ANL/ECT-3
APPENDIX C

27
5/23/89
RAS 24cp. to NTIS

MASTER

ANL/ECT-3
APPENDIX C

ENVIRONMENTAL CONTROL IMPLICATIONS OF GENERATING ELECTRIC POWER FROM COAL

1977 TECHNOLOGY STATUS REPORT

APPENDIX C

GASIFICATION/COMBINED-CYCLE POWER GENERATION: COMPARISON OF ALTERNATIVE SYSTEMS

PREPARED BY
FOSTER WHEELER ENERGY CORP.

ENVIRONMENTAL CONTROL-
COAL UTILIZATION PROGRAM

ARGONNE NATIONAL LABORATORY

PREPARED FOR
SION OF ENVIRONMENTAL CONTROL TECHNOLOGY
ISTANT SECRETARY FOR ENVIRONMENT
UNITED STATES DEPARTMENT OF ENERGY

ENVIRONMENTAL CONTROL

The facilities of Argonne National Laboratory are owned by the United States Government. Under the terms of a contract (W-31-109-Eng-38) among the U. S. Department of Energy, Argonne Universities Association and The University of Chicago, the University employs the staff and operates the Laboratory in accordance with policies and programs formulated, approved and reviewed by the Association.

MEMBERS OF ARGONNE UNIVERSITIES ASSOCIATION

The University of Arizona
Carnegie-Mellon University
Case Western Reserve University
The University of Chicago
University of Cincinnati
Illinois Institute of Technology
University of Illinois
Indiana University
The University of Iowa
Iowa State University
The University of Kansas
Kansas State University
Loyola University of Chicago
Marquette University
The University of Michigan
Michigan State University
University of Minnesota
University of Missouri
Northwestern University
University of Notre Dame
The Ohio State University
Ohio University
The Pennsylvania State University
Purdue University
Saint Louis University
Southern Illinois University
The University of Texas at Austin
Washington University
Wayne State University
The University of Wisconsin-Madison

NOTICE

This report was prepared as an account of work sponsored by an agency of the United States Government. Neither the United States Government or any agency thereof, nor any of their employees, make any warranty, express or implied, or assume any legal liability or responsibility for the accuracy, completeness, or usefulness of any information, apparatus, product, or process disclosed, or represent that its use would not infringe privately owned rights. Reference herein to any specific commercial product, process, or service by trade name, mark, manufacturer, or otherwise, does not necessarily constitute or imply its endorsement, recommendation, or favoring by the United States Government or any agency thereof. The views and opinions of authors expressed herein do not necessarily state or reflect those of the United States Government or any agency thereof.

Printed in the United States of America
Available from
National Technical Information Service
U. S. Department of Commerce
5285 Port Royal Road
Springfield, VA 22161

NTIS price codes
Printed copy: A13
Microfiche copy: A01

Distribution Categories:
Coal Conversion and Utilization
(UC-90), plus UC-90a, -90b,
-90c, -90e, -90f, -90i, -90j

ANL/ECT-3, Appendix C

MASTER

ARGONNE NATIONAL LABORATORY
9700 South Cass Avenue
Argonne, Illinois 60439

ENVIRONMENTAL CONTROL IMPLICATIONS OF GENERATING ELECTRIC POWER FROM COAL

1977 TECHNOLOGY STATUS REPORT

APPENDIX C
Gasification/Combined-Cycle Power Generation: Comparison of Alternative Systems

Prepared by

Foster Wheeler Energy Corporation
Livingston, New Jersey
for
Argonne National Laboratory

December 1977

Work sponsored by
Division of Environmental Control Technology
Assistant Secretary for Environment
United States Department of Energy

DISTRIBUTION OF THIS DOCUMENT IS UNLIMITED

THIS PAGE

WAS INTENTIONALLY

LEFT BLANK

FOREWORD

"Environmental Control Implications of Generating Electric Power from Coal" is a continuing Argonne National Laboratory program sponsored by the Division of Environmental Control Technology of the U.S. Department of Energy. This 1977 Technology Status Report is the third in a series of reports issued as part of the program and represents efforts of Argonne and several subcontractors. The primary emphasis is on characterizing and evaluating recent developments in available and near-term control technologies through detailed engineering and cost analyses. The report also includes an assessment of the effect of recent regulatory developments and comparative evaluations of several possible control technology combinations.

The main volume of the report is supplemented by seven appendices consisting of subcontractor reports that deal with particular control technologies. Each appendix is a separate volume, as indicated below, and is designed to be understandable without reference to other portions of the report. The principal volume of the report and the various appendices are issued independently as they are completed, in order to make the information available in a timely manner. Inquiries regarding the availability of specific volumes should be directed to Technical Information Services, Argonne National Laboratory, Argonne, Illinois 60439.

Appendix,	Title	Subcontractor
A*	Coal Preparation and Cleaning Assessment Study (Part 1), and Appendix (Part 2)	Bechtel Corp.
B	Assessment of Status of Technology for Solvent Refining of Coal	Air Products and Chemicals, Inc.
C	Gasification/Combined-Cycle Power Generation: Comparison of Alternative Systems	Foster Wheeler Energy Corp.
D	Assessment of NO_x Control Technology for Coal Fired Utility Boilers	KVB, Inc.
E	A Review of Technology for Control of Fly Ash Emissions from Coal in Electric Power Generation	Southern Research Institute
F	Flue Gas Desulfurization in the United States - 1977	Tennessee Valley Authority
G	State-of-the-Art Review for Simultaneous Removal of Nitrogen Oxides and Sulfur Oxides from Flue Gas	Tennessee Valley Authority

*Appendix A is published as two separately bound volumes. Part 1 is the main text, and Part 2 consists primarily of data generated by merging coal washability and reserve data obtained from the U.S. Bureau of Mines.

ACKNOWLEDGMENTS

This report was prepared by Foster Wheeler Energy Corporation, Livingston, New Jersey, for Argonne National Laboratory under FWEC Contract 11-53389. The FWEC program officers were Gerald Mazzella and Robert A. McAllister.

Project management by ANL was under the direction of G. Narender Reddy and Kenneth E. Wilzbach.

TABLE OF CONTENTS

TABLE OF CONTENTS (cont'd)

TABLE OF CONTENTS (cont'd)

LIST OF TABLES

LIST OF TABLES (cont'd)

LIST OF FIGURES

ENVIRONMENTAL CONTROL IMPLICATIONS OF GENERATING ELECTRIC POWER FROM COAL

1977 TECHNOLOGY STATUS REPORT

Appendix C Gasification/Combined-Cycle Power Generation: Comparison of Alternative Systems

ABSTRACT

The technical, economic, and environmental aspects of low-Btu gasification/combined-cycle power-generation (LBG/CCPG) plants are assessed, using available published data. Six base-case plants, based on three different gasifiers and two different coals, are investigated. A representative combined power cycle is selected for analysis, and material and energy balances for the six systems are developed. Emissions of various air pollutants, including sulfur dioxide and nitrogen oxides, and discharge rates of aqueous effluents are also calculated.

The costs of electricity produced are derived for the six systems, using estimated plant-investment and operating costs. These costs and the emissions of various pollutants are compared with those for a conventional 500-MWe coal-based power plant using flue-gas cleaning and in compliance with the federal New Source Performance Standards. Finally, the commercialization potential of coal-based combined-cycle plants, based on the technical feasibility of building a first plant in the 1985 period and on economic viability, is evaluated. This evaluation is based on the current status of research and development programs for various components of the combined-cycle plant, such as gas turbines and fuel-gas-cleaning systems, and on the status of the demonstration plant.

THIS PAGE

WAS INTENTIONALLY

LEFT BLANK

1 INTRODUCTION

This study constitutes a preliminary assessment, based on available published information, of the technical, economic, and environmental aspects of low-Btu gasification/combined-cycle power-generation (LBG/CCPG) plants. The assessment focuses on those systems that can be expected to come into commercial use in the mid-1980s.

The three major sub-systems of LBG/CCPG plants--coal gasification, coal purification, and the combined power cycle--receive primary emphasis in this study. Three types of coal gasifiers, operated using two types of coal--midwestern bituminous (Illinois No. 6) and western sub-bituminous (Montana Rosebud)--are considered (see Table 1.1). A low-temperature clean-up technology (the Selexol process), chosen because of its proven commercial performance and its capability of removing ammonia and particulates as well as sulfur compounds, makes the purified fuel gas particularly suitable for gas-turbine firing.

The present state of development of high-temperature turbine technology is such that a 2200°F machine is likely to be commercially available in the time frame of interest. Thus, in this assessment, the investigation centers on a representative combined power cycle based on a gas turbine having a 2200°F nozzle temperature, with a pressure ratio of 16:1. The gas turbine is assumed to be integrated with a standard 1050 psia/900°F/900°F steam-turbine power cycle.

Material and energy balances are presented, assuming a net generating capacity of 500 MWe, for the six integrated-plant/coal combinations. Plant-investment and operating costs are estimated from published data, and a standard method of financial analysis is used to determine electric-power costs. Power costs derived for the integrated LBG/CCPG systems using fluidized-bed and entrained-flow gasifiers are comparable with those estimated for a conventional 500-MWe coal-fired power plant equipped with flue-gas cleaning. These estimates, however, are founded on the present-day cost of coal and on published investment-cost data, and they may vary by at least ± 20%; investment cost, in particular, significantly affects the calculated

Table 1.1 Six Base-Case LBG/CCPG Power Plants

Gasifier	Coal	Gas Cleaning
Lurgi moving bed	Illinois No. 6	Selexol
IGT U-Gas fluidized bed	Illinois No. 6	Selexol
Foster Wheeler entrained flow	Illinois No. 6	Selexol
Lurgi moving bed	Montana	Selexol
IGT U-Gas fluidized bed	Montana	Selexol
Foster Wheeler entrained flow	Montana	Selexol

power costs. Definitive cost estimates on these integrated systems are needed to improve the reliability of the economic analysis.

Environmentally, the integrated LBG/CCPG systems have a potential advantage over conventional coal-fired plants now in compliance with the U.S. Environmental Protection Agency's New Source Performance Standards (NSPS). The integrated low-temperature clean-up systems not only allow the LBG/CCPG plants to satisfy easily the current NSPS with respect to sulfur emissions, but they also have the capability to reduce total sulfur emissions in accordance with the stricter regulations that will obtain in the 1980s. Moreover, the quantities of waste-water and solid-waste streams discharged from LBG/CCPG plants are less than those from conventional coal-fired plants.

It is concluded from this preliminary assessment that LBG/CCPG systems based on moving-bed gasification technology are to be judged technically feasible by the mid-1980s. Systems employing fluidized-bed or entrained-flow gasifiers possibly could be deployed for commercial use by this time as well, assuming the successful conclusion of demonstration programs now in progress using these technologies.

2 SCOPE OF STUDY

The assessment of low-Btu gas/combined-cycle power-generation (LBG/CCPG) plants was conducted under ground rules established by Argonne National Laboratory.

2.1 PLANT SIZE

The size of the LBG/CCPG power-generation plant to be assessed was fixed at 500 MWe. The scope of plant activities encompasses all operations, from use of the plant's coal pile to the generation of electricity.

2.2 LBG/CCPG SYSTEM DEFINITION

The LBG/CCPG plant is defined in terms of the individual process units or sub-systems that make up the whole system. A block diagram for the integrated LBG/CCPG plant, identifying the individual units and their inter-relationships, is shown in Fig. 2.1.

Coal is delivered from the coal pile to a coal-preparation section, where it is crushed, dried, and otherwise conditioned for acceptable feed to the gasifier. Any coal fines that cannot be fed to the gasifier are disposed of by re-sale for fuel value. The coal feed is conveyed to the gasification and gas-cooling section, where it is gasified with air and steam, and residual ash is rejected. Raw gas is cooled and then directed to the gas-desulfurization section for removal of sulfur compounds. Clean low-Btu fuel gas is fired in the gas-turbine system, where the power produced in excess of that required for air compression is used to generate electric power. The air required for gasification is bled from the turbine air compressor. Hot exhaust gas from the gas turbine generates high-pressure superheated steam in the heat-recovery boiler of the steam generation system. This steam, after extraction of that required for fuel-gas production, generates additional electric power via the steam-turbine-generator set.

Condensate resulting from cooling the raw gas is first treated in the oil/tar-recovery section for removal of by-product oils that may be produced during coal gasification. In the condensate-treating section, the oil-free condensate is steam-stripped for the removal of acid gases and recovery of by-product ammonia. The acid gases from condensate treating and gas desulfurization are combined and fed to the sulfur-recovery plant, where elemental sulfur is extracted as a by-product.

The support-facilities section of the LBG/CCPG plant provides the auxiliary services and utilities required by the processing units, such as cooling water, boiler feedwater, and waste-water treating.

2.3 COAL PROPERTIES

Two types of coal were considered as feed for LBG/CCPG systems--midwestern bituminous and western sub-bituminous. Bituminous coals represent

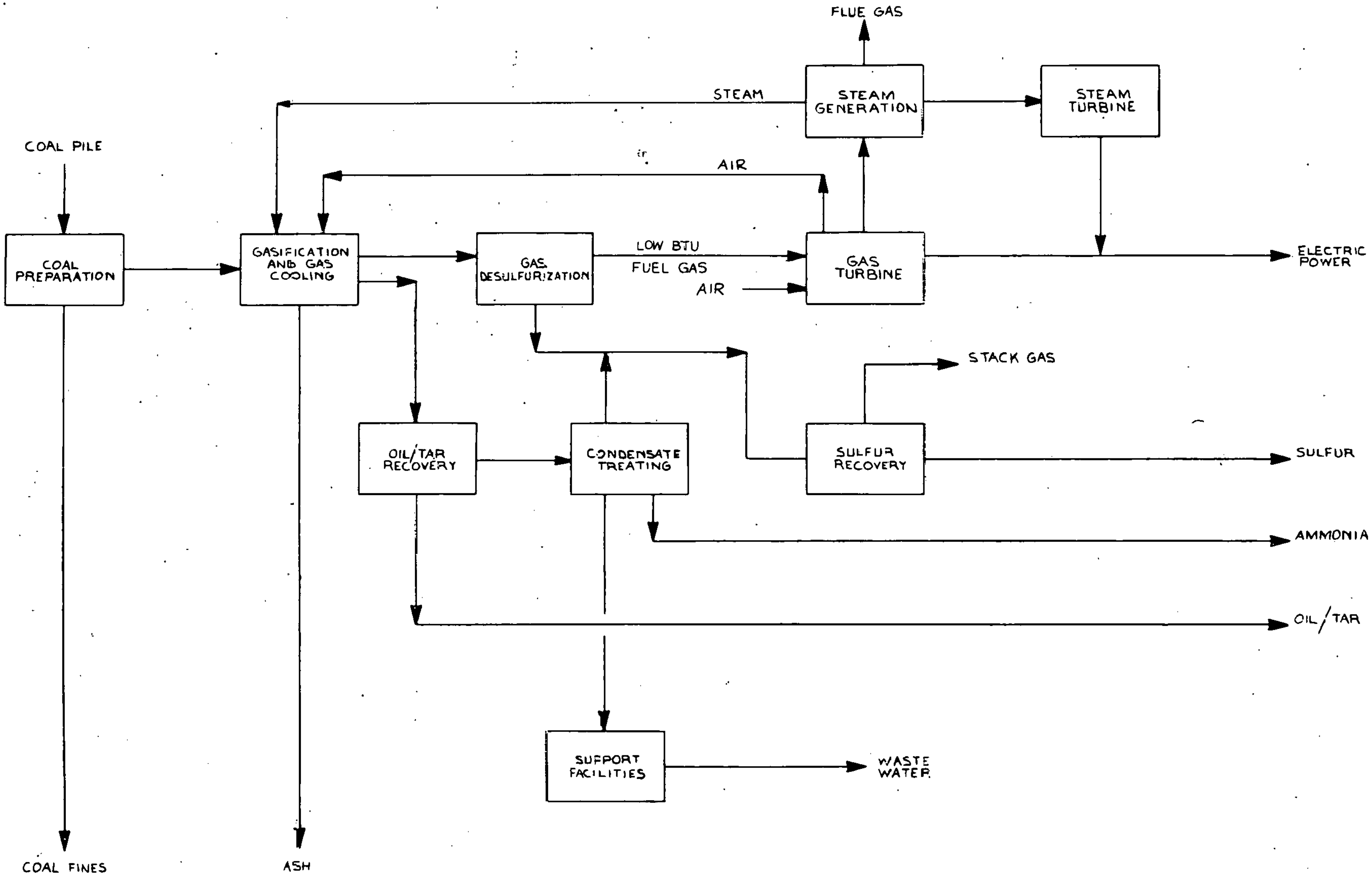


Fig. 2.1. LBG/CCPG System (Block Flow Diagram)

about 45% of the estimated United States coal reserves, one third of these deposits being located in the fields of Illinois, Indiana, and western Kentucky.(150) Almost 80% of the mid-continent bituminous reserves have a sulfur content over three percent.(12)

Deposits of sub-bituminous coal amounting to 25% of the total United States reserve are located entirely in the western states, with Montana and Wyoming accounting for 60% of these deposits.(150) These sub-bituminous coals are generally low in sulfur content, about one percent or less.(12) In addition to the sulfur content, the low-rank western coals are distinguished by their low caking tendency, which permits their use in all types of gasifiers without pretreatment.

The specific coal feedstocks selected for use in this assessment study, representing the above two general classes, are Illinois No. 6 and Montana Rosebud. Typical analyses of these coals, as reported in the literature (71)(190)(241), are given in Tables 2.1 and 2.2.

2.4 FUEL-GAS PROPERTIES

The properties of low-Btu fuel gas relevant to the design and operating conditions of the gas turbine, and characteristic of the type of gasifier and gas-clean-up system employed, are summarized in this section.

2.4.1 Combustion Parameters

Gas produced by air-blown gasification of coal is composed primarily of hydrogen, carbon monoxide, carbon dioxide, nitrogen, small amounts of methane and heavier hydrocarbons, and water vapor. Since the coal-gasification/combined-cycle power plant uses gasifier product gas as fuel for gas turbines, the combustion properties of the gas are of primary interest. Several of these properties are shown in Table 2.4 for the main components of the fuel gas.

Hydrogen and carbon monoxide have heating values of about 300 Btu/SCF. Methane, the major component of natural gas, which has been used extensively as fuel for gas turbines, has a heating value of about 1000 Btu/SCF. Ethane, which is present in minor amounts in some coal-gasifier product gases, has a heating value of about 1800 Btu/SCF.

The heat-release factor, defined as the ratio of heating value to the square root of the gas's specific gravity, is a measure of the Btu-equivalent gas flow through an orifice of a given size and flow characteristics. Of the combustible compounds shown in Table 2.4, carbon monoxide has the lowest heat-release factor because of its low heating value and high specific gravity. Hydrogen has a heat-release factor comparable with that of methane, while ethane has a higher heat-release factor than methane.

Flame-speed factors are used to compute the flame speed of gas-air mixtures as a percentage of the flame speed of a hydrogen-air mixture. Flame speeds of carbon monoxide, methane, and ethane in air are comparable (see Table 2.3).

Table 2.1 Coal Properties

	Illinois No. 6	Montana Rosebud
Rank	HVC Bituminous	Sub-bituminous
Proximate analysis (as rec'd), wt %		
Moisture	12.00	25.59
Ash	8.82	9.35
Volatile matter	31.41	29.15
Fixed carbon	47.77	35.91
Ultimate analysis (dry), wt %		
Carbon	69.52	67.45
Hydrogen	5.33	4.40
Nitrogen	1.25	1.13
Sulfur	3.86	1.40
Oxygen	10.02	13.00
Ash	10.02	12.57
Heating value (dry), Btu/lb		
HHV	12771	11446
LHV	12222	11028
Free-swelling index	4.5	0.0
Initial ash fusion, °F	2120-2240	2000-2430
Ash analysis, wt %		
SiO_2	46.6	22.1
Al_2O_3	19.3	15.5
Fe_2O_3	20.8	6.4
TiO_2	0.8	1.2
P_2O_5	0.2	0.1
CaO	7.7	18.9
MgO	0.9	6.6
Na_2O	0.2	1.0
K_2O	1.7	0.4
SO_3	2.4	26.2

Table 2.2 Trace-Element Analyses

Elements	Concentration, ppm Illinois No. 6	Concentration, ppm Montana Rosebud
In coal		
Beryllium	0.6-7.6	1.0-1.1
Fluorine	50-167	60-70
Arsenic	8-45	1.2-25
Selenium	---	0.8
Cadmium	---	0.04
Mercury	0.04-0.49	---
Lead	8-14	3.6
Boron	13-198	84-92
Vanadium	8.7-67	14-18
Chromium	5-54	5-7
Cobalt	1.2-10	2
Nickel	5-37	4-6
Copper	3.1-25	---
Zinc	0-53	10-12
Gallium	1.5-8	3.4-3.5
Germanium	0.4-27	2-3
Molybdenum	0.6-8.5	8-30
Tin	0.1-5	5-15
Yttrium	1-13	---
Lanthanum	0.2-24	---
Uranium	10	---
In ash		
Lithium	0.017-0.039	0.0215
Scandium	0.007-0.008	0.0034
Manganese	0.020-0.062	0.0456
Strontium	0.058-0.070	0.2612
Barium	0.029-0.047	0.3000
Ytterbium	0.0003-0.0011	0.0004
Bismuth	0.0001-0.0002	

Table 2.3 Flame-Speed Factors for Gas-Air Mixtures

Mixture	Flame Speed, % of H_2-Air Mixture
CO-Air	18
CH_4-Air	14
C_2H_6-Air	17

Flame speed of a gas mixture in air is reduced significantly by the presence of inert substances, such as nitrogen or carbon dioxide. As an example, the flame speed of a 50% CO/50% N_2 gas in air is about 10% of the flame speed of a hydrogen-air mixture.

Flammability limits indicate the composition range within which a combustible gas-air mixture will propagate flame freely. The gas-lean composition limit is known as the upper flammability limit. Extensive data on these limits for various compounds are contained in Bureau of Mines reports.(148)(149)

Hydrogen has the widest flammability range of the compounds shown in Table 2.4. Methane has the narrowest flammability range. Inert substances in the combustible gas tend to narrow the range. Increasing the temperature of the gas widens the range.

The theoretical adiabatic-temperature rise (uncorrected for dissociation and radiation) for the combustible compounds shown in Table 2.4 varies from about 3800°F to about 4500°F. Temperature-rise calculations are of major importance in gas-turbine design.

2.4.2 Composition of Product Gas

The composition of product gas from air-blown coal gasification depends on the composition of the coal fed to the gasifier as well as on the flowrate of air and steam relative to coal, gasifier configuration, and gasifier operating conditions of temperature and pressure. Low-rank coals that are rich in volatiles tend to have a higher hydrogen content than volatile-poor high-rank coals, and this is reflected in the hydrogen content of the product gas. Ash and moisture content of the coal feed are important, because these materials consume heat that would otherwise appear as heating value of the product gas.

Air fed to the gasifier provides the oxygen required for gasification, and the exothermic reactions of oxygen with coal to produce carbon dioxide provide the total heat requirement of the gasification process. Steam is added to the gasifier primarily to control the temperature of gasification, although a portion of the steam may be chemically converted, either by direct gasification of carbon or by reaction with carbon monoxide to produce carbon dioxide and hydrogen. Steam added to the gasifier but not chemically

Table 2.4 Combustion Properties of Gases[a]

Gas	HHV, Btu/scf	Specific Gravity	Heat-Release Factor	Flame-Speed Factor	Combustion Air, Ft^3/Ft^3	Lower Flammability Limit, Vol %	Upper Flammability Limit, Vol %	Theoretical Temperature Rise, °F
H_2	323	0.0694	1230	339	2.39	4.0	75.0	4010
CO	321	0.96	330	61	2.39	12.0	72.0	4475
CH_4	1012	0.5547	1360	48	9.55	5.0	15.0	3750
C_2H_6	1784	1.046	1740	58	16.71	3.0	12.4	3820
CO_2		1.520						
N_2		0.967						
H_2O		0.622						
Air		1.000						

[a] References: (1)(149)

converted, although necessary for temperature control, tends to lower the heating value of the product gas. Unconverted steam leaves the gasifier with the product gas, generally at a higher temperature than that of the steam introduced into the gasifier. Steam in the gasifier effluent thus increases the sensible-heat content of the effluent, thereby lowering the heating value of the product gas. A portion of the heat content of the steam may be recovered externally to the gasifier (for example, by preheating boiler feedwater or generating steam).

The configuration of the gasifier itself has an effect on the composition of the product gas. In a moving-bed gasifier, coal is introduced into the top of the gasifier while air and steam are introduced near the bottom. The coal moves downward through the gasifier countercurrently to the rising gases produced in the lower partial-combustion zone. The coal is preheated, devolatilized, and gasified in the upper portion of the gasifier by the ascending gases. The fixed-carbon portion of the coal is gasified with air in the partial-combustion zone. The countercurrent configuration of the gasifier enables the product gas to leave the top of the gasifier at a relatively low temperature (typically 1000°-1200°F), thereby lowering the sensible-heat content of the product gas and unconverted steam. The temperature of the partial-combustion zone must be controlled, however, by steam addition, either to avoid slagging of ash in the "dry-bottom" mode of operation or to conform to refractory limitations in the slagging mode of operation. Product gas from a moving-bed gasifier typically contains oil and tar vapors, because of the relatively low gasifier-outlet temperature.

In a fluidized-bed gasifier, the backmixing action of the fluidized bed tends to maintain a uniform temperature throughout the gasifier. As a result, product gas and unconverted steam leave the gasifier at a temperature that is approximately the same as the bulk gasifier temperature, typically 1600°-1800°F for single-stage gasifiers. This results in some reduction of the heating value of the product gas, because a greater proportion of the energy of the coal leaves the gasifier as sensible heat rather than chemical heat.

A single-stage entrained-flow gasifier typically operates at temperatures above 2000°F, and the product gas and unconverted steam leave the gasifier at approximately the same temperatures. In this configuration, a large proportion of the coal energy leaves the gasifier as sensible heat of the product gas. In a two-stage gasifier, coal is injected into an upper stage, where it is partially gasified by hot gases from the lower stage. Char is separated from the product gas and injected into the lower stage, where it is gasified with air and steam. The product gas leaves the upper stage at a temperature of 1700°-1900°F. Since this temperature is appreciably lower than the effluent temperature of a single-stage entrained-flow gasifier, the product-gas heating value is increased relative to single-stage operation.

The above discussion indicates the general effects of gasifier configuration and operating temperature on the heating value (and consequently composition) of the product gas. The effect of increasing pressure is primarily to increase the methane content of the gas. The pressure effect is more pronounced at low gasifier temperatures, 1600°-1900°F, than at high temperatures, 2000°F or higher.

Examples of product-gas compositions produced by pressurized air-blown gasifiers are given in Table 2.5. The concentration of hydrogen plus carbon monoxide ranges from 32% to 49%, averaging 39%. The hydrogen-to-carbon-monoxide ratio varies from about 0.5 to 2.0, with an average value of about 0.9. Methane concentration averages about 3.0%, and inert components (nitrogen and carbon dioxide) constitute about 58% of the gas.

The product gas from air-blown coal gasification has significantly lower heating value and heat-release factor than methane. The flame speed, however, is comparable with that of methane, largely because of the hydrogen content of the coal product gas. In addition, the flammability range is wider than for methane (see Table 2.6).

In general, the combustion parameters of product gas from coal gasification indicate that the use of this gas as fuel for gas turbines is entirely feasible, assuming a number of turbine-design considerations are taken into account. These considerations are discussed in the following section.

2.4.3 Utilization of Low-Btu Fuel Gas in Gas Turbines

A simple-cycle gas turbine has three main components--air compressor, combustor, and gas expander. These components in present-day machines using high-Btu fuel, such as natural gas, are designed so that the air compressor delivers the quantity of air necessary to burn the fuel and maintain a selected gas-expander-inlet temperature. In present-day industrial-type gas turbines, this temperature is about 1750°- 1850°F. As a result, the air flow corresponds to about 300% excess air, or an air-to-fuel ratio of about 50 to 1 in the case of methane fuel.

It is feasible to use low-Btu product gas from air-blown coal gasification in gas turbines, because, with this fuel, the same gas-expander-inlet temperature can be maintained by using less excess air in the combustor (that is, a lower air-to-fuel ratio is permissible).

In this case, the mass flow rate of low-Btu gas is about seven times the flow of high-Btu fuel, while the air flow rate required to maintain the selected gas-expander-inlet temperature is reduced by about 13% (see Table 2.7).

Beyond the question of feasibility, however, there are many considerations involved in design of gas turbines for low-Btu fuel gas.(2)(15)(91)(147) Considerations that relate specifically to the properties of the low-Btu gas include the gas-supply system, the combustion system, and impurities in the fuel. For a fixed-Btu flow to the gas turbine, the volumetric flow of low-Btu gas is significantly greater than that of high-Btu fuel, such as natural gas. Fuel-gas piping must be designed accordingly with respect to frictional pressure drop and flow distribution, especially for "can"-type combustors. The response of fuel-gas control valves in large-diameter piping

Table 2.5 Air-Blown Gasifier--Gas Compositions[a]

	Moving-Bed			Fluidized-Bed				Entrained-Flow		
Gasifier	Lurgi	ERDA/MERC Stirred Bed		U-Gas	BCR Low-Btu	Westing-house	Synthane	FWEC Two-Stage	Babcock & Wilcox	AI Molten Salt
Coal	-	W. Va.	N. Mex.	Bitum.	Eastern	Eastern	Ill. #6	Ill. #6	Pitt. #8	Ken. #9
Product-gas composition, mole %[b]										
H_2	24.7	15.5	19.0	17.5	23.4	14.4	21.5	14.5	8.4	13.2
CO	17.2	20.4	16.0	19.6	25.7	19.2	10.1	29.3	23.2	29.7
CH_4	4.1	2.4	3.8	3.4	0	2.7	5.6	3.5	0	1.5
C_2H_6	0.1	0	0	0	0	0	0.7	0	0	0
CO_2	11.0	8.7	12.6	9.9	5.2	9.3	17.9	3.3	4.6	3.5
N_2	42.9	52.5	48.4	48.9	45.5	54.3	43.5	48.7	63.5	48.0
HHV, Btu/SCF	179	140	152	154	159	136	172	177	102	154
LHV, Btu/SCF	162	130	138	142	147	126	154	166	98	145

[a] Reference: (181)

[b] Moisture-, sulfur-, and ammonia-free basis. AI Molten-Salt Gasifier product gas is also on an O_2-free basis.

Table 2.6 Comparison of Combustion Parameters for Product Gas and Methane

Gas	Gasifier Product Gas	Methane
Heating value, Btu/SCF,HHV	156	1012
Specific gravity	0.83	0.55
Heat-release factor	170	1360
Flame-speed factor	16	14
Flammability limits, vol. %		
Upper	65.0	15.0
Lower	15.0	5.0

Table 2.7 Comparison of Turbine-Flow Parameters for Low-Btu Fuel Gas and Methane

Fuel	Low-Btu Fuel Gas, 138 Btu/SCF (LHV)	Methane
Turbine-exhaust flow rate, lb/sec	100	100
Pressure ratio	10	10
Gas expander inlet temperature, °F	1750	1750
Fuel flow rate, lb/sec	14	2
Air flow rate required, lb/sec	86	98
Air-to-fuel weight ratio	~ 6:1	49:1

systems must be taken into account, as well as gland sealing, when handling gas containing a significant amount of carbon monoxide.

Design of the gas-turbine combustor for low-Btu gas is perhaps the major consideration in design. Combustor design is highly empirical, and experimental work is required to determine a satisfactory configuration, particularly with respect to completeness of combustion. Results of work on test-stand combustors(169)(172) indicate that the concentration of carbon monoxide in the combustor exhaust gas increases sharply as the flame speed of the fuel decreases. This effect is illustrated in Fig. 2.2 for fuel gases having heating values of 105, 130, and 200 Btu/SCF. Carbon-monoxide concentration in the combustor effluent from 105-Btu/SCF fuel increased sharply at combustor exit temperatures below about 1300°F, indicating flame instability at part-load temperatures. Flame stability of the 130- and 200-Btu/SCF fuels was good at temperatures down to at least 1000°F. Carbon-monoxide leakage was low for all three fuels at high temperatures, as is typical of advanced gas turbines under full load.

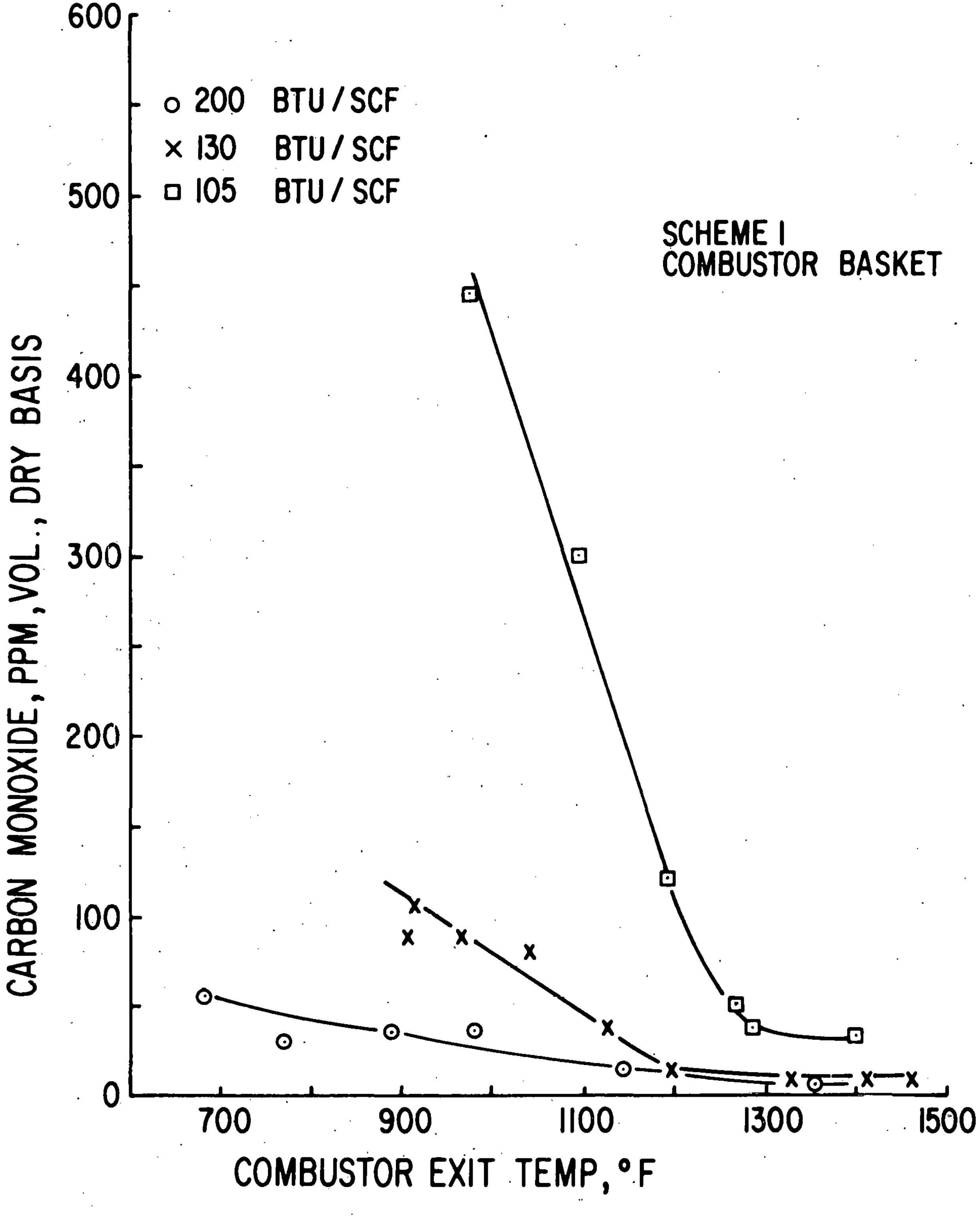


Fig. 2.2. Effect of Heating Value on CO Emissions for Low-Btu Coal Gas

Provision of additional gas-residence time in the combustor and intensifying mixing of fuel and air are methods that can be used to reduce carbon-monoxide leakage with low-Btu fuels. It has been reported(91) that the volume of "can"-type combustors can be increased by over 100% without changing the gas-turbine envelope. Gas turbines using a single, large external combustor can be adapted by modifying the volume of the external combustor.

The stoichiometric temperature rise of low-Btu product gas from coal gasification is significantly lower than that of high-Btu fuels, such as methane. This difference is of importance in regard to thermal NO_x production from gas turbines. Experimental tests(169)(172) indicate that thermal NO_x production from turbine fuels having heating values in the range of 100-200 Btu/SCF will be approximately an order of magnitude less than the thermal NO_x production from high-Btu fuel. This effect is illustrated in Fig. 2.3, in which the thermal NO_x concentration in the combustor effluent is plotted as a function of combustor exit temperature for three fuels--oil, 200-Btu/SCF coal product gas, and 130-Btu/SCF coal product gas. At a combustor exit temperature of 2000°F, NO_x concentration from the oil fuel is over 200 ppm, while NO_x concentration from the 200-Btu/SCF fuel gas is about 50 ppm. The 130-Btu/SCF fuel gas produces a NO_x concentration below 10 ppm at this temperature.

These NO_x levels do not necessarily apply quantitatively to full-scale gas turbines, and methods are available for minimizing NO_x from turbines using high-Btu fuels. The relative performance of low-Btu-gas fuels with respect to NO_x production, however, is expected to hold true for commercial machines. The effect can be explained on the basis that the inert diluents in the low-Btu fuel--nitrogen and carbon dioxide--moderate peak flame temperatures in the combustion process. Low thermal NO_x production is an important environmental advantage of the use of low-Btu coal-gasifier product gas as gas-turbine fuel.

2.4.4 Fuel-Gas Impurities

Stringent requirements are imposed on gas-turbine fuels, because of the severe conditions under which the gas expander operates. Corrosion and erosion of turbine blades must be avoided, as well as deposition of substances on the turbine blades. Particulate matter, including entrained droplets of liquid, must be removed to prevent erosion. Corrosive compounds or substances that form deposits must be minimized. Control of the following specific contaminants is required:

a) Alkali Metals - The presence of sodium or potassium compounds in combusted fuel gases can result in the formation of alkali-metal-sulfate deposits on turbine blades, inducing catastrophic hot corrosion of the metal. A specification of 0.5 ppm by weight of sodium or potassium is generally imposed on current oil-fired gas turbines. Since the weight flow of low-Btu fuel gas is about seven times higher than for high-Btu fuels at constant total-Btu input to the gas turbine, the specification for low-Btu fuel gas should be about 0.1 ppm by weight, in order to limit the contaminant flow rate to a comparable level.

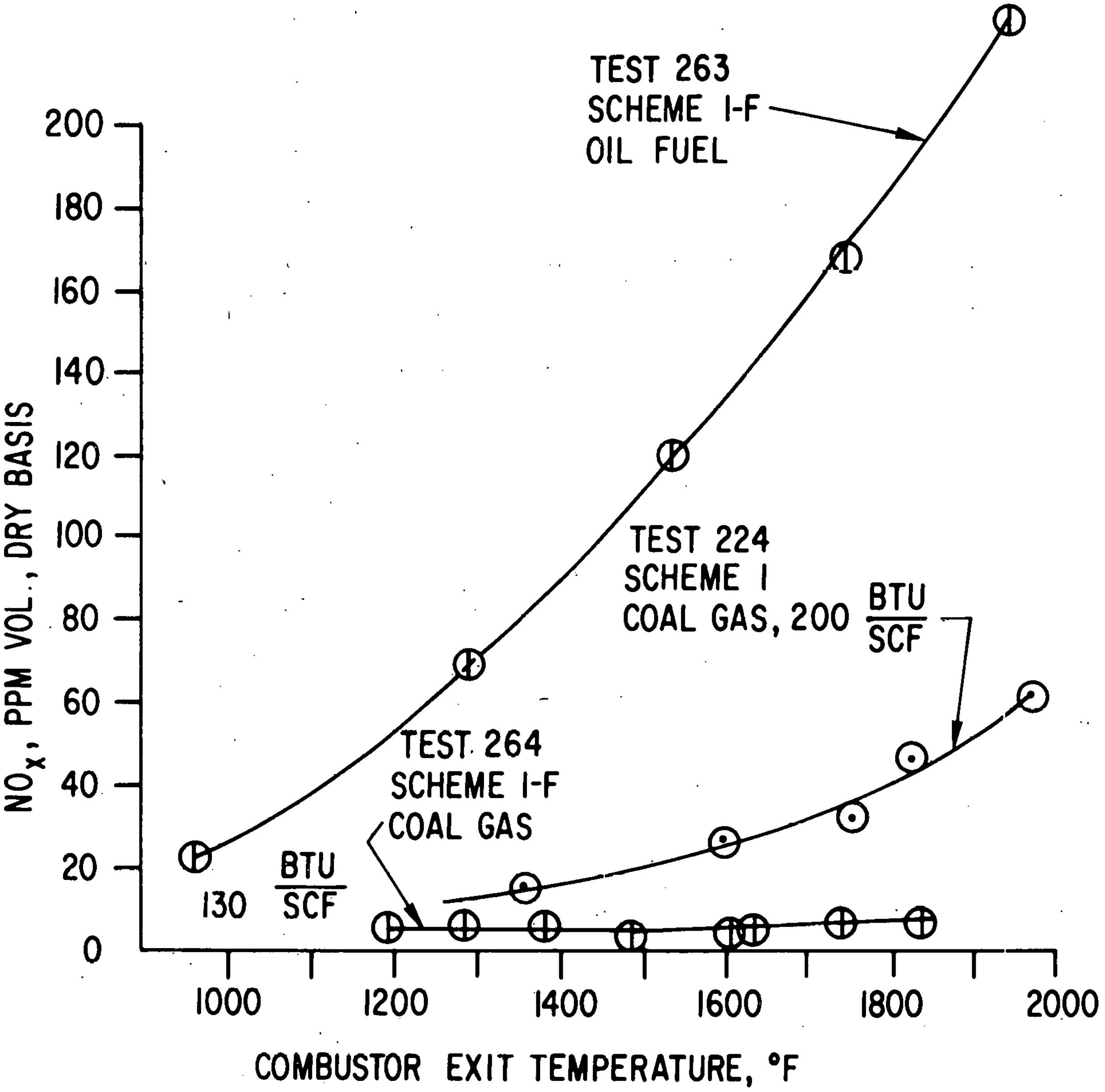


Fig. 2.3. Comparison of NO$_x$ Emissions from Combustion of Distillate Oil and LHV Coal Gas of 130 and 200 Btu/SCF

b) Vanadium - The presence of vanadium in the gas-turbine fuel can also lead to corrosive sulfate deposits, particularly in the presence of alkali-metal compounds, possibly due to formation of low melting eutectic compounds. As a result, the limitation on vanadium should be similar to that of alkali-metal compounds. Lead can also form corrosive deposits in the presence of sulfur.

c) Particulates - Solid particles, as well as droplets of liquids, in the turbine fuel can lead to erosion of turbine blades, depending on particle size and hardness of the particulates. It has been reported(147) that a dust content of about 1 ppm by weight in blast-furnace gas was required to avoid erosion in gas turbines operating with this fuel.

d) Volatile Sulfur Compounds - In the absence of alkali-metal and heavy-metal contaminants, the limitation on sulfur compounds in the turbine fuel is governed by environmental regulations regarding sulfur-dioxide emissions. Generally, these compounds must be removed to a level where the remaining compounds have no significant effect on the combustion of the fuel.

e) Ammonia - Conversion of nitrogen contained in the coal feed to ammonia in the gasifier product gas depends upon the operating conditions in the gasifier. Low temperature, high pressure, and high hydrogen partial pressure favor the formation of ammonia. Published quantitative data on this subject, however, are very limited. One paper(131) reported conversion of nitrogen in coal feed to ammonia ranging from 5 to 35 mole% in an atmospheric-pressure moving-bed gasifier.

At concentrations below about 1% by volume, ammonia contained in gas-turbine fuel gas is converted essentially completely to NO_x. As a result, the ammonia content must be controlled at a level that will satisfy environmental regulations.

2.5 ENVIRONMENTAL ASPECTS

Consideration for the following environmental pollutants is included as part of the assessment of LBG/CCPG systems:

a) sulfur compounds

b) oxides of nitrogen

c) trace elements

The material balances for the integrated LBG/CCPG plants therefore include elemental balances for the sulfur and nitrogen contained in the coal feed. The ultimate fate of other trace elements that enter the system as part of the coal feed is discussed only qualitatively, due to lack of specific information.

The primary guidelines used in establishing the goals for air emissions from LBG/CCPG systems were the then-current regulations for large, coal-fired power stations:

Sulfur : 1.2 lb SO_2/MMBtu
Nitrogen Oxides : 0.7 lb NO_2/MMBtu
Particulates : 0.1 lb/MMBtu

The above sulfur regulation was used to establish the degree of desulfurization required in the low-Btu fuel-gas clean-up system.

3 DATA COLLECTION AND EVALUATION

3.1 LITERATURE SEARCH

A literature search was conducted for the purpose of collecting information about the technical, economic, and environmental aspects of integrated LBG/CCPG plants and their sub-systems. The search was both time-limited and selective. It was imperative that the contents of the literature survey be useful towards accomplishing the assessment project's goal, rather than being exhaustive. The final result, therefore, includes only those items judged to be directly related to and useful for the assessment study.

As conducted, the literature survey included the following sources:

1) A subject search, principally on "combined-cycle power plants," was ordered from the NTIS computer services. The material received was further edited and augmented. The list of Government documents in Appendix D is the product of the search.
2) A careful search of Electric Power Research Institute (EPRI) publications was made, and suitable items were selected from them.
3) A search of the annual Proceedings of the American Power Conference was conducted on a volume-to-volume basis back to 1970, with some additional entries from the 1960s.
4) A thorough check of the Engineering Index for the years 1970 to May 1977 was made, and items obtained from this check were selectively sorted.

The results of the search are presented in the bibliography attached to this report as Appendix D. This has been divided into two parts:

1) All items bearing Government (NTIS or other) document numbers are listed by document number, because the titles are sometimes misleading and the author source unnecessarily complicated. An index to these items is included.
2) All items other than those with Government reference numbers are assembled by year of publication and then sorted by the last names of the authors. An author index for both parts is included.

All items included in this bibliography have been given item numbers, used for reference in the report text and in the indices.

3.2 DATA EVALUATION

Time did not permit thorough review of all the reference material associated with LBG/CCPG systems uncovered by the literature survey. The primary effort was directed to collecting data that could be useful in assessing the performance, cost, and environmental aspects of the major LBG/CCPG sub-systems:

• Coal Gasification	Moving-Bed Gasifier Fluidized-Bed Gasifier Entrained-Flow Gasifier
• Fuel-Gas Cleanup	High Temperature Low Temperature
• Combined Power Cycle	Gas Turbines Steam System

The selection of the specific process technology used for the study of integrated LBG/CCPG systems is discussed in Section 4 of this report, along with the literature data-bases employed. Similarly, the literature data pertinent to evaluating system costs and environmental effects are included in the appropriate report sections (Sections 7 and 5, respectively).

