionation techniques. A portion of the mineral residue slurry and hydrocarbon liquid from the separation area is recycled to blend with the feed coal in the slurry preparation plant. The balance of the mineral residue slurry is vacuum flashed to recover the fuel oil product.

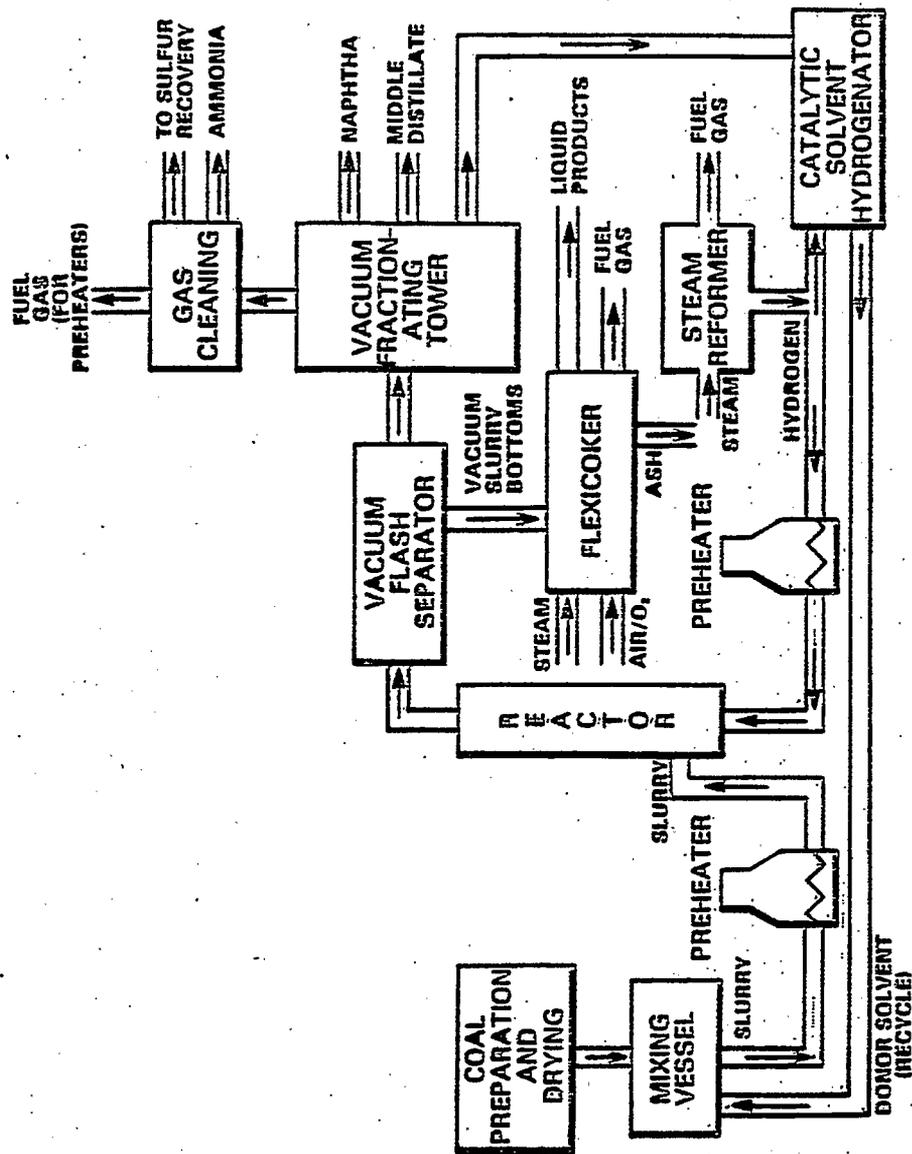
The dissolver area gas stream (consisting primarily of hydrogen, light hydrocarbons, and hydrogen sulfide) is treated for liquid hydrocarbons and acid gas removal, and the major portion of this gas is then recycled to the process. Makeup hydrogen for the process is produced by the gasification of mineral residue slurry to produce synthesis gas, followed by shift conversion.

Liquid products from the main process area are refined in the fractionation section into naphtha, light fuel oil, and heavy fuel oil. Various by-product liquid and gas streams are treated further in the gas plant to produce propane, butane, and pipeline gas. Secondary recovery plants are provided to recover ammonia, tar acids and sulfur.

EDS PROCESS (3)

The Exxon Donor Solvent (EDS) is a noncatalytic process that liquefies coal by the use of a hydrogen donor solvent obtained from coal-derived distillate. The donor solvent transfers hydrogen to the coal, thus promoting the liquefaction of coal.

In the EDS process (Figure 3), ground coal is slurried with the recycle donor solvent. The slurry is heated by a fired-heater, and preheated hydrogen is added. The liquefaction reaction is carried out in a tubular reactor at 800°-900° F and 2000 psig. Products from the liquefaction reactor are sent to several stages of separation units for recovery of gas, naphtha, middle distillate, and bottoms comprised primarily of unreacted coal and mineral matter. Solid and liquid products are separated by distillation.



EXXON DONOR SOLVENT PROCESS

Figure 3.

The heavy vacuum bottoms from distillation are fed to a FLEXICOKING unit with air and steam to produce additional distillate liquid products and a low Btu fuel gas for process furnaces. In the FLEXICOKING unit, essentially all organic material in the vacuum bottoms is recovered as liquid product or combustible gases.

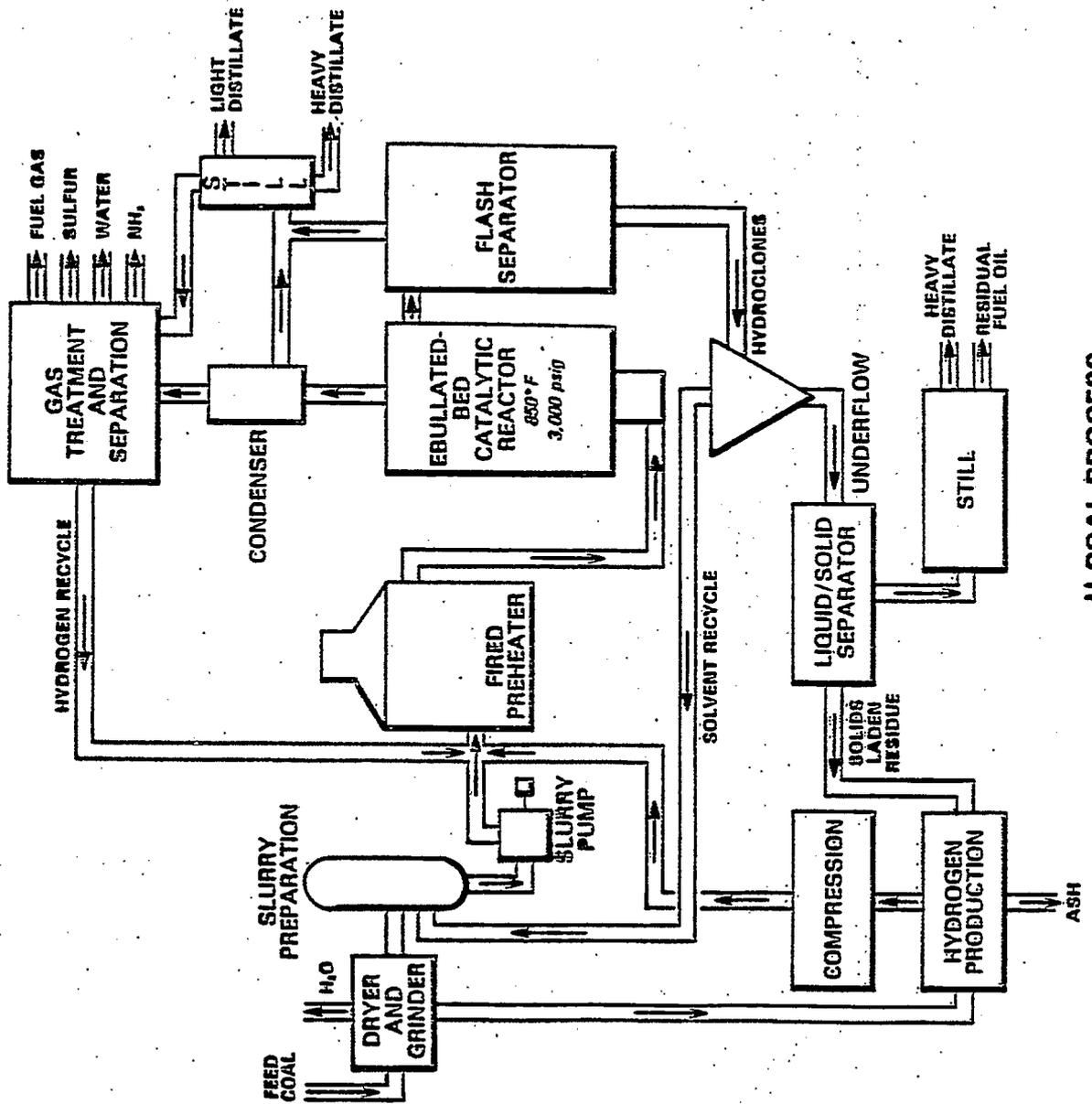
Hydrogen for in-plant use is produced by steam reforming of light hydrocarbon gases. An alternative method for hydrogen production is partial oxidation of the heavy vacuum bottoms or of coal.