By way of summary, the following sub-systems were selected for inclusion in the current assessment of LBG/CCPG technology:

<u>Gasification</u> : Lurgi Moving-Bed Gasifier
IGT U-Gas Fluidized-Bed Gasifier
Foster Wheeler Entrained-Flow Gasifier

<u>Gas Cleanup</u> : Low-Temperature Scrubbing via Selexol Process

<u>Combined Power Cycle</u> : Gas Turbine at 2200°F, Inlet Pressure Ratio (PR) 16:1

Steam Turbine System at 1050 Psia/900°F/900°F

4 DESCRIPTION OF LBG/CCPG SYSTEMS

4.1 COAL-GASIFICATION SYSTEMS

Coal gasification involves the reaction of coal with an oxygen-containing gas and steam to produce a gaseous product, which can be used subsequently as an energy source. Coal gasification has a long history of utilization in the United States, as well as in other countries. In the early part of this century, fixed-bed gasification processes were used extensively in the United States to produce gas from coal and coke or to generate a product called "town gas." The discovery during the 1930s of extensive domestic reserves of natural gas, however, resulted in the abandonment of these processes in favor of usage of the plentiful natural gas. Coal-gasification processes continued in use in other countries until crude petroleum became available in large quantities in the late 1950s. Recently, the spreading realization that world reserves of both natural gas and petroleum have finite limits has prompted renewed interest, particularly in the United States, in coal gasification.

4.1.1 Chemical Reactions of Coal Gasification

The desired product of coal gasification is a combustible gas that can be used subsequently as an energy source. Hence, a reducing atmosphere is maintained in the gasifier. A partial-combustion zone usually exists, where an oxygen-containing gas (either high-purity oxygen or air) reacts with fixed carbon in the coal feed to form a mixture of carbon monoxide and carbon dioxide. This exothermic reaction supplies the heat required for the gasification process.

In the gasification zone, carbon dioxide and steam can react with the carbon in the coal, according to the reactions:

$$C + CO_2 \longrightarrow 2\ CO$$

$$C + H_2O \longrightarrow CO + H_2$$

These reactions are endothermic and absorb a part of the heat produced in the partial-combustion zone. In general practice, steam is added to the gasifier to absorb additional heat, so that the temperature in the gasifier can be controlled within desired limits.

Methane is another product formed in the gasifier, either by cracking of the volatile matter in the coal or by reaction of carbon monoxide with hydrogen. Cracking of volatile matter leads to the formation of oil and tar, which may themselves undergo reaction with steam to form carbon monoxide and hydrogen.

Formation of methane in the gasifier is of major importance when the objective of the gasification plant is to produce pipeline-quality gas. When the production of fuel gas is the objective, the major consideration is the efficient conversion of the energy in the coal to chemical energy (heating value) of the product gas. This can be achieved with gas containing hydrogen and carbon monoxide as the major combustible components rather than methane.

Chemical reactions involving the sulfur and nitrogen compounds in coal are important in coal gasification, because of consideration of environmental regulations. The sulfur content of American coal varies widely, depending on the origin and type of coal. Western coals are generally low in sulfur, while eastern coals have moderate-to-high sulfur content. In the process of coal gasification, the sulfur content of the coal is primarily converted to volatile sulfur compounds in the gas, although a small part may remain in the residual carbon associated with the ash product. Because the atmosphere in the coal gasifier is reducing, the major sulfur compounds in the product gas are hydrogen sulfide and carbonyl sulfide.

United States coals generally have an appreciable nitrogen content. The conversion of coal nitrogen during gasification is more complex, however, than that of coal sulfur and depends on the operating conditions and configuration of the gasifier. When oil and tar are produced from the gasifier, as is typical of moving-bed gasifiers, a part of the coal nitrogen appears in pyridine-type compounds. The remainder of the coal nitrogen is converted either to ammonia or molecular nitrogen, although, in high-temperature gasifiers, a small amount of hydrogen cyanide is also formed.

4.1.2 Oxygen vs. Air Gasification

An important consideration in coal gasification is the choice of oxygen or air as the oxidant. Most of the gasification processes can operate with either oxygen or air, and the choice is determined by the ultimate use of the gas. Oxygen is required when pipeline-quality gas is the objective, because dilution by the nitrogen in air must be avoided. When the product gas is to be used as fuel, air is generally used as the oxidant unless transportation cost is a consideration. In coal-gasification/combined-cycle plants, air is the preferred oxidant. In this case, the production and use of the gas is on the same site. In addition, gas turbines used in the combined-cycle portion of the plant are mass-flow machines and, as such, can recover energy efficiently from the nitrogen introduced with the air used in the gasifier.

4.1.3 Types of Gasifiers

As noted previously, the essential steps in coal gasification are (1) partial combustion of a portion of the coal to supply the heat required for gasification, and (2) further reaction of gases from the partial-combustion zone with the coal to produce the product gas, utilizing the heat generated in the combustion zone. These steps are common to all gasification processes, although the manner in which they occur differs widely in specific types of gasifiers. The types of gasifiers can be classified into four main categories:

(a) Moving Bed
(b) Fluidized Bed
(c) Entrained Flow
(d) Molten Bath

Moving-Bed Gasifier

This type of gasifier involves a bed of coal supported on a grate. Oxygen-containing gas is injected into the lower portion of the gasifier, and reaction gases flow upward through the slowly descending bed of coal. Product gas is removed near the top of the gasifier, while residual ash is discharged from the bottom. A mechanical device is provided to rotate the grate to control the rate of ash removal. In addition, a mechanism is provided to distribute fresh coal over the cross section of the gasifier. For caking coals, a stirrer is provided to agitate the moving coal bed in order to break up any large lumps of partially gasified coal.

The combustion zone in the lower portion of the gasifier is maintained, in "dry-bottom" operation, at a temperature just below the fusion point of the ash. Product gas leaves the top of the gasifier at a temperature of about 1000°F, depending on the type and moisture content of the coal.

Moving-bed gasifiers produce gas with a low ratio of sensible heat to chemical heat (heating value), because of the countercurrent flow of coal and reaction gases. In addition, there is a large inventory of coal in the gasifier, providing stability in the face of variations in coal flow. (Further, there is substantial commercial operating experience with the moving-bed gasifier developed by Lurgi.)

Moving-bed gasifiers require lump-size coal that is not highly caking and contains a minimum of fines, in order to assure uniform gas flow through the bed. The coal fines must either be briquetted before use in the gasifier or used elsewhere as, for example, in steam generation. The relatively low temperature at the top of the gasifier results in the production of oil and tar vapors, which must be condensed from the product gas. In the "dry-bottom" mode of operation, a large amount of steam must be used to control the temperature of the combustion zone, resulting in a reduced heat efficiency. The gasification per unit of gasifier cross section is relatively low, particularly in "dry-bottom" operation.

A relatively recent advance in moving-bed gasifiers, which is now entering the development stage, is the "slagging" mode of operation. In this mode, the combustion zone is maintained at a temperature above the melting point of the ash, and the residual ash is removed from the gasifier in molten form. This type of operation reduces the steam requirement and increases the gasification rate relative to "dry-bottom" gasifiers.

Fluidized-Bed Gasifier

In this type of gasifier, the solids in the gasifier--coal, char, and ash--are suspended by upflowing gases. The relatively small particles of solids in the gasifier are highly agitated, and the bulk of the solid bed has many of the properties of a bubbling bed of liquid. This characteristic of the fluidized bed results in the elimination of vertical temperature differences within the gasifier, and the bulk gasifier temperature is the result of the relative rates of exothermic partial-combustion reactions and endothermic gasification reactions. Fluidized-bed gasifiers may be single-stage or multiple-stage, with coal and reaction gases flowing from one stage to another.

Fluidized-bed gasifiers have no "hot-spot" zones, and high gasification rates are achieved as a result of good gas contact with the relatively small solid particles. The amount of oil and tar in the product gas from single-stage gasifiers is low, because of the high gas-exit temperature--generally 1600-1800°F. As with the moving-bed gasifier, there is a high inventory of carbon in the gasifier.

Product gas from the fluidized-bed gasifier leaves the gasifier at the bulk fluidized-bed temperature. In single-stage gasifiers, this results in a relatively high ratio of sensible heat to chemical heat in the product gas. A certain amount of ungasified carbon is entrained from the gasifier with the product gas, even though multistage cyclones are usually provided. Because of the backmixing action of the fluidized bed, the ash withdrawn from the gasifier contains a substantial amount of ungasified carbon. Finally, fluidized-bed gasifiers cannot handle strongly caking coals without suitable pretreatment, because of fluidization instability from channeling.

Some of the disadvantages of a single-stage fluidized-bed gasifier can be overcome or minimized by using multiple stages.

Multiple-stage fluidized-bed gasifiers provide product gas with lower sensible-heat content by countercurrent flow of coal and gas through the stages, although this arrangement also produces oil and tar. An ash-agglomeration stage will minimize carbon loss with the ash stream.

Entrained-Flow Gasifiers

Gasification by means of an entrained-flow process involves suspension of relatively small coal or coal-char particles in a high-velocity gaseous medium. Residence time of the coal particles in the gasifier is relatively low, and high temperatures are used to maximize the gasification rate. Entrained-flow gasifiers operate under ash-slagging conditions.

Entrained-flow gasifiers may be single-stage or two-stage. In the single-stage version, coal, steam, and oxygen-containing gas are injected into a high-temperature reaction zone, where partial combustion and gasification occur simultaneously. Product gas and ash leave the reaction zone at temperatures above the ash-fusion temperature and are quenched with water to cool the gas and separate ash particles. Alternately, the gas may be cooled in a waste-heat boiler, generating steam.

In a two-stage entrained-flow gasifier, coal is injected into an upper stage, where it is partially gasified by hot gases produced in the lower stage. Gas and char leave the upper stage at a temperature of 1800-2100°F. Char is separated from the gas and injected into the lower stage, together with steam and an oxygen-containing gas. The char is partially combusted at temperatures of 2800 to 3000°F. Molten ash slag is separated from the gases formed and is removed from the bottom of the lower stage.

Entrained-flow gasifiers can handle any grade or type of coal, because the particles of coal are in dilute suspension in the upper stage, and char (injected into the lower stage) has no swelling or caking characteristics. The product gas contains little or no oil or tar, because the reaction temperature is sufficiently high so that these materials are decomposed; however, dust loading could be high. The carbon content of ash withdrawn from the gasifier is low, because of the high temperature in the partial-combustion stage. Capacity of entrained-flow gasifiers is significantly higher than moving-bed or fluidized-bed gasifiers, because gas flow is not limited by considerations of flow through large-particle beds or by fluidization requirements.

Entrained-flow gasifiers require precise control of coal and oxidant flow rates, because of the low inventory of reactants in the reaction zones. This characteristic, however, provides the ability to rapidly change gas output; precise control of oxidant and fuel has been demonstrated commercially in oil partial oxidation plants. In addition, the continuous feeding of coal into a pressurized gasifier, slag withdrawal at high pressure, and construction materials usable in the slagging zone are some of the noticeable problems.

Molten-Bath Gasifiers

Molten-bath gasifiers bring together coal, steam, and oxygen-containing gas in a high-temperature molten fluid. The melt serves primarily to disperse reactants and to provide a heat-storage and heat-transfer medium. The melt may also serve as catalyst for the gasification. In addition, certain types of melts tend to capture sulfur compounds formed during gasification. The slag-bath gasifier is a form of molten-bath gasifier where the reactants are injected into a bath of molten ash.

Molten-bath gasifiers can handle all types and sizes of coal, and the product gas contains little oil and tar because of the high gasification temperature (1800-2500°F).

Certain types of melts require regeneration to remove ash and sulfur compounds, and the regeneration results in loss of some carbon and melt. Melts containing alkali metals have significant vapor pressure at high temperatures, and these materials can be detrimental, particularly when the product gas is subsequently used as gas-turbine fuel.

4.1.4 Applicable Gasifiers

Specific coal gasifiers applicable to coal-gasification/combined-cycle power plants are summarized in Table 4.1. This summary is based on information reported in the literature,(181)(209) and the detailed descriptions of these gasifiers are given in Appendix A.

Gasifiers that operate only at atmospheric pressure were excluded, because the economic penalty of compressing product fuel gas for use in gas turbines was considered prohibitive. Gasifiers that operate primarily with oxygen, for intermediate-Btu fuel-gas or pipeline-gas production, were included if conversion to air-blown operation seemed feasible.

Of those gasifiers considered applicable to LBG/CCPG systems, only the Lurgi moving-bed gasifier, operating in the non-slagging mode, is commercially available at the present time. The others are in various stages of development on the pilot-plant level.

4.1.5 Gasifier Selection

The present assessment of LBG/CCPG systems was predicated on employing three types of air-blown gasifiers that could be commercially available in the mid-1980 time frame. The following systems were selected as being representative of moving-bed, fluidized-bed, and entrained-flow gasifiers that, based on their current state of active development, would likely approach commercial readiness:

Moving Bed - Lurgi (non-slagging)
Fluidized Bed - IGT U-Gas
Entrained Flow - Foster Wheeler

Projected performance data for these gasification systems were collected from the literature(225)(241)(242) and were used to prepare material and energy balances for the LBG/CCPG assessment studies. Table 4.2 summarizes the performance data for the selected air-blown gasification systems.

4.1.6 Process Description

For application in an LBG/CCPG plant, the selected gasifier must be integrated with an oxidant-feed system, ash-handling facilities, and downstream gas-cooling equipment. These system components, along with the gasifier, make up the gasification and gas-cooling section, described in the following paragraphs.

Moving-Bed Gasifier

The flow diagram for the gasification and gas-cooling section, employing the Lurgi non-slagging gasifier, is shown in Figure 4.1.

Table 4.1. Summary of Applicable Gasifiers

	Coal-Feed Conditions			Raw-Gas Conditions				
Gasifier	Size	Type	Pretreat	T,°F	Psig	Tar	Ash Form	Status
Moving Bed								
ERDA-MERC	50% < 1/2"	All	No	1200	Atm-285	Yes	Dry	20 TPD Pilot Unit
Lurgi	1 1/2" x 1/8"	Non-Caking[a]	No	700-1000	450	Yes	Dry	Commercial
Fluidized Bed								
Synthane	< 20 Mesh	All	Yes, 800°F	1400	1000	Yes	Char	72 TPD Pilot Unit
IGT U-Gas	1/4" x 0	All	Yes, 700-800°F	1550-1900	50-350	No	Agglomerate	6 TPD Pilot Unit
BCR Low-Btu	200-235 Mesh	All	Yes, 600-1200°F	1700-2000	Atm-235	No	Dry	1.2 TPD PDU
Westinghouse	1/4" x 0	All	No	1600-1800	130-200	No	Agglomerate	14 TPD PDU
Entrained Flow								
Babcock & Wilcox	70% < 200 Mesh	All	No	1800	Atm-300	No	Slag	12 TPD Pilot Unit
Foster Wheeler	70% < 200 Mesh	All	No	1800-2100	350	No	Slag	480 TPD Pilot Unit
Texaco	Pulverized	All	No	----	300-1200	No	Slag	15-100 TPD Pilot Unit
Molten Media								
AI Molten Salt	1/4" x 0	All	No	1700-1800	Atm-280	No	Dry	120 TPD Pilot Unit
Otto-Rummel	100% < 16 Mesh	All	No	1500-1700	Atm-360	No	Slag	Pilot Unit

[a] Can accept some caking coals with mechanical stirrer

Table 4.2. Air-Blown-Gasifier Performance

Performance Characteristic	Lurgi Moving Bed	U-Gas Fluidized Bed	Foster Wheeler Entrained Flow
Coal type	Illinois No. 6	Illinois No. 6	Illinois No. 6
MAF coal/dry coal	0.90	0.90	0.90
Reference	(241)(242)	(241)	(242)
Air/MAF coal, lb/lb	2.556	3.441	3.183
Steam/MAF coal, lb/lb	1.655	0.646	0.200
Gasifier exit, °F	950-1020	1660	1700
Psig	300	325	360
Raw tar-free gas			
Net SCF/lb MAF coal	89.80	82.13	69.38
HHV, Btu/SCF	129	142	175
Volume %			
CH_4	2.85	3.03	3.35
C_2H_6	0.07	-	-
CO	11.94	17.97	28.17
CO_2	9.71	8.46	3.38
H_2	17.16	15.39	13.88
N_2	29.63	43.77	47.78
H_2S	0.52	0.59	0.67
COS	0.02	0.02	0.07
NH_3	0.36	0.03	0.43
H_2O	27.74	10.74	2.27
	100.00	100.00	100.00
Tar, lb/lb MAF coal	0.08	0.01	0.0
HHV, Btu/lb	15290	-	-
Cold-gas efficiency, %	81.7	82.3	85.0
Coal carbon to gas	90.6	99.1	99.2
to tar	8.8	0.0	0.0
to ash	0.6	0.9	0.8
Coal sulfur to gas	96.5	99.2	100.0
to tar	3.5	0.0	0.0
to ash	-	0.8	0.0
Coal nitrogen to NH_3	85.0	7.0	80.0
to N_2	4.2-8.6	70.6	20.0
to tar	6.4-10.8	22.4	0.0

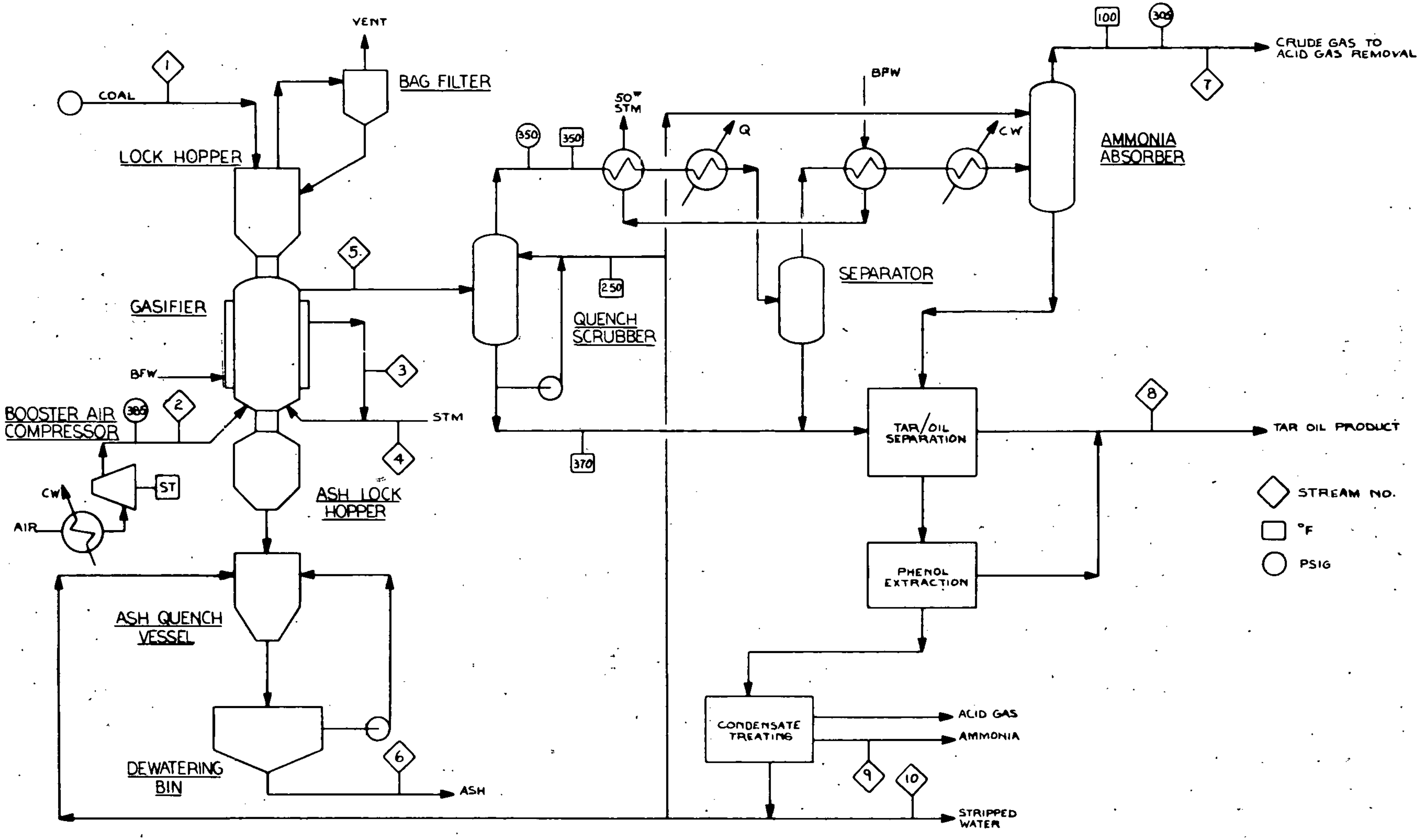


Fig. 4.1. Gasification and Gas Cooling -- Moving - Bed Gasifier (Process Flow Diagram)

The moving-bed gasifier is a water-jacketed, pressurized unit composed of a series of vertically stacked vessels. There are, from top to bottom, a coal hopper, coal lock, water-jacketed gasifier, ash lock, and ash-quench chamber.

Coal is conveyed from the coal-preparation area to the coal hopper, from which it is fed by gravity to the depressurized coal lock through a hydraulically operated valve. The lock is then isolated and pressurized with a slipstream of tail gas (mainly N_2), and the coal is transferred to the gasifier through another hydraulically operated valve. The empty lock is isolated, depressurized through a bag filter, and vented to the atmosphere. In addition, the gas displaced from the coal and lock hoppers during loading is vented to the atmosphere through the bag filter. Coal dust recovered in the filter is returned to the coal hopper.

The coal flowing down through the gas producer represents a slowly moving bed that has several distinct zones. In the first zone, at the top of the gasifier, coal is preheated and dried by contact with the hot crude gas leaving the reactor. As the coal moves down and is heated further, devolatilization occurs and gasification commences. The bottom of the bed is a combustion zone, where carbon reacts with oxygen to form CO and CO_2. The oxidation provides the overall heat for the gasification and devolatilization reactions, which are endothermic. Only a negligible amount of unburned carbon remains in the ash.

Air, partially compressed by the gas-turbine/compressor in the plant power cycle, is cooled and then pumped to gasifier pressure in the booster-air compressor.

Oxidant and steam enter the gasifier near the bottom and are heated as they rise upward to the combustion zone by the hot ash moving down from the combustion zone. Oxidant flow rate is controlled to accomplish complete gasification of coal. Steam rate is controlled to maintain a specified gasifier bottom temperature to prevent melting or clinkering of the ash. A portion of the gasifier process steam is generated in the gasifier jacket.

Ash from the process is continuously collected by a rotating ash grate and moved to the ash-lock hopper. Ash collected in the lock is depressurized and discharged batchwise to an ash-quench chamber, where it is cooled in water. The abrasive slurry from each gasifier train is sent to a common transfer tank, using water as the motive fluid. Ash grinders are provided to prevent large chunks of slag from plugging transfer lines. The ash slurry is dewatered in a bin, producing an ash ready for disposal.

Final cleaning of the water overflowing the dewatering bin is accomplished in a settling tank, where ash fines settle and are pumped back to the dewatering bin. A portion of the clarified water is recycled to the ash-quench chambers after it is cooled. The balance of the water provides the motive fluid for the ash-slurry transfer eductors.

The crude gas leaving the gasifier contains appreciable quantities of tars, oils, naphtha, phenols, fatty acids, ammonia, hydrogen sulfide, sulfur compounds, and a small amount of coal and ash dust. The crude gasifier effluent at 1000°F flows through the quench scrubber, where it is washed with a stream of process condensate. The washing process quenches the gas to 350°F and condenses the high boiling tar fractions. Coal and ash dust are removed with the condensed tar, leaving the quenched effluent gas essentially free of particulate matter.

The quenched gas is further cooled by generation of 50-psig steam in a low-pressure waste-heat boiler and by providing reboiler duty to the solvent regenerator in the gas-desulfurization section. Final gas cooling is achieved by preheating boiler feedwater and exchange with cooling water. The cooled gas is then water-scrubbed in the ammonia absorber to remove essentially all of the ammonia content, as well as final traces of particulates and water-soluble oil components, such as phenols and fatty acids. The crude fuel gas is then delivered to the gas-desulfurization section at 100°F and 305 psig for acid-gas removal.

Condensate streams from cooling and washing the crude gas are collected and processed sequentially for tar/oil separation, phenol extraction, and condensate treating, which includes sour-water stripping and ammonia recovery. Part of the steam-stripped condensate is recycled as make-up water for ash quenching and ammonia absorption.

Fluidized-Bed Gasifier

Figure 4.2 shows the flow scheme for the integrated gasification and gas-cooling section employing the U-Gas fluidized-bed gasifier.

Crushed coal from a tripper flows by gravity into an elevated coal hopper, which provides surge. Displaced air is vented to the atmosphere through a bag filter, and the fines are returned to the hopper. From the surge bin, the coal is charged batchwise into coal-feed lock hoppers. These lock hoppers operate on a switching cycle from fill to fill. While one lock hopper is filling, the other is emptying into a high-pressure coal-feed hopper.

Coal is fed out of the high-pressure feed hopper by means of a volumetric feeder. The coal is picked up and conveyed into a pretreater by a transport-gas stream. This stream is a compressed, recycled raw-gas stream from the overhead of a downstream ammonia absorber.

A small amount of pressurizing gas, either transport gas or nitrogen, is injected into the bottoms of the lock and feed hoppers. In the lock hoppers, the purpose of the injection is to aerate the coal somewhat to prevent bridging. In the feed hopper, the gas fluidizes the coal as well as pressurizing the hopper.

In the pretreater, coal reacts with air at 800°F, so that a small fraction of the coal is oxidized and rendered noncaking. Heat of reaction is removed by generating high-pressure steam in coils submerged in the fluidized bed.

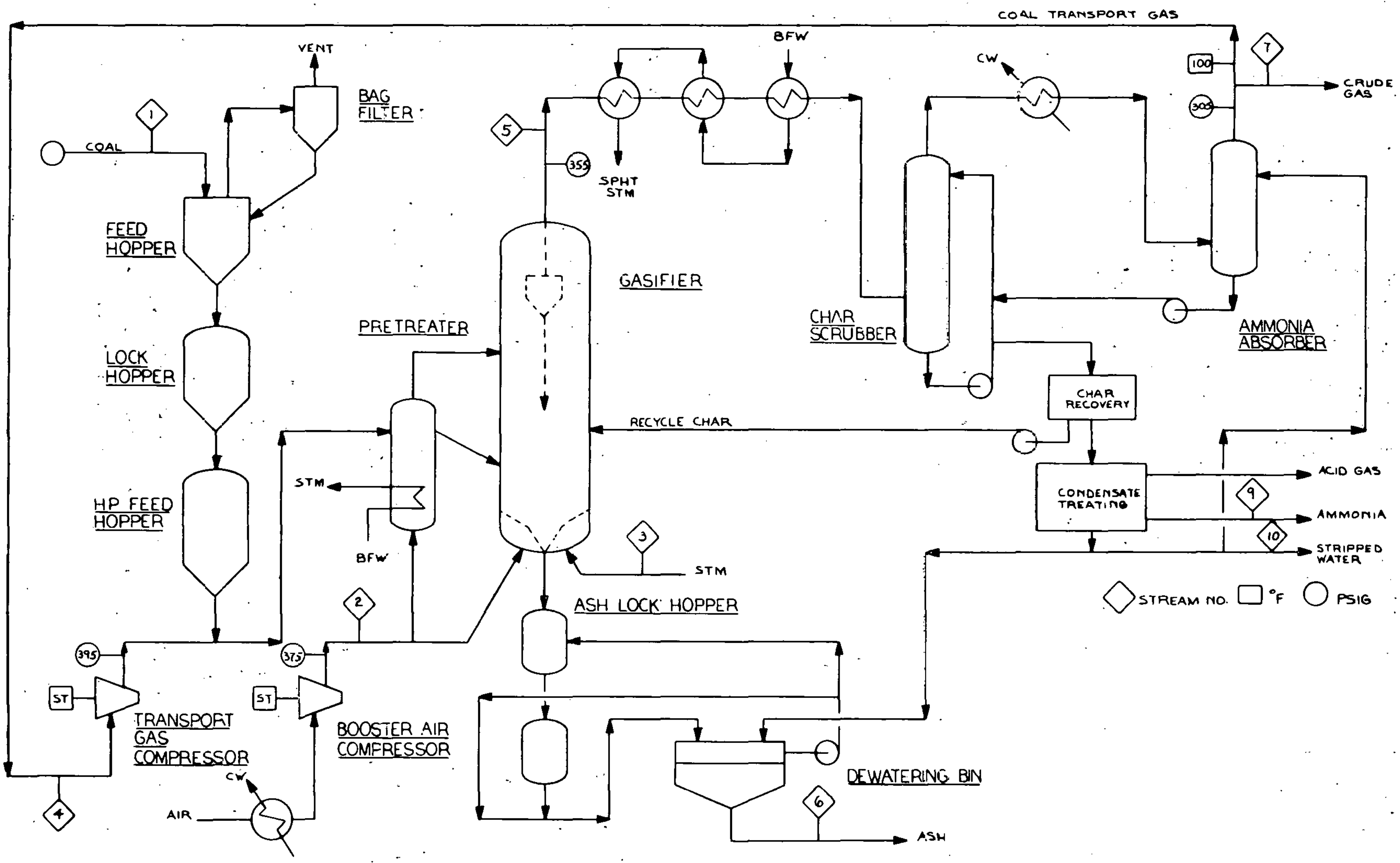


Fig. 4.2 Gasification and Gas Cooling -- Fluidized-Bed Gasifier (Process Flow Diagram)

Pretreated coal overflows from the pretreater into the gasification reactor, and the pretreater effluent gas enters the gasifier above the surface of the bed. The coal in the gasifier is fluidized by a mixture of air and steam, with gasification taking place at temperatures low enough to prevent slagging of the ash. Most of the coal fines entrained in the gasifier crude-gas stream are recovered by two parallel, two-stage cyclone separators mounted internally and are returned directly to the fluidized bed. A relatively char-free effluent flows to the gas-cooling unit.

Air from the power-turbine compressor in the plant power cycle is compressed to gasifier pressure in the booster-air compressor. The total compressed-air flow is then split between the pretreater and gasifier. For the case where a noncaking coal feed is used, the pretreater is eliminated, and the total coal and air streams are fed directly to the gasifier.

In the fluidized bed, ash agglomerates grow in size and are removed at the bottom of the gasifier. The hot agglomerated ash falls into a water-filled lock hopper, where it is quenched. When the lock has been filled, the hopper is isolated and depressurized. The ash slurry is dumped into a lower hopper, from which it is sent to a transfer tank common to all trains. Ash grinders are provided to prevent large chunks of ash from plugging transfer lines. The slurry is dewatered, producing an ash for disposal. Final cleaning of the water overflowing the dewatering bin is accomplished in a settling tank, where the fines settle to the bottom and are pumped back to the dewatering bin. A portion of the clarified water is pumped back to the ash-slurry transfer eductors to serve as the motive fluid, while the remainder is used for ash quenching.

The effluent gas from the gasifier, at 1650°F, contains particulate matter but is essentially free of oils and tars. Crude gas is cooled to about 300°F by preheating boiler feedwater and generating 650-psig superheated steam. The gas is then scrubbed to remove residual entrained char, cooled to 100°F with cooling water, and finally water-washed in an ammonia absorber. Part of the absorber overhead is recycled as coal-transport gas; the remainder is delivered to the gas-desulfurization section at 100°F and 305 psig.

Water-condensate streams from the gas-cooling process are filtered to remove particulate matter and then processed in the condensate-treating unit. Here, the sour-water streams are steam-stripped to remove acid gases and ammonia is recovered. A portion of the stripped water is recycled as make-up in the ash-quenching system and in the ammonia absorber.

Entrained-Flow Gasifier

The flow diagram for the Foster Wheeler entrained-flow gasification and gas-cooling system is shown in Fig. 4.3.

Pulverized coal is conveyed to coal feed hoppers, which are maintained at slight positive pressure with inert-gas purge to prevent infiltration of air. The feed hoppers are alternately pressurized and depressurized with inert gas to allow gravity flow of the coal into the primary

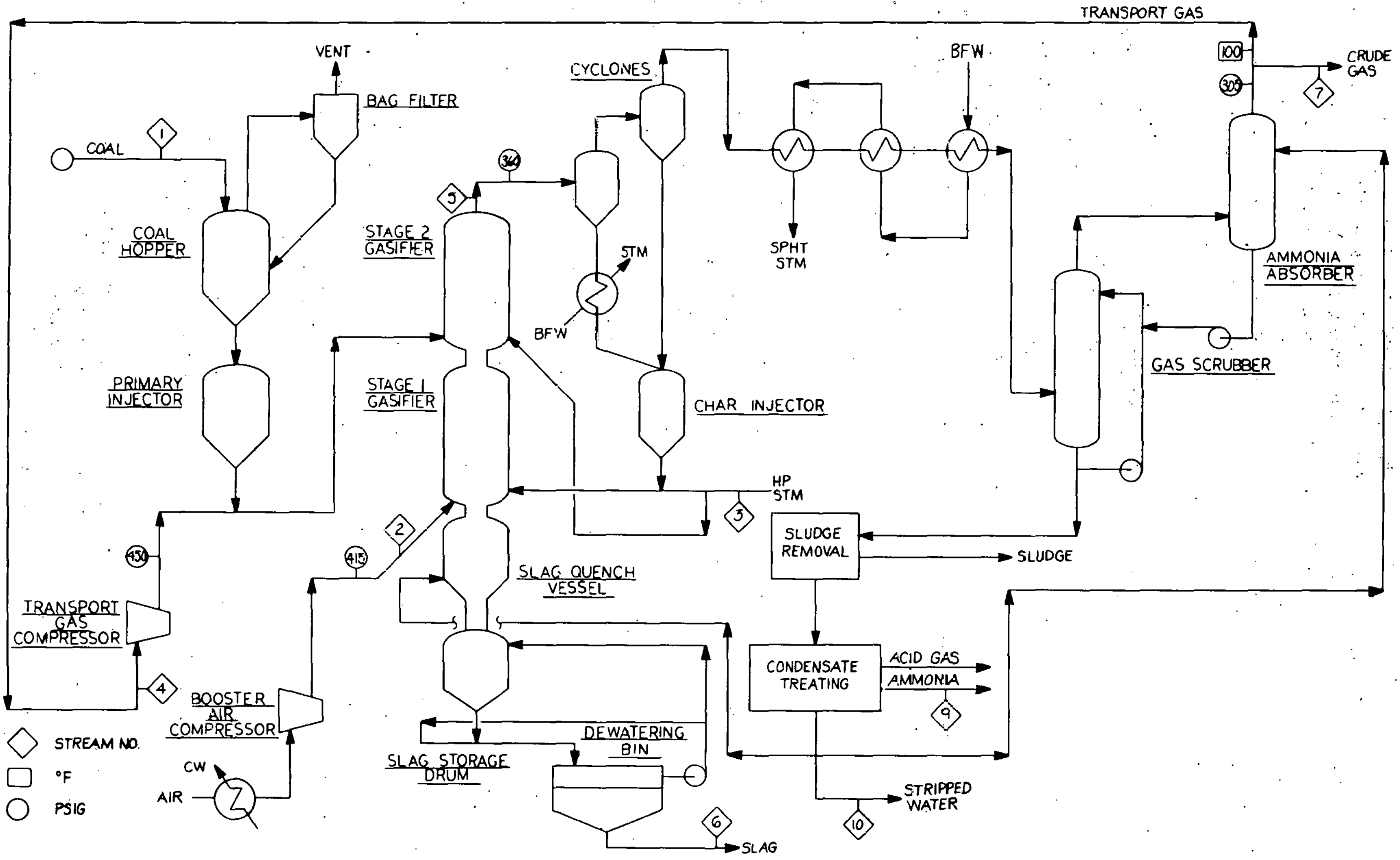


Fig. 4.3. Gasification and Gas Cooling -- Entrained-Flow Gasifier (Process Flow Diagram)

coal injectors, which are maintained at reactor-feed pressure. Coal is fed from the primary injectors to the gasifier by means of a transport-gas stream. This stream is a compressed, recycled raw-gas stream from the overhead of a downstream ammonia absorber. The process uses a two-stage, entrained-flow, high-pressure slagging coal gasifier to produce low-Btu gas. Dry pulverized coal is injected into the upper stage of the gasifier.

This upper stage operates as a coal-devolatization stage with two basic products. The first is a fuel-gas mixture of H_2, CO, CO_2, CH_4, H_2O, and N_2. The second product is the devolatized coal, converted into a char containing ash, a small amount of volatile matter, and sulfur, as well as (essentially) the fixed-carbon content of the original coal feed. Coal devolatization occurs as a result of rapid heating of the coal particles by mixing with the hot effluent from the lower gasifier stage. The gas-coal mixture next flows upward through the reactor, where various endothermic reactions occur, reducing the final temperature to about 1720°F.

In the lower gasification stage, the recovered char reacts with air and steam. This stage also converts the ash to a molten slag. This stage operates under reducing conditions and provides the necessary heat to satisfy the endothermic requirements of the upper stage of the gasifier.

Air and char are injected into the lower stage of the gasifier in such a way as to create a vortex action in the lower stage. Stage I is operated at temperatures in the neighborhood of 2900°F, at which temperature the ash melts into a slag. This slag coalesces along the walls of the gasifier and flows downward and out through a bottom slag-tap hole.

Reaction heat is retained in the gas stream by the use of special refractory and insulating materials designed to minimize heat loss. Use of refractory water cooling is minimized, being restricted to certain critical areas (the injector tips, the throat piece between the two gasifier stages, and the slag-tap area).

The char entrained in the gas stream from the upper stage of the gasifier is removed in two stages of cyclones. Dip-legs from these cyclones discharge to the fluidized bed in a char-seal pot. The recovered char is at a slightly lower pressure than the gasifier operating pressure. An injector system using high-pressure steam is used to feed the char into the gasifier.

Gasifier air is supplied at the required pressure from the booster-air compressor. Air feed to this compressor is delivered partially compressed from the power-turbine/compressor in the plant power cycle.

The hot molten slag is discharged through the slag tap and falls into a cold-water bath maintained in the slag-quench vessel. The slag is thereby quenched into fritz, which is easily discharged from the system through a slag grinder into a lock hopper drum. When depressurized, the drum is pumped out and its contents sent to a series of dewatering bins. Clarified water is recovered from the slag slurry and recycled to slag quenching.

Crude gas from the char cyclones is cooled from 1700°F to about 300°F by preheating boiler feedwater and generating 650-psig super-heated steam. The effluent gas contains residual entrained particulates, which are removed by water-washing in a gas scrubber. Finally, the gas is processed through an ammonia absorber and delivered at 100°F and 305 psig to the gas-desulfurization section. A portion of this gas is recycled for use as coal-transport gas.

Water streams produced in the gas-cooling process are filtered to remove particulates and then sent to condensate-treating, where the sour water is steam-stripped and processed for ammonia recovery. Part of the stripped water is recycled as make-up to ash-quenching and ammonia-absorption.

4.2 GAS-CLEAN-UP SYSTEMS

Raw fuel gas produced by gasification of coal must be conditioned prior to its entry and subsequent combustion in the combined-cycle turbine. The gas-clean-up system is designed to remove those constituents of the fuel gas that would be harmful to the gas turbine or pollute the environment if present in the turbine-exhaust gas:

- Sulfur compounds
- Particulate matter
- Nitrogen compounds

Fuel-gas-clean-up systems are generally divided into two categories: low-temperature systems, requiring cooling of the raw fuel gas to 250°F or below; and high-temperature systems, which require little or no cooling of the raw gas as it is delivered from the gasifier.

4.2.1 Low-Temperature Desulfurization Systems

Low-temperature processes for desulfurizing raw fuel gas are commercially available and have been widely used for natural-gas sweetening and for treating synthesis gas in the chemical process industry. These systems, which normally operate below 250°F, may be classified into four categories, according to their principles of operation:

(1) Chemical solvent processes
(2) Physical solvent processes
(3) Direct-conversion processes
(4) Dry-bed processes

Table 4.3 lists examples of commercial desulfurization processes that are representative of the above system categories. These were extracted from comprehensive literature reviews of low-temperature clean-up technology.(181)(225)(232)

Chemical Solvent Processes

Chemical solvent processes employ aqueous solutions of organic or

Table 4.3. Commercial Low-Temperature Clean-Up Processes

Process	Absorbent	Absorbent Type	Temperature, °F	Pressure, psig	% H_2S Removal	Selective H_2S Removal	COS Removal
Chemical Solvent							
MEA	Mono-Ethanol-Amine	Aqeuous Solution	80-120	Insensitive	99	No	Forms Non-Regenerative Compounds
DEA	Di-Ethanol-Amine	Aqueous Solution	100-130	Insensitive	99	No	Yes
MDEA	Methyl-Diethanol-Amine	Aqueous Solution	80-125	Insensitive	99	Yes	No
Alkazid	Potassium Dimethyl Amino Acetate	Aqueous Solution	70-120	Insensitive	99	Yes	Partial
Benfield	Activated Potassium Carbonate	Aqueous Solution	150-250	Insensitive	99	Partial	Yes
Physical Solvent							
Sulfinal	Sulfolane and Di-Isopropanol-Amine	Organic Solvent	100-125	High Pressure Preferred	99	Partial	Yes
Selexol	Polyethylene Gylcol Ether	Organic Solvent	20-100	300-1000	99	Yes	Yes
Rectisol	Methanol	Organic Solvent	<0	300-2000	99	Yes	Yes
Direct Conversion							
Stretford	Sodium Carbonate and Antraquinone Sulfonic Acid	Aqueous Solution	80-100	0-100	99.9	Yes	No
Townsend	Triethylene Glycol	Aqueous Solution	150-250	-	99.9	Yes	-
Dry Bed							
Iron Sponge	Hydrated Ferric Oxide	Fixed Bed	80-100	0-1000	99	Yes	No
Molecular Sieve	Zeolites	Fixed Bed	60-120	200-1200	99	Yes	Yes

inorganic agents (or both) capable of forming "complexes" with the acid-gas components, notably H_2S and CO_2, present in the raw-gas stream. The absorption solution is regenerated by decomposing the "complex" at elevated temperature, thereby (a) releasing the acid gases for subsequent recovery and (b) recycling the solution for further absorption. These processes are quite insensitive to the partial pressure of acid gases in the feed and generally exhibit little or no selective absorption of H_2S over carbon dioxide. The chemical processes may be subdivided into those using amine scrubbing solutions and those based on alkali scrubbing solutions.

The principal reactions involved in gas-sweetening with amine solutions (10-30 percent by weight) may be represented as:

$$RNH_2 + H_2S \longrightarrow RNH_3 \cdot HS$$

$$RNH_2 + CO_2 + H_2O \longrightarrow RNH_3 \cdot HCO_3$$

Monoethanolamine (MEA) will easily reduce the H_2S content below four ppm; however, it is not considered selective, even though the rate of CO_2 absorption is less than for H_2S. The principal disadvantage of MEA is that it will react with COS and CS_2 to form nonregenerable compounds. Diethanolamine (DEA) will not react with these contaminants and is favored for service where COS and CS_2 are likely to be present. Like MEA, DEA solutions are not selective for H_2S. Tertiary amines, such as triethanolamine and methyldiethanolamine, while not as reactive as the other amines, have the advantage of being selective towards H_2S removal. The tertiary amines are two to four times more costly and find little application in industrial gas-sweetening.

The alkali scrubbing system may be represented by the following chemical reactions:

$$M_2 CO_3 + H_2S \longrightarrow MHS + MH \cdot CO_3$$

$$M_2 CO_3 + CO_2 + H_2O \longrightarrow 2\ MH \cdot CO_3$$

In the "hot-pot" processes, an aqueous solution of 25-35 weight-percent $K_2 CO_3$ is used to absorb acid gases at temperatures in the range of 200-500°F. With low H_2S/CO_2 ratios, the process is capable of sweetening the gas to five ppm. A degree of selective H_2S absorption over CO_2 can be achieved by taking advantage of the relatively slow rate for CO_2 absorption. In addition to removing H_2S and CO_2, the process can remove COS and CS_2 by hydrolysis of these components to CO_2 and H_2S. The Catacarb and Benfield processes are improved versions of the Bureau of Mines "hot-pot" systems insofar as they employ activators to increase the rate of absorption, thereby decreasing the required solution-circulation rate. Disadvantages of these hot-potassium-carbonate systems are a relatively high steam consumption for regeneration, a required operating pressure above 300 psi, and an inability to remove mercaptans.

Physical Solvent Processes

Physical solvent processes all use organic solvents to remove acid gases by physical absorption, which is directly proportional to the partial pressure of the acid-gas components, rather than by chemical reaction.

These processes are most applicable to high-pressure treating, where appreciable quantities of sour gases are present. After absorption, the "loaded" solvent is regenerated by a reduction in heat, pressure, or both, giving a concentrated stream of H_2S plus CO_2 and a recyclable lean solvent. Because of the higher solubility to H_2S in these organic solvents, selective absorption of H_2S over CO_2 can be achieved. In general, these processes have two major disadvantages: The solvents have a great affinity for heavy hydrocarbons (C_5+), which contaminate the gas stream fed to sulfur-recovery units; and the solvents are quite expensive, so that large solvent losses cannot be tolerated.

In order to maximize the solubility of acid gases and minimize solvent loss through vaporization, the processes are generally operated at or below ambient temperature. In addition to removing H_2S and CO_2, the solvent processes are all capable of removing COS, CS_2, and mercaptans without solvent degradation, as well as of dehydrating the gas to a low dew point. The low heats of solution for acid gases result in appreciably lower steam requirements for solvent regeneration compared with the chemical solvents.

The Sulfinol process is unique in that it combines the characteristics of a solvent process and an amine process. The physical absorbent, Sulfolane, gives high acid-gas loadings at high acid-gas partial pressures, giving it bulk-removal capacity, and the chemical absorbent, DIPA, reduces residual acid gases to very low values. However, the presence of the chemical solvent reduces the H_2S selective absorption for this system compared with the straight solvent processes.

Direct-Conversion Processes

These consist of two types of processes:

(1) Those based on oxidation-reduction reactions; and

(2) Those based on the stoichiometric reaction of H_2S with SO_2 in the presence of a solvent.

In the first type, H_2S is absorbed in an alkaline solution containing oxidizing agents. The H_2S is then oxidized to elemental sulfur by feeding air to the regenerator, and the sulfur product is separated from the regenerated solution by froth flotation. Partial removal of COS, CS_2, and mercaptans is also possible.

The second group of direct conversion processes consists of those in which H_2S is absorbed in a solvent and converted to elemental sulfur by the Claus-type reaction with SO_2:

$$2H_2S + SO_2 \longrightarrow 3S + 2H_2O$$

The solvents are usually aqueous solutions of organic or inorganic agents.

Generally speaking, the low solution loadings exhibited by this group of processes make them uneconomical for treating large, very sour gas streams. They are best suited for sour gases containing less than 1.0% H_2S, with sulfur production under 20 tons/day. These processes are almost totally selective for H_2S removal.

Dry-Bed Processes

These sweetening processes are based on adsorption of acid gases by a fixed bed of solid absorbent. Due to their low adsorbent loading, they are applicable to gases containing low concentrations of H_2S and mercaptans, perhaps less than 500 ppm. These processes can be subdivided into the iron-oxide processes and the various molecular-sieve processes.

The iron-oxide, or dry-box, process is one of the oldest processes known for removing sulfur compounds from industrial gases. In the iron-sponge system, wood shavings impregnated with hydrated ferric oxide are used to absorb H_2S:

$$2\ Fe_2\ O_3 + 6\ H_2S \longrightarrow 2\ Fe_2\ S_3 + 6\ H_2O$$

Regeneration of the absorbent is carried out with air:

$$2\ Fe_2\ S_3 + 3O_2 \longrightarrow 2\ Fe_2\ O_3 + 6S$$

This process is best suited for small-to-medium gas volumes with low sulfur contents, otherwise the sponge-bed life would be too short to be economical. The process is selective towards H_2S and mercaptans and will partially remove COS and CS_2. Sweetened gas of less than 5 ppm H_2S is easily obtained. However, sulfur recovery would not be economical using the iron-sponge system.

Molecular sieves can be tailor-made to have pore sizes that will permit selective absorption of H_2S over CO_2. The sieve processes also appear to be economically attractive for small-to-medium gas volumes having low H_2S content. Additionally, for efficient H_2S removal, the raw sour gas should have a water content below 20 lb/MMSCF, because water will also be absorbed by the molecular-sieve structure.

4.2.2 High-Temperature Desulfurization Systems

High-temperature systems for sulfur removal from fuel gases are not presently available in commercial scale. Several processes, now in various stages of development, may prove acceptable for desulfurization over a temperature range of 800-2000°F. These systems employ limestone, dolomite, iron oxides, molten salts, and molten metals as sulfur-capture agents. The principle underlying high-temperature desulfurization is the formation of metal sulfides by chemical reaction of the absorbent with sulfur compounds in the gas. The degree of desulfurization attainable depends on the chemical equilibria for the particular system at operating conditions. As with low-temperature processes, economics dictate that the sulfided absorbent be regenerated for re-use.

High-temperature technology currently under development, as described in the literature,(181)(232) is summarized in Table 4.4. The Sintered-Iron-Oxide Process of the Bureau of Mines and Consol's Half-Calcined-Dolomite Process are relatively advanced in their development and may reach commercialization sooner than the others.

Bureau of Mines Process

This process, under development at the Morgantown Energy Research Center, is based on a sintered absorbent consisting of a mixture of iron oxide (Fe_2O_3) and fly ash. This sorbent satisfies the primary requirements for high-temperature sulfur removal in that it is readily available and inexpensive, has reasonable absorption capacity for sulfur, can be regenerated for repeated use, and is resistant to fusion and disintegration over the operating temperature range of 1000-1500°F. The absorbent is prepared by mixing iron oxide with "as-received" fly ash, to a total iron-oxide content of about 35%. Iron-oxide contents above 40% were unsatisfactory, because the fusion temperature was lowered within the operating range.

Absorption studies over the range of 1000-1500°F show sulfur capacities of 10 to 25% by weight, respectively, for dry simulated producer gas. The presence of water vapor reduces the capacity to 6-10% by weight, but there is no evidence of loss of absorption effectiveness over 150 cycles of regenerations.

The reaction mechanism is chemisorption, wherein hydrogen sulfide diffuses into the sorbent particle and reacts with iron oxide, forming iron sulfide:

$$Fe_2O_3 + 3H_2S \longrightarrow FeS + FeS_2 + 3H_2O$$

$$FeO + H_2S \longrightarrow FeS + H_2O$$

Sulfided absorbent is regenerated with air at temperatures of 1000-1500°F, producing an SO_2-containing off-gas and reusable Fe_2O_3. Since sulfur recovery in the elemental form is preferable for pollution control, the formation of SO_2 is a disadvantage in this process.

Although the absorption of other sulfur compounds on this sorbent has not been studied, the removal of COS appears to be practical thermodynamically:

$$COS + FeO \longrightarrow FeS + CO_2$$

To date, this process has been operated on a pilot scale, absorbing H_2S in the raw producer gas from a 1.0 ton/hour stirred-bed coal gasifier. The H_2S content was reduced from 0.6% to 150 ppm at 1100-1200°F and 120 psi. Tar present in the raw gas was not removed by the absorbent. Further work on the regeneration cycle is currently in progress. Commercial-scale plants would be based on the multiple fixed-bed principle, alternating between absorption and regeneration cycles. Fluidized-bed operation would not be considered, because of potential attrition of the absorbent.

Table 4.4 High-Temperature Clean-Up Processes

					Efficiency of Sulfur Removal		Absorbent Characteristics			
Process	Absorbent	Type of Bed	Temp., °F	Pressure	% H_2S Influent	Effluent H_2S, ppm	Regeneration	Selectivity toward	Form of Sulfur Recovery	Status
1. Bureau of Mines	Sintered pellets of Fe_2O_3 (25%) and fly ash	Fixed bed	1000 to 1500	Insensitive to variation in pressure	95	350	With air	H_2S, COS	As SO_2 gas	Pilot
2. Babcock and Wilcox	Fe_2O_3	Fixed bed	800 to 1200	Insensitive to variation in pressure	99	75			As 12-15% SO_2 gas	Experimental
3. Consolid. Coal	Half-calcined dolomite	Fluidized bed	1500 to 1800	200 psia H_2S removal is high at low pressure.	95	350	10-13% with steam and CO_2	H_2S, COS	As H_2S gas to Claus process	Pilot
4. Air Products	Calcined dolomite	Fixed bed	1600 to 2000	Insensitive to variation in pressure			80-90% with steam and CO_2	H_2S, COS	As H_2S gas to Claus process	Abandoned
5. Battelle Northwest	Molten carbonates (15% $CaCO_3$)	Solution	1100 to 1700	Atmospheric; H_2S removal is high at low pressure, 5-6 psig.	95	350	With steam and CO_2	H_2S, COS, fly ash	As H_2S gas to Claus Process	Pilot
6. IGT-Meissner	Molten metal (proprietary)	Splashing contact	900		98	150	Electrolytic	H_2S, COS		Conceptual

Consol's Dolomite Process

In this process, raw fuel gas is desulfurized in a fluidized bed of half-calcined dolomite acceptor at 1600-1700°F, according to the following reaction:

$$\left[CaCO_3 \cdot MgO\right] + H_2S \longrightarrow \left[CaS \cdot MgO\right] + H_2O + CO_2$$

The sulfided acceptor is regenerated by the addition of steam and CO_2 at reduced temperature, thereby reversing the absorption reaction. Regeneration is conducted in a fluidized bed at around 1300°F, giving a dilute H_2S off-gas (less than 10% by volume). Because the low-H_2S off-gas content prohibits the direct use of a vapor-phase Claus unit for sulfur recovery, Consol is proposing the use of a liquid-phase sulfur-recovery system based on the Wachenroeder reaction:

$$2H_2S + H_2SO_3 \longrightarrow 3S + 3H_2O$$

Although no data have been reported for COS adsorption by half-calcined dolomite, high COS-removal efficiencies are predicted thermodynamically, according to the reaction:

$$\left[CaCO_3 \cdot MgO\right] + COS \longrightarrow \left[CaS \cdot MgO\right] + 2\,CO_2$$

A maximum operating temperature for this process is imposed by the partial pressure of carbon dioxide in the gas phase; i.e., the temperature cannot exceed that at which the CO_2 partial pressure is equal to the decomposition pressure for $CaCO_3$ via the following reaction:

$$CaCO_3 \longrightarrow CaO + CO_2$$

An apparent drawback to the process is the low degree of regeneration obtainable for the sulfided acceptor, around 10-13%, which results in a large recirculation of sulfided dolomite to the absorber. At present, the Consol desulfurization process is under development in the pilot-plant stage.

4.2.3 Comparison of Low- and High-Temperature Clean-Up Systems

Several investigators have estimated the effects of low- and high-temperature gas clean-up on LBG/CCPG system performance.(212)(225)(242) The results of these investigations are summarized in Table 4.5. In general, it appears that hot clean-up systems, using the Bureau of Mines Sintered-Iron-Oxide Process at 1000°F, result in an increase in the combined-cycle efficiency of about one percentage point. Where a moving-bed gasifier is employed without tar recycle (i.e., by-product tar is used to generate steam in a fired boiler), the efficiency advantage for hot clean-up is about six percentage points. Comparison with LBG/CCPG systems based on the Consol Half-Calcined-Dolomite Process for gas clean-up at 1700°F shows an advantage of one to six percentage points, depending on the investigator.(212)(225)

Table 4.5. Comparison of Low- and High-Temperature Clean-Up

Reference	Gasifier Type	Gas Turbine Inlet, °F/PR	Low-Temperature Clean-Up System	High-Temperature Clean-Up System	Plant Efficiency, %
(225)[a]	Moving Bed - Air	2200/16	Selexol at 100°F	- - -	31.4
(225)[a]	" "	2200/16	- - -	Iron oxide at 1000°F	32.0
(225)	Entrained Flow - Air	2200/16	Selexol at 100°F	- - -	31.9
(225)	" "	2200/16	- - -	Dolomite at 1700°F	37.6
(225)	" "	2600/24	Selexol at 100°F	- - -	36.0
(225)	" "	2600/24	- - -	Dolomite at 1700°F	42.5
(212)	" "	2400/16	Benfield at 230°F	- - -	43.9
(212)	" "	2400/16	- - -	Dolomite at 1700°F	44.9
(242)	" "	1950/10	Benfield at 230°F	- - -	38.0
(242)	" "	1950/10	- - -	Iron Oxide at 1000°F	38.4
(242)	" "	2400/16	Benfield at 230°F	- - -	40.8
(242)	" "	2400/16	- - -	Iron Oxide at 1000°F	41.6
(242)	Moving Bed - Air	1950/10	Benfield at 230°F	- - -	31.0
(242)	" "	1950/10	- - -	Iron Oxide at 1000°F	37.0
(242)	" "	2400/16	Benfield at 230°F	- - -	34.5
(242)	" "	2400/16	- - -	Iron Oxide at 1000°F	41.2
(242)	Moving Bed - O_2	2400/16	Benfield at 230°F	- - -	32.4
(242)	" "	2400/16	- - -	Iron Oxide at 1000°F	39.9
(242)[a]	" "	2400/16	Benfield at 230°F	- - -	39.6
(242)[a]	" "	2400/16	- - -	Iron Oxide at 1000°F	40.6

[a] Tar by-product recycled to gasifier

While high-temperature clean-up systems do appear to offer some efficiency advantage for LBG/CCPG plants, the selection of a cleanup system for integration in a commercial installation in the mid-1980s will be based on low-temperature technology. This conclusion follows from consideration of the development status of high-temperature technology, as well as from the associated design, operating, and environmental problems imposed on integrated LBG/CCPG systems using high-temperature clean-up.

In general, commercialization of high-temperature systems appears to be 5-10 years away. The processes under development are all capable of selectively removing H_2S down to acceptable levels (less than 500 ppm). Areas that need further attention include ability to contend with other sulfur-compound and nitrogenous-compound contaminants present in raw producer gas, absorbent life expectancy, actual performance data to demonstrate long-term reliability, and recovery of elemental sulfur from regenerator off-gases. It would appear that the Bureau of Mines process shows promise of being the first to mature.(220)(225)(242) This process has been demonstrated on actual producer gas; it involves relatively simple operation, without complex solids handling, and has proven suitable for cyclic operation without loss in acceptor activity. The problem of sulfur recovery from the regeneration step represents the major area for refinement.

Along with the development of high-temperature desulfurization processes, parallel developmental efforts are required in the areas of gas-turbine protection and NO_x emission control.

Gasifiers followed by quenching and subsequent scrubbing operations probably establish the complete removal of dust and trace vapor-phase contaminants occurring in the fuel gas. Chlorine and sodium are of particular concern as dangers to the gas turbine. The high additional degree of purification provided in the cold-purification-type process configuration may be essential for securing prolonged gas-turbine life, in which case hot purification has no future in combined-cycle applications. Turbine manufacturers (212) have cautioned against the development of gasification-purification schemes without regard for the stringent constraints of the gas turbine on trace materials in the fuel. As things stand, hot purified fuel gases may not be suitable for use in high-temperature gas turbines, even with near-perfect fuel filtration. The question must be settled by a development program leading to the simultaneous testing of all the component equipment in the hot-purification-supported combined-cycle unit in an integrated system.

Commercialization of hot fuel-gas purification cannot occur without supporting dust-removal-equipment development.(220)(225)(242) Methods considered for removing dust from high-pressure, hot sulfur-containing fuel gas are cyclones, panel-bed filters, and filters based on the use of a metallic cloth. Only cyclones are commercially available for this service, but cyclones may not have the capacity to prevent plugging of the absorbent bed with gasifier dust. Cyclones certainly do not have the ability to prevent submicron-size dust from entering the gas turbine. If submicron-size dust becomes a problem, some form of stack-gas scrubbing or filtration could be required in combined-cycle units.

Another problem associated with the application of hot desulfurization processes is their lack of capability to remove nitrogen compounds, such as ammonia, from fuel gas. Ammonia in the fuel gas will be burned to NO_x in the gas-turbine combustor, contributing greatly to the emission-control problem. Robson(225) has indicated that NO_x emissions from a moving-bed gasification/combined-cycle system with high-temperature desulfurization could be 20 times greater than the emission from the same system with low-temperature desulfurization. The combined-cycle NO_x emission problem may prove to be the most important factor preventing use of hot purification systems.

4.2.4 Clean-Up-System Selection

Low-temperature desulfurization systems for application in low-Btu fuel-gas plants will have to treat large volumes of sour gas, 500-1000 MMSCFD, having a total sulfur content in the range of 0.4 to 1.0%. In addition to H_2S, the raw gas will contain CO_2, COS, CS_2, probably mercaptans, cyanides, and heavy hydrocarbons. Of the types of process described in 4.2.1, it is evident that the liquid-scrubbing processes, physical solvents and some chemical solvents, are the best suited. These processes are currently available and can easily reduce the sulfur content such that, when combusted, SO_2 emissions well within present EPA regulations for conventional steam stations would result.

Moreover, these systems are available for integration with low-temperature water scrubbers to effect essentially complete removal of particulate matter, volatile trace metals, and ammonia from the fuel gas.

Selection of a low-temperature desulfurization process for LBG/CCPG application must be based on the following factors:

- Sulfur-removal capabilities, not only with respect to H_2S, but also other sulfur compounds, such as COS and CS_2.
- Selective absorption of sulfur compounds over carbon dioxide. Since CO_2 need not be removed from fuel gas intended for use in advanced power cycles, absorption of CO_2 represents an increased operating load to the system.
- Type of absorbent, insofar as the treated fuel gas may be contaminated by entrained or volatilized solvent, which could be detrimental to downstream system components (e.g., the gas turbine).
- Tendency to physically absorb combustible fuel-gas components and therefore to reduce the power-generating capacity of the system.
- Tendency of solvent to react chemically with fuel-gas components and to reduce the power-generation capacity of the system or to become deactivated.
- Energy consumption for stripping (remembering that saved energy must be at a level where it can be usefully employed for other purposes).

- Environmental compatibility of the solvent. (Is it harmless? poisonous? biodegradable?, etc.).
- Capability to remove nitrogen compounds that cause NO_x pollution on combustion.
- Is the process commercially proven in the capacity range proposed?

No single recommendation can be made as to the best low-temperature sulfur-removal process. For an actual combined-cycle project, it is advisable to conduct a detailed process-evaluation study with the assistance of the process licensors. A literature evaluation of three low-temperature desulfurization processes integrated with LBG/CCPG systems concluded that their performances were comparable (see Table 4.6)(225).

For the purpose of the present assessment of LBG/CCPG technology, the Selexol process was selected as being typical of the available commercial low-temperature processes.

A schematic flow diagram of the desulfurization system, based on Allied Chemical Corporation's Selexol process, is given in Fig. 4.4(241). In this unit, hydrogen sulfide and carbonyl sulfide in the crude gas are selectively absorbed in a solvent in order to reduce the sulfur content in the treated fuel gas to about 1.0 pound of sulfur-dioxide equivalent per million Btus (HHV) of coal charged to the plant.

The cooled, ammonia-free crude gas flows up through an acid-gas absorber, where it contacts Selexol solvent countercurrently over a carbon-steel packing. The treated gas from the top of the absorber flows through a knockout drum, which minimizes solvent losses, and is delivered as fuel gas to the gas turbine in the power cycle.

The rich solvent from the bottom of the absorber is let down through a hydraulic turbine that supplies a portion of the power required by the lean-solution pump. The solvent then flows to a flash drum, where most of the gases (other than H_2S) that dissolved in the solvent flash off. The flashed gas is compressed and recycled to the absorber.

The rich-solvent solution from the flash drum exchanges heat with hot, regenerated solution and flows on to the top of a regenerator. In the regenerator the absorbed H_2S and CO_2 are stripped from the solution.

Table 4.6. Plant Efficiencies for Three Low-Temperature Desulfurization Processes

Clean-Up System	Plant Efficiency, %
Selexol	31.2
Benfield	30.5
Rectisol	31.4

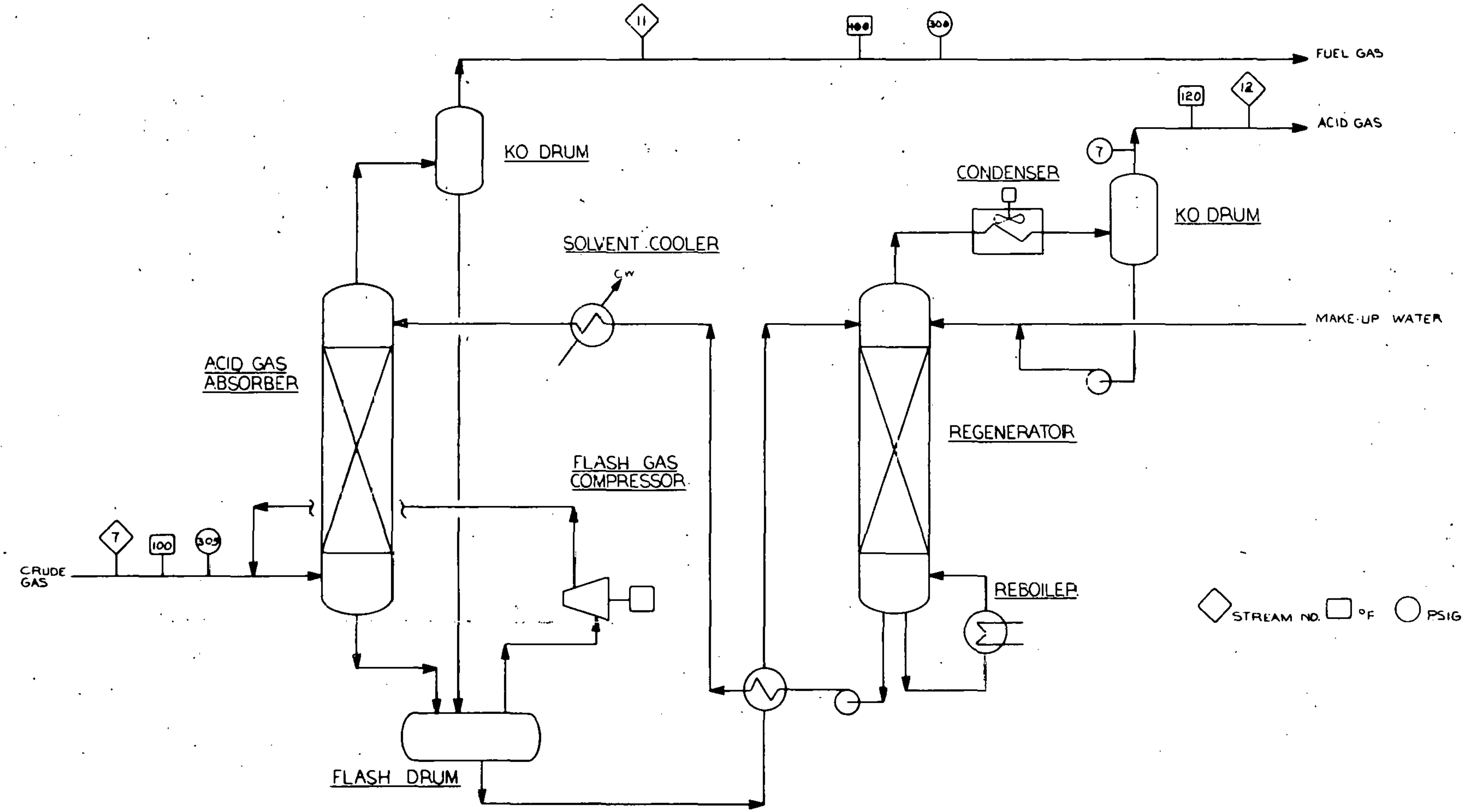


Fig. 4.4. Fuel-Gas Desulfurization (Process Flow Diagram)

Reboil heat is supplied by heat exchange with gasifier effluent or steam in a horizontal thermosiphon reboiler. Hot, regenerated solvent is pumped back to the absorber through three heat exchangers. Heat is first exchanged with rich solution, in order to reduce reboiler duty. Then the lean solution is cooled against boiler feedwater make-up and finally cooled down to operating temperature with cooling water. Acid gas from the regenerator overhead is cooled to 120°F in an air-fan cooler. The condensate produced in cooling is pumped back to the regenerator. To maintain the absorption system in water balance, demineralized water is added to the regenerator overhead.

Cooled acid gas from the regenerator overhead, containing at least 15% H_2S by volume, is sent to the sulfur-recovery unit.

4.3 COMBINED-CYCLE POWER GENERATION

4.3.1 General Background

Although the concept of combining gas-turbine generators with steam-turbine generators is not new, the recent proliferation of literature concerned with these power-generating schemes attests to the increased consideration being given to increasing power-generating efficiency now that most of the world finds itself in an expensive, energy-short position. Electric utilities presently are using a rather small number of combined gas/steam cycles for peak-load applications. Literature studies on various fuels indicate a strong potential in using a combined cycle for substantially improving the over-all thermal efficiency of power-generating stations by gas-turbine power extraction at elevated temperatures.

With the continuing advances being made in materials technology, enabling the turbine blades to withstand increasingly higher temperatures and compression ratios, placing the gas turbine ahead of the steam-boiler cycle results in steadily increasing over-all plant generating efficiency, as well as permitting choice-of-fuel flexibility. Since turbine-materials technology has not advanced to the stage where the blades can tolerate the adiabatic temperature rise, using stoichiometric air in the combustion process, large amounts of excess air are required, even when low-Btu fuel is used. Therefore, the hot turbine-exhaust gas, at 800-1100°F for 2200°F turbine-inlet conditions, can be used to generate high-pressure steam in either a fired or unfired boiler.

The effectiveness of the gas turbine obviously lies in its ability to extract energy at the highest temperature possible. This is seen in Table 4.7 and dramatizes the potential gains as peak turbine temperature and compression ratio increase. The theoretical efficiency of the steam cycle is based on a peak steam temperature of 1100°F, which is about the limit of foreseeable steam-cycle technology. Only when gas-turbine technology advanced to the point where inlet temperatures in excess of about 1500°F were realized was serious consideration given to using the gas turbine as a power-generating machine on the front end of a steam system.

Table 4.7 Carnot Efficiencies of Gas and Steam Cycles

Power Cycle	Peak Fluid Temp.,°F	Sink Temp.,°F	Carnot Efficiency,%
Gas Turbine	1600	800	39
Gas Turbine	2200	800	53
Steam Turbine	1100	300	51
Topping Gas Turbine/Steam	2200	300	71

4.3.2 Power-Cycle Characteristics

Consideration of ideal, combined open gas/steam cycles, using low-Btu gas available from coal-gasification plants, is useful for indicating the variations that, on a pure thermodynamic-efficiency basis, lead to substantial improvements in over-all electric-power-generating efficiency. In this analysis of the idealized gas-turbine/steam-turbine cycle, no import or export of air or steam was considered. In the analysis of the real cycle combinations, the export of compressed air, required for operation and energy balance on the gasification section, as well as the export or import of process steam required by the fuel-gas production facilities, must be considered.

In a simple-cycle configuration, the gas turbine can be taken as a stand-alone unit to which a high-temperature moderate-pressure combustion gas is fed; energy is extracted to drive both an electric generator and the air compressor used to supply the fuel oxidant to the combustion chamber. The combustion-chamber pressure is determined by a judicious choice of compression-ratio and operable-temperature limitations imposed on the turbine machinery. The properties of the gas, essentially air in the case of low-temperature, then determine the turbine-exhaust temperature. For a stand-alone unit, this exhaust temperature is on the order of 1000°F and would be vented at atmospheric pressure. Depending on the design turbine temperature and pressure, the ideal net efficiency is on the order of 40 to 60%, after the power needed to drive the air compressor is subtracted.

Since the hot turbine-exhause gas possesses considerable enthalpy, the addition of a conventional steam cycle, in a non-fired waste-heat-boiler configuration, permits the generation of additional power at some added capital cost and increment in over-all efficiency.

Another possible configuration is the extension to a front-end gas-turbine topping system, followed by a steam-cycle system in which additional fuel is fired in the boiler. Supplemental air is not generally necessary, because large amounts of excess air have already been required for gas-turbine operation, dictated by the limitation imposed on the turbine-blade temperature. In this way, gradually increased fuel firing in the boiler approaches the conventional base case, in which all of the eletric power is generated via steam turbines in a closed steam/fired-boiler cycle.

The complete range of gas-turbine/steam-turbine combinations, using low-Btu gas (162 Btu/SCF, LVH), has been considered in this ideal analysis. Thermodynamic efficiencies were calculated for the following cases:

(1) Gas turbine, with no exhaust-heat recuperation

(2) Gas-turbine front-end, with exhaust-gas-heat recuperation in an unfired steam-boiler cycle

(3) Gas turbine/unfired steam boiler, with single steam reheat

(4) Gas turbine/supplemental fired steam boilers

(5) Gas turbine/fired steam boiler, with single reheat

(6) Conventional fired steam boiler, with and without single heat.

A generalized schematic illustrating various combinations of gas-turbine/steam-turbine power cycles is shown in Fig. 4.5. LBG fuel gas is received from the front-end coal-gasification unit and is compressed, drawing power from the gas turbine, to a pressure fixed by the choice of turbine compressor ratio (10, 15, or 20). Ambient air is likewise drawn and compressed to the same pressure, drawing power from the turbine. Air and fuel then enter a combustion chamber, at the compressor-outlet pressure, where the desired adiabatic temperature rise is achieved as dictated by turbine-blade inlet temperature and the percent excess air. The hot combustion gases then drive the gas turbine, where sensible heat is extracted to yield a net electric-power generation from the compressor-turbine combination. The moderately hot gas-turbine exhaust is then either vented (in the simple gas-turbine case) or enters a steam boiler that is either an unfired waste-heat boiler or a supplementary fired steam boiler, with or without steam reheat to extract incrementally more power from the system. The steam turbine, or final turbine stage if steam reheat is used, exhausts at two psia and 126°F, with a moisture content dictated by isentropic expansion. A water condenser supplies a sink for the latent heat of condensation for the exhaust steam. The 100°F condensate is then returned to the steam boiler to complete the cycle. In essence, the de-aerator has been considered to be an integral part of the boiler system.

In order to facilitate a true comparison based strictly on thermodynamic efficiencies, several terminal conditions in the gas/steam cycle were standardized at arbitrary values. The conditions chosen for all cases studied were:

(1) 162-Btu/SCF (LHV) fuel gas, available at 100°F and 14.7 psia.

(2) Air, available at 100°F and 14.7 psia.

(3) Stack-gas temperature of 300°F is attained.

(4) Cooling-water feed temperature to the condenser was set at 100°F, sink-effluent temperature at 126°F, and the assumed steam-turbine-exhaust pressure at 2 psia.

(5) No import or export of compressed air or steam was considered.

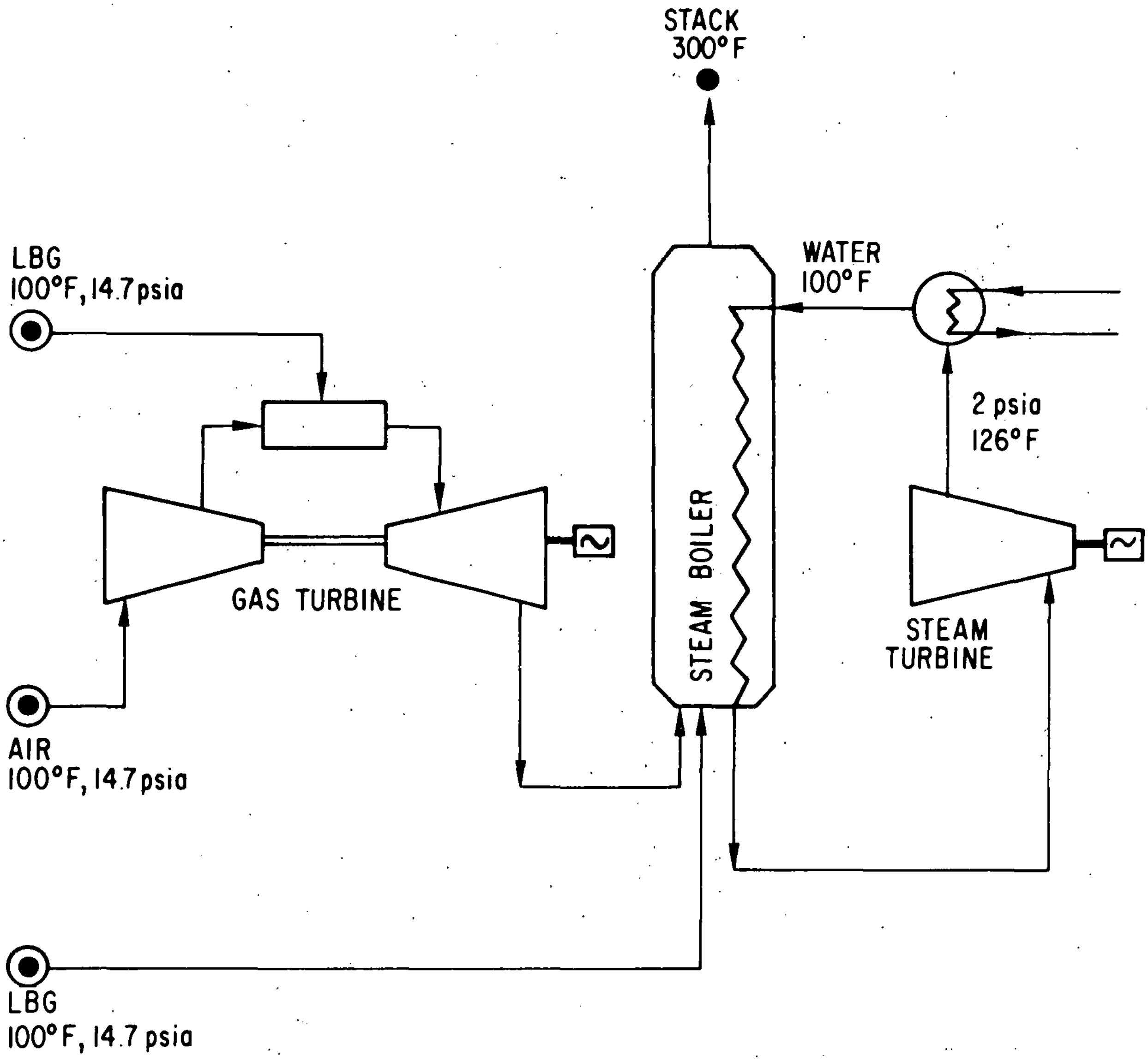


Fig. 4.5. Idealized Combined-Power-Cycle System

The simplest cases are those involving gas turbines alone, operating at various compression ratios. For the configuration in which additional power is generated by incorporating an unfired steam cycle, complications arise because of the rather low sensible heat in the turbine exhaust. Consequently, a match has to be made between the gas enthalpy and the enthalpy required to heat water, vaporize it, and superheat steam. What usually results is a low steam pressure (200-400 psi) at temperatures approaching 1000°F.

Typical enthalpy-temperature relationships for steam/water and combustion gas are illustrated in Fig. 4.6. It is evident that the maximum steam pressure that can be generated at t_s, from a hot combustion gas available at t_4 and exhausting at 300°F, is limited by the evaporation-temperature pinch point. Thus, for the case of a 2200°F gas-turbine inlet and 15 : 1 compression ratio, the exhaust gas enters the heat-recovery boiler at about 795°F, and the pressure of the steam raised is limited to 175 psia (t_s = 370°F). These conditions assume a 50°F superheat approach and a ΔT of 30°F at the evaporation pinch point.

The following boiler-heat balance (I) and ΔT-approach calculations (II) for 564 lb moles of combustion gas (100 lb moles of LBG and 464 lb moles of air) illustrate the method of estimation of the maximum steam-generating pressure:

(I) Gas Enthalpy = Steam/water enthalpy change = Turbine power + Condenser duty

$$564(7.2)(793 - 300) = F_w(1403 - 68) = F_w(1403 - 1024) + F_w(1024 - 68)$$

(II)

$$\Delta T \text{ pinch point} = \left[H_L^{t_{s1}} - H_L^{100°F}\right] \frac{F_w}{GC_p} + t_2 - t_{s1}$$

$$= \left[343 - 68\right] \cdot \frac{1500}{564(7.2)} + 300 - 370 = 32°F$$

Therefore, for a balanced boiler/steam turbine/condenser system with a boiler feed rate, F_w, equal to 1500 lb/hr, a low-grade 175-psia steam system results, with a boiler evaporation temperature of 370°F and steam superheat to 745°F.

In essence, the above procedure was used in calculating the theoretical efficiencies of various combinations of power cycles. However, because in the lowest turbine-compression-ratio cases (10:1 at 1800°F nozzle) the theoretical turbine-exhaust temperature is 732°F, 100 psia steam was chosen as the standard of comparison for the three unfired-boiler cases.

The results of the theoretical case studies are shown in Fig. 4.7. Since the theoretical turbine-exhaust temperatures are considerably lower than actual temperatures, the unfired boilers can (theoretically) raise only low-grade steam. For this reason, the gas-turbine cases at 10:1 pressure ratio followed by supplemental firing in the boiler were studied at 100

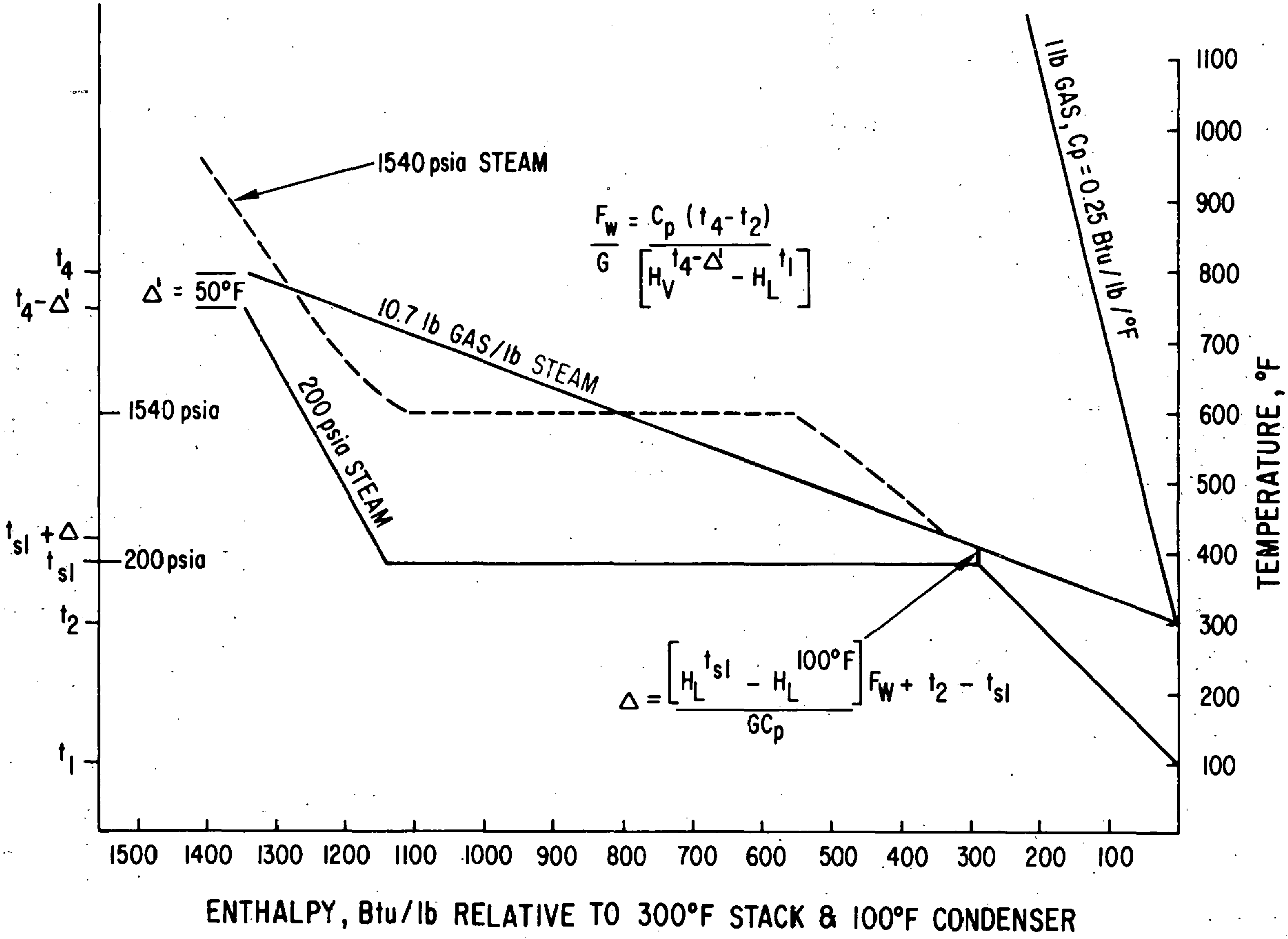


Fig. 4.6. Enthalpy-Temperature Diagram for Steam Boiler System

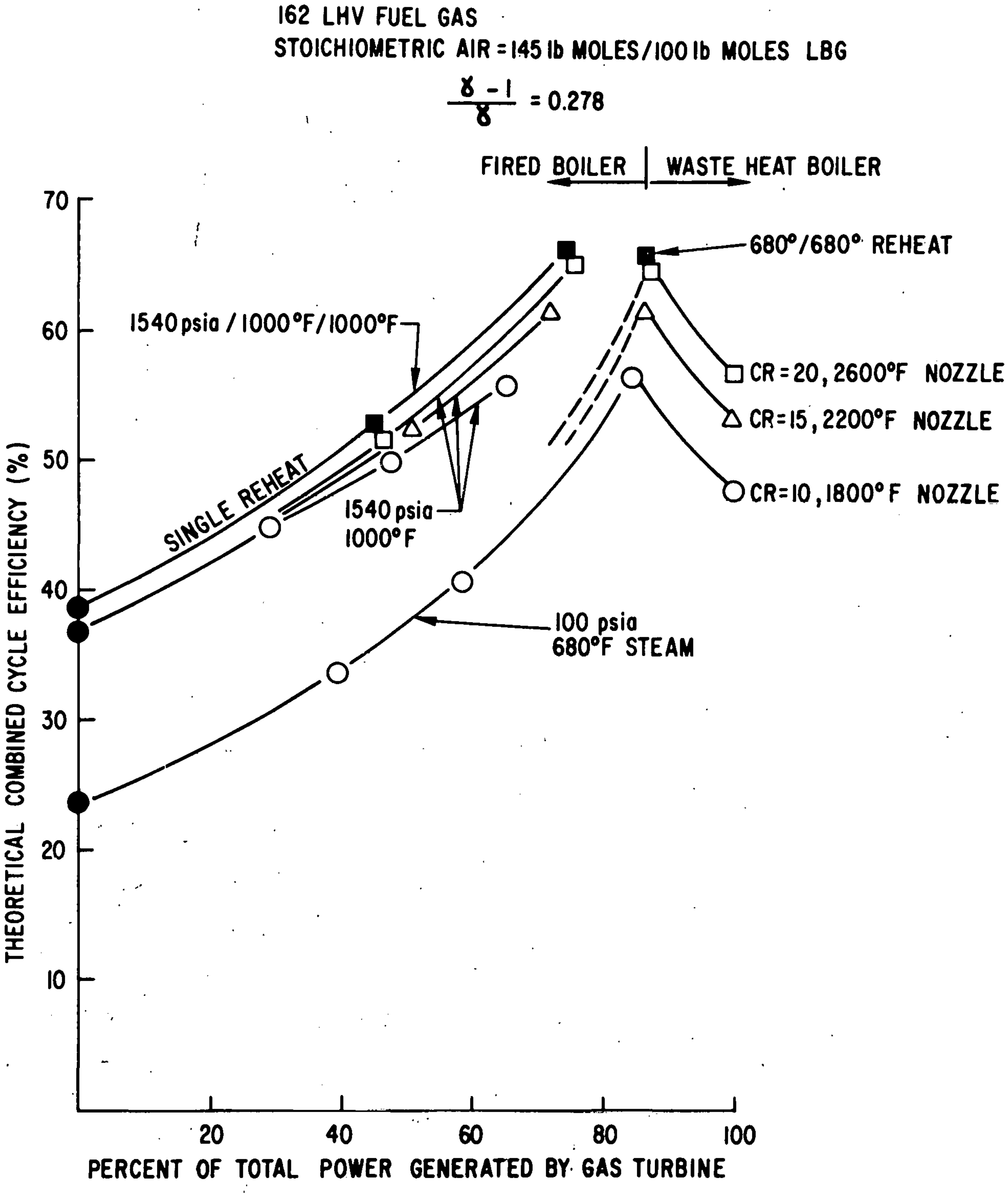


Fig. 4.7. Theoretical Efficiencies of Combined Gas- and Steam-Turbine Cycles for Power Generation

psia/680°F steam, even though 1540 psia/1000°F steam is usable when the boiler is fired to above 1050°F gas temperature. This procedure yields an efficiency comparison between various cycle combinations at high- and low-grade steam production and gas-turbine compressor ratios of 10 (1800°F nozzle), 15 (2200°F), and 20 (2600°F).

The results, which are a theoretical expansion of the trends in combined-cycle efficiencies presented by Wood(49), show a nearly linear increase in efficiency as the sensible heat in the hot (732°F - 870°F) turbine-exhaust gas is recovered via the steam cycle, even though the steam-condenser duty is consuming about 25% of the heat input. The net gain is a substantial increase in over-all LBG/combined-cycle efficiency. The gain in efficiency shown for the three turbine-nozzle temperatures for these idealized cases is merely the Carnot-cycle efficiency gain for the respective sink temperatures (732°F, 793°F, and 870°F).

At the point where approximately 15% of total power is being generated by the steam system, all the sensible heat has been extracted from the turbine exhaust and a fairly constant 25% of the heat input goes to the steam condenser; 10 to 20% is stack gas vented at 300°F. The former value is associated with considerably fewer moles of air, made possible by the higher tolerable gas-turbine-nozzle temperature. As supplemental LBG fuel is fired in the steam boiler, higher-grade steam can be produced. There is a balance between the efficiency gained by raising higher-level steam and having a lower percentage of heat loss to the stack, and the efficiency lost by imposing more percentage load on the steam-power-generating cycle. Thus, for a 10-20% increase in load on the steam cycle, the over-all combined-cycle efficiency remains about constant until supplemental boiler firing reaches the point at which the efficiency gain is limited by present steam-boiler technology.

Any additional boiler firing then begins to degrade the over-all cycle efficiency, even though considerable gains are made in reducing the percentage heat loss to the stack (no additional air is needed in the boiler until the stand-alone steam boiler is approached). Degradation from the maximum efficiency point, where condenser duty is approximately 25% of heat input, occurs in the conventional steam-cycle situation when approximately 56% of the heat input has been lost to cooling water.

As Fig. 4.7 shows, the gain in efficiency obtained by utilizing elevated nozzle temperatures in the gas turbine is reduced to a differential of about one percentage point as the drain (from the steam cycle) on the over-all efficiency begins to dominate.

Although a large number of steam reheats is theoretically possible (higher extracted power per condenser duty), the practical gain diminishes as capital cost increases. Figure 4.7 shows that in all cases studied, from the unfired boiler to the complete steam cycle, the gain in efficiency is approximately one percentage point for a single reheat; from commercial steam-plant experience, such a gain is well worth the effort.

4.3.3 Gas-Turbine Technology

Improvement of the gas-turbine component in the combined-cycle power plant is fundamental to increasing the over-all power-plant efficiency. One of the primary indicators of gas-turbine improvement for combined-cycle operation is the gas turbine's specific power. This is a measurement of gas-turbine output per unit of air-flow input, usually expressed in terms of KW/(lb/sec). Figure 4.8 shows the basic relationship between the gas turbine's specific power and combined-cycle efficiency.(224)

The two principal parameters that determine a gas turbine's specific power are the turbine-inlet temperature and compressor pressure ratio. The influence of these parameters on the turbine's specific power is illustrated in Fig. 4.9. The results shown in these curves were obtained by relatively simple cycle-analysis calculations(224) and are therefore strictly qualitative; however, the curves serve to demonstrate two points:

- The gas turbine's specific power increases in almost direct proportion to the turbine-inlet temperature.
- The optimum specific power is obtained when the pressure ratio is gradually increased as turbine-inlet temperature rises.

Therefore, gas-turbine manufacturers have increased compression ratios and firing temperatures together in their development of turbine machines.