H-COAL PROCESS⁽⁴⁾

The H-Coal process is a catalytic hydroliquefaction process that converts high-sulfur coal to either a low-sulfur boiler fuel or to a refinery syncrude. In this process (Figure 4), coal is dried and crushed, then slurried with recycled oil and pumped to a pressure of 2000 atm. Compressed hydrogen is added to the slurry, and the mixture is preheated and charged continuously to the bottom of the ebullated-bed catalytic reactor. Upward passage of the internally recycled reaction mixture maintains the catalyst in a fluidized state (catalyst activity is maintained by the semicontinuous addition of fresh catalyst and the withdrawal of spent catalyst). Typical mixing temperature entering the reactor is 600° to 700° F.

The vapor product leaving the top of the reactor is cooled to condense the heavier components as a liquid. Light hydrocarbons, ammonia and hydrogen sulfide, are absorbed and separated from the remaining gas, leaving a hydrogen-rich gas which is recompressed and recycled to be combined with the input slurry. The liquid-solid product, containing unconverted coal, ash, and oil, is fed into a flash separator. The bottoms product containing solids and heavy oil is further separated with a hydroclone, a steam stripper, and a vacuum still.

The gas and liquid products (hydrocarbon gas, hydrogen sulfide, ammonia, light and heavy distillates, and residual fuel) may be further refined while heavy distillate is recycled as the slurry medium.



H-COAL PROCESS
Figure 4.

APPROACH TO PROCESS CHARACTERIZATION

A methodology has been established that uses a baseline design for each process, sized at 100,000 bbls/day net equivalent of product liquids, fuel gases, and coal-replacement solid products. The design and pilot-plant experience of the several liquefaction processes has been limited to certain types of feed coals, so that the guidance document will have to recognize that expected variations in proposed liquefaction plant feed coals will be limited to an experience range. This will be particularly critical for the non-catalytic SRC-I and SRC-II processes, which depend on the catalytic properties of constituents found in bituminous coals for adequate yields. At least two feed coals will be used in the PCGD analysis for each given liquefaction process, with Illinois No. 6 grade being common to all processes. Initial baseline design concepts are being prepared and submitted for comment to the developers of the four liquefaction processes. In most cases, commercial design concepts of these process developers are somewhat of a moving target, and it is generally recognized that the baseline design cases will not necessarily represent a particular final design configuration. The process developers will be asked to confirm that proposed baseline designs represent a feasible plant configuration, and to estimate the impact that various design options may have on the waste stream characteristics of a baseline case. The goal of this preparatory step is to provide a process description that EPA permit reviewers can reasonably compare with submitted applications.

The initial baseline designs, including material balances and flowcharts which identify the major and minor stream constituents at key points, are being prepared by incorporating pilot plant test results and engineering estimates with commercial-plant design cases that have been released by each process developer. A critical feature of these analyses will be the validation and interpretation of pilot-plant test data. Determinations will be made as to whether these data were obtained under steady-state conditions, using standardized sampling and analysis techniques. The uncontrolled constituents in each waste stream (gaseous, liquid, or solid) have to be estimated in these baseline design cases in order to realistically evaluate control technology

requirements. A substantially inaccurate estimate could lead to either inadequate control technology specifications or unnecessary pollution control investment requirements.