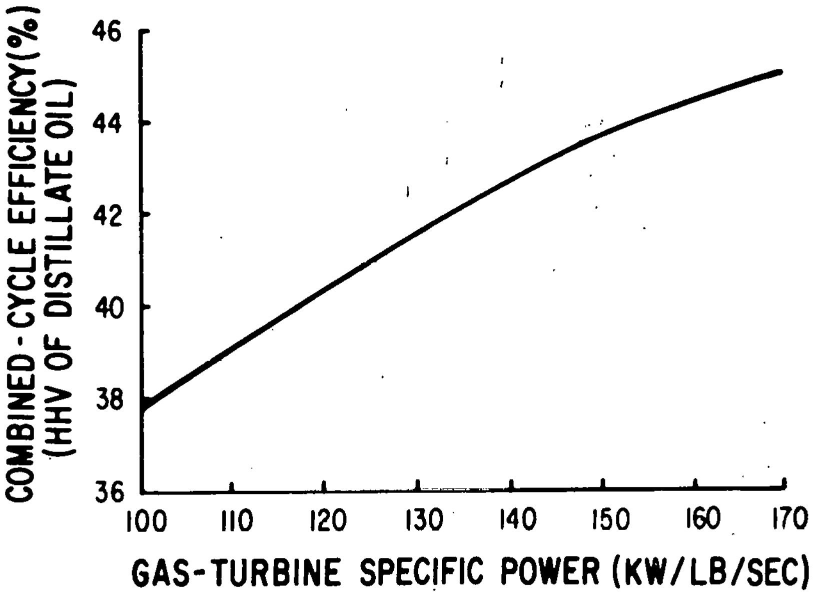


Fig. 4.8. Combined-Cycle Efficiency vs. Gas-Turbine Specific Power

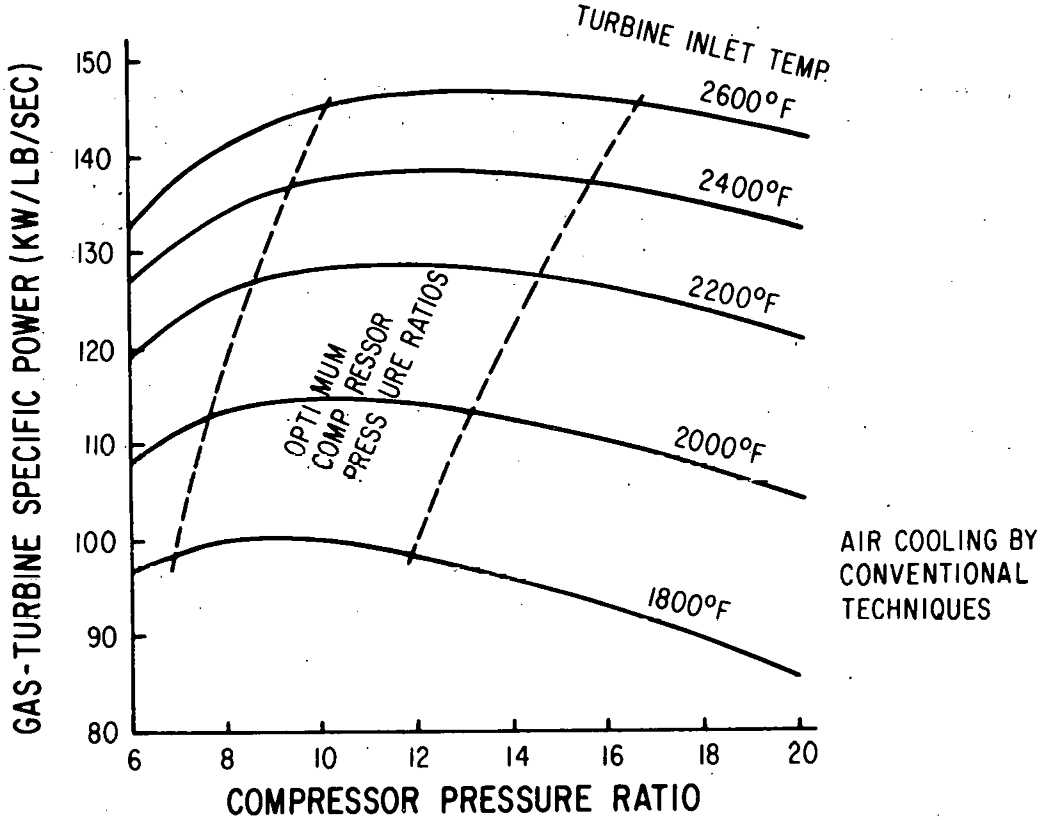


Fig. 4.9. Effect of Turbine-Inlet Temperature and Compressor Pressure Ratio on Gas-Turbine Specific Power

The band of optimum pressure ratios of Fig. 4.9 encompasses specific powers within approximately one percent of the maximum. Mechanical-design considerations dictate that design-point compressor pressure ratios be selected at values near the high limits of this band. Specifically, the lowest-pressure sections of the turbine element are subjected to greatly reduced temperatures for given turbine-inlet conditions at the higher pressure ratios. Thus, for the higher-pressure-ratio case, last-row vanes and rotating blades are subjected to lower temperatures and, therefore, require less cooling or less costly heat-resistant materials. Alternatively, with maximum cooling or best available materials in the last-stage section, higher blade stresses, and consequently larger annulus areas (for a give rpm), can be accomodated, thereby contributing to larger air-flow and higher unit-output capability.

As design turbine-inlet temperatures are increased from the current 1800-2000°F level to 3000°F, which is about the maximum level projected for low-Btu fuel-gas firing, the pressure ratios may be expected to rise from 10 to 18. Increasing the compression ratio does not require any technological breakthrough, but higher turbine temperatures will require significant improvements in combustor, nozzle, and blade materials, or in the extended use of air or water to cool the blades and nozzles.(66)

Turbine-Inlet Temperature

Historically, gas-turbine-inlet temperatures have increased by approximately 40°F per year since 1968. About two thirds of this increase has resulted from advances in cooling techniques, while the remainder has been generated by materials improvements. This general trend is expected to continue into the future. However, it is not clear at this time how much of the improvement will come from cooling and how much from materials development.

Projections in the literature for the development and commercialization of high-temperature turbine technology are summarized in Table 4.8 and plotted in Fig. 4.10. Current commercial gas turbines using conventional air cooling operate with firing temperatures up to 2000°F. By application of advanced air-cooling techniques, the turbine manufacturers project development to 2500-2600°F. Development of ultra-high-temperature turbines, 2600-3000°F, will likely employ transpiration and water-cooling techniques.

EPRI and, more recently, DOE are funding development programs for high-temperature turbine technology (HTTT). EPRI's program is expected to raise turbine temperatures to the 2800-3000°F range, rather than evolve with existing systems to 2200°F. Approaches being considered include advanced cooling systems based on air, water, and steam, as well as the use of ceramic components.(120) The goal of this program is to have operational systems ready in the 1986-1988 time frame.

DOE's HTTT program is emphasizing the development of the high-temperature portion of the gas turbine for a firing temperature of 2600°F (and, possibly, up to 3000°F, depending on the projected cost benefits associated with proceeding to 3000°F).(133) The over-all objective of the program is development of a 100-MW or larger size industrial gas turbine to a state of technology readiness by 1982. Commercial utilities could be using this technology by the mid-1980s.(186) In a separate program,(144) DOE is funding the development of a 10-MW industrial turbine operating at 2500°F to demonstrate technology readiness by 1980 and production readiness by 1982.

Gas-Turbine Selection

A gas-turbine-inlet temperature of 2200°F was selected, based on the projections for high-temperature-turbine commercialization in Fig. 4.10, for use in the combined-cycle power plant. This choice is consistent with basing the assessment of LBG/CCPG systems on technology likely to be commercially available in the mid-1980 time frame. This inlet temperature represents an increase of 150-200°F above present industrial designs and remains within the latest advances in air-cooling technology.

In addition, a pressure ratio of 16:1 was selected for the gas turbine. Although this ratio is not in the optimum range as shown by Fig. 4.9, it represents a desirable balance among several design objectives and limitations that must be met (including the highest possible combined-cycle efficiency, the desirability of a compressor design using only one shaft, and a turbine design resulting in gas temperatures at the large last row of turbine blades such that cooling is not required for currently available blading materials).(224)

Table 4.8. High-Temperature Turbine Technology

Reference	Turbine Inlet, °F	Turbine PR	Cooling Mode	Year of Availability	
				Technology	Commercial
(204) (209)	1850	10	Air	--	1974
(204) (209)	2000	10-12	Air	--	1978
(209)	2500	--	Air	--	1990
(225)	2200	16	Air	1978	--
	2600	24	Air	1985	--
(144)	2500	18	Air	1980-1982	--
(188)	2200	12	Air	--	1982
	2800	--	Water	--	1986
(201)	2400	12	Air	1980	1987
	3000	16	Water	1984	1990
(193)	2500	16	Air	--	1988
(157) (186)	2600	15-16	Air/Water	1982	>1985
(229)	2400	12	Air	--	1984
	2800	16	Water	--	1988
	3000	16	Water	--	1987

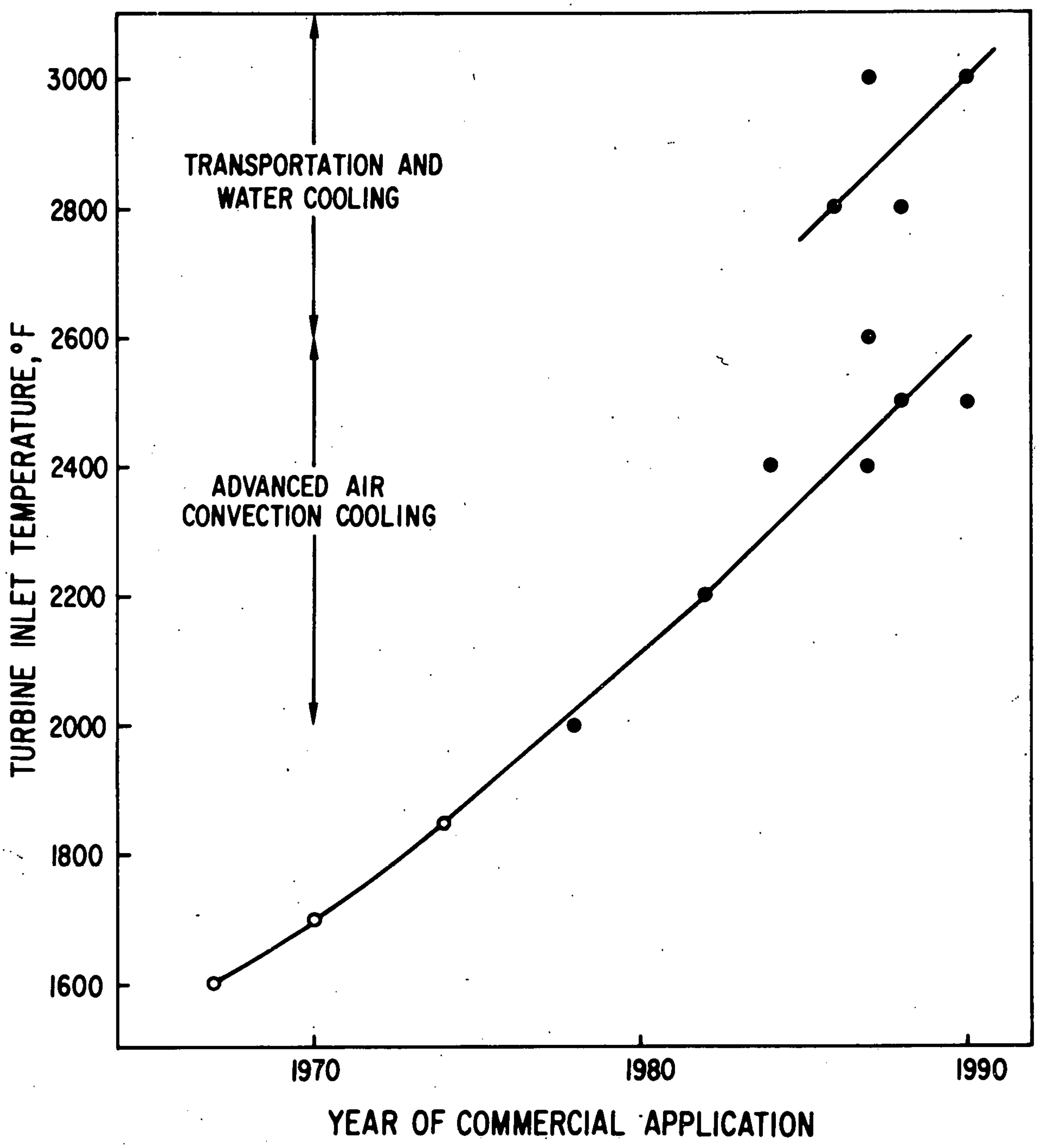


Fig. 4.10. Gas-Turbine Projections for Base-Load Application

4.3.4 Representative Combined Power Cycle

The representative combined power cycle selected for the assessment of LBG/CCPG systems in this study is illustrated in Fig. 4.11.

Based on the development of high-temperature gas-turbine technology, as discussed in the previous section, a gas-turbine-nozzle temperature of 2200°F, along with a 16:1 pressure ratio, was assumed. Because the idealized cases showed an increase of about one percentage point in efficiency when a single reheat was incorporated in the steam system, and because a fired boiler only contributes to over-all degradation of efficiency, a non-fired boiler and a single steam reheat were chosen as the standard operations by which to compare the calculated efficiencies of the six separate coal-gasification/combined-cycle power-generation systems. In all cases, mass and energy-balance requirements for exporting compressed air and exporting (or importing) various steam streams from the gas-turbine/steam cycle to the coal-gasification section were included.

Low-Btu gas (LBG) is available to the power-generation cycle at approximately 315 psia and 100°F. The fuel components are essentially CO, H_2 and CH_4, and the gas contains trace amounts of sulfur compounds and particulates. Because the LBG pressure is such that it permits direct injection into the turbine combustor, whose pressure is set by the turbine compression ratio, the power drain on the turbine/compressor/generator system is shaft horsepower to drive the air compressor and the generator. Depending on the front-end gasification process chosen for study, various quantities of compressed air must be exported to the gasification section for plant energy balance.

With a 949°F turbine exhaust gas available in all cases, the waste-heat boiler system is capable of producing 900°F/1045 psia steam for driving the steam turbines. Steam reheat to 900°F from the turbine exhaust at 470°F and 200 psia was used in all cases. Conditions for the steam-turbine-exhaust condenser were set at two psia and 126°F.

4.4 COAL-PREPARATION FACILITIES

Coal-preparation facilities are provided to condition the "as-received" coal to a specified degree of fineness and moisture content as required for feed to the gasifier. In addition, any tramp material present in the coal feed is removed.

In the present study of LBG/CCPG systems, from coal-storage pile to electric-power generation, it is assumed that coal feed is available from live storage in a size range of 2" x 0. The degree and complexity of the coal-preparation system, therefore, depends on the type of gasification system employed (i.e., moving bed, fluidized bed, or entrained flow). Figure 4.12 is a schematic diagram of the facilities required to prepare the "as-received" coal for feed to each of these gasifier types.(241)

For a moving-bed gasifier system, which can accept coal sized 1 1/2" x 1/4", the coal is reclaimed from storage piles by a bridge-type bucket-wheel reclaimer and processed via Scheme A. "As-received" coal is screened to

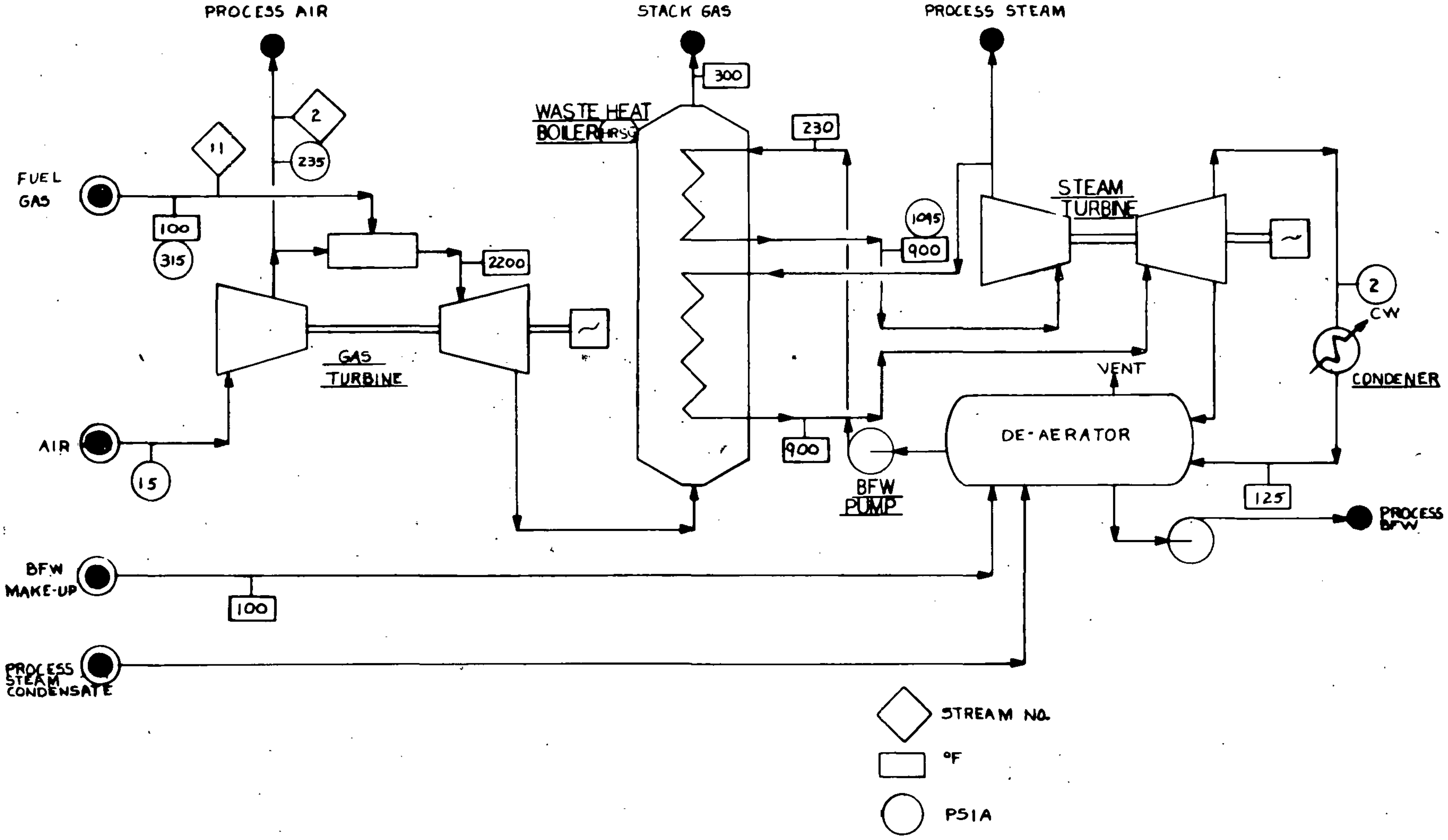


Fig. 4.11. Combined-Cycle Power Generation (Process Flow Diagram)

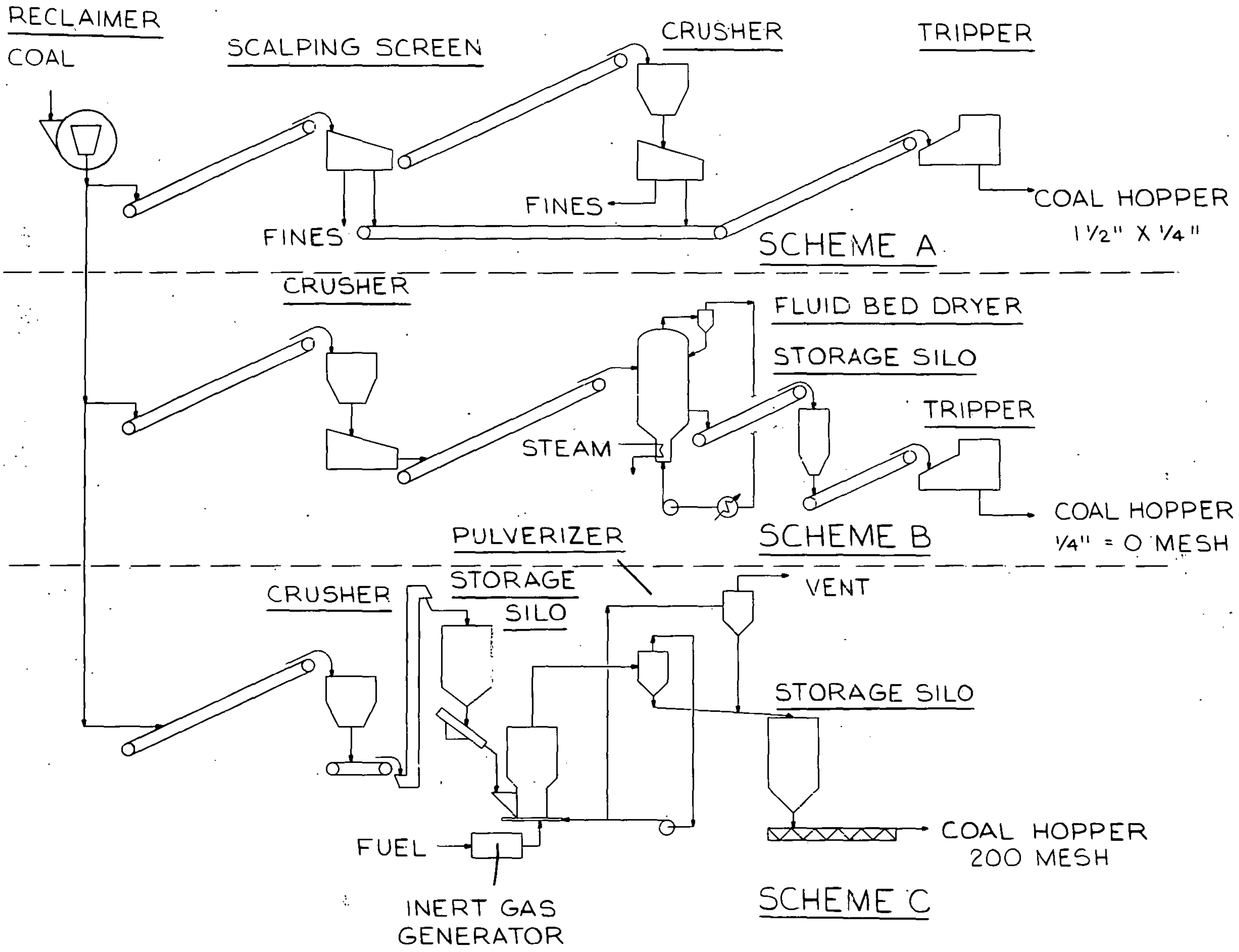


Fig. 4.12. Coal Preparation (Process Flow Diagram)

reject minus-1/4" fines and over-sized material. The latter is directed to a secondary crusher to maximize the 1 1/2" x 1/4" coal yield. Sized coal is carried by a series of conveyors to a tripper, which distributes the feedstock to the coal-feed hoppers above the operating gasifiers.

More extensive coal preparation is required for fluidized-bed and entrained-flow gasifiers, as illustrated by Schemes B and C, respectively. For the fluidized-bed gasification mode, the coal must be ground to 1/4" x 0, with a maximum of 10% passing through 100 mesh. Coal is reclaimed from storage and carried by a series of conveyors to a secondary crushing system. The crushed coal is transported by conveyor to a fluidized-bed drier, where the surface moisture is reduced to 2% or less. Moisture reduction to this level is required to prevent clogging in the pneumatic conveying lines that feed to the gasifiers. Steam is used as the heating medium to heat indirectly the gas stream that actually contacts and dries the coal. Ground, dry coal from the dryer is belt-conveyed to storage silos, from which the coal is conveyed and fed to the gasifier-feed hoppers through an automatic tripper.

As is shown in Scheme C, coal feed for an entrained-flow gasification system requires pulverization to 70% passing through a 200-mesh screen. In a typical arrangement, reclaimed coal is conveyed to a secondary crusher, where size reduction to minus 3/4" is achieved. Crushed coal is fed from storage silos to the pulverizers through a coal weigh-belt feeder. In the pulverizer, the coal is simultaneously ground, classified, and dried as hot inert gases fluidize the coal in the lower section of the mill. Pulverized coal is thereby dried to 2% moisture or less and conveyed by the drying gas to a separation cyclone. From the cyclone, the coal flows by gravity into storage silos, and the drying gas is recycled to the pulverizer. Water is removed from the system by venting a slip stream of the drying gas from the cyclone system to the atmosphere through a bag filter. Make-up inert gas and heat required for the drying process are supplied by low-Btu fuel gas.

Dry, pulverized coal is conveyed, either pneumatically or by screw conveyer, to the gasifier coal-feed hoppers.

4.5 BY-PRODUCT RECOVERY SYSTEMS

In general, by-products recovered from integrated LBG/CCPG plants include light oils and tar, elemental sulfur, and ammonia. The quantities of these by-products depend on the particular gasification system employed and the type of coal fed to the gasifier. Raw gas from low-temperature gasifiers (such as the moving-bed type that operates at 800-1200°F) will contain substantial quantities of oils and tars, resulting primarily from the devolatilization of coal. Fluidized-bed and entrained-flow gasifiers, operating at 1500°F-1800°F, yield only trace amounts of these materials in the raw gas. All gasifiers will convert the coal's sulfur and nitrogen content into volatile compounds, principally hydrogen sulfide and ammonia.

These by-products from coal gasification are removed from the raw fuel gas during gas clean-up and subsequently recovered in saleable form via downstream process systems.

4.5.1 Oil/Tar Recovery

Light oils and tars are separated from the gasifier offgas as a condensate stream, along with water, as the gas is cooled and scrubbed prior to low-temperature desulfurization. These condensates are collected and treated in an oil/tar-recovery system (see Fig. 4.13).(241)

Insoluble hydrocarbons are physically separated from the oily water by settling and sent to storage. The water phase is filtered to remove entrained solids and then treated by solvent extraction for removal of soluble phenolic compounds. The Phenosolvan process, licensed by American Lurgi Corporation, is typical of the available commercial technology, which can extract 99+% of the phenols and higher homologs from the foul water.

In this process scheme, the foul water is fed to an extraction tower, where it comes into contact with a circulating ether solvent. Solvent is recovered from both extract and raffinate phases, and the crude phenols are sent to storage. The raffinate water phase is subsequently processed in a condensate-treating system for recovery of other dissolved impurities.

4.5.2 Ammonia Recovery

Aqueous condensates from gas cooling and scrubbing, as well as the water effluent from oil/tar recovery, contain dissolved ammonia, hydrogen sulfide, carbon dioxide, and other trace compounds (such as phenols and hydrogen cyanide). These water streams are collected and processed in a condensate-treating system, where the volatile compounds are stripped from the liquid phase and anhydrous ammonia is recovered as a by-product. Figure 4.14 is a schematic representation of a typical treating system that incorporates sour-water stripping and ammonia recovery. This system is based on the USS Phosam process, licensed by USS Engineers and Consultants.(181)

In this arrangement, the feed stream is process condensate containing ammonia and other contaminated waters from the coal-gasification process. The water, which has been preheated in the lean-solution cooler, is stripped of its free ammonia and acid gases in the countercurrent sour-water stripper, using direct or indirect low-pressure steam.

The ammonia/acid-gas/water-vapor mixture passes into the bottom of the ammonia absorber, where its ammonia is removed by countercurrent contact with ammonia-lean phosphate solution entering at the top. Ammonia-free acid gas and water vapor leave the top of the absorber and are directed to the sulfur-recovery unit.

The ammonia-rich phosphate solution from the bottom of the absorber, which is heated by interchange with the hot, lean solution and further heated by overhead vapors from the stripper, then enters the top of the stripper, where NH_3 is stripped from the rich solution at elevated pressure by live steam entering the bottom of the column. Alternatively, a reboiler may be used, with high-pressure steam, and the steam condensate recovered. Lean solution leaving the stripper bottom, cooled by exchange with the rich solution from the absorber, is further cooled and recycled to the top of the absorber to continue the process.

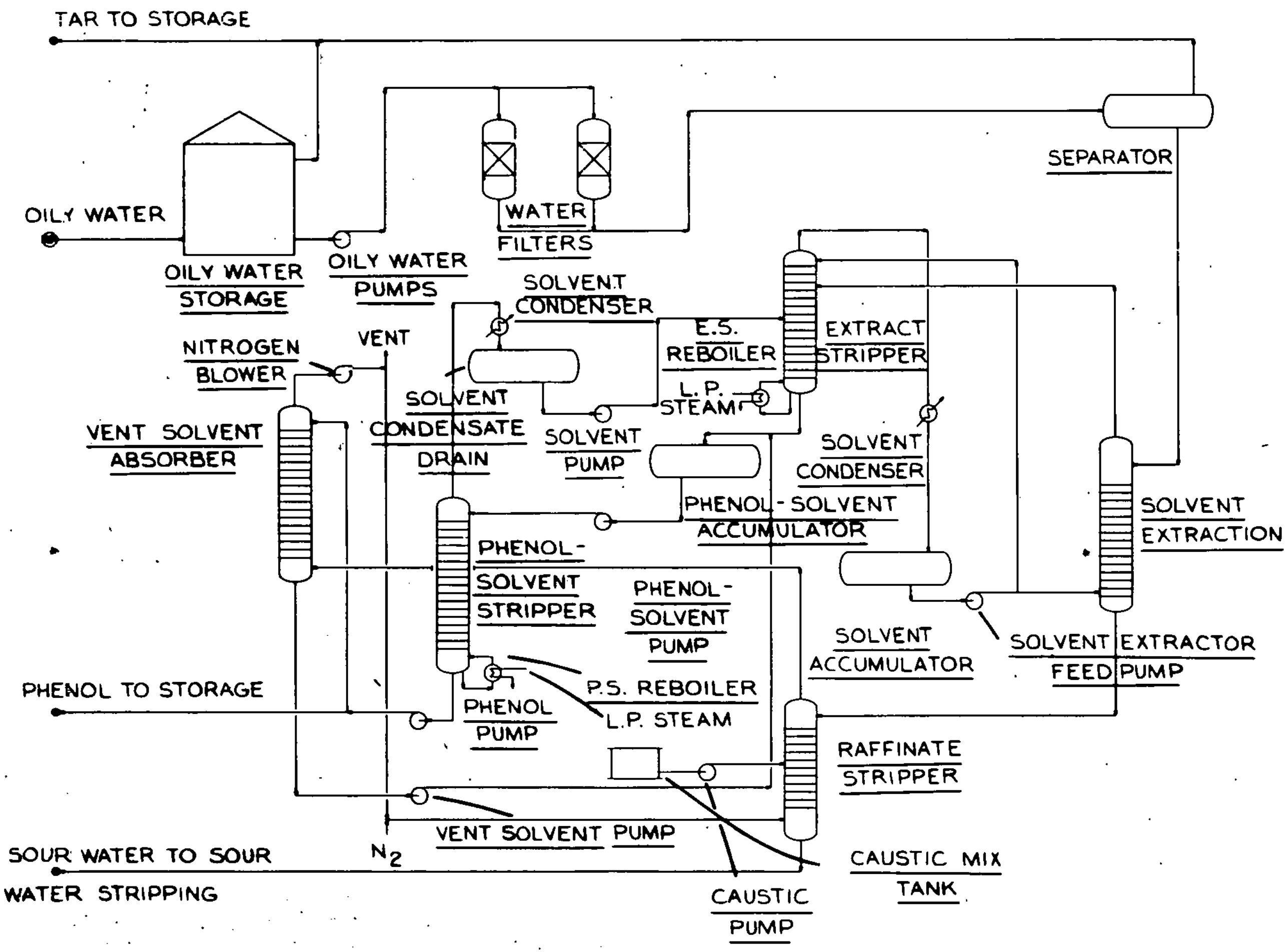


Fig. 4.13. Oil/Tar Recovery (Process Flow Diagram)

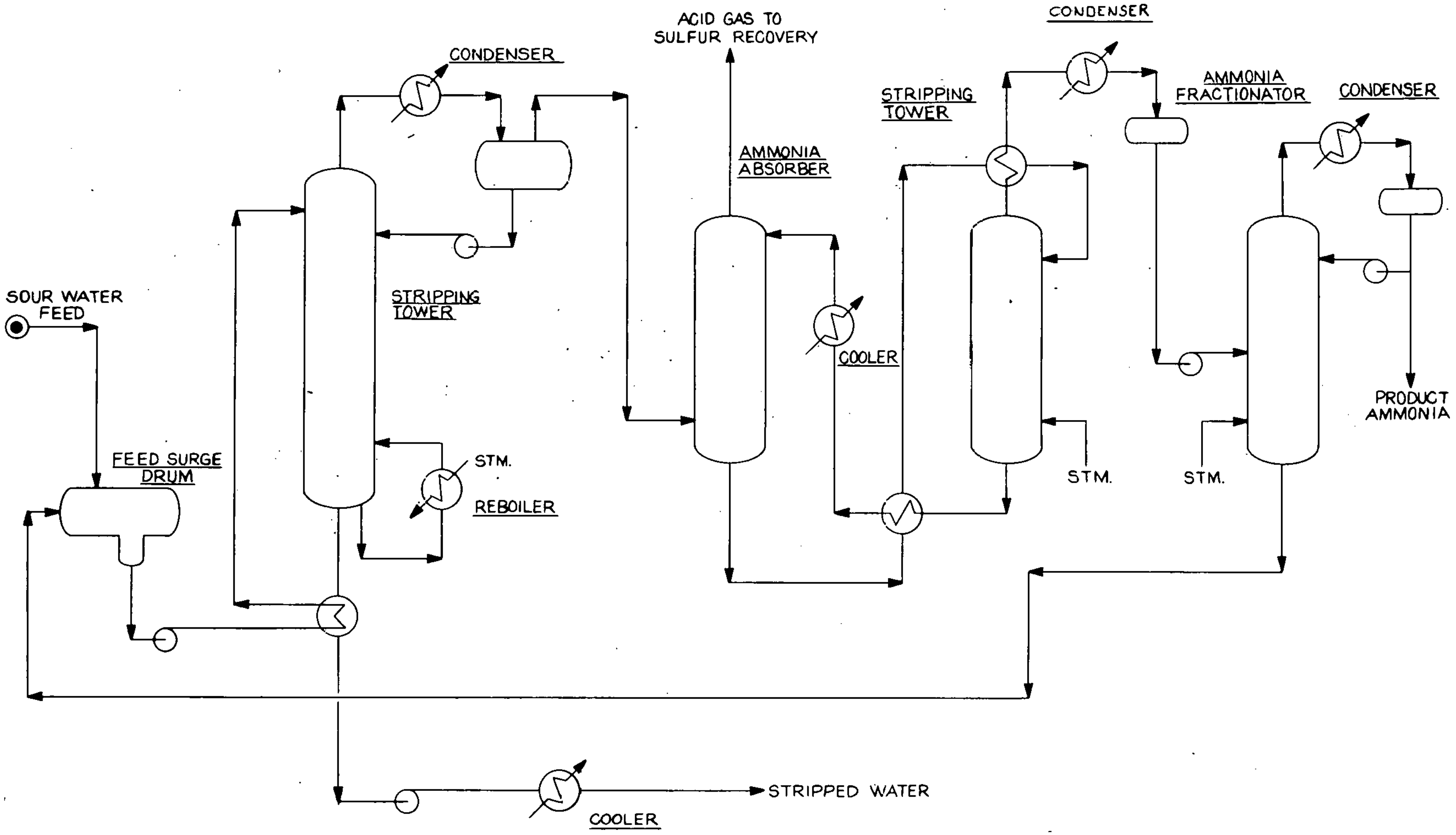


Fig. 4.14. Sour-Water Stripping and Ammonia Recovery (Process Flow Diagram)

Aqua-ammonia vapor from the top of the stripper passes through the two-stage condenser and flows to the fractionator feed tank. From here, the aqua-ammonia is pumped into the ammonia fractionator, where it is distilled at elevated pressure into a high-purity NH_3 vapor in the overhead and into a water stream containing less than 0.05% NH_3 in the bottoms. Steam enters at the base of the column and provides the necessary vapor flow for stripping and rectifying the NH_3 from the feed stream. Alternatively, the vapor may be generated in a reboiler. The overhead, pure-NH_3 vapor is condensed to form reflux and the product anhydrous liquid ammonia.

The Phosam process can reduce the free-ammonia content in the stripped waste water to about 100 ppm and recover 99% or more of the ammonia as anhydrous liquid (99.99% purity). The stripped waste water is subsequently treated in a biological treating unit and reused as process or cooling-tower make-up.

4.5.3 Sulfur Recovery

Sulfur compounds, primarily hydrogen sulfide together with some carbonyl sulfide and carbon disulfide, are present in the acid-gas streams produced by low-temperature desulfurization of fuel gas and generated in the condensate-treating unit. These acid-gas streams are combined and processed in a sulfur-recovery system, where elemental sulfur is produced as a marketable product. A typical commercial process scheme for the recovery of sulfur from H_2S containing acid gases is shown in Fig. 4.15.(241)

In this arrangement, the sulfur-recovery unit is a two-stage, acid-gas-bypass-type Claus unit with hot-gas reheat. About one third of the combined acid-gas feed is burned in a sulfur furnace. Air is supplied to the furnace by a blower. Heat is recovered from the combustion products by generating medium-pressure steam in a waste-heat boiler. The effluent from the sulfur furnace is mixed with the two-thirds portion bypassed around the furnace and fed to the first sulfur converter. The amount of acid gas bypassing the furnace is controlled to maintain a ratio of H_2S to SO_2 slightly greater than 2:1, to ensure a reducing atmosphere.

H_2S and SO_2 react in the converter to produce elemental sulfur and water according to the reaction

$$2H_2S + SO_2 \longrightarrow 3\,S + 2H_2O$$

The reaction is catalyzed by a bauxite or aluminum catalyst contained in the converter. The reaction is exothermic and results in a temperature rise in the gas flowing through the converter. The reaction is limited by thermodynamic equilibrium and consequently does not proceed to completion.

The sulfur produced in the converter and the heat of reaction are recovered by cooling the effluent below its sulfur dew-point against 50-psig steam generation. The sulfur condenses and flows by gravity to a concrete sulfur sump. Sulfur, which is a solid at ambient temperature, is kept molten in the sump by condensing low-pressure steam in pipe coils that cover the bottom of the sump.

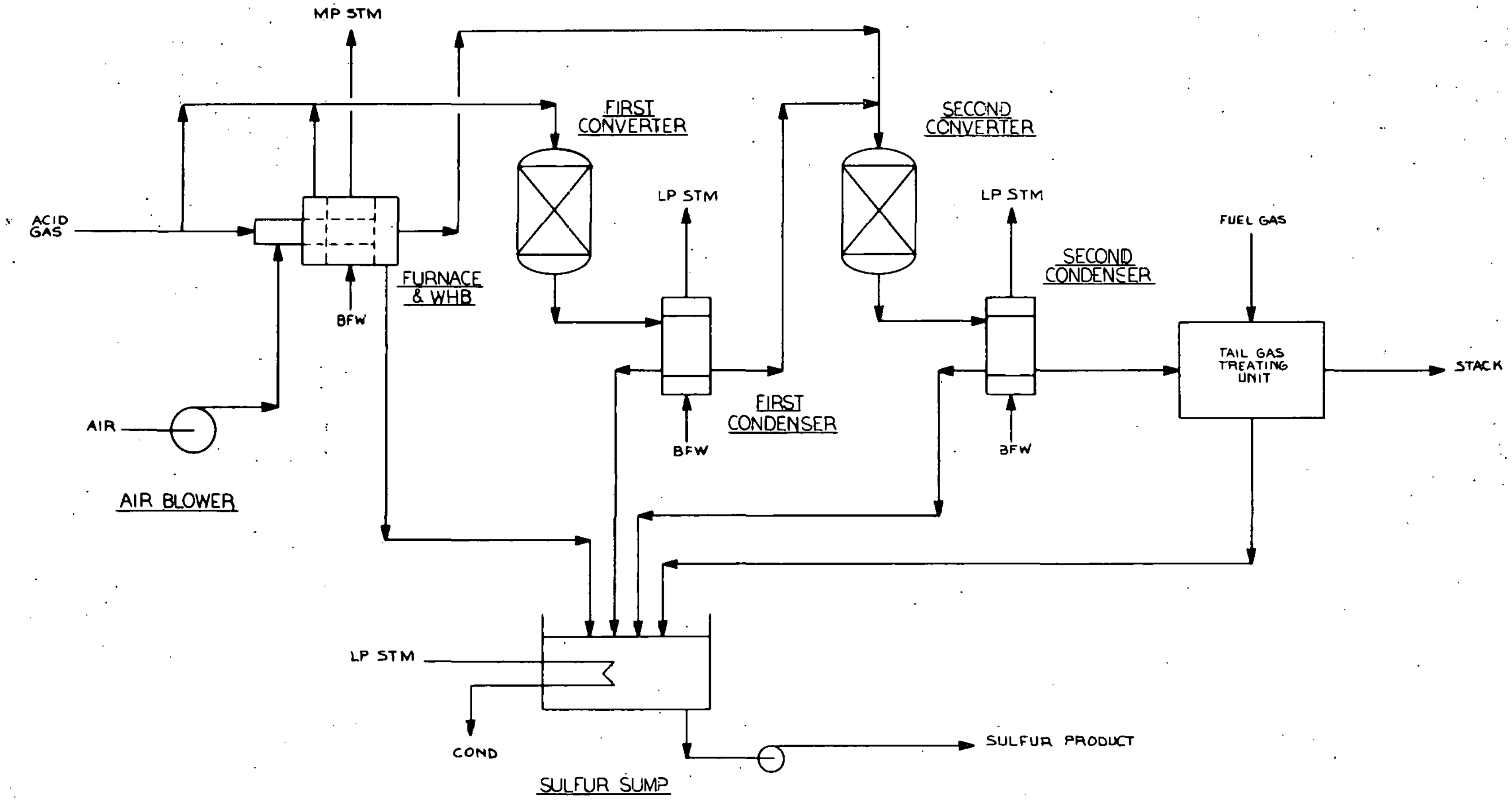


Fig. 4.15. Sulfur Recovery (Process Flow Diagram)

The cooled gases from the condenser are reheated to reaction temperature (by mixing them with a hot stream of combustion gases drawn off the sulfur furnace) before entering a second converter stage. In the second converter, the sulfur reaction proceeds further. Again, the converter effluent is similarly cooled to condense sulfur, which flows to the sulfur sump.

The gas stream from the last converter, called tail gas, contains unreacted H_2S and SO_2. To meet environmental requirements pertaining to process emissions, the tail gas is processed further to remove these sulfur compounds. The tail-gas-treating unit is a proprietary process called the Beavon-Stretford process, in which the remaining SO_2 is hydrogenated to H_2S, which is in turn oxidized to elemental sulfur using a chemically active solution. The sulfur recovered in the process is combined with sulfur from the Claus unit in the sump.

Typically, the over-all sulfur recovery from the combined Claus unit and tail-gas-clean-up system is greater than 99%, and the stack gas released to the atmosphere contains less than 250 ppm of sulfur, measured as SO_2.

4.6 ANCILLARY FACILITIES

In addition to the main processing sections, various support facilities are necessary for the integrated operation of an LBG/CCPG installation. Essentially, the ancillary facilities include the following systems:

Raw-water-supply system
Make-up-water treatment
Fire-water system
Potable-water facilities
Condensate storage and polishing
Cooling-water system
Auxiliary-steam generation
Fuel-oil facilities
Instrument/plant air system
Flare facilities
Ash disposal
Waste-water treatment

4.6.1 Raw-Water-Supply System

This system is required to deliver the plant make-up from the raw-water source to the plant's make-up-water treating system. Assuming that raw water is supplied from a surface source, this system would include a pump house accommodating two or more vertical water-supply pumps, each having a separate inlet channel. Traveling water screens would be installed in each inlet channel, and chlorination facilities would be provided for control of algae.

4.6.2 Make-up-Water Treatment

Raw water is taken into the plant to supply processing, cooling-tower, and steam-generation systems, and for miscellaneous uses. Details of the water-treating system depend on the source and quality of the raw water. Typically, raw water is received from the pumping station and stored in a raw-water/fire-water storage tank, which provides for eight hours holdup of water for utility purposes. Water is transferred from this tank to a conventional cold-lime-pretreatment system, which consists of a clarifier, gravity filters, and chemical feeders for lime, alum, and a coagulant aid.

Pretreated water is stored in a clarified-water storage tank, from which make-up water is fed to the demineralization system. The latter includes activated carbon filters, cation/anion-exchange beds, and acid- and caustic-regeneration systems. De-ionized water is stored in the demineralized-water storage tank, from which make-up boiler feed water is fed to de-aeration facilities.

4.6.3 Fire-Water System

The fire-water system provided for plant protection would include a fire-water storage tank, fire-water pumps, and an underground distribution system. Sufficient fire-water storage is provided by the raw-water/fire-water storage tank to allow one of the distribution pumps to operate at full capacity for a period of four hours. Two distribution pumps, rated at full capacity, are included. The main pump is equipped with conventional electric-motor drive, while the auxiliary pump is driven by a diesel engine. A jockey pump is included to pressurize the fire-water-distribution grid.

4.6.4 Potable-Water Facilities

A slip stream from the raw-water-distribution pumps is filtered, chlorinated, and stored in a potable-water storage drum, from which it is distributed to plant users via a buried piping system.

4.6.5 Condensate Storage and Polishing

Steam condensates from the plant are accumulated in a condensate storage tank. The condensate is treated in a condensate polishing unit and then returned to the de-aeration facilities. Condensate polishing is accomplished in mixed-bed demineralizers containing cation/anion resins and equipped with the necessary regeneration system for automatic operation.

4.6.6 Cooling-Water System

A conventional cooling-tower system is required to supply cooling water to the processing units. This system includes one or more mechanical-draft towers, each equipped with vertical-type circulation pumps, and a water-distribution system. A centralized chemical-feed package is provided to treat the total recirculated-water flow. This package includes equipment to monitor and control levels of corrosion inhibitor, pH, and biocide in the cooling-water system.

4.6.7 Auxiliary-Steam Generation

Auxiliary steam is required to warm up equipment when the plant is started up from a cold state and for winterization purposes if the plant is idle during cold weather. Equipment associated with the steam-generation facilities includes a standard water-tube packaged boiler, complete with a motor-driven forced-draft fan, self-supporting stack, oil-fired burner, feed-water controls, and burner instrumentation.

4.6.8 Fuel-Oil Facilities

Fuel-oil storage and supply facilities are required to supply the fuel-oil needs of the gas turbines during the startup sequence and for firing the auxiliary-steam boiler. These facilities include a cone-roof fuel-oil storage tank, transfer pumps, and fuel-oil heater to maintain proper temperature and viscosity of the oil for firing purposes.

4.6.9 Instrument/Plant Air System

This system provides air at about 100-psig nominal pressure to suit instrument-air and utility-plant-air requirements. Two air compressors, one normally operating and one spare, are included, along with a common aftercooler and air receiver. The receiver supplies the utility-plant-air system directly and also provides air to the instrument-air drier, which furnishes air with a dew point of -40°F to the instrument-air-distribution system.