The major gaseous emission streams requiring control include the following:

- Fugitive dust emissions from coal storage
- Fugitive dust emissions from coal and slag handling
- Fugitive hydrocarbon emissions from valves, flanges, and seals
- Fugitive hydrocarbon emissions from product and byproduct storage
- Off gas from coal dryer
- Acid gases containing H_2S , CO_2 , COS , CS_2 , and mercaptans and NH_3 from sour water stripping units
- Flue gas from process heaters
- Flue gas from steam plant
- Flue gas from power plant
- Evaporation and drifts from cooling towers

An essential element of these uncontrolled stream characterizations is the fugitive vapor emission category. A very limited amount of ambient organic vapor sampling has been conducted at the SRC-II pilot plant at Ft. Lewis. Although this sampling and analysis effort cannot be directly extrapolated to full-scale plants because of operations which are unique to the pilot plant, the measurements offer some insight into the ability of heavy organics (e.g., POM) to disperse into the surrounding atmosphere as a result of small vapor emissions.

The major wastewater streams requiring control include the following:

- Sour process wastewater from vapor washes, condensers, fractionator overhead drums, sulfur recovery plant, and coal slurry mixing operation
- Cooling tower blowdown
- Boiler blowdown
- Coal pile runoff
- Oily water runoff from processing areas
- Miscellaneous small wastewater streams

Untreated wastewater characterizations will be derived from measurements conducted by process developers, EPA, and DOE sampling and analysis efforts. Some judgements will have to be made concerning the effects of coal feed

characteristics and process operating configurations on these measurement values. Most of these measurements have focused on process wastewater (or "sour water", following refinery terminology). Other anticipated sources of wastewater include coal pile and area runoff, cooling tower blowdown, and discharge from dust collection and conveying use. These other categories are analogous to related discharges from coal handling and other industrial operations.

Solid waste discharges will include gasifier slag (from hydrogen synthesis), spent catalysts, wastewater and raw water treatment sludges, and possibly non-salable byproduct residues. Some limited amount of leaching tests have been done to characterize gasifier slags and some residue material, but more work will have to be done before a determination can be made as to the possible characterization of these wastes as non-hazardous or hazardous.

CONTROL TECHNOLOGY EVALUATION

EPA permit reviewers will be faced with a range of possible control technologies connected with direct liquefaction process designs. To help the permit reviewers in their examination of submitted plans, a number of best-available-control-technology (BACT) options will be evaluated for each potential waste stream for each of the four major liquefaction processes. In addition, two levels of control effectiveness will be included. The evaluation of each control technology will include the efficiency of pollutant removal from a stream, multipollutant removal capability, installed and operating cost, reliability, turndown ratio, sensitivity to process stream conditions, energy consumption, and any other operating history information such as maintenance requirements.

A primary air pollution control concern in liquefaction processes is the treatment of acid gases generated in the liquefaction reactor, from sour water stripping, and in gasification of residuum streams to make hydrogen. A typical process design method for removing CO₂ and H₂S constituents from these streams is some form of absorption, such as DEA, Selexol, or Benfield processes. The H₂S-rich gas stream stripped from the absorbing liquid constitutes the acid gas stream requiring further control. Representative

acid gas stream compositions are shown in Table 1. These streams can be subjected to two stages of sulfur removal. Concentrated (20-70%) H₂S streams will be handled by a process technology that does bulk sulfur removal. The Claus sulfur recovery process is the most likely candidate for this job, based on a long history of refinery and gas processing experience, but investigations are underway to evaluate Stretford process applicability with high H₂S concentrations. Residual sulfur removal options are numerous; some technologies accept Claus tail-gas directly and hydrolize SO₂ to H₂S, others require oxidation of H₂S in the stream to SO₂. The PCGD evaluation will evaluate many combinations of control technology types to establish BACT performance and cost ranges.