4.6.10 Flare Facilities

Startup, shutdown, and emergency conditions in the plant may require venting of process vessels and piping. The plant is equipped with a header to collect essentially all relief-valve discharges, except nonhazardous or non-polluting services. The relief header leads to a flare-knockout drum, where liquids are separated and retained, and then to the flare stack. The knockout drum is equipped with a steam coil to facilitate vaporization of hydrocarbon liquids and a pumpout pump, which can be used to recover condensed liquids. The flare may be an elevated, derrick-supported type, with integral molecular seal to prevent ingress of air down the stack and with steam jets for smoke suppression. If, for the specific plant site, the frequency of visible flaring must be kept at a minimum, a ground flare (in which the flare is completely enclosed in a refractory-lined chamber) may be used.

4.6.11 Ash Disposal

Residual ash, resulting from the gasification of coal, is conveyed from the de-watering bins located in the gasification section. The wet ash, containing about 25% moisture, is collected in ash-holding bunkers, from which it is loaded and trucked to the ultimate disposal site as landfill.

4.6.12 Waste-Water Treatment

Treatment of waste water from coal-conversion plants is a critical design aspect. Specification of the treating facilities is hampered by the lack of commercial coal-conversion-plant experience and by the scarcity of detailed information on process water composition from pilot-plant operations. Therefore, the treating facilities described here are only meant to typify those required to protect the environment. For a commercial plant design, the specific coal-gasification system, plant location, and local regulations may dictate more stringent control measures.

Special consideration is given to maximizing internal recycling within the main processing sections to reduce the number and volume of water effluents. All sour-water streams and process condensates are steam-stripped in the condensate-treating section, and, where possible, the stripped water is recycled as process water and cooling-tower make-up. The remaining water effluents are treated by a combination of oily-water separation, activated sludge for BOD reduction, and activated carbon for COD reduction before disposal to the environment.

Miscellaneous streams, such as steam condensates, air-compressor knock-out-drum effluents, boiler feed-water blowdowns, and cooling-tower blowdowns, are filtered to remove suspended solids that cause turbidity and then discharged to the raw-water source. Caustic and acid streams used for regenerating demineralizers are first neutralized in a holding tank, thereby converting the chemicals to innocuous soluble salts. The neutralized streams are then disposed of along with the filtered cooling-tower blowdown.

Pad washings and rain-water runoff from the process areas are collected in the oily-water sewer and sent to a surge basin. The water from the surge basin is processed at a controlled rate through the oily-water-treatment system.

4.7 EQUIPMENT AVAILABILITY

Equipment lead time is generally defined as the time from date of order to equipment shipment. Lead time depends both on the type of equipment involved and on the general level of activity in the equipment-supply industry. Estimates of current lead times for several types of equipment used in the coal-gasification/gas-clean-up sections of the LBG/CCPG are shown in Table 4.9. It should be noted that these lead times are difficult to extrapolate into the future, because of the effect of the level of business activity on vendor shops.

Lead time for the combined-cycle system of the LBG/CCPG plant is estimated to be about two years. This estimate is based on the following assumptions: (1) that gas turbines capable of firing low-Btu gas at turbine-inlet temperatures of at least 2200°F will have been developed and readied for commercial production by the mid-1980s, and (2) that general business activity in the gas-turbine/steam-turbine equipment-supply industry will be comparable with current conditions.

Table 4.9 Estimates of Current Equipment Lead Times[a]

Equipment Type	Lead Time, Weeks
Reactors (gasifiers)	35 - 55
Towers (absorbers, strippers)	35 - 50
Waste-Heat Boilers	52 - 78
Compressors (centrifugal)	64 - 96
Heat Exchangers (S/T)	30 - 50
Valves	Stock - 52
Water-Treatment Systems	40 - 65
Conveyors	24 - 52[b]
Pumps	26 - 52
Drums and Tanks	20 - 40

[a] Time from date of order to shipment

[b] After drawing approval

THIS PAGE

WAS INTENTIONALLY

LEFT BLANK

5 LBG/CCPG SYSTEM PERFORMANCE

Material and energy balances were developed for six integrated LBG/CCPG plants employing the gasification systems and coal feeds as shown in Table 5.1.

Utilities balances were made for each case study to determine the internal plant-utility flows between the fuel-gas-production section, the power system, and the offsite facilities. These balances permitted estimation of the over-all plant energy balance and net-utilities requirement, from coal pile to buss bar.

5.1 MATERIAL BALANCES

Of the three gasification systems considered, the Lurgi moving bed is rated deficient in coal utilization, because of its restrictive size specification on coal feed (i.e., 1 1/2" x 1/4"). Coal fines, present in the as-received coal and produced in the crushing operation, cannot be utilized in the gasifier and must be disposed of in some other way.(224) For this study, 30% of the as-received coal is assumed to be rejected as fines in the moving-bed-gasifier cases. Furthermore, the Lurgi gasifier is the only one that produces oil and tar by-products. Typical compositions of the oil/tar streams were estimated from the literature (see Table 5.2).(71)

Table 5.1 Gasification Systems and Coal Feeds for Integrated LBG/CCPG Plants

Case	Gasifier	Coal
1	Lurgi - Moving Bed	Illinois No. 6
2	Lurgi - Moving Bed	Montana Rosebud
3	IGT U-Gas - Fluidized Bed	Illinois No. 6
4	IGT U-Gas - Fluidized Bed	Montana Rosebud
5	Foster Wheeler - Entrained Flow	Illinois No. 6
6	Foster Wheeler - Entrained Flow	Montana Rosebud

Table 5.2 Compositions of Oil/Tar Streams (wt %)

	Coal	
Constituent	Illinois No. 6	Montana Rosebud
Naphtha	23	13
Light oil	12	24
Tar	49	29
Phenols	16	16

These streams were assumed to have the ultimate analyses as shown in Table 5.3.(241)

The LBG/CCPG-plant feed and product streams considered correspond to a net electric-power production of 500 MW at the indicated plant thermal efficiency (see Table 5.4).

In addition to electric power, the integrated LBG/CCPG plants produce elemental sulfur and anhydrous ammonia as salable by-products.

Performance characteristics of the section for the production of low-Btu fuel gas in LBG/CCPG plants are summarized in Table 5.5. Properties and yields of the clean fuel gas as supplied to the plant power cycle are given. The difference between the gross and net fuel-gas-production figures represents the internal plant consumption of fuel for process needs.

Detailed stream compositions for the gasification and raw-gas-desulfurization sections are given in Table 5.6, Cases 1 through 6. The indicated stream numbers correspond to those shown on the process flow diagrams in Section 4 of this report.

5.2 COMBINED-CYCLE PERFORMANCE

Integration of the combined-cycle power system into the over-all LBG/CCPG plant requires that the process air and steam requirements for the fuel-gas-production facilities be considered in determining the net plant efficiencies. For the six case studies, these demands on the gas-turbine and steam cycles, as required to satisfy the over-all plant energy and material balances, were as is shown in Table 5.7.

Table 5.3 Ultimate Analyses of Oil/Tar Streams
(wt %)

Element	Naphtha, Oil, and Tar	Phenols
Carbon	85.80	74.10
Hydrogen	6.80	6.40
Oxygen	4.35	17.00
Nitrogen	1.12	1.00
Sulfur	1.93	1.50
	100.00	100.00

Table 5.4. LBG/CCPG Plant-Feed and Product Summary

<table>
<tr><th rowspan="2">Characteristic</th><th colspan="6">Case</th></tr>
<tr><th>1</th><th>2</th><th>3</th><th>4</th><th>5</th><th>6</th></tr>
<tr><td><u>Gasifier</u></td><td>Lurgi</td><td>Lurgi</td><td>U-Gas</td><td>U-Gas</td><td>FWC</td><td>FWC</td></tr>
<tr><td><u>Coal</u></td><td>Illinois</td><td>Montana</td><td>Illinois</td><td>Montana</td><td>Illinois</td><td>Montana</td></tr>
<tr><td><u>Feedstock</u></td><td></td><td></td><td></td><td></td><td></td><td></td></tr>
<tr><td>Coal (dry),[a] TPD</td><td>8021</td><td>8429</td><td>4310</td><td>4639</td><td>4318</td><td>4818</td></tr>
<tr><td><u>Products</u></td><td></td><td></td><td></td><td></td><td></td><td></td></tr>
<tr><td>Electric power, MW</td><td>500</td><td>500</td><td>500</td><td>500</td><td>500</td><td>500</td></tr>
<tr><td>Sulfur, TPD</td><td>177.6</td><td>46.8</td><td>139.4</td><td>41.4</td><td>139.1</td><td>42.5</td></tr>
<tr><td>Ammonia, TPD</td><td>72.7</td><td>69.0</td><td>19.8</td><td>18.7</td><td>52.7</td><td>53.1</td></tr>
<tr><td>Coal fines (dry), TPD</td><td>2406</td><td>2529</td><td colspan="4">← None →</td></tr>
<tr><td>Naphtha, TPD</td><td>94.0</td><td>51.0</td><td colspan="4">← None →</td></tr>
<tr><td>Light oil, TPD</td><td>49.0</td><td>164.9</td><td colspan="4">← None →</td></tr>
<tr><td>Tar, TPD</td><td>200.2</td><td>113.8</td><td colspan="4">← None →</td></tr>
<tr><td>Phenols, TPD</td><td>65.3</td><td>62.8</td><td colspan="4">← None →</td></tr>
<tr><td><u>Plant efficiency,[b] %</u></td><td>28.6</td><td>30.3</td><td>37.2</td><td>38.6</td><td>37.1</td><td>37.1</td></tr>
<tr><td>HHV</td><td>12,771</td><td>11,446</td><td>12,771</td><td>11,446</td><td>12,771</td><td>11,446</td></tr>
<tr><td>Heat rate</td><td>11,950</td><td>11,260</td><td>9,180</td><td>8,850</td><td>9,200</td><td>9,200</td></tr>
</table>

[a] Total coal feed before fines rejection

[b] $$\text{Efficiency} = \frac{\text{Electric power (kW)}}{\text{Coal HHV}} \times 3413 \times 100$$

$$\left[= \frac{500{,}000 \times 3413 \times 100 \times 24}{12{,}771 \times 8{,}021 \times 0.7 \times 2{,}000} = 28.6 \text{ for Case 1, for example} \right]$$

Table 5.5 Low-Btu Fuel-Gas Production Summary

	Case					
Characteristic	1	2	3	4	5	6
Gasifier	Lurgi	Lurgi	U-Gas	U-Gas	FWC	FWC
Coal	Illinois	Montana	Illinois	Montana	Illinois	Montana
Dry coal,[a] TPD	8021-2406	8429-2529	4310	4639	4318	4818
DAF coal,[a] TPD	5052	5159	3878	4056	3885	4213
Fuel gas, Mol%						
CH_4	4.17	3.74	3.45	3.96	3.52	3.45
H_2	24.99	27.50	17.46	18.06	14.43	12.93
CO	16.93	14.56	20.62	22.65	29.57	29.31
CO_2	11.14	15.92	7.98	8.84	1.95	3.90
N_2	42.42	37.95	50.15	46.15	50.17	50.07
H_2S	0.11	0.10	0.10	0.10	0.10	0.10
COS	0.01	0.01	0.01	0.01	0.03	0.01
H_2O	0.23	0.23	0.23	0.23	0.23	0.23
Output, MW	22.79	22.95	24.33	24.24	24.15	24.85
HHV, Btu/SCF	177.8	174.0	157.9	171.6	177.5	171.0
LHV, Btu/SCF	161.0	156.4	145.6	158.5	166.7	161.1
Gross fuel gas, MMSCFD	633.3	654.2	555.3	539.7	513.0	547.6
Net fuel gas, MMSCFD	631.7	653.7	553.9	539.3	500.7	520.4
SCF/lb DAF Coal	62.52	63.36	71.42	66.49	64.44	61.76
Cold-gas efficiency, %	78.3	84.2	79.4	87.1	80.6	80.7

[a] Net coal feed to gasifier

Table 5.6. Gasifier-Stream Parameters
Case 1: Lurgi Gasifier with Illinois Coal

	Stream Number and Description											
	1	2	3	4	5	6	7	8	9	10	11	12
Operating Parameter	Coal Feed	Air	Jacket Steam	External Steam	Gasifier Offgas	Ash	Crude Gas	Tar/Oil Product	Ammonia Product	Stripped Water	Fuel Gas	Acid Gas
Fluid State	Solid	Vapor	Vapor	Vapor	Vapor	Solid	Vapor	Liquid	Liquid	Liquid	Vapor	Vapor
Temp., °F	77	390	450	750	1,015	120	100		110	150	105	120
Pres., psig		385	370	370	350		305		230		300	7
Total, #/hr	531,683	1,085,880	202,055	494,564	2,265,685	64,861	1,693,805	34,042	6,056	515,566	1,582,448	114,288
Mol. Wt. of Vapor		28.69	18.02	18.02	21.88		23.48				22.79	39.90
Components, mols/hr												
CH_4					2,917.3		2,917.3				2,894.8	22.5
H_2					17,359.1		17,359.1				17,352.2	6.8
CO					11,779.0		11,770.0				11,759.9	19.0
CO_2					9,846.8		9,846.8				7,734.5	2,112.4
N_2		29,460.4			29,478.5		29,478.5				29,458.0	20.5
O_2		7,829.7										
H_2S					531.9		531.9				73.3	458.6
COS					11.2		11.2				7.3	3.9
NH_3					355.1							
H_2O (v)		552.9	11,212.9	27,445.2	29,733.9		216.4				159.7	220.8
Total, lb mols/hr		37,843.0	11,212.9	27,445.2	102,012.7						69,439.7	2,864.5
							72,140.1					
DAF Coal, lb/hr	421,009											
Ash, lb/hr	46,887					46,887						
Water (l), lb/hr	63,786					16,215						
Char, lb/hr						1,758						
Tar, lb/hr					34,042			34,042				

Table 5.6. (Cont'd)
Case 2: Lurgi Gasifier with Montana Coal

Operating Parameter	1 Coal Feed	2 Air	3 Jacket Steam	4 External Steam	5 Gasifier Offgas	6 Ash	7 Crude Gas	8 Tar/Oil Product	9 Ammonia Product	10 Stripped Water	11 Fuel Gas	12 Acid Gas
Fluid State	Solid	Vapor	Vapor	Vapor	Vapor	Solid	Vapor	Liquid	Liquid	Liquid	Vapor	Vapor
Temp., °F	77	390	450	750	710	120	100		110	150	105	120
Pres., psig		385	370	370	350		305		230		300	7
Total, #/hr	660,810	1,003,638	135,136	576,358	2,312,505	84,848	1,679,515	32,710	5,749	573,319	1,646,474	33,371
Mol. Wt. of Vapor		28.70	18.02	18.02	21.52		23.14				22.95	38.91
Components, mols/hr												
CH_4					2,700.7		2,700.7				2,680.2	20.5
H_2					19,733.1		19,733.1				19,725.2	7.9
CO					10,464.6		10,464.6				10,448.1	16.5
CO_2					12,023.4		12,023.4				11,418.8	604.6
N_2		27,230.7			27,247.8		27,247.8				27,228.7	19.2
O_2		7,829.7										
H_2S					192.3		192.3				71.4	120.9
COS					3.3		3.3				2.0	1.3
NH_3					336.4							
H_2O (v)		507.5	7,499.5	31,984.5,	33,215.6		218.1				165.2	66.1
Total, lb mols/hr		34,975.4	7,499.5	31,984.5	105,917.3		72,583.4				71,739.5	857.1
DAF Coal, lb/hr	429,923											
Ash, lb/hr	61,786					61,786						
Water (l), lb/hr	169,101					21,212						
Char, lb/hr						1,850						
Tar, lb/hr					32,710			32,710				

Table 5.6. (Cont'd)
Case 3: U-Gas Gasifier with Illinois Coal

	Stream Number and Description											
Operating Parameter	1 Coal Feed	2 Air	3 Jacket Steam	4 Transport Gas	5 Gasifier Offgas	6 Ash	7 Crude Gas	8 Tar/Oil Product	9 Ammonia Product	10 Stripped Water	11 Fuel Gas	12 Acid Gas
Fluid State	Solid	Vapor	Vapor	Vapor	Vapor	Solid	Vapor	None	Liquid	Liquid	Vapor	Vapor
Temp., °F	77	650	800	100	1,650	120	100		110	150	105	120
Pres., psig		375	370	305	355		305		230		300	7
Total, #/hr	374,910	1,129,304	208,787	19,945	1,694,856	50,988	1,541,705		1,650	118,846	1,481,157	61
Mol. Wt. of Vapor		28.59	18.02	24.71	24.00		24.71				24.33	38.94
Components, mols/hr												
CH_4				27.4	2,145.2		2,117.9				2,101.4	16.5
H_2				137.6	10,772.7		10,635.1				10,630.9	4.1
CO				162.7	12,739.8		12,577.1				12,556.9	20.2
CO_2				76.5	5,975.3		5,898.8				4,860.7	1,038.1
N_2		30,438.6		395.5	30,946.6		30,551.0				30,526.7	24.4
O_2		8,092.1										
H_2S				5.6	429.6		424.0				63.4	360.7
COS				0.4	9.0		8.6				5.6	3.0
NH_3					96.4							
H_2O (v)		975.8	11,588.8	2.2	7,492.2		187.5				140.2	122.2
Total, lb mols/hr		39,506.5	11,588.8	807.9	70,606.8		62,400.0				60,885.8	1,589.2
DAF Coal, lb/hr	323,172											
Ash, lb/hr	35,991					35,991						
Water (1), lb/hr	15,746					12,747						
Char, lb/hr						2,249						

Table 5.6. (Cont'd)
Case 4: U-Gas Gasifier with Montana Coal

	Stream Number and Description											
	1	2	3	4	5	6	7	8	9	10	11	12
Operating Parameter	Coal Feed	Air	Jacket Steam	Transport Gas	Gasifier Offgas	Ash	Crude Gas	Tar/Oil Product	Ammonia Product	Stripped Water	Fuel Gas	Acid Gas
Fluid State	Solid	Vapor	Vapor	Vapor	Vapor	Solid	Vapor	None	Liquid	Liquid	Vapor	Vapor
Temp., °F	77	650	800	100	1,650	120	100		110	150	105	120
Pres., psig		375	370	305	355		305		230		300	7
Total, #/hr	406,901	1,010,109	218,333	20,623	1,605,006	67,895	1,462,672		1,558	103,219	1,434,724	28,311
Mol. Wt. of Vapor		28.59	18.02	24.42	23.78		24.42				24.24	38.73
Components, mols/hr												
CH_4				33.2	2,396.8		2,363.6				2,345.4	18.2
H_2				150.6	10,843.9		10,693.3				10,689.1	4.2
CO				189.6	13,617.9		13,428.3				13.407.0	21.3
CO_2				81.0	5,811.8		5,730.8				5,230.0	500.8
N_2		27,224.4		385.4	27,719.4		27,334.0				27,312.2	21.8
O_2		7,237.8										
H_2S				2.6	167.8		165.2				58.7	106.5
COS					3.6		3.6				2.1	1.5
NH_3					92.5							
H_2O (v)		874.8	12,118.7	2.6	6,851.3		179.7				136.1	56.1
Total, lb mols/hr		35,337.0	12,118.7	845.2	67,505.1		59,898.5				59,180.6	730.4
DAF Coal, lb/hr	337,967											
Ash, lb/hr	48,570					48,570						
Water (1), lb/hr	20,363					16,987						
Char, lb/hr						2,338						

Table 5.6. (Cont'd)
Case 5: Foster Wheeler Gasifier with Illinois Coal

	Stream Number and Description											
	1	2	3	4	5	6	7	8	9	10	11	12
Operating Parameter	Coal Feed	Air	Jacket Steam	Transport Gas	Gasifier Offgas	Ash	Crude Gas	Tar/Oil Product	Ammonia Product	Stripped Water	Fuel Gas	Acid Gas
Fluid State	Solid	Vapor	Vapor	Vapor	Vapor	Solid	Vapor	None	Liquid	Liquid	Vapor	Vapor
Temp., °F	77	650	710	100	1,700	120	100		110	150	105	120
Pres., psig		415	410	305	360		305		230		300	7
Total, #/hr	375,620	1,036,035	64,794	34,933	1,474,482	50,746	1,412,481		4,395	8,977	1,358,430	55,216
Mol. Wt. of Vapor		28.76	18.02	24.51	24.35		24.51				24.15	38.68
Components, mols/hr												
CH_4				49.2	2,043.0		1,993.8				1,978.4	15.4
H_2				201.0	8,320.4		8,119.4				8,116.0	3.4
CO				412.1	17,075.7		16,663.6				16,637.0	26.7
CO_2				48.8	2,031.4		1,982.5				1,096.1	886.5
N_2		28,219.6		698.7	28,950.2		28,251.5				28,229.0	22.5
O_2		7,500.8										
H_2S				10.1	421.1		410.9				56.3	354.6
COS				0.8	23.3		22.5				14.3	8.3
NH_3					257.3							
H_2O (v)		300.1	3,596.6	4.1	1,380.8		172.8				129.2	110.1
Total, lb mols/hr		36,020.5	3,596.6	1,424.7	60,503.0		57,617.1				56,256.2	1,427.4
DAF Coal, lb/hr	323,784											
Ash, lb/hr	36,060					36,060						
Water (l), lb/hr	15,776					12,696						
Char, lb/hr						1,990						

Table 5.6. (Cont'd)
Case 6: Foster Wheeler Gasifier with Montana Coal

	Stream Number and Description											
	1	2	3	4	5	6	7	8	9	10	11	12
Operating Parameter	Coal Feed	Air	Jacket Steam	Transport Gas	Gasifier Offgas	Ash	Crude Gas	Tar/Oil Product	Ammonia Product	Stripped Water	Fuel Gas	Acid Gas
Fluid State	Solid	Vapor	Vapor	Vapor	Vapor	Solid	Vapor	None	Liquid	Liquid	Vapor	Vapor
Temp., °F	77	650	710	100	1,700	120	100		110	150	105	120
Pres., psig		415	410	305	360		305		230		300	7
Total, #/hr	422,684	1,103,793	70,205	38,583	1,582,813	70,151	1,512,879		4,425	9,389	1,492,157	20,613
Mol. Wt. of Vapor		28.76	18.02	24.97	24.77		24.97				24.85	35.57
Components, mols/hr												
CH_4				52.9	2,138.0		2,085.1				2,068.9	16.2
H_2				198.0	7,964.8		7,766.8				7,763.5	3.2
CO				449.5	18,074.6		17,625.1				17,597.0	28.1
CO_2				68.0	2,731.6		2,663.6				2,339.8	323.8
N_2		30,064.9		767.3	30,865.2		30,097.8				30,073.6	24.3
O_2		7,992.3										
H_2S				4.3	170.0		165.7				57.7	107.9
COS					9.7		9.7				6.5	3.2
NH_3					258.5							
H_2O (v)		318.4	3,896.6	4.9	1,681.5		181.9				138.1	42.1
Total, lb mols/hr		38,375.6	3,896.6	1,544.9	63,893.7		60,595.5				60,045.1	548.8
DAF Coal, lb/hr	351,077											
Ash, lb/hr	50,454					50,454						
Water (1), lb/hr	21,153					17,538						
Char, lb/hr						2,159						

Table 5.7 Gasifier Demands on Gas-Turbine and Steam Cycles
(Lb/hr)
(Basis: 100 Lb-Mols/hr Fuel Gas)

			Steam Exported		Steam Imported		De-aerator Steam
Case		Air to Gasifier 235 psia/843°F	65 psia/ 298°F	165 psia/ 366°F	665 psia/ 497°F	665 psia/ 770°F	65 psia/ 600°F
1	Lurgi	1568	351	116	62	927	188
2		1400	346	113	83	1002	172
3	IGT	1860	283	116	-598	-206	244
4		1708	154	307	20	-292	218
5	FW	1887	429	- 8	-118	-390	219
6		1935	377	-2.4	- 99	-378	222

The power-cycle efficiencies were calculated using these demands on the combined-power cycle together with the procedure outlined in the idealized case studies, Section 5.3, except that isentropic efficiencies of 87.5% and 85% were used for the gas turbine and steam turbines, respectively, as suggested by the literature.(107)

The results of these cycle calculations for the six case studies are tabulated in Table 5.8. A schematic flow diagram for a typical case is shown in Fig. 5.1.

Because the choice of coal-gasification process has a large influence on the power-cycle performance, essentially due to wide variations in exporting or importing steam to and from the gasifier, power-cycle efficiencies vary from 44% in the Lurgi/Montana-coal case (export of 1.9 MM Btu/hr steam enthalpy, which is lost to the power cycle) to 54% efficiency in the IGT/Illinois-coal case (where 0.5 MM Btu/hr steam enthalpy is imported to the power cycle).

The indicated power-cycle efficiencies were adjusted for 2% mechanical and generator losses, thereby giving the net power-cycle efficiencies (based on the HHV of coal) shown in Table 5.9.

Over-all plant thermal efficiencies were reduced to values below these when the plant auxiliary-power usage was taken into account.

5.3 UTILITIES SUMMARY

Over-all plant utilities are summarized in Table 5.10 for the six LBG/CCPG case studies. The integrated plant, from coal pile to buss bar, requires that only raw water and consumptive catalysts and chemicals be

Table 5.8 Low-Btu Gasification/Combined-Cycle Power Generation[a]

Characteristic	Case 1	2	3	4	5	6
Gasifier	Lurgi	Lurgi	IGT	IGT	FWEC	FWEC
Coal	Illinois	Montana	Illinois	Montana	Illinois	Montana
Relative gasifier coal rate[b]	607.8	599.8	532.1	571.5	589.8	615.3
LBG input (LHV at 100°F), MM Btu/hr	6.118	5.943	5.533	6.023	6.336	6.122
Export steam-import steam,[c] MM Btu/hr	+1.816	+1.930	-0.506	+0.154	-0.182	-0.196
De-aerator steam,[d] MM Btu/hr	+0.237	+0.217	+0.308	+0.275	+0.276	+0.281
Condenser duty,[e] MM Btu/hr	0.544	0.414	1.944	1.607	1.993	1.932
Gas-turbine power, MM Btu/hr	2.332	2.305	2.055	2.266	2.357	2.265
Steam-turbine power, MM Btu/hr	0.265	0.209	0.888	0.835	0.910	0.879
Air exported,[f] MM Btu/hr	0.291	0.260	0.346	0.317	0.350	0.360
Combined-cycle efficiency,[g] %	42.5	42.3	53.2	51.5	51.6	51.4
Export steam-import steam, MM Btu/hr						
65 psia/298°F	0.390	0.384	0.315	0.171	0.477	0.420
165 psia/366°F	0.131	0.128	0.132	0.347	-0.009	-0.003
665 psia/497°F	0.071	0.095	-0.681	0.023	-0.134	-0.113
665 psia/770°F	1.224	1.323	-0.271	-0.385	-0.515	-0.499
Lb/hr at 230°F BFW[d]	1954	1921	1405	1893	1770	1696
Condensate, lb/hr 100°F	498	377	1809	1487	1857	1799
Stack loss, MM Btu/hr	0.822	0.799	0.734	0.806	0.855	0.822

[a] Gas-turbine nozzle temperature = 2200 °F; compression ratio = 16; 949 °F waste-heat boiler entrance; 1045 psia/900 °F/900 °F steam.

[b] Lb DAF coal/hr to produce 100 lb moles of LBG/hr.

[c] Various combinations of saturated steam and superheated steam, not including de-aerator steam.

[d] 600 °F(65 psia) de-aerator steam; enthalpy is returned to the steam boiler system via increased BFW temperature.

[e] Including increased duty due to 15% steam-turbine efficiency loss.

[f] 235 psia and 843 °F.

[g] Electric power out/LBG energy in; gas-turbine and compressor isentropic-efficiency are assumed to be 87.5%, steam-turbine efficiency 85%; mechanical and generator losses are neglected.

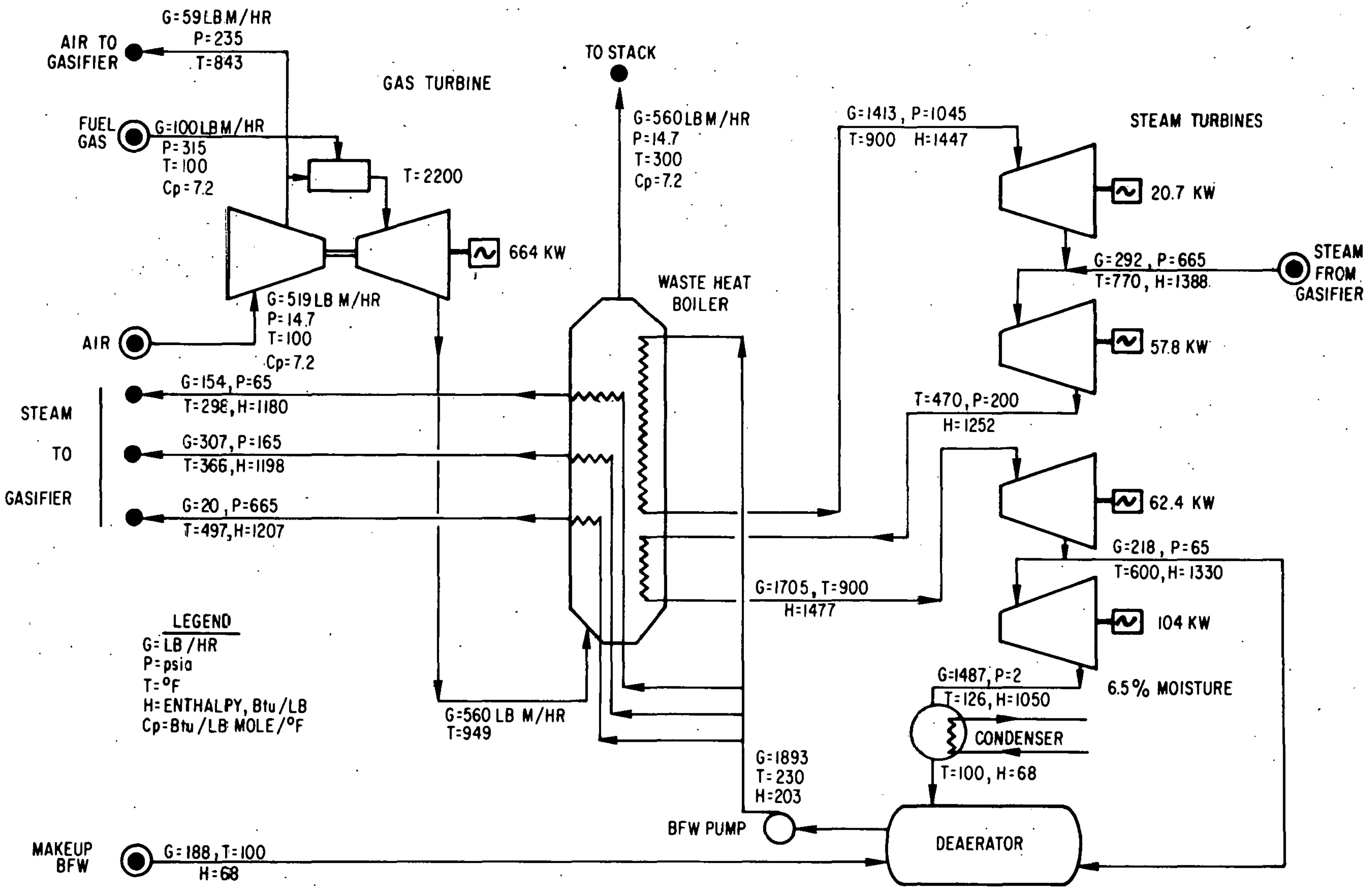


Fig. 5.1. Typical Combined Cycle (Case 4) Integrated with Gasifier Demands

Table 5.9 Gasifier Power-Cycle Efficiencies

Case	Efficiency, %
1 Lurgi/Illinois	30.0
2 Lurgi/Montana	31.8
3 U-Gas/Illinois	39.0
4 U-Gas/Montana	40.3
5 FW/Illinois	38.9
6 FW/Montana	39.0

supplied from external sources. Net electric power, 500 MW, is produced and exported from the plant in all cases.

The auxiliary power use, deducted from the plants' gross power production, provides power needs for the fuel-gas-production sections and plant offsite facilities. The latter includes power for cooling-tower fans, cooling-water-distribution pumps, boiler feedwater pumps, condensate-transfer pumps, raw-water- and demineralized-water-distribution pumps, instrument/plant air compressors, and miscellaneous items (such as plant lighting). In all cases, the auxiliary power usage represents about 3% of the plants' net power production.

Table 5.10 LBG/CCPG Plant Utilities Summary

	Case					
Characteristic	1	2	3	4	5	6
Gasifier	Lurgi	Lurgi	U-Gas	U-Gas	FWEC	FWEC
Coal	Illinois	Montana	Illinois	Montana	Illinois	Montana
Electric power, MW						
Gas turbine	464.4	473.3	359.0	385.6	372.0	371.2
Steam turbine	52.7	42.8	155.3	127.8	143.3	144.4
Auxiliary use[a]	17.1	16.1	14.3	13.4	15.3	15.6
Net production	500.0	500.0	500.0	500.0	500.0	500.0
Raw water, GPM	5900	5325	4640	4175	4400	4455
Cooling water circulation[b], GPM	164700	149400	133300	117600	129700	128200
Fuel gas[c], MMBtu/hr (LHV)	10.7	2.6	8.2	2.6	86.0	182.4
Catalyst/chemicals, $/Day	3940	3680	945	825	1030	945

[a] Auxiliary use is subtracted from the power generated by gas and steam turbines to obtain net power production.

[b] Provided by offsite cooling-tower system

[c] Supplied by gross low-Btu fuel-gas production

Table 5.11 shows a breakdown of the LBG/CCPG plants' raw-water consumption. The major water consumption in these plants, accounting for about 90% of the make-up requirement, is associated with losses from the cooling towers. These mechanical-draft cooling towers, included as part of the plants' offsite facilities, provide the cooling-water-circulation requirement for the integrated processing and combined-cycle power plant.

Similarly, the processing plants' fuel requirement is supplied internally from the gross production of clean low-Btu fuel gas. In all gases, the sulfur-recovery unit requires a small quantity of fuel gas, and, for the entrained-flow-gasifier cases, additional fuel gas is needed for coal pulverization and drying.

Make-up quantities of catalysts and chemicals are required in all cases to offset those consumed in the Selexol gas-desulfurization unit, the Phosam ammonia-recovery section, the sulfur-recovery unit, and the raw-water- and boiler-feedwater-treating facilities. The phenolsolvan unit associated with the Lurgi gasification systems requires additional make-up solvent costs.

Table 5.11 LBG/CCPG Plant Water Consumption

	Case					
Characteristic	1	2	3	4	5	6
Gasifier	Lurgi	Lurgi	U-Gas	U-Gas	FWEC	FWEC
Coal	Illinois	Montana	Illinois	Montana	Illinois	Montana
Water supply, GPM						
Raw water	5900	5325	4640	4175	4400	4455
Water usage,%						
Cooling tower						
Evaporation	69.8	70.2	71.8	70.5	73.7	71.9
Windage loss	2.8	2.8	2.9	2.8	3.0	2.9
Blowdown	14.6	14.7	15.1	14.8	15.5	15.1
Water treating and BFW blowdown	5.0	5.2	4.9	4.4	3.7	3.8
Process use	6.6	5.4	4.2	5.7	2.9	4.6
Potable-/utility-water use	1.2	1.7	1.1	1.8	1.2	1.7
Total	100.0	100.0	100.0	100.0	100.0	100.0

5.4 ENERGY BALANCES

Over-all energy balances for the six integrated LBG/CCPG systems are summarized in Table 5.12.

These balances are based on coal pile to buss bar; consequently, the Lurgi gasifier cases show a 20% thermal efficiency for electric-power generation, because 30% of these plants' total coal feed is rejected as fines. However, even on the basis of net coal feed to the gasifier, the Lurgi systems are at an efficiency disadvantage with respect to the fluidized-bed and entrained-flow gasification systems - 30% as compared with 37%. The major part of this efficiency differential comes about because about 9% of the gasifier-coal-feed energy leaves the moving-bed system in the form of oil and tar by-products having an average HHV of 15,300 Btu/lb.

LBG/CCPG systems based on the IGT U-Gas fluidized-bed gasifier and the Foster Wheeler entrained-flow gasifier are equivalent in terms of over-all plant efficiency for power generation. These systems produce no by-product tars and can accept 100% of the plants' coal feed for gasification (i.e., no fines rejection is necessary).

Table 5.12 LBG/CCPG Plant Over-all Energy Balances

Characteristic	Case 1	 2	 3	 4	 5	 6
Gasifier	Lurgi	Lurgi	U-Gas	U-Gas	FWEC	FWEC
Coal	Illinois	Montana	Illinois	Montana	Illinois	Montana
DAF coal[a], TPD	7217	7370	3878	4056	3885	4213
Energy input, 10^9 Btu/day						
Coal (HHV)	204.9	193.0	110.1	106.2	110.3	110.3
Energy output, %						
Electric power	19.99	21.22	37.20	38.57	37.13	37.13
Oil/tar	6.10	6.22	0.00	0.00	0.00	0.00
Sulfur	0.69	0.20	1.01	0.32	1.01	0.31
Ammonia	0.63	0.63	0.32	0.32	0.84	0.86
Stack gas	13.80	14.92	20.36	20.64	20.37	22.22
Cooling water	27.04	25.19	37.96	37.08	37.64	36.45
Ash carbon	0.29	0.32	0.69	0.74	0.61	0.66
Misc. losses	1.46	1.30	2.46	2.33	2.40	2.37
Coal fines	30.00	30.00	0.00	0.00	0.00	0.00
	100.00	100.00	100.00	100.00	100.00	100.00

[a]Total coal feed to plant

5.5 PLANT EMISSIONS

Conversion of coal to electric power via an integrated gasification and combined-cycle power system requires a multiple processing plant, which discharges a number of effluent streams to the environment. In the following discussion, the major effluent streams from the LBG/CCPG plants are identified, along with the treating facilities that are incorporated to mitigate the environmental impact. To a certain degree, this discussion is qualitative, because

(a) no specific plant site is considered, and

(b) detailed information on potential pollutants in effluents from coal-conversion plants needs to be determined from existing or future installations.

5.5.1 Atmospheric Emissions

The following atmospheric-emission sources are expected from an integrated LBG/CCPG plant during normal operation:

- Flue gas from the flue-gas HRSG in the combined power-generation system
- Stack gas from the sulfur-recovery plant
- Vent gas from the coal-preparation-and-drying systems
- Vent gas from the pneumatic coal-conveying systems
- Cooling-tower evaporation and drift losses

In addition, there will be short periods of gaseous emissions during plant start-up and shutdown procedures. During these transient periods, the major effluent will be gasifier offgas, which is vented through the flare system.

Emission-control systems are incorporated in the design of LBG/CCPG plants to minimize environmental intrusion of known pollutants, such as particulates, sulfur compounds, and nitrogen oxides. High-efficiency cyclones, wet venturi scrubbers, and bag filters are used to remove particulate matter from the low-Btu fuel gas fired in the gas turbines and the vent gases discharged to the atmosphere from the coal-preparation-and-handling systems. Low-temperature scrubbing systems, such as Selexol, are used to remove sulfur compounds from the fuel gas; a sulfur-recovery unit is employed to convert these sulfur compounds to an environmentally acceptable form, (e.g., molten elemental sulfur). Ammonia, present in the raw fuel gas, is removed by water washing and eventually recovered as a salable product via a Phosam ammonia-recovery system.

Sulfur Dioxide

Over-all plant sulfur balances for the six LBG/CCPG systems studied are given in Table 5.13. The total sulfur enters the plant as organic and pyritic sulfur contained in the coal feed. Except for the small amounts

Table 5.13 LBG/CCPG Plant Sulfur Balance

Characteristic	Case 1	Case 2	Case 3	Case 4	Case 5	Case 6
Gasifier	Lurgi	Lurgi	U-Gas	U-Gas	FWEC	FWEC
Coal	Illinois	Montana	Illinois	Montana	Illinois	Montana
Dry coal[a], TPD	5615	5900	4310	4639	4318	4818
(HHV) 10^9 Btu/day	143.4	135.1	110.1	106.2	110.3	110.3
Sulfur content, Wt %	3.86	1.40	3.86	1.40	3.86	1.40
Sulfur in, TPD	216.7	82.6	166.4	64.9	166.7	67.4
Sulfur out, %						
Sulfur product	81.94	56.62	83.78	63.72	83.42	63.05
Oil/tar	3.57	9.02	0.00	0.00	0.00	0.00
Flue gas (HRSG) main stack	14.30	34.07	15.95	35.99	16.31	36.66
Stack gas (S recovery)	0.19	0.29	0.27	0.29	0.27	0.29
Total	100.0	100.0	100.0	100.0	100.0	100.0
Sulfur emission, Lb SO_2/MM Btu coal	0.87	0.84	0.98	0.89	1.0	0.90

[a] Net coal feed to gasifier

present in the oil/tar by-product streams, the coal's sulfur content is converted to volatile compounds, such as H_2S, COS, and CS_2, in the gasification process. The Selexol desulfurization system reduces the sulfur content in clean low-Btu fuel gas to about 1000 ppmv, and more than 99% of the removed sulfur compounds are recovered in the elemental form. The net sulfur emissions to the atmosphere are therefore derived from three sources:

(1) Flue gas resulting from combustion of low-Btu fuel gas in the gas turbines

(2) Residual sulfur in the sulfur-recovery-plant stack gas

(3) Stack gases resulting from combustion of low-Btu fuel gas for process needs.

In all cases, the total plant sulfur emissions can be maintained at less than 1.0 lb SO_2/MMBtu (HHV) of coal gasified.

Nitrogen Oxides

Table 5.14 summarizes the plant nitrogen balance for the coal-bound nitrogen that enters as feed to the gasification systems. A portion (depend-

Table 5.14 LBG/CCPG Plant Nitrogen Balance

	Case					
Characteristic	1	2	3	4	5	6
Gasifier Coal	Lurgi Illinois	Lurgi Montana	U-Gas Illinois	U-Gas Montana	FWEC Illinois	FWEC Montana
Dry coal[a], TPD	5615	5900	4310	4639	4318	4818
Nitrogen, wt %	1.25	1.13	1.25	1.13	1.25	1.13
Nitrogen in, TPD	70.2	66.7	53.9	52.4	54.0	54.4
Nitrogen out, %						
Ammonia	85.0	85.0	30.0	30.0	80.0	80.0
Oil/tar	6.4	6.5	0.0	0.0	0.0	0.0
Molecular N_2	8.6	8.5	70.0	70.0	20.0	20.0
Total	100.0	100.0	100.0	100.0	100.0	100.0

[a] Net coal feed to gasifier

ing on the type of gasifier employed) of the coal-bound nitrogen will appear in the oil/tar by-product stream, with the remainder being converted to ammonia and molecular nitrogen in the raw fuel gas. The low-temperature scrubbing system employed for cleaning the raw gas will essentially remove all of the ammonia. Residual ammonia present in fuel gas fired in the gas turbines is expected to be on the order of 5-10 ppmv.(186)

Atmospheric NO_x emissions from the LBG/CCPG systems will result from combustion of low-Btu fuel gas in the combined-power cycle and from combustion of fuel gas for miscellaneous process uses. Since the low-temperature clean-up processes remove essentially all the chemically bound nitrogen from the fuel gas, the principal NO_x emission comes from thermal NO_x formation, resulting from the combination of the relatively low flame temperatures associated with low-Btu fuel gas, thermal NO_x emissions should be well below those of other turbine fuels. Robson(235) has estimated total NO_x emissions from integrated LBG/CCPG plants utilizing low-temperature clean-up systems at 0.3-0.5 lb NO_2/MMBtu of coal gasified.

Particulates

Under normal operating conditions, LBG/CCPG plants will discharge particulates to the atmosphere via the following sources:

(1) Coal fines in the vent gas from the coal-preparation-and-drying systems.

(2) Coal fines in the vent gas from the pneumatic coal-conveying system.

(3) Particulates in flue gas resulting from combustion of low-Btu fuel gas in the gas turbine and for process uses.

Emission of coal fines in vent gases can be minimized by employing high-efficiency cyclones and bag filters. Particulates resulting from combustion of low-Btu fuel gas are directly related to the particulate content of the fuel gas as it leaves the gas-clean-up system. Aqueous scrubbing, using available scrubber technology, in the low-temperature clean-up systems is capable of removing essentially all the particulates from the fuel gas (to about 0.01 gr/ft^3 or less).(186)(235) On this basis, the expected total particulate emission from the integrated LBG/CCPG plants will be in the neighborhood of 0.01 lb/MMBtu (HHV) of coal gasified. This figure is an order of magnitude below the federal standard for coal-fired power stations (0.1 lb/MMBtu).

Another source of particulate emissions is that associated with the windage loss from the mechanical-draft cooling towers. Local regulations and the quality of the cooling-tower make-up water may make it necessary that the solids content in the cooling-water circuit be adjusted via increased blowdown to avoid excessive particulate emission.

Other Pollutants

During normal operation, the discharge of non-methane hydrocarbons, phenols, and cyanides to the atmosphere should not present an environmental hazard. These compounds, when formed in the gasifier, will largely be removed in the low-temperature gas-clean-up system. Residual amounts in the clean low-Btu fuel gas and in the sour-water-stripper acid gas will be destroyed upon subsequent combustion of these gas streams.

The fate of volatile metals, which could enter the raw fuel-gas stream during gasification of coal, is less certain. Using a low-temperature scrubbing system for gas clean-up, it is believed, will remove the volatile metals from the gas prior to combustion and discharge to the atmosphere. This remains to be confirmed by actual operating data.

5.5.2 Aqueous Effluents

In the design of LBG/CCPG plants, special consideration must be given to maximizing internal recycling to reduce the number and volume of water effluents. All sour-water streams and process condensates are steam-stripped, and the stripped water is recycled as process water and cooling-tower make-up. However, before recycling the stripped water, additional treatment may be necessary to reduce the content of non-strippable components (see Table 5.15). Perhaps the worst offender would be the stripped water derived from the moving-bed gasification system, because a significant amount of organic materials is likely to be present. In addition, trace elements present in the raw coal may be volatilized during the gasification process and subsequently scrubbed out in the low-temperature scrubbing steps. Of particular concern are those elements considered hazardous to human health, such as beryllium,

Table 5.15 Non-Strippable Pollutants in Water Streams

Component	Concentration, ppm (by weight)
Ammonia	200-400
Sulfur	10-100
Phenol	500
Thiocyanates	100
Cyanide	1-10
Fatty Acids	1800
Chlorides	500
Carbonates	250
Heavy Metals	10-20
BOD	2500
pH	9

fluorine, arsenic, selenium, cadmium, mercury, and lead.(225) These elements are all volatile and may be expected to appear in the raw gasifier gas and ultimately in the water-condensate streams.

Although specific data are not available on the type and quantity of non-strippable pollutants in these water streams, the literature(225)(235) does reference the potential chemical characteristics of stripped process condensate from an LBG/CCPG system, based on a moving-bed gasifier with a Selexol gas-clean-up system.

Table 5.16 shows the trace-element analysis reported for process condensate from the gasification of Illinois No. 6 coal via the Synthane process.(225) This analysis is indicative of the types of heavy metals that may be present in the stripped water from LBG/CCPG plants.

Design of a water-treatment system would have to render the stripped aqueous streams acceptable for recycling for cooling-tower make-up and ultimate discharge to the environment. This would require detailed analysis of the water streams from each gasification system, with consideration for the appropriate local regulations regarding discharge of aqueous effluents.

Plant Blowdowns

A summary of the total estimated blowdown streams from the LBG/CCPG plants is given in Table 5.17. These streams are collected in a clean-water sewer and filtered to remove suspended solids that cause turbidity before discharge to the environment.

Caustic and acid used for regenerating the demineralizers are sent to a tank, where they are mixed and neutralized, converting the chemicals to innocuous soluble salts. The neutralized chemical streams are disposed of with the filtered cooling-tower blowdown.

Table 5.16 Trace Elements in Illinois Coal Condensate

Element	Average (by weight), ppb
Calcium	4000
Iron	3000
Magnesium	2000
Aluminum	800
Selenium	360
Potassium	160
Barium	130
Phosphorus	90
Zinc	60
Manganese	40
Germanium	40
Arsenic	30
Nickel	30
Strontium	30
Tin	20
Copper	20
Columbium	6
Chromium	6
Vanadium	3
Cobalt	2

Smudges and Backwashes

Water streams that are high in suspended solids but otherwise relatively pure are filtered for removal of solids and are recycled to raw-water make-up. The resultant insoluble sludges are collected in ponds, where they are de-watered by settling and evaporation before disposal to landfill.

Oily Water

During normal plant operations, no oily process-water streams are discharged to the environment. However, during certain start-up operations, oily waste waters may be produced. These streams are collected in an oily-water sewer and processed in an API separator (for oil removal) and a carbon-adsorption system before the water stream is discharged to the environment.

Similarly, pad washings and rain-water runoff from the process area are collected in the oily-water sewer and sent to a surge basin. The water from the surge basin is then processed at a controlled rate through the oily-water-treatment system.

5.5.3 Solid Wastes

The major solid waste discharged from the LBG/CCPG plants is the slag or ash residue from the coal-gasification system. This material is de-watered

Table 5.17 LBG/CCPG Plant Aqueous Blowdown Streams (Gallons/minute)

Characteristic	Case 1	2	3	4	5	6
Gasifier Coal	Lurgi Illinois	Lurgi Montana	U-Gas Illinois	U-Gas Montana	FWEC Illinois	FWEC Montana
Raw-water treating	59	53	46	42	44	45
BFW treating	166	166	61	59	27	35
BFW blowdown	67	50	120	83	92	87
Cooling tower	864	784	700	618	681	673
Total	1156	1053	927	802	844	840

to about 25% moisture before discharge from the plant. These solids are expected to be inert, similar to ash from burning coal, and are assumed to be disposed of as landfill.

The actual composition and leaching character of the ash and slag wastes must be determined during pilot-plant operation to confirm that no environmental effects other than filling of a landfill site will result.

Coal fines rejected from the coal-preparation system in the moving-bed-gasifier plants are assumed to be marketable for fuel value and should present no difficulty environmentally.

Thermal Pollution

The design of LBG/CCPG plants incorporates a recirculating cooling-water system to reject waste heat to the atmosphere. Discharge of heated water streams to the environment is thereby avoided.

Table 5.18 Wet-Ash Residues from Gasifiers (Tons/Day)

LBG/CCPG Case	Wet Ash
1	778
2	1018
3	612
4	815
5	609
6	842

THIS PAGE

WAS INTENTIONALLY

LEFT BLANK

6 PROCESS ECONOMICS

The economic analysis presented in this section is based on published investment-cost data. Only those literature sources that gave some detailed breakdown of the cost elements were considered. Such sources of useful cost data were found to be limited in number and often at variance with each other. It was therefore necessary to select those data that appeared to represent realistic appraisals of the costs for the LBG/CCPG subsystems. Although the error margins for these data range up to ± 40% in certain instances, they represent the best available data from the literature.

For this assessment, the costs associated with alternative electric-power-generating facilities have been determined--with the assistance of Argonne National Laboratory staff--on the basis of a fixed capital charge rate. The method employed stresses three factors:

- A capital-related charge
- An operating and maintenance charge
- A raw-materials charge

6.1 CAPITAL INVESTMENT

A summary of the investment-cost data for LBG/CCPG systems is given in Table 6.1. The data prepared by Fluor Engineers and Constructors, Inc.,(241) in their assessment of gasification processes for fuel-gas production, were most complete and detailed. The stated accuracy of Fluor's estimates varied from ± 20% to ± 40%. These data were subsequently used as the basis for estimating the costs associated with the fuel-gas-production sections of the LBG/CCPG plants.

The other three references cited(94)(225)(242) contained cost data for the combined-cycle power section. However, even when adjusted to a common (1977) time frame, these costs varied from $185-290/kW for a plant capacity of 500 MWe. For lack of more definitive information, these cost data were averaged and a figure of $240/kW was used to estimate the capital cost of the combined-cycle power-generation section.

Table 6.2 shows the estimated plant-investment costs for the six LBG/CCPG case studies. These costs are figured for the mid-1977 time period and for an over-all plant capacity of 500 MW.

For the most part, the Fluor data were used to estimate the costs of those sections associated with fuel-gas production and were adjusted from the original 1975 basis by an escalation factor of 1.17. The costs for the coal-preparation sections were prorated for the total "as-received" coal feed to the plant, while the gasification sections were prorated for the gasifier coal-feed rate. The total dry-fuel-gas production rate was used to prorate the costs for gas-cooling, gas-purification, and condensate-treating sections. Air-compression costs were prorated for the process-air requirement for gasification.

Table 6.1 Summary of Literature Cost Data for LBG/CCPG Systems

	Case								
	1	2	3	4	5	6	7	8	9
Gasifier	Lurgi	Lurgi	Lurgi	Merc	Lurgi	Lurgi	IGT U-Gas	Foster Wheeler	Foster Wheeler
Gas desulfurization	Benfield	Benfield	Selexol	Selexol	Benfield	Stretford	Selexol	Benfield	Selexol
Gas turbine inlet, °F	1950	2400	--	2200	1955	1955	--	2400	2600
Coal	Illinois	Illinois	Illinois	Kentucky	Illinois	Montana	Illinois	Illinois	Illinois
Reference	(242)	(242)	(241)	(225)	(94)	(94)	(241)	(242)	(225)
Cost basis	Mid-1975	Mid-1975	Mid-1975	Mid-1974	Jan.1975	Jan.1975	Mid-1975	Mid-1975	Mid-1974
Estimated accuracy, %	--	--	± 20	± 25	--	--	± 40	--	± 25
Coal feed, tons/day	10,780	9,720	10,000	8,400	10,700	13,180	10,000	8,200	8,400
LBG, MMSCFD (dry)	1,136	1,024	1,075	1,003	---	---	1,235	965	993
Power output, MW	1,000	1,000	--	737	855	885	--	1,000	908
Estimated costs, $\$10^6$									
Coal preparation	13.42	12.09	12.33 (1)[a]	--	16.5	18.7	15.65 (1)[a]	10.20	--
Air compression	28.34	25.54	26.28 (4)	10.80			43.03 (4)	26.72	11.00
Gasification and ash	66.12	59.56	66.21 (4-16)	62.42	120.0	92.8	29.49 (1-4)	28.35	82.23
Gas cooling	34.28	30.87	30.97 (4)	14.86			49.42 (4)	26.42	23.78
Gas purification	47.34	42.66	40.74 (2-4)	26.75			36.33 (2-4)	35.37	32.69
Condensate treating	75.48	68.02	61.69 (1-2)	21.16			10.79 (1)	6.89	21.04
Tar-fired boiler	109.37	98.54	--	--			--	--	--
Power recovery	--	--	28.08 (1)	--			21.02 (1)	--	--
Combined cycle	178.15	180.30	--	146.77	115.3	114.5	--	200.00	156.70
Sub-total	552.50	517.58	266.41	280.71	251.8	226.0	205.73	33.54	328.44
Offsite facilities	97.39	91.12	68.49	40.55	55.7	51.3	52.81	57.01	47.28
Contingency	97.48	91.30	47.65		21.5	19.3	38.78	58.64	
Plant investment	747.37	700.00	382.55	321.26	329.0	296.6	297.32	449.60	375.72
$/kW	747	700	--	435	385	335	--	450	414
Paid-up royalties	18.68	17.50	9.56	NA	NA	NA	7.43	11.24	NA
Initial catalyst/chemical	3.74	3.50	2.34	NA	NA	NA	2.39	2.25	NA

[a] ( ) Parentheses indicate number of process trains

Table 6.2 Estimated LBG/CCPG Plant-Investment Cost
(Basis: 500-MWe Capacity - Mid-1977)

	Case					
Characteristic	1	2	3	4	5	6
Gasifier	Lurgi	Lurgi	U-Gas	U-Gas	FWEC	FWEC
Coal	Illinois	Montana	Illinois	Montana	Illinois	Montana
Coal feed, tons/day						
As received	9,115	11,328	4,898	6,234	4,906	6,475
To gasifier	6,380	7,930	4,499	4,883	4,507	5,072
Fuel gas, MMSCFD (dry)	632	653	554	538	512	546
Process air, MM lb/hr	1.086	1.004	1.129	1.010	1.036	1.104
Estimated cost, $$10^6$						
Coal preparation	13.64	15.88	11.11	13.15	12.23	14.86
Air compression	17.18	16.27	23.37	21.62	16.21	16.95
Gasification	50.64	60.92	16.02	16.97	17.72	19.25
Gas cooling	20.28	20.75	26.78	26.24	25.34	26.51
Gas purification	26.68	27.29	19.69	19.29	18.63	19.49
Condensate treating	26.48	26.72	7.20	7.06	6.82	7.12
Combined power cycle	120.00	120.00	120.00	120.00	120.00	120.00
Sub-total	274.90	287.83	224.17	224.33	216.95	224.18
Offsite facilities	54.98	57.57	44.83	444.87	43.39	44.84
A & E Fee (15%)	49.48	51.81	40.35	40.38	39.05	40.35
Contingency (20 %)	75.87	79.44	61.87	61.92	59.88	61.87
Plant investment, $$10^6$	455.23	476.65	371.22	371.50	359.27	371.24

Investment for offsite facilities was estimated at 20% of the battery limits plant cost. This factor is consistent with that employed in the cost estimates given in Table 6.1. The contingency shown under plant investment is an allowance to account for developments in the state of the art. Historically, as a technology develops from the conceptual state to commercial reality, a variety of technical problems not considered in the early stages emerges. Solution of these problems generally results in an increase in the cost of the technology, because of the need for more expensive materials of construction, more complex equipment specifications, and, sometimes, additional processing equipment. The purpose of the contingency is to account for these costs, not to cover escalation or estimating inaccuracies. (In the Energy Conversion Alternatives Study (ECAS) by GE(202) of capital requirement and cost of electricity for a conventional coal-fired power plant with a wet lime scrubber, a contingency factor of 20% was assumed. To provide a meaningful cost comparison between emerging and existing coal-utilization technologies, the same contingency factor was also used here for gasification/combined-cycle plants.)

The estimated investments for the LBG/CCPG systems based on the Lurgi dry-ash gasification system are significantly higher than those for the fluidized-bed or entrained-flow gasification systems. The differences are related, essentially, to the large number of multiple Lurgi gasifiers required, and to the complex condensate-treating section needed to handle the large flows of oily condensate produced by this system. The LBG/CCPG plants based on the U-Gas fluidized-bed and Foster Wheeler entrained-flow gasifiers have comparable investment costs.

Estimated total capital requirements for the six LBG/CCPG case studies as well as for a conventional coal-fired power station with stack-gas scrubbing are shown in Table 6.3. The total plant investment includes the cost of land, initial catalyst and chemical charge, and paid-up process royalties, in addition to the physical-plant cost estimated in Table 6.2. In estimating the cost of land for the LBG/CCPG systems, an allowance of 500 acres was included for landfill disposal of solid wastes over and above the 100 acres required for siting the physical plant. The total plant investment for the conventional coal-fired power station is taken from the literature. Construction funds, plant start-up costs, and working capital were estimated in accordance with the procedure outlined in Appendix B. A plant-construction period of four years was assumed for the LBG/CCPG systems, five years for the conventional steam-power plant.

As indicated by Table 6.3, the conventional power station with stack-gas scrubbing appears to be about 5 to 40% less costly than the LBG/CCPG plants. It is generally believed, however, that the unit capital requirement for a combined-cycle plant would be significantly reduced as ultrahigh-inlet-temperature turbines (i.e., those with inlet temperatures greater than 2600°F) become available.

6.2 OPERATING COST

Table 6.4 summarizes the raw materials and operating-labor requirements and the by-product rates for the six LBG/CCPG cases, as well as the conventional coal-fired power plant. The operating requirements for the

Table 6.3. Estimated Total Capital Requirement ($\$10^6$)
(Basis: 500-MW Capacity - Mid-1977)

Characteristic	Case 1	Case 2	Case 3	Case 4	Case 5	Case 6	Conventional Power Plant
Gasifier	Lurgi	Lurgi	U-Gas	U-Gas	FW	FW	
Coal	Illinois	Montana	Illinois	Montana	Illinois	Montana	Illinois
Total plant investment							
Land, at $2,000/acre	1.2	1.2	1.2	1.2	1.2	1.2	
Onsites and offsites	455.2	476.7	371.2	371.5	359.3	371.2	
Initial catalyst/chemicals	1.5	1.9	1.1	1.2	1.2	1.4	
Paid-up royalties	6.1	7.6	3.3	3.6	3.3	3.8	
Total	464.0	487.4	376.8	377.5	365.0	377.4	335.0
Construction funds	99.8	104.8	81.0	81.2	78.5	81.1	90.0
Start-up costs	18.7	21.1	12.7	14.0	12.5	14.2	12.3
Working capital	9.1	10.5	6.0	6.8	5.9	6.9	5.9
Total capital requirement	591.6	623.8	476.5	479.5	461.9	479.6	443.2

Table 6.4. Estimated Operating Requirements at Design Capacity

	Case						
Characteristic	1	2	3	4	5	6	Conventional Power Plant
Gasifier	Lurgi	Lurgi	U-Gas	U-Gas	FWEC	FWEC	
Coal	Illinois	Montana	Illinois	Montana	Illinois	Montana	Illinois
Raw materials							
Coal, tons/day (TPD)	9115	11328	4898	6234	4906	6475	5391
Limestone, TPD	--	--	--	--	--	--	960
Catalyst/chemicals, $/day	3940	3680	945	825	1030	945	--
Raw water, AF/day	24.78	22.37	19.49	17.54	18.48	18.71	30.20
Operating labor							
Men/Shift	25	25	21	21	21	21	10
By-products							
Sulfur, TPD	177.6	46.8	139.4	41.4	139.1	42.5	--
Ammonia, TPD	72.7	69.0	19.8	18.7	52.7	53.1	--
Naphtha, barrels/day (BPD)	632.6	343.1	--	--	--	--	--
Light oil, BPD	294.0	989.5	--	--	--	--	--
Tar, BPD	995.3	565.7	--	--	--	--	--
Phenols, BPD	373.4	359.1	--	--	--	--	--
Coal fines, TPD	2734	3398	--	--	--	--	--

[a] As-received basis

coal-fired power plant were determined from performance data (given in Appendix C), adjusting the coal rate for a higher heating value of Illinois coal of 11,240 Btu/lb instead of 10,800 Btu/lb. The coal feed rate was therefore adjusted from 0.936 lb/KWh to 0.899 lb/KWh.

Following the method given in Appendix B, the gross and net operating costs were calculated, based on a 70% plant-service factor. The estimated plant operating costs are given in Table 6.5.

The net operating cost for the conventional coal-fired power plant, using Illinois coal, is comparable to that for the LBG/CCPG plants that employ the second-generation gasification (U-Gas and FW) systems. The Lurgi-based LBG/CCPG plant shows an operating cost about 20% higher than that of the conventional power plant. Again, as high-temperature turbine technology advances, the combined-cycle plants employing second-generation gasifiers should have clear advantages over the conventional power plant in terms of the operating cost. It should also be noted that the Lurgi-system economics are substantially influenced by the by-product credits, which play a relatively minor role in the other cases considered.

In this analysis, the cost of coal delivered to the plant was taken at $18 per ton on the "as-received" basis, regardless of moisture content or heating value; consequently, the LBG/CCPG cases based on Montana coal are penalized for the higher moisture content of the coal feed.

6.3 COST OF ELECTRICITY

The cost of electric power using private financing was calculated in accordance with the procedure given in Appendix B. The calculated power costs for the six LBG/CCPG cases and for the conventional coal-fired power station are summarized in Table 6.6.

The calculated cost of electricity (COE) for the Lurgi-based LBG/CCPG plant appears to be 30% higher than that for the conventional coal-fired power plant with stack-gas scrubbing. However, LBG/CCPG plants employing fluidized-bed or entrained-flow gasification systems show a COE competitive with that of the conventional plant. The differences in the COE calculated for LBG/CCPG plants using Illinois coal versus Montana coal are essentially due to the higher moisture content of the latter; prices were taken at $18 per ton"as-received" for both coals.

Table 6.7 summarized the literature data in which the cost of electricity for LBG/CCPG systems was compared directly with that for conventional power plants. These data are quite varied, showing a cost advantage for LBG/CCPG plants ranging from minus 10% to plus 20%.

The sensitivity of the calculated power cost to the LBG/CCPG plant-investment cost and to the price of raw coal is illustrated in Fig. 6.1. At a given coal price, a 20% variation in plant investment is equivalent to about 5 mills/kWh in cost of electricity. Considering that the LBG/CCPG

Table 6.5. Estimated Gross and Net Operating Cost ($10^6/yr) (Basis: 70% Plant Service Factor)

Characteristic	Case 1	Case 2	Case 3	Case 4	Case 5	Case 6	Conventional Power Plant
Gasifier	Lurgi	Lurgi	U-Gas	U-Gas	FWEC	FWEC	
Coal	Illinois	Montana	Illinois	Montana	Illinois	Montana	Illinois
Raw materials							
Coal at $18/ton	41.92	52.10	22.52	28.67	22.56	29.78	24.79
Limestone at $5/ton							1.22
Catalyst and Chemicals	1.01	.94	.24	.21	.26	.24	
Raw water at $130/AF	.82	.75	.64	.58	.62	.63	1.00
	43.75	53.79	23.40	29.46	23.44	30.65	27.01
Labor							
Operating	2.08	2.08	1.74	1.74	1.74	1.74	0.83
Maintenance	12.53	13.16	10.17	10.19	9.86	10.19	9.05
Supervision	2.92	3.05	2.38	2.39	2.32	2.39	1.98
	17.53	18.29	14.29	14.32	13.92	14.32	11.86
GAOH expense	10.52	10.97	8.57	8.59	8.35	8.59	7.12
Plant supplies							
Operating	.62	.62	.52	.52	.52	.52	.25
Maintenance	8.35	8.77	6.78	6.79	6.57	6.79	6.03
	8.97	9.39	7.30	7.31	7.09	7.31	6.28
Local taxes and insurance	12.53	13.16	10.17	10.19	9.85	10.19	9.05
Gross operating cost	93.30	105.60	63.73	69.87	62.66	71.06	61.32
By-product credits							
Sulfur at $22/ton	1.00	.26	.78	.23	.78	.24	
Ammonia at $170/ton	3.15	3.00	.86	.81	2.29	2.31	
Naphtha at $10/bbl	1.61	.88					
Light oil at $10/bbl	.75	2.53					
Tar at $5/bbl	1.27	.72					
Phenols at $5/bbl	.48	.46					
Coal fines at $16/ton	11.18	13.89					
Total credits	19.44	21.74	1.64	1.04	3.07	2.55	0.00
Net operating cost	73.86	83.86	62.09	68.83	59.59	68.51	61.32

Table 6.6 Cost of Electricity Produced by Integrated and Conventional Plants

Case	Gasifier	Coal	Cost of Electricity, mills/kWh
1	Lurgi	Illinois	52.5
2	Lurgi	Montana	57.3
3	U-Gas	Illinois	43.1
4	U-Gas	Montana	45.4
5	FW	Illinois	41.6
6	FW	Montana	45.3
Conventional Power Plant		Illinois	41.2

investment-cost data used for this economic analysis are probably accurate to no better than ± 20%, the indicated differential in power costs calculated for LBG/CCPG systems and for the conventional coal-fired power plant may not be significant. More detailed estimates of LBG/CCPG-system investments are required to confirm the economic advantage or disadvantage of these advanced power plants.

Table 6.7 Electric-Power Cost--Summary of Literature Data

	Conventional Power Plant[a]		LBG/CCPG Plants				
Reference	Thermal Efficiency,%	COE, Mills/kWh	Gasifier Type	Turbine Inlet Temp., °F	Thermal Efficiency,%	COE, Mills/kWh	COE Ratio -- Conventional/CCPG
(190)	34.7	25.3	Fluidized Bed	2200	42.6	24.3	1.04
(188)	37	30.2	Fixed Bed	2200	35.6	25.5	1.18
	36	23.9	Fluidized Bed	2200	42.3	24.2	0.99
(224)	36.3	34.1	Fluidized Bed	2200	42.1	31.1	1.10
(225)	35.1	25.8	Fixed Bed	2200	31.4	28.8	0.90
(196)	32	39.8	Fixed Bed	2400	39.6	35.1	1.13
(229)	37.1	39.4	-	2400	36.2	35.8	1.10
(225)	35.1	25.8	Entrained Flow	2600	36.0	27.9	0.92
(229)	37.1	39.4	-	3000	35.3	35.6	1.11

[a] Equipped with stack-gas scrubber

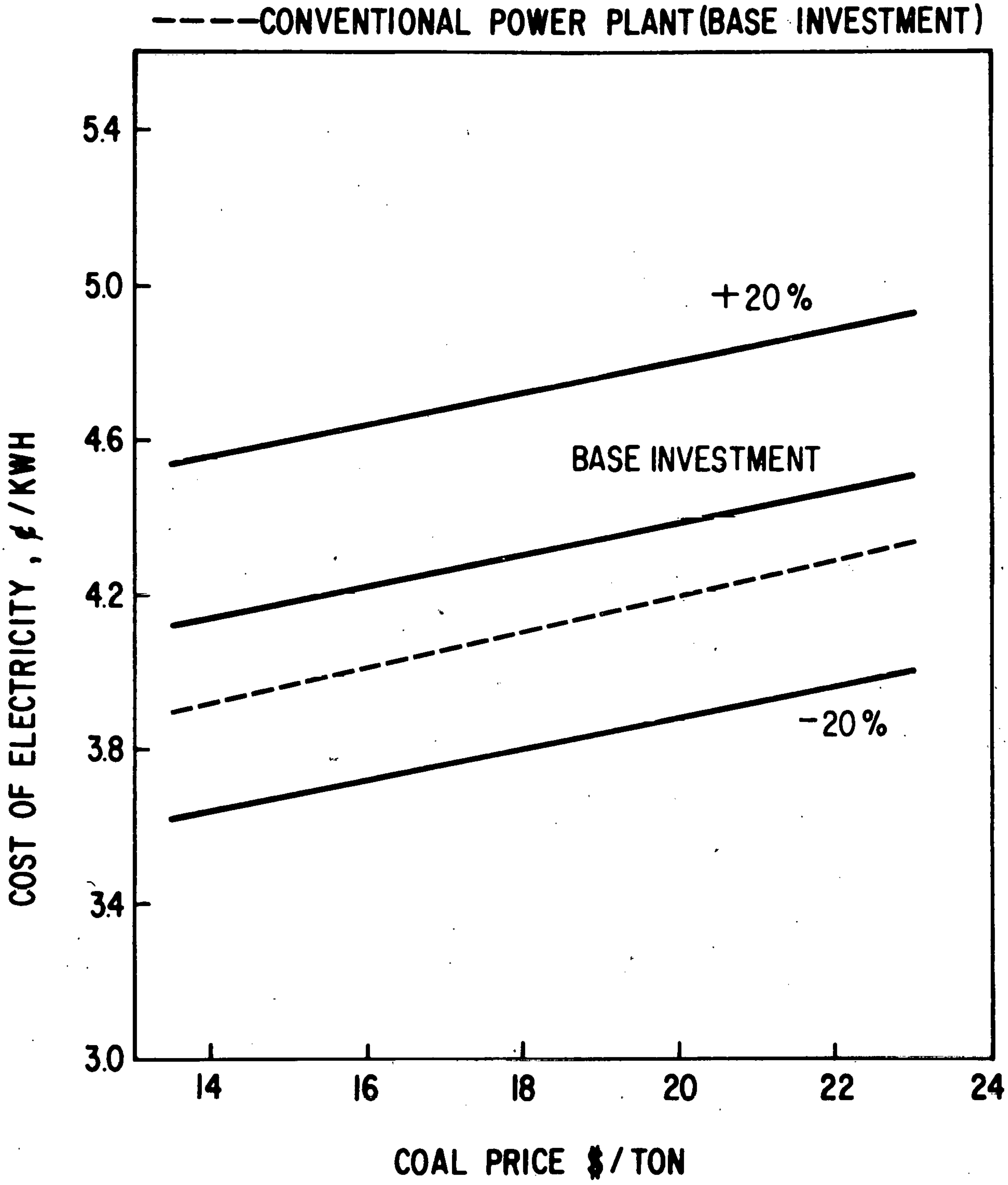


Fig. 6.1. Effect of Coal Price and Investment on Electric-Power Cost (Case 3: U-Gas Gasifier/Illinois Coal)

THIS PAGE
WAS INTENTIONALLY
LEFT BLANK

7 COMMERCIALIZATION POTENTIAL

Assessment of the commercialization potential of LBG/CCPG technology is of interest, because this technology has the capability to improve efficiency and to reduce power cost, particularly under conditions requiring rigorous control of emissions affecting the environment. The efficiency of a conventional steam-boiler/steam-turbine power plant is limited to about 34% when stack-gas scrubbing, the only presently feasible method for control of boiler-stack atmospheric-sulfur emissions, is taken into account. Reduced efficiency, as well as additional capital cost for scrubbing equipment, is reflected in increased power cost. The LBG/CCPG technology has the potential of improved efficiency and lower power cost, as well as controlled emissions.

7.1 TECHNICAL FEASIBILITY

Technical feasibility of LBG/CCPG technology is to be considered in terms of the principal systems involved--coal gasification, low-Btu gas cleanup, and combined-cycle power generation--and the interaction of these systems in an integrated plant for electric-power production.

7.1.1 Coal Gasification

Three coal-gasification processes were considered in this study for production of low-Btu fuel gas:

- Lurgi moving-bed non-slagging gasifier
- U-Gas fluidized-bed gasifier
- Foster Wheeler two-stage entrained-flow gasifier

The non-slagging Lurgi coal gasifier has an extensive commercial background, primarily in the production of hydrogen-carbon monoxide "syn-gas." The Sasol plant in South Africa is the largest plant currently operating Lurgi gasifiers to produce syn-gas for liquid-fuels production. An air-blown Lurgi gasifier was installed in 1973 in a 170-MW coal-gasification/pressurized-boiler/hot-gas-expander plant in Germany for the production of electric power. Another application in the power-generation field is the proposed Powerton Project demonstration plant, supported by the U.S. Department of Energy (DOE). In this plant, two air-blown Lurgi gasifiers will be used to produce low-Btu fuel gas for a 25-30-MW combined-cycle system. The slagging version of the Lurgi gasifier will be installed in another proposed DOE demonstration plant (Conoco Project) for production of substitute natural gas. The Lurgi gasification process is considered technically feasible, in view of the prior commercial operation of the gasifier in syn-gas applications and the proposed demonstration-plant projects.

The U-Gas coal gasifier is being developed by the Institute of Gas Technology (IGT) specifically for application to production of medium- and low-Btu fuel gases. This single-stage fluidized-bed gasifier is an outgrowth of IGT's extensive pilot-plant work on the multi-state fluidized-bed Hy-Gas gasifier for high-Btu gas production. IGT has tested the U-Gas gasifier at atmospheric pressure on a six-ton-per-day scale and is continuing test work at a pressure of 55 psig. Oxygen-blown U-Gas gasifiers will be installed in the proposed DOE demonstration plant (Memphis Project) for production of medium-Btu fuel gas for distribution to industrial gas consumers. These gasifiers will be designed to operate at pressures up to about 100 psig. The U-Gas gasification process is considered technically feasible, in view of the background of fluidization technology developed for the Hy-Gas gasifier and the proposed demonstration-plant project, which will extend experience with the gasifier to a large scale.

A design has been prepared for a demonstration electric-power plant based on an air-blown, two-stage entrained-flow gasifier and a gas turbine. The design was based on experimental data obtained by Bituminous Coal Research (BCR), and the design program included tests on a scaled cold-flow model of the gasifier to supplement the BCR data. Currently, the installation of a hot-flow model of the gasifier is being considered for the purpose of obtaining scale-up information under operating conditions prior to installation of a demonstration-size gasifier.

The experimental basis for judging the technical feasibility of the two-stage entrained-flow gasifier is limited at present, although the available data indicate that the gasifier is feasible. The proposed hot-flow model will provide important new information; the original time schedule for the demonstration plant has been extended.

7.1.2 Low-Btu Gas Clean-up

Gas-clean-up processes that use liquid solvents to absorb sulfur compounds at near-ambient temperatures have extensive commercial background in petroleum and chemical-processing plants. The technical choice of the gas-clean-up process for a LBG/CCPG plant depends primarily on details of gas composition and sulfur-removal requirements. A number of processes can be considered, all of which are technically feasible in view of the commercial experience in closely related applications.

Several processes for removal of sulfur compounds from low-Btu gas at elevated temperatures are in the early stages of development. Impetus for these developments is the expectation of some improvement in thermal efficiency of LBG/CCPG plants compared with ambient-temperature gas-clean-up processes. The technical feasibility of these high-temperature processes is uncertain at present. If research continues, feasible processes may be available in the late 1980s.

7.1.3 Combined-Cycle Power Generation

The two major elements of the combined-cycle power-generation system are the gas turbine and the heat-recovery-boiler/steam-turbine system. The boiler/steam-turbine system is considered technically feasible, because of the extensive commercial experience in steam-boiler power plants and waste-heat-recovery applications. The gas turbine also has extensive commercial background, although this experience is primarily in peaking power plants fueled with natural gas or distillate fuel oil. The LBG/CCPG plant requires gas turbines capable of operating with low-Btu fuel gas and with combustor-gas temperatures in excess of 2000°F.

These new requirements necessitate development work. Gas turbines, however, have been successfully operated on blast-furnace gas, which is similar to the low-Btu gas produced by air-blown coal gasifiers. In addition, there has been a steady increase in the firing temperature of commercially available gas turbines during the past decade, averaging slightly more than 30°F per year. Gas turbines fired at a temperature of about 2200°F are considered technically feasible for the early 1980s. Firing temperatures of 2500-3000°F appear probable in the late 1980s, although temperatures above 2600°F will require new technology for withstanding the severe temperature conditions. A 10-MW gas turbine fired at 2500°F is expected to be in a state of technological readiness in 1982 as a result of a DOE-sponsored program.

7.1.4 Interaction of Major Systems in LBG/CCPG Plants

An LBG/CCPG plant must be capable of following the power-load pattern of the power system. Load-following capability has been developed over the years in commercial steam-boiler/steam-turbine power plants, but this experience has limited applicability to the LBG/CCPG plant. Response characteristics of combined-cycle power-generation systems are relatively well known, but there is only limited experience at the present time on the integration of coal-gasification and gas-clean-up processes with the combined-cycle systems. This experience is critical, because uncoupling clean-fuel-gas production processes from the combined-cycle system by storage of fuel gas is impractical. Development programs sponsored by DOE and EPRI are currently in progress to develop transient mathematical models of LBG/CCPG plants. Results of this work presently available indicate that development of load-following capability in LBG/CCPG plants is technically feasible. Confirmation of this is required, however, in demonstration-size plants.

Based on the foregoing discussion of major systems, the LBG/CCPG (2200-°F turbines) technology appears to be technically feasible for commercial applications in the 1980-1985 time period. This conclusion, however, requires confirmation in demonstration plants to assure industry acceptance of this technology. The extent of progress in relevant demonstration-plant projects ultimately will determine the timing of commercial application of the technology in the American power industry.

7.2 ECONOMIC VIABILITY

Estimates of the cost of power produced by LBG/CCPG plants and by a present-day steam-boiler/steam-turbine power plant equipped with a stack-gas scrubber are given in Section 6. These estimates are based on several published investment and operating-cost studies. Published cost data vary significantly, possibly because of different design bases and estimating methods used by the different groups involved in the studies. The cost differences between the LBG/CCPG plants employing second-generation gasifiers and the steam-boiler/steam-turbine power plant appear, however, to be insignificant. On this basis, the LBG/CCPG technology appears to be economically viable.

7.3 EXPECTED DATE OF COMMERCIALIZATION

As noted in the discussion of technical feasibility, the timing of commercialization of LBG/CCPG technology by the American power industry will depend to a large extent upon progress achieved in the demonstration projects based on this technology. Since this progress depends on continued efforts by both government and industry in supporting the projects and developing solutions to the inevitable problems that arise, the timing of commercialization is difficult to predict. Under favorable circumstances, it appears that commercialization might begin in the 1985-to-1990 time period. Adverse conditions could delay industry acceptance into the 1990s.

8 CONCLUSIONS AND RECOMMENDATIONS

8.1 CONCLUSIONS

Assessment of the status of low-Btu gasification/combined-cycle power-generation systems was made in terms of their technical, economic, and environmental aspects. This assessment was based primarily on information available in the literature, with consideration for possible commercialization in the mid-1980 time frame. Table 8.1 summarizes the performance and economic characteristics of LBG/CCPG plants relative to conventional coal-fired power plants equipped with stack-gas scrubbers.

8.1.1 Technical Feasibility

From a technical standpoint, LBG/CCPG plants employing either moving-bed, fluidized-bed or entrained-flow gasification technology combined with low-temperature gas purification and a combined gas/steam power cycle, based on a projected 2200°F gas-turbine nozzle temperature, are judged to be entirely feasible. Low-temperature gas-treating technology, capable of conditioning low-Btu fuel gas for firing gas turbines, is currently commercially available. Although high-temperature gas-clean-up technology is under development, it will certainly not be a proven technology for use in the mid-1980s. Moreover, there is some doubt as to its viability for use with gas-turbine systems at all. Past and current trends in gas-turbine technology indicate that a machine operating at an inlet temperature of 2200 °F and a 16:1 pressure ratio will be commercially available by 1980, without the need for developing new materials or blade-cooling techniques.

The only questionable aspect of the commercial availability of these integrated LBG/CCPG plants is the gasification system. Fluidized-bed and entrained-flow gasifiers suitable for this application are under active development. Assuming that this rate of development is continued or increased and that the demonstration-plant efforts prove successful, these technologies could be available by the mid-1980s. The moving-bed gasification systems, typified by the dry-ash Lurgi gasifier, are presently at the commercial level. However, these gasifiers result in lower over-all thermal efficiencies and higher investment costs than LBG/CCPG systems based on fluidized-bed or two-stage entrained-flow gasifiers. The slagging version of the Lurgi gasifier that is currently being developed holds promise of improving this situation. In this operational mode, by-product oils and tars may be recycled for conversion to additional fuel gas, and the higher slagging temperature allows a lower steam/coal feed ratio, which should result in higher thermal efficiencies. In addition, the higher throughput per gasifier will decrease the capital cost of the gasification system.

However, the slagging moving-bed gasifier will have the same drawback as the dry-ash version with respect to coal-fines rejection. A system whereby the fines material can be briquetted and fed to the gasifier as suitably sized coal is required to render this system competitive with the fluidized-bed or entrained-flow systems with respect to coal utilization.

Table 8.1 Assessment of LBG/CCPG Systems (Basis: 500-MWe Net Plant Output)

Characteristic	LBG/CCPG Case						
	1	2	3	4	5	6	Conventional Power Plant[a]
Gasifier	Lurgi Moving Bed		U-Gas Fluidized Bed		FW Entrained Flow		---
Coal	Illinois	Montana	Illinois	Montana	Illinois	Montana	Illinois
Thermal efficiency[b], %	28.6	30.3	37.2	38.6	37.1	37.1	33.8
Total plant investment[c], $MM	464.0	487.4	376.8	377.5	365.0	377.4	335.0
Total capital required, $MM	591.6	623.8	476.5	479.5	461.9	479.6	443.2
Cost of electricity[d], mills/kWh	52.5	57.3	43.1	45.4	41.6	45.3	41.2
By-products							
Sulfur, STPD	177.6	46.8	139.4	41.4	139.1	42.5	--
Ammonia, STPD	72.7	69.0	19.8	18.7	52.7	53.1	--
Oil/tar, STPD	408.5	392.5	--	--	--	--	--
Coal fines, STPD	2734	3398	--	--	--	--	--
Environmental emissions							
Air: SO_2, lb/MMBtu	0.87	0.84	0.98	0.89	1.0	0.90	0.87
NO_x, lb/MMBtu	← Less than 0.3 Expected →						0.65
Particulates, lb/MMBtu	← About 0.01 Expected →						0.09
Water:							
Plant blowdown, GPM	1156	1053	927	802	844	840	1600
Solids:							
Ash/slag[e],TPD	778	1018	612	815	609	842	400 (dry)
Sludge, TPD	--	--	--	--	--	--	1100

[a] Equipped with stack-gas scrubber

[b] Coal pile to buss bar

[c] Mid-1977 basis

[d] Utility financing method

[e] Wet basis (25% moisture)

8.1.2 Economic Outlook

The economics for LBG/CCPG plants appear to be comparable with and possibly better (when high-temperature turbines are employed) than those for conventional coal-fired steam-power plants. The primary uncertainty in this aspect of the over-all assessment is the accuracy of the investment-cost data available for the integrated LBG/CCPG plants. Literature cost data have reported ranges of ± 20% to ± 40% in their estimates, and in some instances no claimed accuracy at all is stated. Up to the present time, only conceptual designs of LBG/CCPG systems have been reported, and detailed cost estimates based on sound engineering designs are either lacking or have not been made generally available.

Based on the available cost data, the LBG/CCPG plants employing fluidized-bed or entrained-flow gasifiers achieve a significantly lower cost of electricity than those using the dry-ash moving-bed gasifier. The economics of the LBG/CCPG systems based on the dry-ash Lurgi gasifier are substantially dependent on by-product credits. The marketability of the oil/tar by-product, as well as the rejected coal fines, may be problematic, depending on plant location; the economic advantages would vary accordingly. As noted above, the development of the slagging Lurgi gasifier will tend to improve the economics of the moving-bed gasification system.

8.1.3 Environmental Acceptability

The environmental aspects of LBG/CCPG systems are perhaps most indicative of the potential advantages that these advanced power cycles have over conventional coal-fired stations. The estimated emissions from LBG/CCPG plants, as shown in Table 8.1, are considerably less than those from the conventional power plant, with the exception of the SO_2-emission level. For this assessment study, the SO_2 emission was fixed at about 1.0 lb/MMBtu (to meet the current federal air-pollution regulations), which corresponds to about 1000 ppmv of sulfur in the low-Btu fuel gas after purification. However, the low-temperature desulfurization systems now commercially available have the capability to reduce the sulfur level in fuel gas to much lower levels, less than 100 ppmv, and reduce the over-all plant SO_2 emission accordingly. This flexibility is not available in the coal-fired station using stack-gas scrubbing. The LBG/CCPG plants, therefore, have the potential for meeting future reductions in the allowable sulfur emissions from large power-plant sources.

Similarly, the fuel-gas-purification system, combined with the inherent low firing temperature of low-Btu fuel gas, results in low NO_x and particulate emissions for LBG/CCPG plants. The contribution of coal nitrogen to the total NO_x emission is essentially eliminated with these systems.

The environmental advantage of LBG/CCPG plants is also evident in terms of the total discharge of water and solid-waste streams. The large quantities of sludge resulting from the stack-gas scrubber in the conventional power plant are eliminated. However, it should be pointed out that the environmental acceptability of the water and solid discharges from LBG/CCPG plants remains to be confirmed via operating experience.

In view of the current trends in pollution-control regulations, it is likely that environmental considerations will ultimately be the prominent factor for future electric-power generation.

8.2 RECOMMENDATIONS

As a result of the findings in this preliminary assessment of LBG/CCPG plant, it is recommended that the following areas be given further emphasis in future R&D efforts:

- Definitive designs and cost estimates of LBG/CCPG plants are required to confirm their economic potential.
- Future assessment of moving-bed gasification systems should consider the slagging gasifier concept, rather than the dry-ash version.
- Critical assessment of the development programs concerned with advancing the technology of fluidized-bed and entrained-flow gasifiers is needed to project their commercial availability for LBG/CCPG plants.
- Turbine manufacturers should be canvassed to assess the commercial availability of "intermediate-temperature" (2000-2400°F) gas-turbine technology. Current development programs emphasizing high-temperature technology (2500-3000°F) are directed towards commercialization in the 1990s.
- Environmental assessment of LBG/CCPG systems will have to consider the fate of trace elements in the coal, as well as trace contaminants in the raw fuel gas. Data are not available in either area at the present time. Development efforts on the pilot-plant and demonstration-plant levels should emphasize the collection and reporting of this information. These data are absolutely necessary for the design of adequate gas-cleaning and waste-water-treating facilities associated with LBG/CCPG plants.
- Information is also needed on the composition and leaching character of the ash and slag residues resulting from various coal gasifiers. Ultimate disposal of these solid wastes could present a problem for LBG/CCPG plants if the properties of these wastes differ significantly from those of fly ash.

APPENDIX A

DESCRIPTION OF COAL GASIFIERS

This appendix describes developmental-stage and commercial coal gasifiers judged applicable in LBG/CCPG systems. The descriptions have been extracted unchanged from References (181) and (209).

1.17 ERDA-MERC STIRRED BED

Type:

Fixed bed gasifier equipped with central agitator.

Developer:

U. S. Energy Research & Development Administration
Morgantown Energy Research Center
Collins Ferry Road
P.O. Box 880
Morgantown, WV 26505

State of Development:

The ERDA-MERC (Energy Research & Development Administration-Morgantown Energy Research Center) Stirred Bed process has been demonstrated in a 20 TPD pilot scale unit.

The ERDA-MERC Stirred Bed process has been under development since 1968. It is an extension of the McDowell-Wellman (Wellman-Galusha) atmospheric pressure gasifier, modified for pressurized operation.

The pilot-scale unit, located in Morgantown, West Virginia, is still in operation testing bituminous coals. Various U.S. coals have been tested, and the results confirm that strongly caking coals can be gasified in a fixed bed. Continuous stirring of the fuel bed is required to maintain gas quality and prevent ash agglomeration. The gasifier has been tested at pressures from 85 to 180 psig with no significant effect on gas yield or heating value.[4]

Description:

The ERDA-MERC Stirred Bed gasifier (Figure 1.17-1) is of vertical cylindrical construction equipped with a vertical stirrer in the center and a rotating grate at the bottom. The grate is composed of three flat circular plates, spread eccentrically one above the other, which support the fuel bed. The rotation of the grate pushes the ash horizontally between the plates so that it can drop through centrally located holes in the lower two plates. Ash is withdrawn from the bottom of the gasifier via a lock hopper for analysis and disposal. Cooling water is circulated inside the stirring shaft and the two lower, horizontal agitators. The third agitator arm is not cooled and is used to level the bed surface. A portion of the reactor wall, approximately equal to the bed height, is cooled with water, while the remainder is faced with fire brick backed up with insulating refractory.

Sized coal is mechanically transported from a storage silo to the coal feed hopper. Inert gas is used to pressurize the hopper to a pressure slightly higher than the operating pressure of the gasifier. (See Figure 1.17-2.) Coal then falls by gravity and forms a bed on the grate. Air, mixed with superheated steam, is fed into the gasifier below the grate and flows upward through the descending coal, gasifying and partially burning it. The stirrer is continuously rotated and moved up and down to provide for complete mixing of the air, steam, and coal and to minimize ash and coal agglomeration.

Product gas is withdrawn through a side outlet at the top of the gasifier. The gas pressure is reduced via a restriction orifice before the gas flows to the cyclone dust collector. In the cyclone, entrained char particles (2 to 4% of the coal feed) are recovered and can be either recycled to the gasifier or burned for fuel. In the Morgantown pilot unit, the gas pressure is further reduced via another restriction orifice. It then flows through a series of mufflers and is finally burned in the stack.

In a commercial plant, the gas from the cyclone would be cooled to separate the tar and oil. The condensate would contain approximately 68% tar, 22% water, and 10% oil. The oil can be separated from the tar by azeotropic distillation. The gas would then be sent to an acid gas removal unit and a low-BTU producer gas would result. Medium-BTU gas can be produced by oxygen-blown operation.

Feed Requirements:

Sized coal, 50% less than 1/2 in. Run-of-mine coal can also be used. Gasifier has been tested using both strongly caking and non-caking coals.

Predrying of feed coal is not necessary.

Temperature in the gasifier must be maintained below ash fusion temperature.

Operating Conditions:[3]

Temperature in combustion zone = 2400°-2500° F
Temperature of gas leaving the gasifier = 1200° F
Pressure = Atmospheric to 285 psig

Gas Produced:

Typical gas composition (dry basis) after gas scrubbing and cooling –

		Air-Blown Operation	
Feed Coal		West Virginia Pittsburgh Bed[1]	New Mexico Sub-Bitum.[2]
HHV of coal, BTU/lb, dry		13,850	8900
Mole %,	CO	20.4	16.0
	CO_2	8.7	12.6
	H_2	15.5	19.0
	CH_4	2.4	3.8
	H_2S	0.5	0.2
	N_2	52.5	48.4
HHV, BTU/SCF, dry		140	151

By-Products:

About 70 pounds of tar per ton of coal feed is produced.

Utility Requirements:[2] ¶

Air, lb/lb of coal	2.3
Steam, lb/lb of coal	0.7
BFW	N/A*
Electric Power	N/A

*In a commercial unit, steam will be generated in the water jacket.

Labor Requirements:

In a commercial plant, the gasification area using one gasifier would require one operator and one helper, 4 shifts a week, 365 days a year. Battery limits for the gasification area are from receiving coal into the coal hopper to delivery of ash from ash hopper and cooled, scrubbed product gas.

The pilot-scale unit at Morgantown, West Virginia, having a capacity of 20 TPD of coal, requires four men (shift supervisor, technician, operator, and helper) per shift and a daily analysis technician.

Thermal Efficiency:[2] ¶

Based on cooled and scrubbed product gas, and air-blown operation –

Cold Gas Efficiency = 79%
Overall Thermal Efficiency = N/A

Capacity:

The pilot scale ERDA-MERC Stirred Bed gasifier, with a 3.5 ft. I.D. and 24 ft. tall, can gasify about 20 TPD of coal to produce about 2 MM SCFD of low-BTU gas.

Expected turndown ratio = 100/25.