An example of a number of combinations is shown in Table 2, using two bulk-sulfur removal options, three residual sulfur removal options, and a final incineration step option (for potential trace organic removal and oxidation of trace sulfur to SO₂).

TABLE 1. REPRESENTATIVE ACID GAS STREAMS FROM DIRECT LIQUEFACTION

SOURCE

	Stripper offgas from process gas treating	Stripper offgas from syngas purification	Sour water stripper offgas
H ₂ S	75	30	25
CO ₂	20	50	50
CO	Trace	10	-
COS	Not determined	.0003	-

Constituent concentration (mol%)

TABLE 2

Options Combinations	Bulk-S Removal		Residual-S Removal		Incineration
	Claus	Stretford	Beavon	SCOT/ SUPERSCOT Wellman- Lord	
1		•	•		•
2		•		•	•
3		•			•
4	•		•		•
5	•			•	•
6	•				•

An additional combination will be examined for streams containing very low H₂S (or COS, CS₂ etc.) concentrations, since these may be directly incinerated.

Both capital and operating costs will be determined according to the standardized guidelines prepared by IERL/RTP⁽⁵⁾. The impacts on other media for any of the pollution control technologies will also be quantified; the acid gas treatment systems above will produce spent catalysts as well as minor liquid purge streams. A substantial non-hazardous solid waste quantity will require disposal planning if the recovered sulfur is not salable. Wastewater treatment guidance is expected to emphasize the stripping of ammonia and H₂S from sour water streams, and the absorption of phenols. The sequence of these byproduct recovery steps may be significant to recovery efficiency.

Subsequent treatment steps will be selected to minimize the release of trace organics and heavy metals to the environment. Investigations of "zero discharge" evaporative methods are currently being compared with more conventional biological treatment technologies. A high degree of water reuse will be emphasized no matter what treatment method is used.

The impact on solid waste handling and management requirements may be substantial, depending on the control options recommended for wastewater treatment and air pollution control technology. The cost and stringency of solid waste management practices will be greatest for wastes designated as hazardous under RCRA definitions.

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APPENDIX: ATTENDEES

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Raden	Dennis P.	12700 Park Central Place, Suite 1400	Dallas	TX	75251	Phillips Coal Company
Ramachandran	G.	555 17th Street	Denver	CO	80123	ARCO Coal Co.
Rapean	John C.	3333 Highway 6 South	Houston	TX	77079	Shell Development
Reinert	Bruce D.	805 Goethals Drive	Richland	WA	99352	Hanford Env. Hlth. Foundation
Reveal	William S.	3412 Hillview Avenue	Palo Alto	CA	95070	Electric Power Research Institute
Rhodes	William J.	IERL, MD-61	Jefferson City	NC	27711	U.S. EPA
Rice	Beth L.	P. O. Box 1368, Air Program	Research Triangle Park	NC	65102	MO Dept. of Natural Resources
Rickert	Louillie	P. O. Box X	Oak Ridge	TN	37830	Oak Ridge National Laboratory
Riegel	Kurt W.	401 N Street, S, W. (RD-681)	Washington	DC	20460	U.S. EPA
Riggin	Ralph M.	505 King Avenue	Columbus	OH	43201	Battelle
Rosenfeld	Michael	245 Summer Street	Boston	MA	02107	Stone & Webster Engineering Corp.
Rosenfield	Henry	P. O. Box 2521	Houston	TX	77001	Texas Eastern Transmission Corp.
Ruckriegel	Michael J.	P. O. Box 101	Florham Park	NJ	07932	Exxon Research & Engineering Co.
Ruggieri	Sam	P. O. Box 487	Canton	OH	44701	American Elect. Power Serv. Corp.
Salemme	Robert	Box 43	Schenectady	NY	12301	General Electric Co.
Samela	Daniel	1 Penn Plaza	New York	NY	10019	Stone & Webster Engineering Corp.
Samematsu	Henry	P. O. Box 111	Los Angeles	CA	90051	Los Angeles Dept. of Water & Power
Sauter, Jr.	Lawrence J.	825 N. Capitol St., N. E., Rm. 7102	Washington	DC	20426	Federal Energy Regulatory Commission
Schlosberg	John	P. O. Box 2752	Allentown	PA	18001	International Coal Refining Company
Sealiger	Jochen	Friedrichstrabe 1	4300 Essen	F.R.GERMANY	18001	Gesamtverband des deutschen
Shaughnessy	Mary E.	1000 Independence Avenue	Washington	DC	20585	U.S. Department of Energy
Sherman	Sandra	Box 13015, Iron Works Pike	Lexington	KY	40511	Institute for Mining & Minerals Research
Siewers	Henry E.	6330 Highway 290 East	Austin	TX	78723	Texas Air Control Board
Singer	Philip C.	Dept. of Environ. Sci. Eng.	Chapel Hill	NC	27514	University of North Carolina
Sizemore	Freddie A.	1558 Washington St., E.	Charleston	WV	25311	WV Air Pollution Control Commission
Strinde	Rolf T.	1319 Dexter N., (P.O. Box 9445)	Seattle	WA	98109	Olympic Associates Co.
Slinger	Glenn	16200 Park Row, Industrial Park Ten	Houston	TX	77084	Pullman Kellogg Research Center
Smith	N. Dean	IERL, MD-61	Research Triangle Park	NC	27711	U.S. EPA
Smith	Tracey I.	P. O. Box 2180	Houston	TX	77001	Exxon Company

Smithson, Jr.	G. Ray	505 King Avenue	OH	43201	Battelle Columbus Laboratories
Soukup	Charles L.	Military Road	WI	54474	Zimpro Inc.
Stern	Jay L.	P. O. Box 2744 Terminal Annex	CA	90051	Joy Mfg. Co.
Stevens	Nicholas J.	P. O. Box 1500	NJ	08876	Research-Cottrell
Szluha	Adam T.	500 Boyd Building, Wyoming Office	WY	82002	Industrial Siting Administration
Taylor	Don	Suite 1400, Park Central III	TX	75251	Phillips Coal Co.
Tell	Barbara Lorin	29623 W. Western Highway	MI	48034	Swanson Environmental, Inc.
Thoen	Terry L.	Suite 900, 1860 Lincoln St.	CO	80295	U.S. EPA, Region VIII
Thomas	Susan J.	4 Research Place	MD	20850	NUS Corporation
Thomas	William C.	8500 Shoal Creek Boulevard	TX	78758	Radian Corporation
Trabert	Angela L.	816-16th Street	IL	60091	The Standard Oil Co.
Traquill	Paul C.	Midland Building	OH	44115	GCA Corporation
Tyndall	Frank	500 Eastowne Drive	NC	27514	Department of Energy
Vlahakis	John	12th and Pennsylvania Ave., N. W.	DC	20461	EG&G
Vyas	Kaushik	P. O. Box 880	WV	26505	University of Illinois
Wadden	Richard	P. O. Box 6998, School/Public Health	IL	60680	Research Triangle Institute
Wallace	Anna W.	P. O. Box 12194	NC	27709	Texaco Inc.
Wammel	A. W.	P. O. Box 509	NY	12508	American Natural Service Co.
Weinreich	Gary N.	One Woodward Avenue	MI	48226	Ecological Analysts, Inc.
Weitzel	Richard L.	509 Estes Avenue	IL	60193	U.S. EPA
West	Chris	ND-51	NC	27711	Envirotech/Chemico
Wiener	Richard	One Penn Plaza	NY	10001	Tennessee Valley Authority
Williamson	Phebus G.	Ammonia from Coal Projects	AL	35660	Grand Forks Energy Technology Center
Willson	Warrack G.	P. O. Box 8213, University Station	ND	58202	Herrick & Smith
Wiperman	Robert C.	100 Federal S.	MA	02110	Department of Energy
Witmer	Fred E.	Mailstop E-201, Env. Safety & Eng.	DC	20545	International Coal Refining Company
Yen	Alan F.	P. O. Box 2752	PA	18001	TRW, Inc.
Yu	Kar Y.	One Space Park Drive, R4/1136	CA	90278	UOP/SDC
Yu	Wen C.	7929 Westpark Drive	VA	22102	Dynallectron
Zaklan	Gerri	1313 Dolley Madison Boulevard	VA	22101	Bechtel
Zoueshtiagh	Nahid	50 Beale Street	CA	94119	

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