Environmental Considerations:

The ash produced from the stirred bed gasifier contains a minimal amount of carbon. It is disposed of by landfill.

The tar and oil produced will need additional facilities for storage or for further disposal.

Waste water generated in the process will require treatment for phenolics and other organic removal before it is discharged.

Remarks:

The ERDA-MERC Stirred Bed gasifier will accept both caking and non-caking coal. The thermal efficiency, taking into account the tar and oil produced, will be high. The tar and oil, however, will require extra handling and their disposition must be determined for each particular installation. Further process development is underway at Morgantown.

References:

1. Lewis, P. S., A. J. Liberatore, and J. P. McGee, "Strongly Caking Coal Gasified in a Stirred-Bed Producer", Bureau of Mines Report of Investigations 7644, 1972.
2. Rahfuse, R. V., G. B. Goff, and A. J. Liberatore, "Non-caking Coal Gasified in a Stirred-Bed Producer", Bureau of Mines Technical Progress Report 77, March, 1974.
3. Private communications, between Dravo Corporation and ERDA, Morgantown Energy Research Center, November, 1975.
4. Lewis, P. S., A. J. Liberatore, R. V. Rahfuse, and G. R. Friggens, "Bituminous Coal Gasified in a Stirred-Bed Producer", ERDA Report MERC/RI-71/1, 1975.

¶ Based on New Mexico Sub-Bituminous coal as in the case of Gas Produced.

ERDA - MERC STIRRED BED GASIFIER

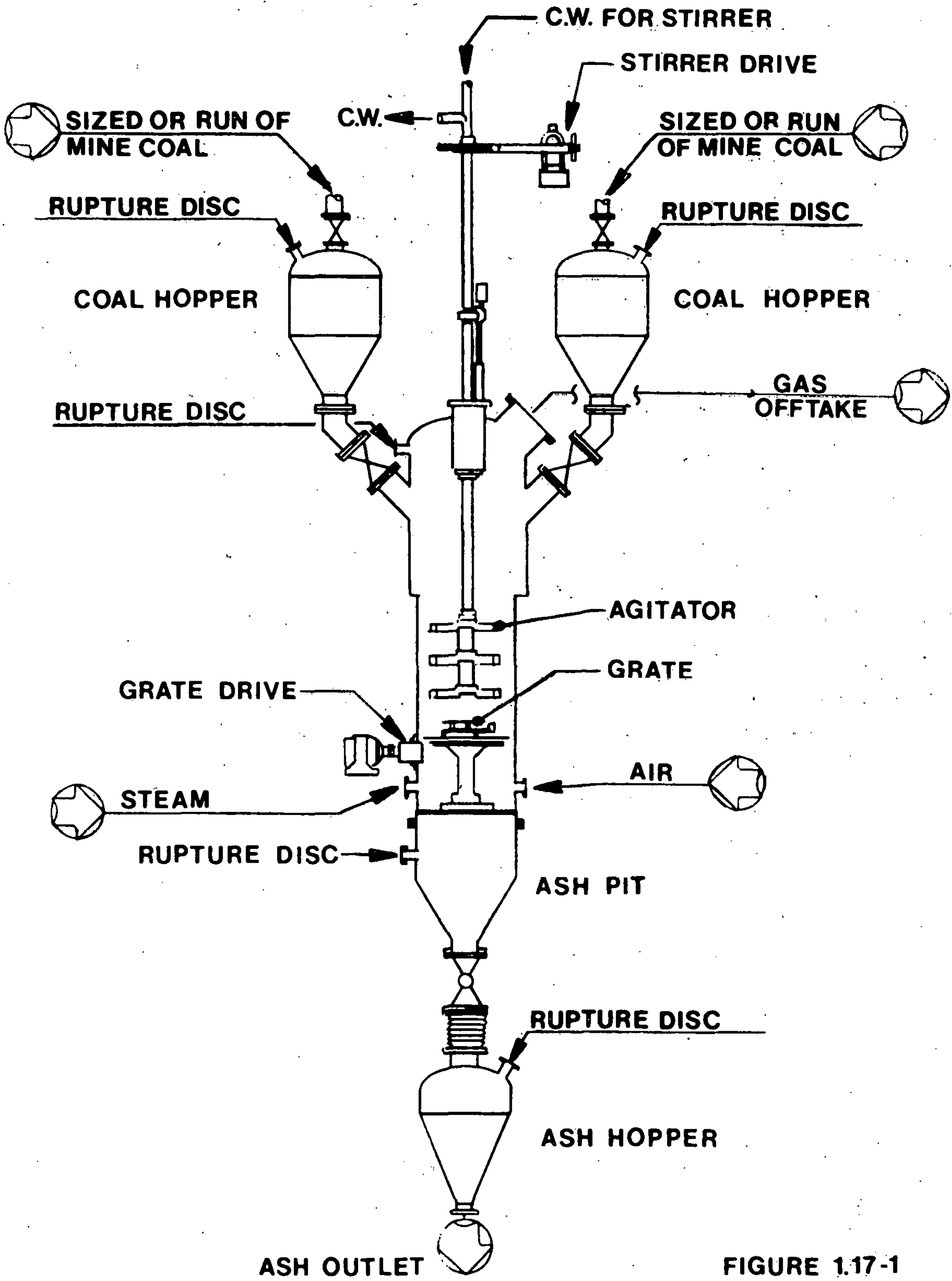


FIGURE 1.17-1

ERDA-MERC STIRRED BED GASIFICATION SYSTEM

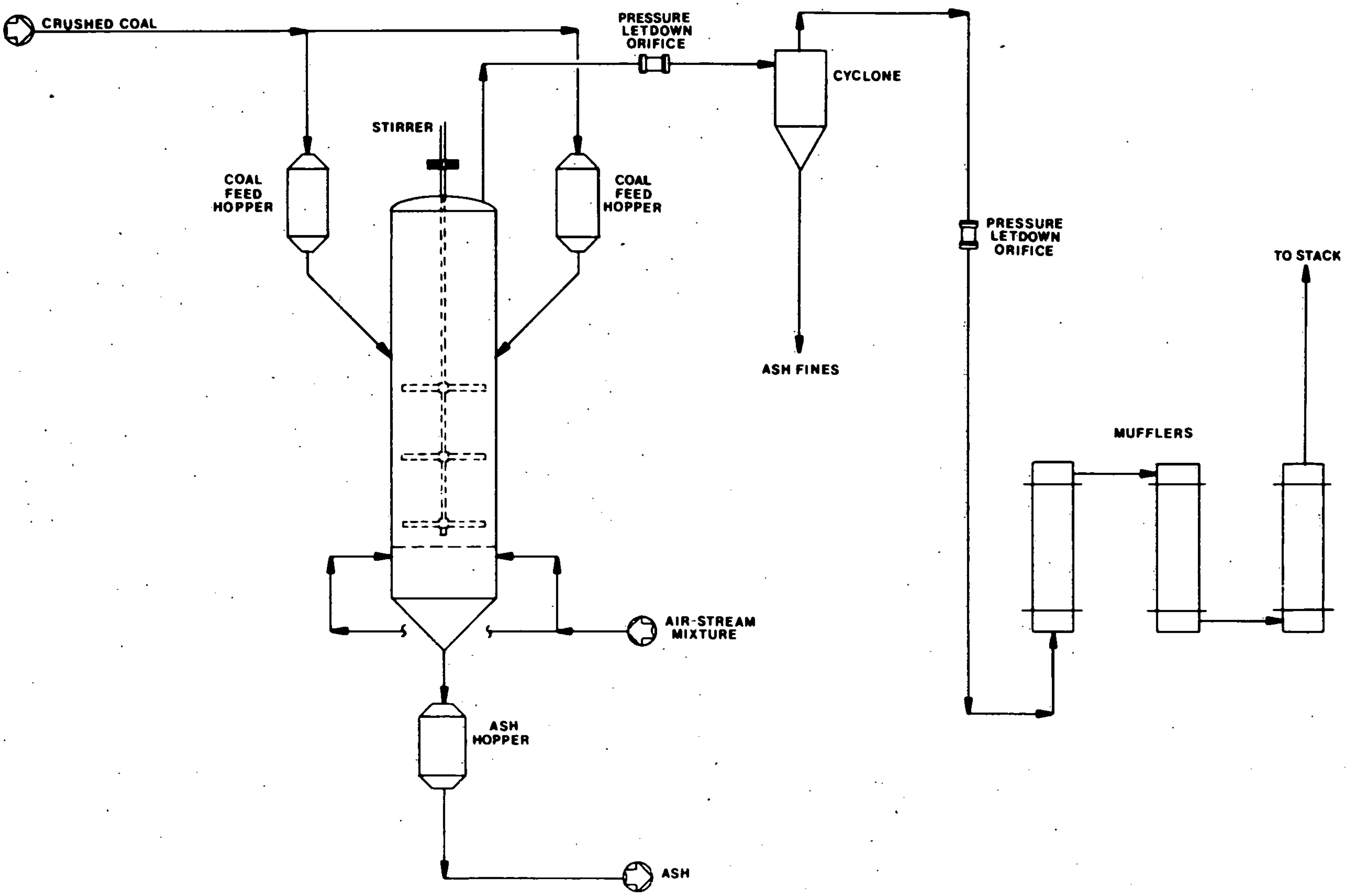


FIGURE 1.17 2

1.18 LURGI

Type:

Fixed bed gasifier

Licensor:

American Lurgi Corporation
377 Route 17
Hasbrouck Heights, NJ 07604

State of Development:

The Lurgi process is a commercially proven high pressure gasification process for manufacturing fuel gas and other by-products from coal.

The first full-scale Lurgi coal gasification plant was constructed at Hirschfelde, Germany, in 1936. Since then, 18 commercial plants have been installed worldwide. These are summarized in the attached table.

Various bench and pilot scale units have also been erected to test different types of coal and alternate gasifier designs. For example, in 1946, bench scale Lurgi gasifiers of 4 in., 6 in. and 13.5 in. I.D. were built at the Central Experimental Station of the Bureau of Mines to test the Alabama caking coals.[9] In 1953, a pilot scale plant was erected at Holten, Germany, to test the Lurgi gasifier for various high-volatile coals and weakly caking coals. A 170 MW combined cycle plant utilizing the Lurgi pressure gasification system was tested in Lunen, Germany, in 1973. A commercial 800 MW plant is planned for start-up in 1980.[13]

In 1973, a design study was conducted for the El Paso Natural Gas Company Burnham I Coal Gasification Complex. In this study, 38 Lurgi pressure gasifiers with 12 ft. 3 in. I.D. were proposed. Twenty-eight of these gasifiers will be oxygen-blown and will be used to produce 288 MM SCFD of pipeline quality gas from lignite. Ten air-blown gasifiers will be used for fuel gas production.[7]

In 1974, a design study was made for the ANG Coal Gasification Company. For this North Dakota Coal Gasification Project, 24 Lurgi pressure gasifiers have been proposed to produce 275 MM SCFD of pipeline quality gas from lignite.[5]

Other announced projects to produce SNG from coal employing Lurgi technology include: Wesco, Panhandle Eastern, Natural Gas Pipeline, Northern Natural Gas/Cities Service Gas. A project to produce utility power gas was announced by Commonwealth Edison.

Description:

The Lurgi gasifier is a fixed bed type gasifier with a vertical cylindrical construction. (See Figure 1.18-1.) It is a high pressure gasifier, operating at 350-450 psig. The main gasifier shell is surrounded by a water jacket. Boiler feed water is circulated through the jacket to recover heat escaping from the gasifier shell. A coal lock hopper is mounted on top of the gasifier to feed the coal, while a motor driven distributor is used to spread the incoming coal evenly over the coal bed. A motor driven grate at the bottom of the gasifier is used to withdraw the ash formed. The ash drops into an ash lock hopper, which is an integral part of the gasifier.

Coal received from the stockpiles is crushed and screened to obtain 1/8" x 1-1/2" coal. The coal is transported to the gasifier lock hopper by a system of belt conveyors. Fines generated during the crushing and screening are removed and are available for use in the plant or for export. Steam and oxygen are introduced at the bottom of the gasifier to effect the coal gasification reactions. The steam and oxygen are distributed into the coal bed through the rotating grate. The grate supports the coal bed and is continuously rotated to assure a constant and even withdrawal of the ash formed.

As the steam and oxygen pass upward, four different zones can be characterized in the coal bed by the prevailing reactions and temperatures. They are, from bottom to top, carbon combustion, gasification, devolatilization, and drying. As the coal descends through the bed, some volatile matter in the coal is first removed and the remaining carbon is then gasified and combusted. The ash is withdrawn from the bottom of the gasifier into the ash lock hopper and subsequently sent to disposal. Excess steam is added to the ash layer just above the grate to prevent slagging of the ash.

Crude gas formed in the gasifier leaves from the top and flows through a scrubber cooler, where it is washed by circulating gas liquor. (See Figure 1.18-2.) The gas then passes through a waste heat boiler, where it is cooled and low pressure steam is generated. Condensate formed is subcooled and sent to a tar-liquor separator. Gas exiting the waste heat boiler is further cooled by three water cooled heat exchangers in series. A part of the condensate recovered from this cooling is sent to the tar/liquor separator, and the remainder is sent to an oil/liquor separator.

Tar and the aqueous tar liquor are decanted in the tar/liquor separator. Similarly, tar oil and the aqueous oil liquor are decanted in the oil/liquor separator. The tar liquor and oil liquor are then combined and fed to a Phenosolvan unit and a Chemie Linz-Lurgi (CLL) ammonia plant, where crude phenols and anhydrous ammonia are recovered.

Gas from the final cooler is desulfurized in an acid gas removal unit. By-product naphtha will be recovered from the condensate collected in a cooling step prior to acid gas removal. The final product gas is a desulfurized medium-BTU gas.

Feed Requirements:

Sized coal: 1/8" x 1-1/2"[6]

Gasifier will accept caking and non-caking coals. The following U.S. coals, which include caking coals, have been tested with satisfactory results in Lurgi gasifiers: Illinois #5 and #6, Pittsburgh #8, Montana Rosebud, and Nor Dakota Lignite.[6,10] It has been observed that use of high caking coals slightly reduces the gasifier throughput and increases the steam requirement.

Up to 30-35% moisture can be tolerated in the coal feed; therefore, predrying is rarely necessary.[11]

The initial deformation temperature of the ash should not be significantly lower than the combustion zone temperature in order to avoid clinker formation.[12] Control of the ash temperature by increasing steam flow or by variation in grate speed may avoid the problem.

Operating Conditions:[2]

Temperature in combustion zone = 1800°-2500°F
Temperature in gasification zone = 1200°-1500°F
Temperature in gas leaving the gasifier = 700°-1000°F
Pressure = 350 to 450 psig

Temperatures depend on the type of coal gasified.

Gas Produced:[6]

Typical gas composition (dry basis) after gas scrubbing and cooling –

	O_2-Blown Operation
Feed Coal	Pittsburgh #8
HHV of coal, BTU/lb, dry	14,900
Mole %, CO	16.9
CO_2	31.5
H_2	39.4
CH_4	9.0
C_2H_6	0.7
C_2H_4	0.1
$H_2S + COS$	0.8
$N_2 + Ar$	1.6
HHV, BTU/SCF, dry	285

By-Products:[6] ¶

Tar, lb/ton of coal	75
Tar Oil, lb/ton of coal	25
Oil Liquor + Tar Liquor, lb/ton of coal	5200
Steam Generated @ 350 psig, saturated, lb/ton of coal	1300
Steam Generated @ 100 psig, saturated, lb/ton of coal	3530

Utility Requirements:[6] ¶

Oxygen (98%), lb/lb of coal	0.6
Steam, lb/lb of coal	3.2
BFW, Gal/ton of coal	580
Electric Power, KWH/ton of coal	23*

*From receiving crushed coal to delivery of cooled ash, gas, tar, tar oil, and liquor. Does not include oxygen compression.

Labor Requirements:

The gasification area, using one gasifier with a capacity of approximately 800 TPD of coal, requires one operator and one helper, 4 shifts per week, 365 days a year. Battery limits for the gasification area are from receiving sized coal into coal lock hoppers to delivery of ash and cool product gas from the final cooler. This excludes the by-product separation and recovery.

Thermal Efficiency:[14]

Based on cooled and scrubbed product gas, and a coal with HHV of 8380 BTU/lb, dry.

Cold Gas Efficiency = 63%
Overall Thermal Efficiency = 76%

Capacity:

A typical commercial Lurgi pressure gasifier with a 12 ft. I.D. can gasify approximately 800 TPD of coal to produce about 56 MM SCFD of medium-BTU gas at 400 psig.

Expected turndown ratio = 100/25.

Environmental Considerations:

Extra handling of the fines from coal handling and crushing is required, and their final disposition must be determined for each installation.

Waste water from the scrubber cooler, Phenosolvan unit, etc., has organic and inorganic contaminants and will require bio-oxidation treatment. Inorganic solids recovered may be mixed with ash and disposed of as landfill.

Tar, oil, phenol, naphtha, ammonia, and sulfur are the by-products produced in a Lurgi pressure gasification system. The quantity of these by-products varies according to the coal feedstock. If a market is not available, special handling of these will be required. Recovered organics, for example, may be recycled to the gasifier.

Remarks:

Lurgi is a proven commercially available coal gasification process. It is projected from the Westfield tests that it will gasify all types of coal. Use of highly caking coals, however, reduces the gasifier throughput and increases the steam requirement.

Coal preparation costs are reduced since the process does not require pulverizing and drying, but utilization and/or disposal of the fines generated in the sizing operation may be a problem at some installations.

The process produces by-products such as tar oil, crude phenols, and naphtha; the final disposition of these products must be ascertained for each installation.

¶ Based on Pittsburgh #8 coal, as in the case of Gas Produced.

LURGI PRESSURE GASIFIER

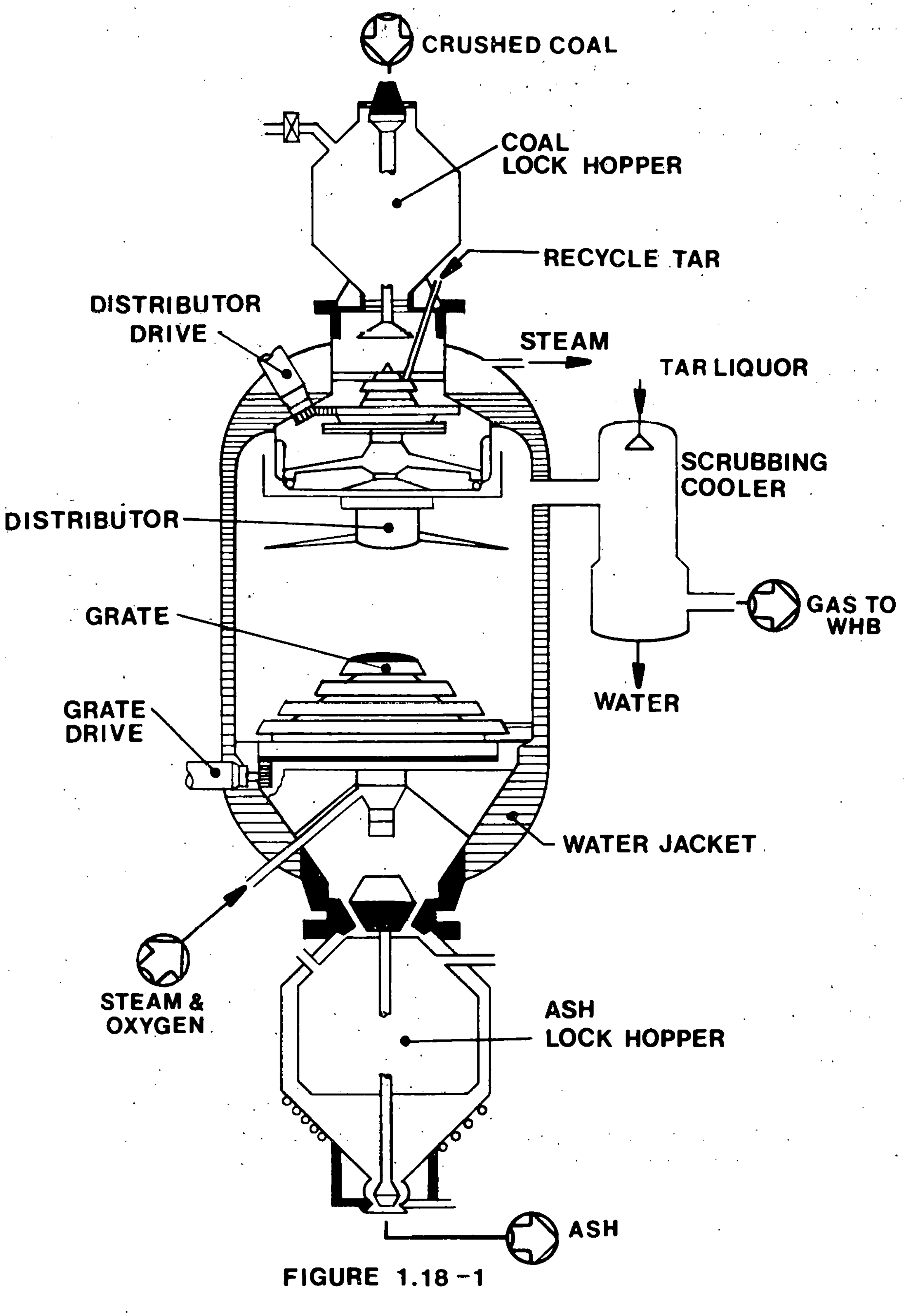


FIGURE 1.18 -1

LURGI COAL GASIFICATION SYSTEM

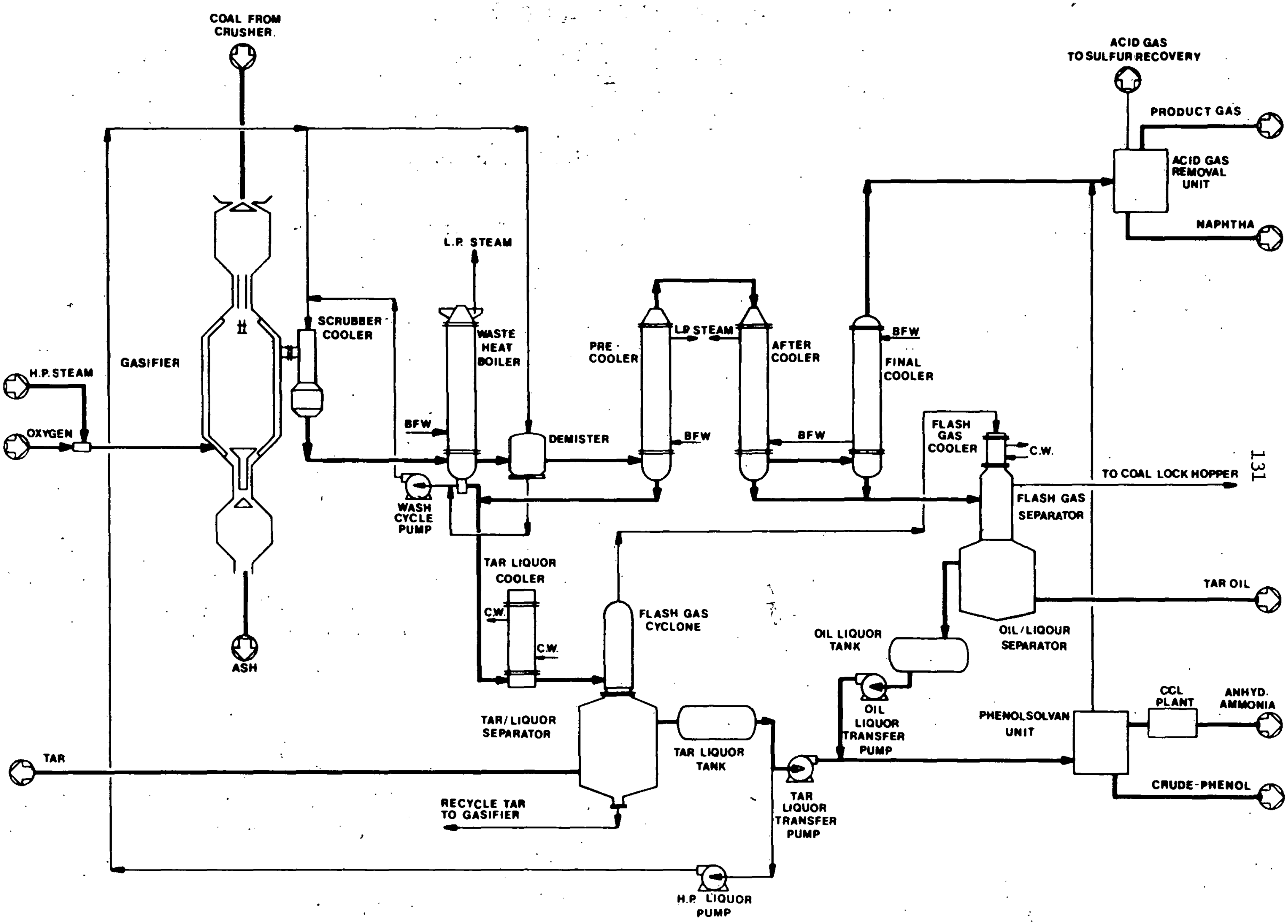


FIGURE 1.18-2

1.13 SYNTHANE

Type:

Fluid bed gasifier

Developer:

U.S. Energy Research & Development Administration
Pittsburgh Energy Research Center
4800 Forbes Avenue
Pittsburgh, PA 15213

State of Development:

Construction of a 72 TPD Synthane pilot plant is completed, and shakedown runs are expected to begin in early 1976.

The concept of the Synthane gasifier was initiated in 1961 while experimenting with methods of pretreating caking coals in a fluidized bed reactor. It was observed that pretreatment of any caking coal was possible by the proper combination of oxygen content of the fluidizing gas, temperature, and residence time. Earlier gasification tests with a two fluid bed system led to the development of a single vessel construction wherein the operations of coal pretreatment, carbonization, and gasification were combined.[1]

The first PDU scale Synthane gasifier built at the Bureau of Mines Research Center at Bruceton, Pennsylvania, was 4 in. I.D. and 6 ft. tall. It was operated at about 40 atmospheres (~570 psig) and a maximum temperature of 1800°F. The original gasifier combined the operation of free-fall pretreatment, carbonization, and gasification in one unit, and it used a 70% through 200 mesh coal. Because of limitations of the free-fall pretreater, a separate fluid bed pretreater was added to the gasifier. The fluid bed pretreater could handle a 30%, instead of 70%, through 200 mesh coal, and therefore raised the permissible linear velocity in the gasifier from below 0.2 ft/sec to 0.4, thus increasing the gasifier throughput of coal.

The results indicated that a 65% carbon conversion can be obtained. This would require the gasifier char to be burned to generate steam. (Expected carbon content of char is approximately 50-70%.) The gas produced had a 540 BTU/SCF HHV after acid gas removal. The pretreating step operated satisfactorily to render caking coals noncaking. Among the coals tested were Pittsburgh seam coals with an FSI of 8 or 9 and Illinois #6 coal with an FSI of 3 to 5.

The next step in the development of the Synthane gasifier was to use the Hydrocarbon Research, Inc. (HRI) gasifier (26-1/2 in. I.D. by 80 ft. high trimmed to 18 in. I.D. and operated at approximately 9 TPD) to simulate the Synthane gasifier. Tests were run on the unit, during 1972-73, and results were satisfactory with regard to pretreatment and gasification. Some elutriation of fines was noted, but these are expected to be reduced significantly with the use of a cyclone in the pilot plant.

Currently, construction of the 72 TPD Synthane pilot plant has been completed at Bruceton, Pennsylvania. Checking and field testing of the equipment is in progress. The gasifier is designed to operate at a maximum of 1000 psig, with the fluid bed operating at approximately 1800°F. Shakedown runs with sub-bituminous coals are expected to begin in early 1976. The plant will produce 2 MM SCFD of medium-BTU gas of which about 25% will be methanated.[5]

Description:

The Synthane pilot plant is oriented toward manufacture of SNG instead of a medium-BTU industrial gas, and therefore CO shift and methanation are also a part of the plant. The present description, however, will be restricted mainly to manufacture of the medium-BTU gas.

The Synthane gasifier in the pilot plant is a vertical cylindrical fluid-bed reactor operating at elevated pressures and temperatures. The gasifier vessel is 101 ft. high with an I.D. of 5 ft. (See Figure 1.13-1.)[5] The upper monel clad section will be used for gasifying; the lower Cr-Mo steel section is used for char discharge. Pretreated coal overflows from the pretreater into the gasifier through a nozzle on the side of the gasifier. It free-falls some 20 ft. in the gasifier and enters a fluidized bed maintained in the lower section of the gasifier. Steam and oxygen enter at the bottom through multiple orifices in a cone-shaped distributor. Approximately 65% of the carbon in the coal is gasified, and the unconverted carbon in the form of char is removed from the bottom. A fluidized bed type char cooler is made an integral part of the gasifier. The entire gasifier vessel, except for the char cooler, is lined with 9 in. of insulation: 6 in. of lightweight insulating castable refractory and 3 in. of dense erosion resistant castable refractory. In the fluidized bed, provisions have been made to install baffles to maintain a temperature gradient of 1400° to 1800°F from top to bottom. However, initial operations will not include these baffles. Also, in the gasifier fluidized bed, provisions have been made to install Incolloy 800 shrouds of different diameters (33, 36, 39, and 42 in.) to permit different ranges of fluidizing velocity.[6]

The feed coal is dried, pulverized to 20 mesh, and transported to the pressurized feed hopper through a system of cyclones, bins, and lock hoppers.[5] (See Figure 1.13-2.) The coal is then entrained by high pressure steam and a small amount of oxygen and fed into the pretreater. The pretreater is a fluid bed reactor maintained approximately at 1000 psig and 800°F. Steam and oxygen react with coal in the pretreater to nullify the caking tendencies of the coal. The pretreatment is required only for caking coals. Noncaking coals would merely pass through the pretreater.

The coal from the pretreater overflows into the gasifier and is gasified in the fluidized bed with steam and oxygen. The gas produced passes up the gasifier through the free-fall zone, where it countercurrently contacts pretreated coal and devolatizes it. The gas is then passed through an internal cyclone to remove entrained particles larger than 50 microns. The particles removed return to the fluidized bed through a cyclone dip-leg. The gas exits the gasifier and passes through a water-sprayed venturi scrubber. The gas, condensates, and particulate matter such as carbon fines not removed in the cyclone enter the scrubber surge tank, where separation of the gas and liquids takes place. The gas is then sent to a scrubbing tower. The tower contains a water wash section and an oil wash section for further cleanup.

The net condensates and carbon fines from the venturi scrubber and scrubbing tower collected in the scrubber surge tank are depressurized and sent to a decanter. In the Synthane pilot plant, the heavier than water tar will be sent to the thermal oxidizer. The aqueous condensates will overflow from the decanter into the waste water receiver, which will also collect other process condensates. This process waste water, which is expected to contain oil, tar, and carbon fines, will also be sent to the thermal oxidizer. Cooling of the recirculating liquid streams for the venturi scrubber and the gas scrubbing tower will be accomplished by generation of low pressure steam.[3]

The medium-BTU gas from the scrubbing tower will subsequently be processed in a shift converter, acid gas absorber, and methanator to produce SNG with an HHV of approximately 950 BTU/SCF, dry. In the pilot plant, the SNG will be consumed in a high pressure boiler.

Returning to the gasifier, the char formed in the gasifier passes down through the center of the cone-shaped distributor and into the char cooler attached to the gasifier. Spray water quenches the char here, and, as a result, high pressure steam is produced. This steam is filtered and used in the shift converter. The char is discharged alternately into char lock hoppers and picked up by low pressure steam. In a commercial plant, the char will be used to generate steam for the process. In the pilot plant, it will be used as a landfill.

Feed Requirements:[1]

Pulverized coal through 20 mesh. Gasifier will handle all types of coal; caking coals will require pretreatment.

The moisture content of the coal can limit operation by affecting pulverized coal flow – not gasification. Coal moisture should be below about 14% for the coal to be free flowing. Sub-bituminous coal has been dried to about 7% moisture. Thus, coals of virtually any moisture content can be adequately dried and handled.

The influence of the ash fusion point on operability has not been studied as such. However, the char softening point has been found to differ from pure ash softening point by as much as 200° F.[6] And as long as the char softening point is higher than the operating temperature, no difficulty should be experienced.

Operating Conditions:[6]

Temperature of coal entering the gasifier from pretreater = 800° F
Temperature in fluid bed = 1800° F
Temperature of gas leaving the gasifier = 1400° F
Pressure = 1000 psig

Gas Produced:

Typical gas composition (dry basis) after gas scrubbing and cooling –

	O_2-Blown Operation[6]	Air-Blown Operation[2]
Feed Coal	Illinois #6	Illinois #6
HHV of coal, BTU/lb, dry	11,695	11,695
Mole %, CO	13.2	10.1
CO_2	36.2	17.9
H_2	32.3	21.5
CH_4	15.0	5.6
C_2H_6	1.6	0.7
$H_2S + COS$	1.6	0.7
$N_2 + Ar$	Negl.	43.5
HHV, BTU/SCF, dry	355	165

By-Products:[6]

Tar, lb/ton of coal	94
NH_3, lb/ton of coal	16
BTX, lb/ton of coal	10
Steam, lb/ton of coal	N/A
Char, lb/ton of coal	600

These figures are based on Illinois #6 coal and 40 atm (~570 psig) oxygen-blown operation. Char contains approximately 50-70% carbon by weight. It will be used for steam generation in a commercial plant.

Utility Requirements:[6]

	O_2-Blown Operation
O_2, lb/lb of coal	0.35*
Steam, lb/lb of coal	1.25*
BFW, Gal/ton of coal	N/A
Electric Power, KWH/ton of coal	N/A

*For caking coals. Non-caking coals consume less O_2 and steam.

Labor Requirements:

The gasification area in the Synthane pilot plant, with a gasifier capacity of 72 TPD of coal, will require one operator and possibly one helper, 4 shifts a week, 365 days a year. Battery limits for the gasification area are from receiving pulverized coal into pressurized feed hoppers to delivery of char and cool product gas from the scrubbing tower.

Labor requirement breakdown for the complete pilot plant is given below.[6] There will be 8 operators plus a shift supervisor on each shift, with 4 shifts:

Slurry area and coal handling – 1 operator
Gasifier area – 1 operator
Recovery area (Stretford, Benfield, Methanation) – 1 operator
Utilities – 2 operators

Control room – 1 operator
Additional operator – 1
Field man – 1

Thermal Efficiency:

Based on cooled and scrubbed product gas, and O_2-blown operation.

Cold Gas Efficiency = N/A
Overall Thermal Efficiency = 65 to 70%[6] for the complete plant producing SNG.

Capacity:[5, 6]

The gasifier in the Synthane pilot plant is designed to gasify approximately 72 TPD of coal at 1000 psig to produce 2 MM SCFD of medium-BTU gas.

Turndown has not been studied. However, the minimum gas flow required for fluidization (not determined) will limit operation.

Environmental Considerations:

The char produced contains approximately 50-70% carbon. In a commercial plant, it is planned to be utilized for steam generation.

The pressurizing gas used in the coal handling system will be CO_2 obtained from the Stretford plant off-gas. The Stretford plant will recover sulfur from the acid gas separated in a hot potassium carbonate system which removes H_2S and CO_2 from the main process gas stream after shift conversion. The CO_2 from the Stretford will contain less than 5 ppm H_2S.[1] Particulate matter will have to be removed before the lock hopper gas is vented to the atmosphere. The composition of the vent gas can only be surmised at this point. It will be a function of the method of operation of the coal feed system and the properties of coal used. In the pilot plant, the lock hopper vent gas, along with the off gas from the Stretford plant, will be incinerated in a thermal oxidizer.

The tar and aqueous condensates from the gas cooling and scrubbing area will also be sent to the thermal oxidizer in the pilot plant.

Impact on the environment of various streams leaving the Synthane pilot plant has been discussed in Reference [1] Analyses of tars, chars, gases, and water found in effluen from the Synthane process are presented in Reference 4. It is believed that these materials in the effluents from the Bruceton laboratory-scale gasifier are representative of those from a commercial operation.[4]

Remarks:

The 72 TPD Synthane pilot plant construction is complete, but operation is yet to begin. The gasifier will handle all types of coal. Caking coals will be processed in the pretreater. Design is based on 65-70% conversion of the carbon in the feed. Highest sustained conversion in the PDU was 90% with Montana sub-bituminous coal. The gas produced contains about 60% of methane in SNG product methane. Some tar is also produced as a by-product, and its disposition will have to be ascertained for each installation.

References:

1. "Evaluation of Pollution Control in Fossil Fuel Conversion Processes, Gasification, Sec. I, Synthane Process", by Esso Research & Engineering Company, prepared for National Environmental Research Center, June, 1974.
2. Gasior, S. J., A. J. Forney, W. P. Haynes, and R. F. Kenny, presented at 78th National AIChE Meeting, Salt Lake City, Utah, August 18-21, 1974.
3. Torkos, T., and R. Lewis, "A Pictorial Tour of the Synthane Pilot Plant", U.S. Bureau of Mines Publication, Pittsburgh, Pennsylvania, 1974.
4. Forney, A. J., *et al.*, U.S. Department of the Interior, Pittsburgh Energy Research Center, Technical Progress Report 76, Pittsburgh, Pennsylvania, January, 1974.
5. Carson, S. E., C. E. Lummus Co. of Combustion Engineering, Inc., "Status of the Synthane Process", presented at the Seventh Synthetic Pipeline Gas Symposium, Chicago, Illinois, October, 1975.
6. Private communications, between Dravo Corporation and ERDA, Pittsburgh Energy Research Center, October, 1975.

SYNTHANE COAL GASIFICATION PROCESS
(PILOT PLANT SET-UP)

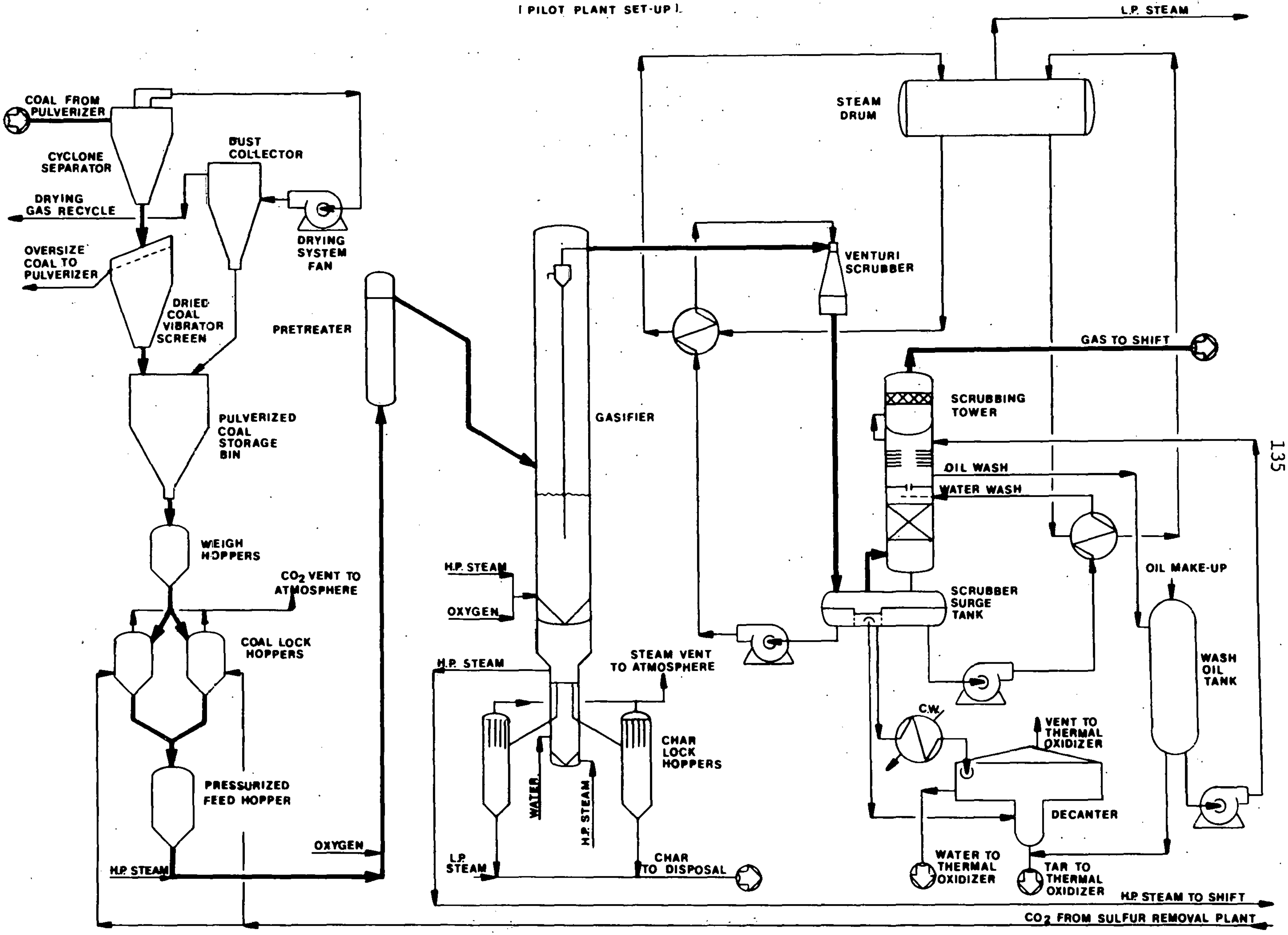


FIGURE 1.13 2

1.14 U-GAS

Type:

Single stage, fluidized, ash agglomerating gasifier.

Developer:

Institute of Gas Technology
3424 S. State Street
Chicago, IL 60616

State of Development:

A 4 ft. diameter, near atmospheric pressure gasifier has been in operation since February, 1974, processing 6 TPD of metallurgical coke.[2]

The low pressure gasifier was originally designed as part of the ERDA-AGA Hygas program to test the concepts of elutriated fines return, carbon utilization and ash agglomeration using metallurgical coke or char from the COED pilot plant as feedstock. Funding for a similar 4 ft. diameter reactor with a design pressure of 350-400 psig is being sought. The proposed reactor will test these concepts under pressure with different coals as the feedstock.

This process is an outgrowth of studies begun in 1945 when the Institute of Gas Technology (IGT) constructed a reactor to study the kinetics of carbon-oxygen-steam reactions at 2700° F and atmospheric pressure. Later, a similar reactor extended the studies to the 750 psig range.

A 6 in. diameter fluidized bed reactor was built in 1947 to investigate the gasification of coal and coke fines. A pilot plant with a capacity of 18 TPD of coal was then built in 1950. It was based on the suspension process and operated at 100 psig. These studies were made in the period 1951 to 1953.

Description:

The U-Gas gasifier is of vertical cylindrical construction with an internal cyclone for returning the elutriated fines to the bed. A sloped grid at the bottom, containing one or more inverted cones, serves as the air and steam distributor and the agglomerated ash outlet.

The U-Gas process is shown schematically in Figure 1.14-1. Raw coal is crushed to 1/4 in. size. The feed may contain up to 10% <200 mesh material as generated in the crushing step.[4] Non-caking, sub-bituminous coals or lignite can be fed directly to the gasifier from the crusher. Caking coals (Eastern bituminous, for example) must at present be pretreated by contact with air in a fluidized bed operating at gasifier pressure and 700° to 800° F. An oxidized outer layer forms on the coal particles, and this prevents agglomeration and possible blockage in the gasifier.[3]

Coal fed to the gasifier is gasified with a mixture of air and steam in a single stage fludized bed. The residence time of the coal is about 45 minutes to an hour. Fluidizing velocity is in the order of 1 to 2.5 feet per second.

The key to operation of the gasifier is the agglomeration and separation of the low carbon content ash from the bed. The U-Gas gasifier accomplishes this and maintains a bed of approximately 70% carbon and 30% ash by proper design and operation of the grid and the fines return system in the bottom of the gasifier. The grid is sloped toward one or more inverted cones contained in the grid. Part of the fluidizing steam and air flow through the grid while the remaining fluidizing gas flows upward at high velocity through the throat at the cone apex. The ratio of steam to air in the fluidizing gas fed to the cone is chosen so that the resulting submerged jet in the cone is hotter than its surroundings. The temperature of the jet is maintained near the softening point of the ash particles for the specific coal being gasified. Ash particles preferentially stick together, and the agglomerates grow until they are heavy enough to move downward counter to the force of the gas stream in the apex of the cone and, thus, fall out of the fluidized bed.

Fines elutriated from the fluid bed are separated from the product gas by two cyclones in series: the first inside the gasifier and the second outside. Fines removed by the first cyclone are returned to the bed by a standleg. Fines removed by the external cyclone are entrained in the inlet air/steam to the gasifier grid cone where they are instantly gasified.

The hot product gas, after fines removal in the two cyclones, is cooled via waste-heat recovery and the result is a low-BTU fuel gas. A medium-BTU gas can be produced by using oxygen in lieu of air in the gasifier.

Feed Requirements:[1]

Crushed coal, 0" x 1/4"

Non-caking coals can be fed directly to the gasifier from the crusher. Caking coals at present require pretreatment.

The moisture content of coal can limit operation by affecting crushed coal flow — not gasification. Therefore, coals with virtually any moisture content can be handled if they are properly prepared.

Temperature in the ash agglomerating zone of the fluidized bed is influenced by the ash softening and fusion points.[4]

Operating Conditions:[5]

Temperature in fluidized bed = ~1900° F
Temperature of product gas and pretreater off gas leaving the gasifier = 1550° to 1900° F
Pressure = 50 to 350 psig

Gas Produced:[5]

Typical gas composition (dry basis) after waste-heat recovery –

	Air-Blown Operation
Feed Coal	Bituminous
HHV of coal, BTU/lb, dry	12,235
Mole %, CO	19.6
CO_2	9.9
H_2	17.5
CH_4	3.4
$H_2S + COS$	0.7
$N_2 + Ar$	48.9
HHV, BTU/SCF, dry	154

By-Products[1, 5 ¶]

Oils or tars are not produced.

Steam generated @ 285 psig, saturated = 5910* lb/ton of coal.

*Includes steam generated in the pretreater and the steam generated in the waste heat boiler by cooling gas to 260° F.

Utility Requirements:[1, 5 ¶]

Air, lb/lb of coal	2.8 to 3.3
Steam, lb/lb of coal	0.4 to 0.6
BFW, Gal/ton of coal	710
Electric Power, KWH/ton of coal	44**

**From receiving crushed coal to the delivery of ash and product gas at 275 psig and 260° F. Electric power required for air compression is not included.

Labor Requirements:

The gasification area using one gasifier with a capacity of 3000 TPD of coal, requires one operator and one helper, 4 shifts a week, 365 days a year. Battery limits for the gasification area are from receiving raw coal to delivery of coal ash and cool raw gas from the waste heat recovery system.

Thermal Efficiency:[5 ¶]

Based on cooled and scrubbed product gas, and air-blown operation at 340 psig.

Cold Gas Efficiency = 79%
Overall Thermal Efficiency = 79%

¶ Based on Bituminous coal, and air-blown operation as in the case of Gas Produced.

Capacity:[1]

It is projected that a commercial U-Gas gasifier 22 ft. I.D. and 50 ft. high will gasify approximately 3000 TPD of coal to produce about 380 MM SCFD of dry low-BTU gas at 5 psig. The gasifier will have a 10/1 turndown capability.

Environmental Considerations:

Fines elutriated from the fluid bed are separated in the cyclones and returned to the gasifier. The ash produced in the gasifier contains up to 5-10% carbon and must be covered with dirt after landfill.

Remarks:

The U-Gas process was originated for integration into combined-cycle power generation. It can also be utilized to manufacture a low-BTU industrial fuel gas. A high temperature (~800° F) sulfur removal process (IGT-Meissner Process) has been under study by IGT, in conjunction with the U-Gas gasifier.[1] This was proposed with the objective of achieving a high overall thermal efficiency for the total coal gasification-power generation complex. The concepts of ash agglomeration and fines removal and recycling have been demonstrated on a pilot plant scale in the ERDA-AGA Hygas program. The high temperature sulfur removal process is at the bench scale level of development.

References:

1. Loeding, J. W., and E. L. Tsaros, "IGT U-Gas Process", paper presented at Clean Fuels from Coal Symposium, IGT, Chicago, Illinois, September, 1973.
2. Howard-Smith, I., and G. J. Werver, *Coal Conversion Technology: A Review,* under the Auspices of Millmerran Coal Pty. Ltd., Brisbane, Australia, May, 1975.
3. Loeding, J. W., and J. G. Patel, "The U-Gas Process", Chemical Engineering Progress, *71* (4), April, 1975.
4. Private communications, between Dravo Corporation and Institute of Gas Technology, January, 1976.
5. Patel, J. G., K. B., Burnham, and J. W. Loeding, "The IGT U-Gas Process – An Economic Analysis", Symposium on Comparative Economics for Synfuels Processing, 171st National Meeting of American Chemical Society, New York, April 5-9, 1976.

U-GAS COAL GASIFICATION SYSTEM

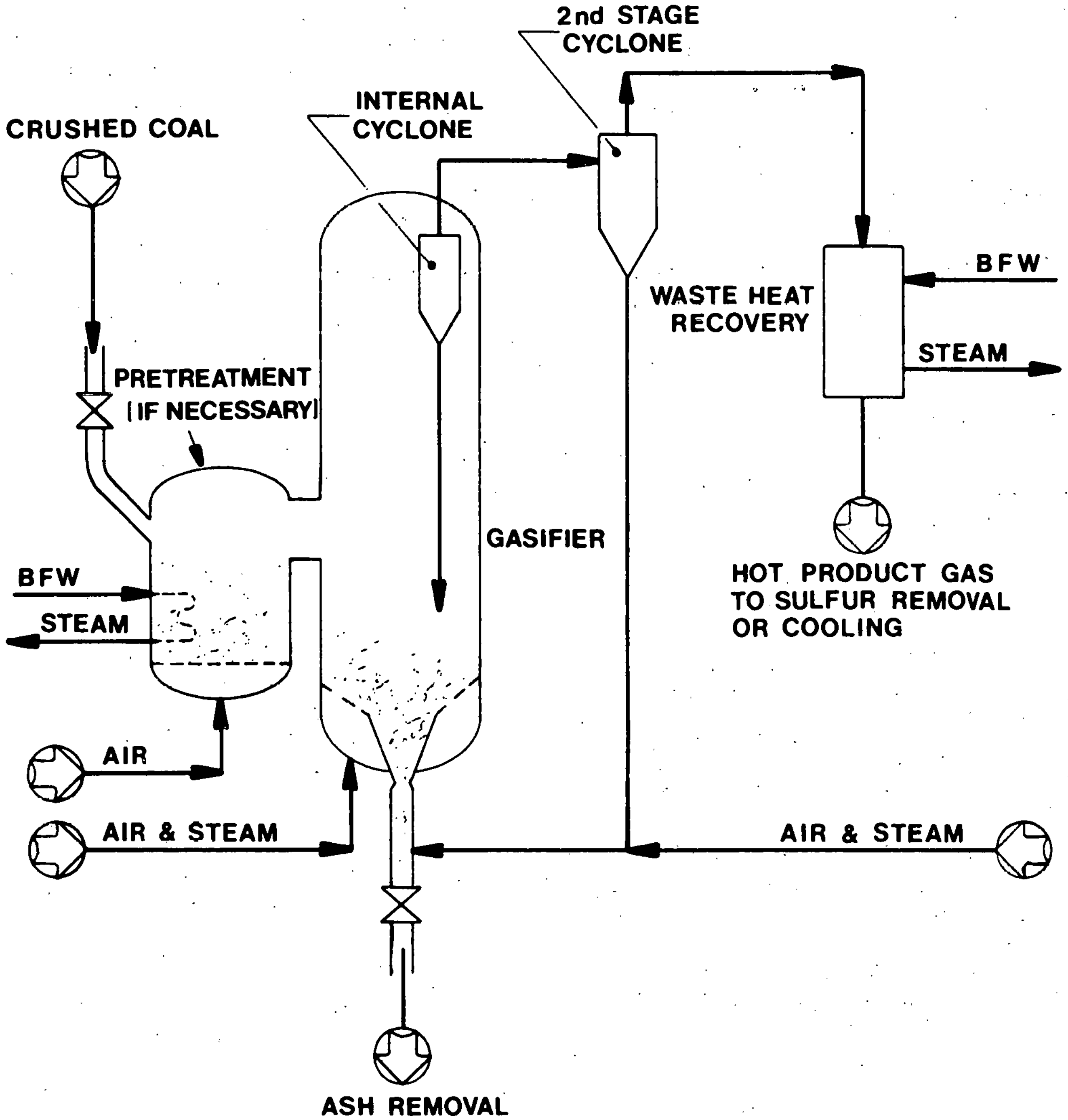


FIGURE 1.14-1

1.8 BCR LOW-BTU

Type:

Three-stage, fluidized bed gasifier

Developer:

Bituminous Coal Research, Inc.
Research Center
350 Hochberg Road
Monroeville, PA 15146

State of Development:

Bench scale work on the BCR Low-BTU gasification process began in the late 1960's. A 1.2 TPD process development unit PEDU has recently been completed and start-up is expected in early 1976.

The goal of the multiple fluid bed process is the gasification of both caking and non-caking coals, with fuel gas as the only product. At the present time, the program is aimed toward application of the system to steam boilers and gas turbines in a combined cycle operation for electric power generation.

Description:

The BCR Low-BTU process is shown schematically in Figure 1.8-1. Each of the three gasification stages is of vertical cylindrical construction designed to allow solids flow, by gravity, between stages.

Pulverized coal is metered from a pressurized lock hopper through a rotary air lock feeder and flows by gravity to the first of three fluidized bed reactors in series. The operating temperature is progressively higher in each reactor from Stage 1 through Stage 3. Stage 1 serves as a pretreatment step by contacting the fresh coal with hot flue gas from Stage 3. This gas also serves as the Stage 1 fluidizing medium. The coal is devolatilized in Stage 1 and flows by gravity to the lower part of the Stage 2 bed. The Stage 1 off gas, containing entrained volatiles, enters Stage 2 below the gas distributor.

Stage 2 is the major gasification stage. Here the devolatilized coal from Stage 1 and the tars and oils entrained in the Stage 1 off gas are gasified with air mixed with steam or carbon dioxide to generate the desired product gas. Product gas exiting Stage 2 flows to a cyclone which removes entrained solids. These solids are returned to Stage 2 while the product gas is cooled and any remaining char fines are removed in a bag-house filter. Product gas is then taken to a scrubber-cooler, and finally to a sulfur recovery unit. The resulting cleaned cooled gas is a low-BTU fuel gas.

Char from Stage 2 flows by gravity to Stage 3 where it is fluidized and gasified by air and steam. The ash formed flows to an ash lock hopper for removal. Stage 3 flue gas passes through a cyclone where entrained ash is removed and returned to the Stage 3 bed. Flue gas is then sent to Stage 1 to continue the process.

Product gas heating value requirements dictate the operating conditions as well as the gasifying medium in Stage 2. Air and steam gasification yield a low-BTU fuel gas while oxygen and steam yield a medium-BTU gas.

Feed Requirements:

Pulverized coal, 60% + 200 mesh, 40% – 200 + 325 mesh.

Moisture content of the raw coal is not critical as moisture is reduced to approximately 2% during pulverization.

Ash initial deformation temperature should be above 2200° F.

Operating Conditions:[2]

	Stage 1	Stage 2	Stage 3
Temperature, ° F	600-1200	1700-2000	2100
Pressure, psig	Up to 235	Up to 235	Up to 235

Gas Produced:

Typical gas composition (dry basis) after gas scrubbing and cooling –

	Steam-Air Operation[1]
Feed Coal	Eastern Coal
HHV of coal, BTU/lb, dry	14,090
Mole %, CO	25.7
CO_2	5.2
H_2	23.4
H_2S + COS	0.2
N_2 + Ar	45.5
HHV, BTU/SCF, dry	160

By-Products:[1]

Oils or tars are not produced.
Steam generated = N/A

Utility Requirements:[1] ¶

	Steam-Air Operation
Air, lb/lb of coal	3.25
Steam, lb/lb of coal	0.7
BFW	N/A
Electric Power	N/A

Labor Requirements:

The BCR Low-BTU gasification is currently in a development stage, and the labor requirements are not defined as yet.

Thermal Efficiency:[1] ¶

Based on cooled and scrubbed product gas, and steam-air operation.

Cold gas efficiency = 88%
Overall Thermal Efficiency = N/A

¶ Based on Eastern coal, and steam-air operation as in the case of Gas Produced.

Capacity:

The process development unit currently under construction has the following dimensions:

	I.D. (in.)	Height (ft.)
Stage 1	10	11
Stage 2	16	11
Stage 3	12	11

Projected capacity is 1.2 TPD of coal gasified to produce approximately 0.2 MM SCFD of low-BTU gas at 235 psig.

Environmental Considerations:

The Stage 2 off-gas passes through a cyclone and then through a bag house filter to remove the char fines. The char fines are recycled to Stage 2 for gasification and do not constitute a disposal problem. A fine grain ash, typical of pulverized coal operation, will be produced. The ash will be disposed of by landfill, but it must be covered with soil to prevent dusting.

Remarks:

A 1.2 TPD PDU for the process has recently been completed. The program is oriented toward application of the system to steam boiler and gas turbine in a combined cycle operation. The process handles both caking and non-caking coals. Oils or tars are not produced.

References:

1. Stewart, J. T., and E. K. Diehl, "Fluidized Bed Coal Gasification Process and Equipment Development", presented at Third International Conference on Fluidized Bed Combustion, Hueston Woods, Ohio, October, 1972.
2. Bituminous Coal Research, Inc., Information, November, 1975.

BCR LOW BTU COAL GASIFICATION PROCESS

(PEDU SET-UP)

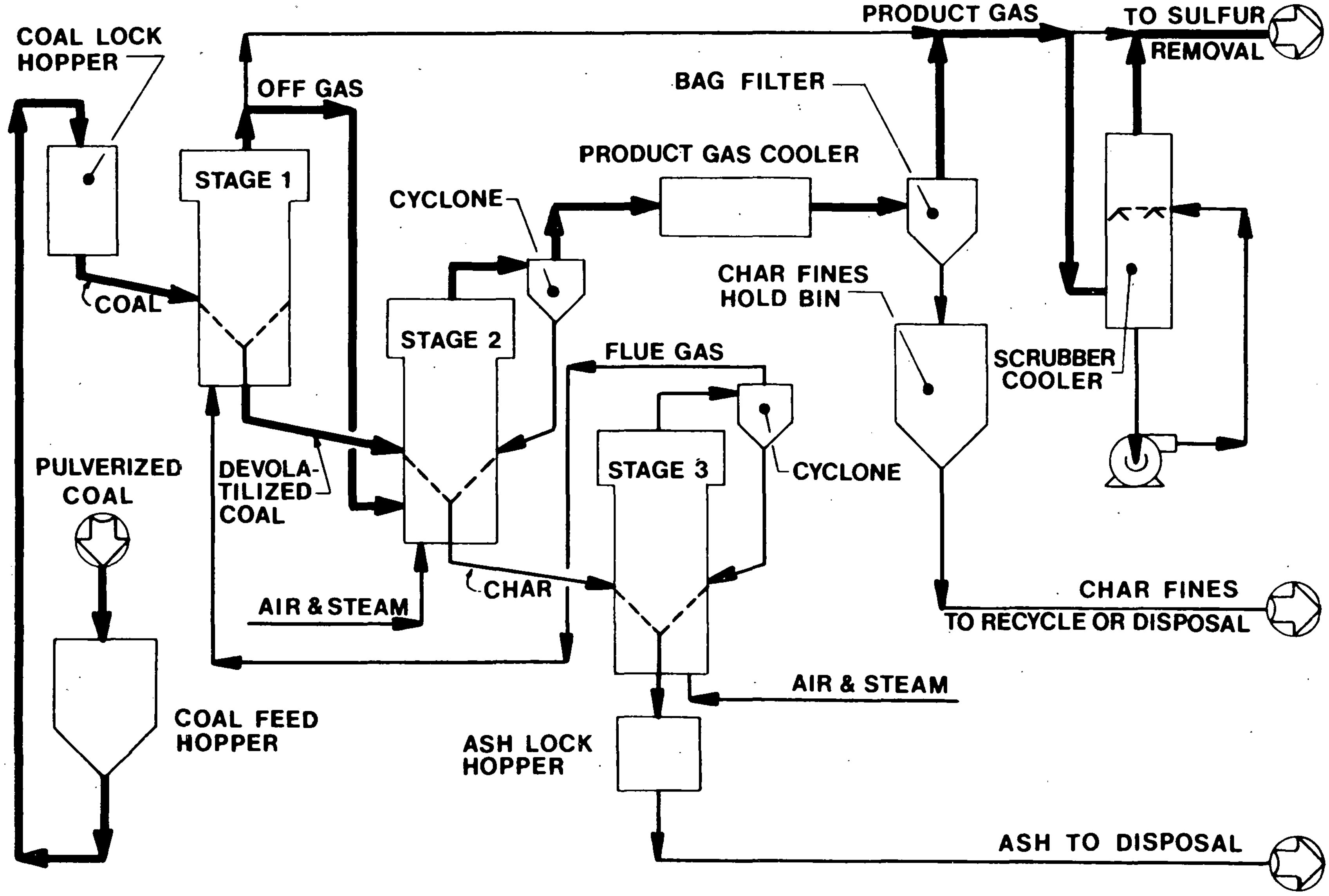


FIGURE 1.8-1

1.15 WESTINGHOUSE

Type:

Fluidized bed gasifier

Developer:

Westinghouse Electric Corporation
Research and Development Center
Pittsburgh, PA 15235

State of Development:

The current Westinghouse coal gasification program was initiated in late 1972. It is sponsored jointly by a six member industry/government cost-sharing partnership. Members include ERDA, Public Service of Indiana, Bechtel, Inc., Amax Coal Company, Peabody Coal Company/Kennecott Copper Corporation, and Westinghouse Electric Corporation. In addition, a number of utility companies are sponsoring the program as associate members.

A 1200 lb/hr process development unit (PDU) was the first integrated test of the fluidized bed gasification process developed by Westinghouse. The design was initiated in mid 1972, and site work at the Westinghouse facility at Waltz Mill, Pennsylvania, started in January, 1973. Erection of the PDU began in September, 1973, and was mechanically completed in September, 1974. Hot operations started in early 1975.

The program consists of the following 3 phases:

1. Evaluate fluidized gasification with the PDU.
2. Scale-up the gasifier to a commercial size generating plant.
3. Operate the 1200 TPD combined cycle generating plant.

The combined cycle power plant site is Dresser Station near Terre Haute, Indiana. Detailed engineering and construction are scheduled to begin in 1977. The test program is scheduled for completion in 1981.

Description:

The Westinghouse multistage gasification process, Figure 1.15-1, consists of two vertical cylindrical vessels: a recirculating bed devolatilizer/desulfurizer and an agglomerating, fluidized bed combustor/gasifier. In the process, heat for the mildly endothermic devolatilization reaction is provided by hot gases generated from the partial oxidation of char in the combustor/gasifier.

Crushed coal is dried in a fluidized bed dryer and fed to the devolatizer through the bottom. It then mixes with internally recycled solids (char and/or dolomite sorbent) and is carried upward through a draft tube at 40 ft./sec. by hot gases from the gasifier/combustor.[1] This mixing prevents agglomeration of the fresh coal as it devolatilizes and passes through the plastic, sticky phase. A dense dry char is produced atop the draft tube, which then flows downward in the annulus at weight rates approximately 100 times the feed coal rate.

Crushed dolomite is added to the bed to remove H_2S in the fuel gases. Dense, sulfided dolomite settles to the lower portion of the bed and is withdrawn into the dolomite draw-off pot. Char is stripped from the dolomite and returned to the devolatilizer by a small amount of recycle product gas. The spent dolomite is either regenerated in combination with sulfur recovery, or oxidized for sulfur retention and disposed of as sulfate.

Desulfurized gases exit at the top of the devolatilizer and flow to the cyclone collector. Fines are removed in the cyclone and recycled to the combustor/gasifier. The product gas is a hot, clean, low sulfur, low-BTU gas suitable for combined cycle power plant operation.

Gasification of char takes place in the agglomerating, fluidized bed combustor/gasifier. Char from the devolatilizer, withdrawn via the char draw-off pot and the cyclone collector, is oxidized in the lower section with air to provide the main heat source for the process. Ash agglomerates under the high oxidizing temperatures and settles in the lower leg for removal. Hot gases from the combustion section pass into the upper, fluidized bed, gasification section. Here, steam is reacted with the coarse char to form a CO and H_2 rich gas, which then flows to the devolatizer to provide its heat requirements.

Feed Requirements:[1]

Crushed coal, 0" x 1/8" to 1/4".

The process will accept variety of coals including caking coals and those with a high ash content.

Surface moisture removal is necessary to pneumatically convey the coal into the gasifier.

The effect of ash fusion temperature on gasifier performance is not available, but is expected to be minimal.

Operating Conditions:[1]

Temperature in combustion zone = 2100° F
Temperature in devolatilizer = 1600°-1800° F
Pressure = 130-200 psig

Gas Produced:

Typical gas composition (dry basis) after gas scrubbing and cooling –

		Air-Blown Operation[1, 2]
Feed Coal		Eastern Coal
HHV of coal, BTU/lb, dry		13,600
Mole %,	CO	19.2
	CO_2	9.3
	H_2	14.4
	CH_4	2.7
	$H_2S + COS$	0.1
	$N_2 + Ar$	54.3
HHV, BTU/SCF, dry		135

By-Products:

Oils or tars are not produced.
Steam generated = None before the gas turbine.

Utility Requirements:[3] ¶

Air, lb/lb of coal	2.8
Steam, lb/lb of coal	0.5
BFW, Gal/ton of coal	None
Electric power, KWH/ton of coal	80

Labor Requirements:[3]

The gasification area, using one gasifier with a capacity of 1200 TPD of coal, requires two operators and one helper, 4 shifts a week, 365 days a year. Battery limits for the gasification area are from receiving crushed coal into the coal feed hopper to delivery of ash from the ash hopper and product gas from the cyclone collector.

Thermal Efficiency:[3] ¶

Based on hot (1200°F), clean product gas, and air-blown operation –

Hot Gas Efficiency = 97%*
Overall Thermal Efficiency = 94%

* This is cold gas efficiency plus percentage of sensible heat of gas with respect to input coal.

Capacity:

The vessels in the 1200 lb/hr PDU have the following dimensions: combustor/gasifier – 12 in./20 in. I.D. x 40 ft. high; devolatilizer/desulfurizer – 20 in. I.D. x 40 ft. high. The PDU is designed to produce approximately 2.45 MM SCFD of low-BTU gas.

The commercial size generating plant will consume about 1200 TPD coal. Detailed design and construction are scheduled to begin in 1977.[3]

Environmental Considerations:

A multi-stage system is used to remove particulates from the hot product gases and should be adequate. The system may include conventional cyclones, high efficiency cyclones, or granular filter beds.[2]

The spent (sulfided) dolomite, if not regenerated and recycled, will require proper disposal. The ash is not expected to contain significant amounts of carbon and will be disposed of by landfill.

Sulfur in the feed coal is removed by reaction with the dolomite. The product gas, therefore, will not require desulfurization for most coal feeds.

Remarks:

The process is oriented toward a combined cycle operation for electric power generation. It is expected to accept all types of coal, and oils or tars are not generated as by-products. The process produces a clean low sulfur hot gas, and the product gas will not require further sulfur removal before consumption.

References:

1. Archer, D. H., E. J. Vidt, D. L. Keairns, J. P. Morris, and J. L. Chen, "Coal Gasification for Clean Power Production", from Symposium papers, "Clean Fuels from Coal", sponsored by Institute of Gas Technology, Chicago, Illinois, September, 1973.
2. Holmgren, J. D., and L. A. Salvador, "Low-BTU Gas from the Westinghouse System", Chemical Engineering Progress, *71* (4), April, 1975.
3. Private communications, between Dravo Corporation and Westinghouse Electric Corporation, January, 1976.

¶ Based on Eastern Coal, as in the case of Gas Produced.

WESTINGHOUSE COAL GASIFICATION PROCESS

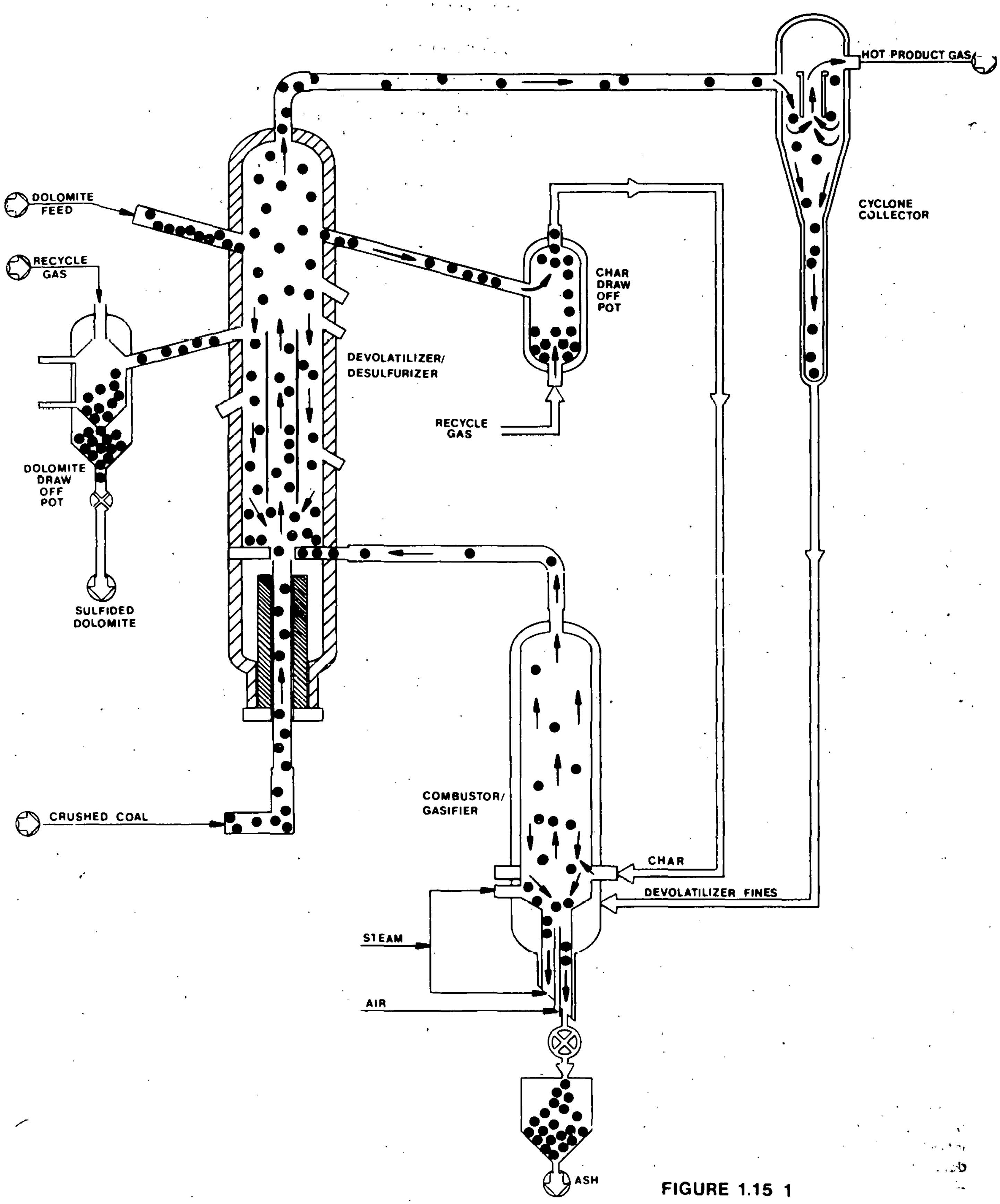


FIGURE 1.15 1

ENTRAINED FLOW GASIFIERS

1.1 BABCOCK & WILCOX

Type:

Entrained flow slagging gasifier

Licensor:

The Babcock & Wilcox Company
Barberton, OH 44203

State of Development:

The Babcock & Wilcox (B&W) gasifier has been demonstrated in a semi-commercial unit and other pilot scale units.

The first pilot plant was erected at the Bureau of Mines Station at Morgantown, West Virginia. It went into service in the summer of 1951, and was operated during the 50's and 60's.[1] The gasifier had a 2-1/2 ft. I.D. and a capacity of 6 TPD of coal.

A larger B&W gasifier was installed by the duPont Company at its Belle Works in West Virginia. It had a 5 ft. I.D. and a capacity of 36 TPD of coal. It went into service in October, 1951 and was operated for over 5000 hours.[2]

In 1955, a semi-commercial gasifier was built for the duPont Company. It was 15 ft. in diameter, 88 ft. tall, and had a capacity of 400 TPD of coal. It was oxygen-blown and was run at near atmospheric pressures. The unit was operated for a year and then was converted to partial oxidation of natural gas when natural gas became abundant.[2, 4]

Another pilot unit was constructed and operated by the B&W Company at Alliance, Ohio, in the early 60's. It had a capacity of approximately 60 TPD of coal.[3] This was an air-blown unit, and it was designed for the study of combined gas turbine-steam turbine cycles.[2] Another pilot unit with a capacity of 5 TPD of coal is currently being constructed at Alliance to study devolatilization of coal and the effect of heat loss on gasification.[3] The char recycle technique was evaluated with the 60 TPD unit and is currently being evaluated with the 5 TPD unit.

All of the above units have been run at atmospheric pressure. Another pilot unit built at Morgantown was designed for pressure operation and run at pressures up to 300 psig. Final design of the unit featured a down-fired axial coal feed with tangential feed of steam and oxygen. Operating data at 100 psig, and to a lesser extent at 300 psig, were generated during the 1950's and 1960's.[2] The capacity of the unit was about 2.5 TPD at 100 psig and 12 TPD at 300 psig.[3] Continuous slagging and lock hopper discharge of slag under pressure were demonstrated. Duration of each run was limited to approximately 8 hours by the capacity of the batch feeder. A total of 300 hours of operation was logged.[3] B&W have observed that pressurized operation does not significantly alter the chemistry of gasification.

Through the years, B&W have been modifying the type of refractory used in the gasifier. In the current design, B&W use a chrome refractory suitable for high temperature flowing slag. The refractory is held in place by steel studs welded to the tubes.

Description:[2]

The B&W gasifier has a vertical, cylindrical construction with an outer pressure shell and an inner shell of a tube wall type construction which is covered with castable refractory in the reaction zone. (See Figure 1.1-1.) The tubes above the reaction zone are uncovered. The lower portion of the cylindrical shell contains two horizontal rows of coal and char burners and view ports. The heat from the rising gases is recovered by the boiler feed water flowing up through the water wall tubes, and a steam-water mixture at 600 psig is collected at the top.

The feed coal is dried and pulverized to 70% through 200 mesh. It is pneumatically transported to a system of lock hoppers and subsequently fed to a pulverized coal feed tank, wherefrom it is injected into the coal burners of the gasifier. (See Figure 1.1-2.) Oxygen (or air) is also injected into the burners, and the combustion reactions take place in the lower section of the reaction zone at approximately 3400° F. Water is sprayed through the burner for temperature control. Flashback into the burners is prevented by using diffusion type burners which do not require premixing of the reactants. The reactants are mixed in the reaction zone after leaving the burner.

Since the operating temperature is above the ash fluid temperature, the ash in the coal forms a molten slag. This is continuously withdrawn into a slag quench tank. The slag is quenched by circulating water and shatters to a sand-like granular material. The quenched slag is discharged intermittently into slag lock hoppers and sluiced away for disposal. The water tubes in the reaction zone are protected initially by the refractory. Experience has shown that this refractory is gradually replaced by the slag formed.

The gas is cooled by the water gas reaction in the upper section of the reaction zone and by heat given up to the waterwall. The gas temperature is about 1800° F before leaving the gasifier. On the first pass, approximately 85% of the carbon in fresh coal is gasified, and the remaining ungasified carbon leaves the gasifier along with the hot gases as suspended char particles. The char is recovered in a pair of cyclones and is recycled to the gasifier reaction zone. The gas is then cooled in a waste heat boiler where additional steam is generated. The boiler feed water may be preheated in the economizer section of the same waste heat boiler. The gas from the waste heat boiler passes through a second pair of cyclones provided for char separation. This char is also recycled to the gasifier. The gas is then passed through a venturi scrubber and a packed tower, where further cooling and particulate removal is effected by the scrubbing liquor. A side stream of the scrubbing liquor is sent to a clarifier. The solids are separated and disposed of with the slag, while the water is recycled to the scrubber. The cooled gas is processed in an acid gas removal system.

The resultant desulfurized gas is the medium-BTU product gas (or low-BTU for air-blown operation).

Feed Requirements:

Pulverized coal, about 70 to 90% through 200 mesh.[2] Gasifier will accept all types of coal.

The moisture content of the coal can limit operation by affecting pulverized coal flow – not by gasifier requirements. Drying during pulverization produces a coal of approximately 2% moisture content. Thus, raw coals of virtually any moisture content can be handled.

Optimum performance is obtained when the ash initial deformation and ash fluid temperatures are close and in the range 1900° to 2400°F. For extremely high initial deformation and fluid temperatures, a fluxing agent may be required.

Operating Conditions:[2]

Temperature in combustion zone = 3400°F
Temperature of gas leaving the gasifier = 1800°F
Pressure = Atmospheric to 300 psig

Gas Produced:

Typical gas composition (dry basis) after gas scrubbing and cooling –

	O_2-Blown Operation[3]	Air-Blown Operation[3]
Feed Coal	Pittsburgh #8	Pittsburgh #8
HHV of coal, BTU/lb, dry	13,860	13,860
Mole %, CO	65.3	23.3
CO_2	5.0	4.6
H_2	27.9	8.4
H_2S + COS	0.6	0.2
N_2 + Ar	1.2	63.5
HHV, BTU/SCF, dry	301	102

By-Products:[3]

Oils or tars are not produced.
Steam generated @ 600 psig, saturated = 4300 lb/ton of coal.¶

Utility Requirements:

	O_2-Blown Operation[3] ¶
O_2 (98%), lb/lb of coal	1.0§
Steam, lb/lb of coal	None*
BFW, Gal/ton of coal	760
Electric Power, KWH/ton of coal	36**

§ B&W expect that this value can be as low as 0.8
*Water used @ ~0.05 lb/lb of coal for temperature control
**From receiving raw coal through gas cooling and scrubbing

Labor Requirements:

The gasification area, using one gasifier with a capacity of approximately 850 TPD of coal, requires one operator and one helper, 4 shifts a week, 365 days a year. Battery limits for the gasification area are from receiving pulverized coal into lock hoppers to delivery of cool product gas from the venturi scrubber and slag from the quench tank.

Thermal Efficiency:[3] ¶

Based on cooled and scrubbed product gas at 50 psig and O_2-blown operation.

Cold Gas Efficiency = 74%
Overall Thermal Efficiency = 68%

Capacity:

A typical commercial B&W unit with a 7 ft. 7-1/2 in. I.D. and 110 ft. tall is projected to gasify approximately 850 TPD of any type of dried coal to produce about 16×10^9 BTU/day of medium-BTU gas, at 50 psig. At a higher pressure of 175 psig, a unit with a 7 ft. 7-1/2 in. I.D. and 220 ft. tall is projected to gasify about 3000 TPD of coal.[2]

Turndown to approximately 25% of capacity should be possible.[3] This will be limited by the ability to maintain slagging temperatures in the gasifier, the generation of sufficient steam for operation, and by gas quality as determined by the proportions of oxygen and steam required to maintain slagging conditions.

Environmental Considerations:

Char separated from the gas produced is recycled to the gasifier. The slag made is granular and contains about 5% unconverted carbon. It is disposed of by landfill. Inert transport gas, either N_2 from the oxygen plant or CO_2 from the acid gas removal system, used for coal transport in the coal feeding system is vented off to the atmosphere through bag filters.[2]

Remarks:

The B&W gasifier has been demonstrated in a semi-commercial unit and other pilot scale units. It accepts all types of coal and produces no undesirable by-products. The hot char recycle from the product gas is expected to increase the percent carbon conversion of the gasifier. However, the char recycle system needs further demonstration.

References:

1. Grossman, P. R., and R. W. Curtis, Babcock & Wilcox Company, presented at the Annual Meeting of ASME, New York, NY, Paper No. 53-A-49, November 29-December 3, 1953.
2. "Technical Summary – Coal Gasification", Babcock & Wilcox Company, Fossil Power Generation Division, Barberton, Ohio, February, 1975.
3. Private communications, between Dravo Corporation and Babcock & Wilcox Company, January, 1975 through January, 1976.
4. McGeorge, A., and R. V. Green, E. I. duPont de Nemours & Company, Inc., "Coal Gasification at the Belle Works", 1975.

¶ Based on Pittsburgh #8 coal, as in the case of Gas Produced.

BABCOCK & WILCOX GASIFIER

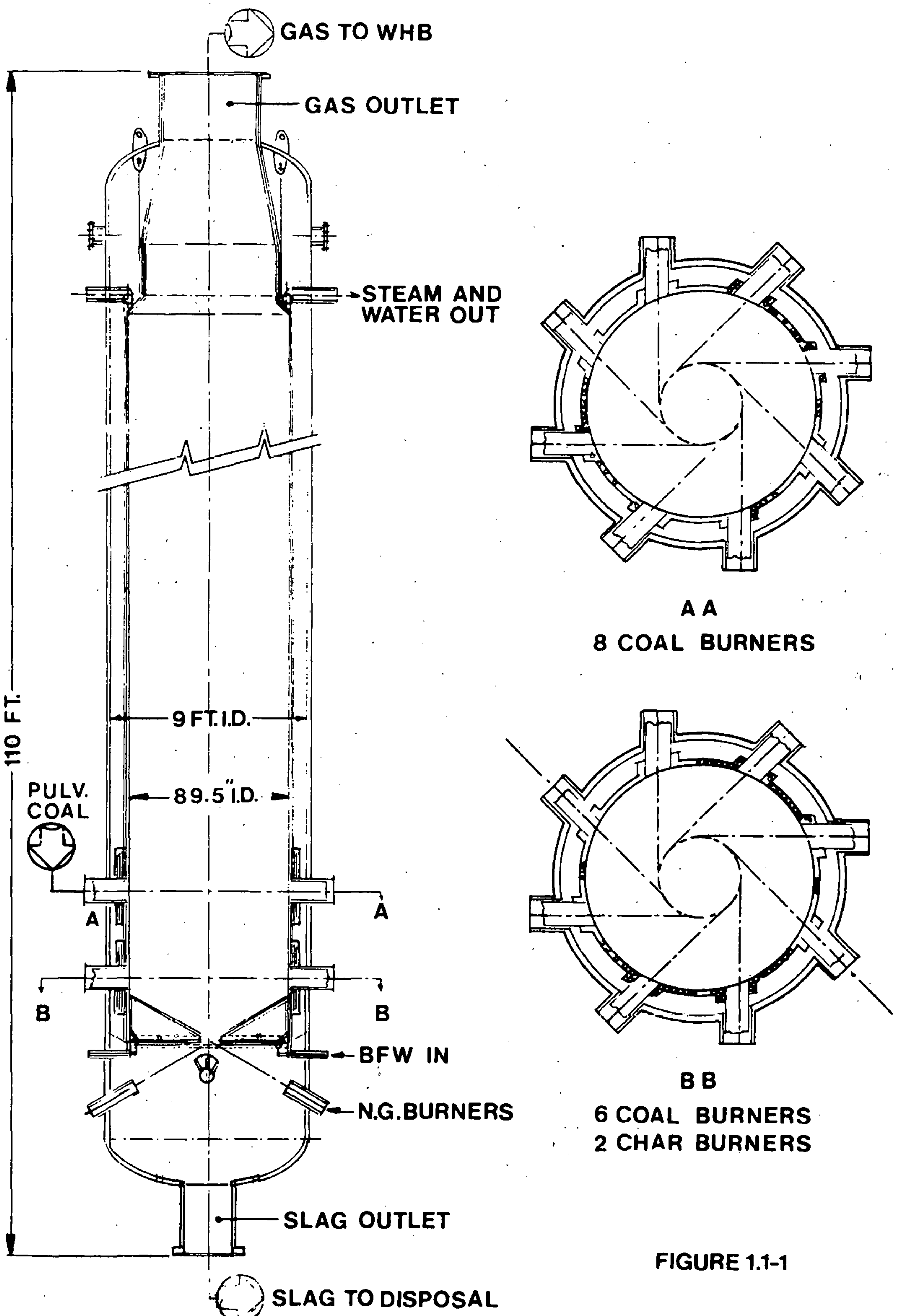


FIGURE 1.1-1

B & W COAL GASIFICATION SYSTEM

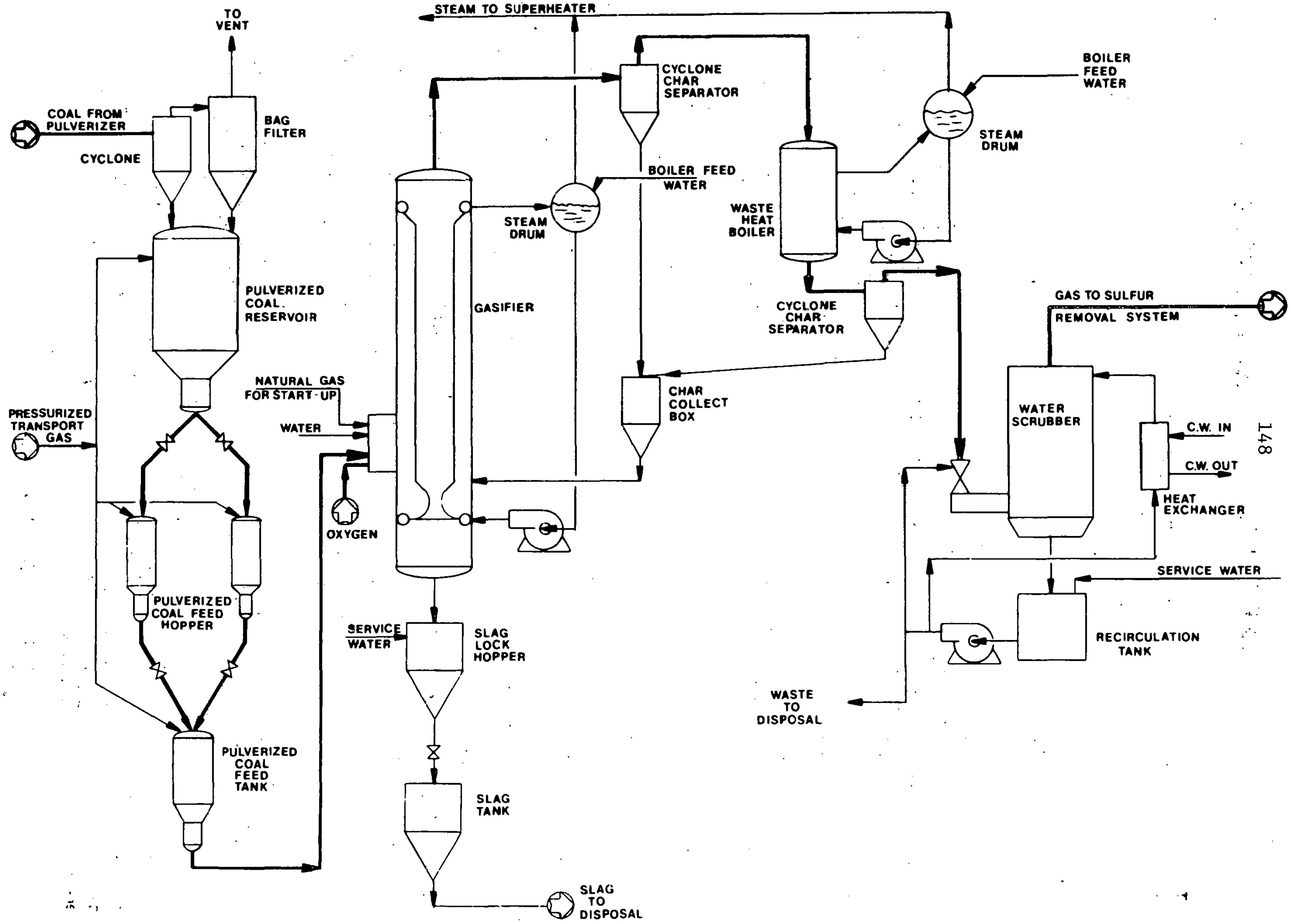


FIGURE 1.1-2

1.4 FOSTER WHEELER

Type:

Two-stage, entrained flow, slagging gasifier

Developer:

Foster Wheeler Energy Corporation
110 South Orange Avenue
Livingston, NJ 07039

State of Development:

A research and development program for this process was initiated in August, 1972, and a 480 TPD pilot plant is currently under construction near Sioux Falls, South Dakota. Operations are expected to begin in 1977.[3,4]

Foster Wheeler Energy Corporation was awarded a contract from the Office of Coal Research for the development, design and long-lead items procurement of a pilot plant to produce clean, low-BTU gas from coal.[1,2] The contract provides that Foster Wheeler will be program manager for an industry team which will construct and operate the pilot plant using a low-BTU gas in a combined cycle power generation system. The pilot plant is designed for 480 TPD of coal feed rate and 34 MW power generation. Foster Wheeler will also develop conceptual design and analysis for a 400 to 1000 MW commercial utility plant based on technology developed in this program.[2]

To produce 125-190 BTU/SCF low-BTU gas for the pilot plant gas turbine, Foster Wheeler selected an air-blown, pressurized, two-stage entrained flow slagging gasifier. The gasifier design is based on the work performed by Bituminous Coal Research, Inc.

Description:

The Foster Wheeler gasification process is shown schematically in Figure 1.4-1. The gasifier is of a vertical cylindrical construction with upper and lower gasification stages. Each stage has its own coal or char, and steam and air injection nozzles.

Feed coal is pulverized to 70% through 200 mesh and dried to about 2 wt% moisture. The coal is introduced into the upper stage of the gasifier through a lock hopper. (Alternate feed systems will be considered for a commercial plant design.) Hot gases rising from the lower stage entrain and partially gasify the incoming coal. The resulting product gas, containing char, exits the top of the gasifier and flows to a cyclone where the char is removed. This char is then injected into the lower stage of the gasifier along with air and steam. Essentially all of the char, except for its ash content, is gasified here. The gas produced rises into the upper stage to continue gasification of the incoming coal. The ash becomes molten slag and flows from the bottom of the gasifier. It is then quenched with water and withdrawn for disposal.

The reaction temperatures in the gasifier are high enough to ensure that no tars or heavy hydrocarbons are contained in the product gas exiting the top of the gasifier. It is therefore possible to recover the sensible heat in this gas, after removal of the char, by generating superheated steam. The cooled product gas is then scrubbed to remove dust and ammonia and sent to a sulfur removal unit. The resulting product gas is a clean low-BTU gas.

Feed Requirements:[1]

Pulverized coal 70% through 200 mesh and dried to 2% moisture level. The gasifier is expected to handle all types of coal.

Drying during pulverization produces a coal of approximately 2% moisture content. Thus raw coals of virtually any moisture content can be handled.

Gasifier can handle any coal with ash fusion temperatures of less than 2800°F. Fluxing agents may allow handling of coals with higher ash fusion temperatures.

Operating Conditions:[3]

Temperature in upper stage = 1800° to 2100°F
Temperature in lower stage = 2500° to 2800°F
Pressure = 350 psig

Gas Produced:[5]

Typical gas composition (dry basis) after gas scrubbing and cooling –

Feed Coal		Illinois #6
HHV of coal, BTU/lb, dry		12,800
Mole %,	CO	29.3
	CO_2	3.3
	H_2	14.5
	CH_4	3.5
	$H_2S + COS$	0.7
	N_2	48.7
HHV, BTU/SCF, dry		177

By-Products:

Oils or tars are not produced.
Steam Generated = N/A

Utility Requirements:

Not available.

Labor Requirements:

Not available.

Thermal Efficiency:[5]

Power station applications have an expected efficiency of 45% with advanced gas turbine designs.

Capacity:[3]

Pilot plant capacity = 480 TPD of coal

Dimensions of the pilot plant gasifier = N/A
Turndown Ratio = N/A

Environmental Considerations:

The slag generated is expected to contain very little carbon and can be disposed of by landfill. Vent gases are free of sulfur and ammonia.

Remarks:

The Foster Wheeler gasifier is oriented toward producing a clean low-BTU gas for use in combined cycle electric power generation. The process has not yet been proven on a pilot plant scale. Tar or oil by-products are not produced.

References:

1. Broeker, R. J., and R. A. McCallister, "Portent for Future: Coal Gasification/Combined Cycle Power", Foster Wheeler Energy Corporation Brochure, 1975.
2. "Combined-Cycle Gasification Pilot Plant to be Developed by Foster Wheeler", Chemical Engineering Progress, *71* (4), p. 100, April, 1975.
3. "Fuels Technology – A State-of-the-Art Review", prepared for National Environmental Research Center, by Battelle Columbus Laboratories, Report No. EPA-650/2-75-034, April, 1975.
4. Howard-Smith, I., and G. J. Werner, *Coal Conversion Technology: A Review,* under the Auspices of Millmerran Coal Pty. Ltd., Brisbane, Australia, May, 1975.
5. Private communications, between Dravo Corporation and Foster Wheeler Energy Corporation, January, 1976.

FOSTER-WHEELER COAL GASIFICATION PROCESS

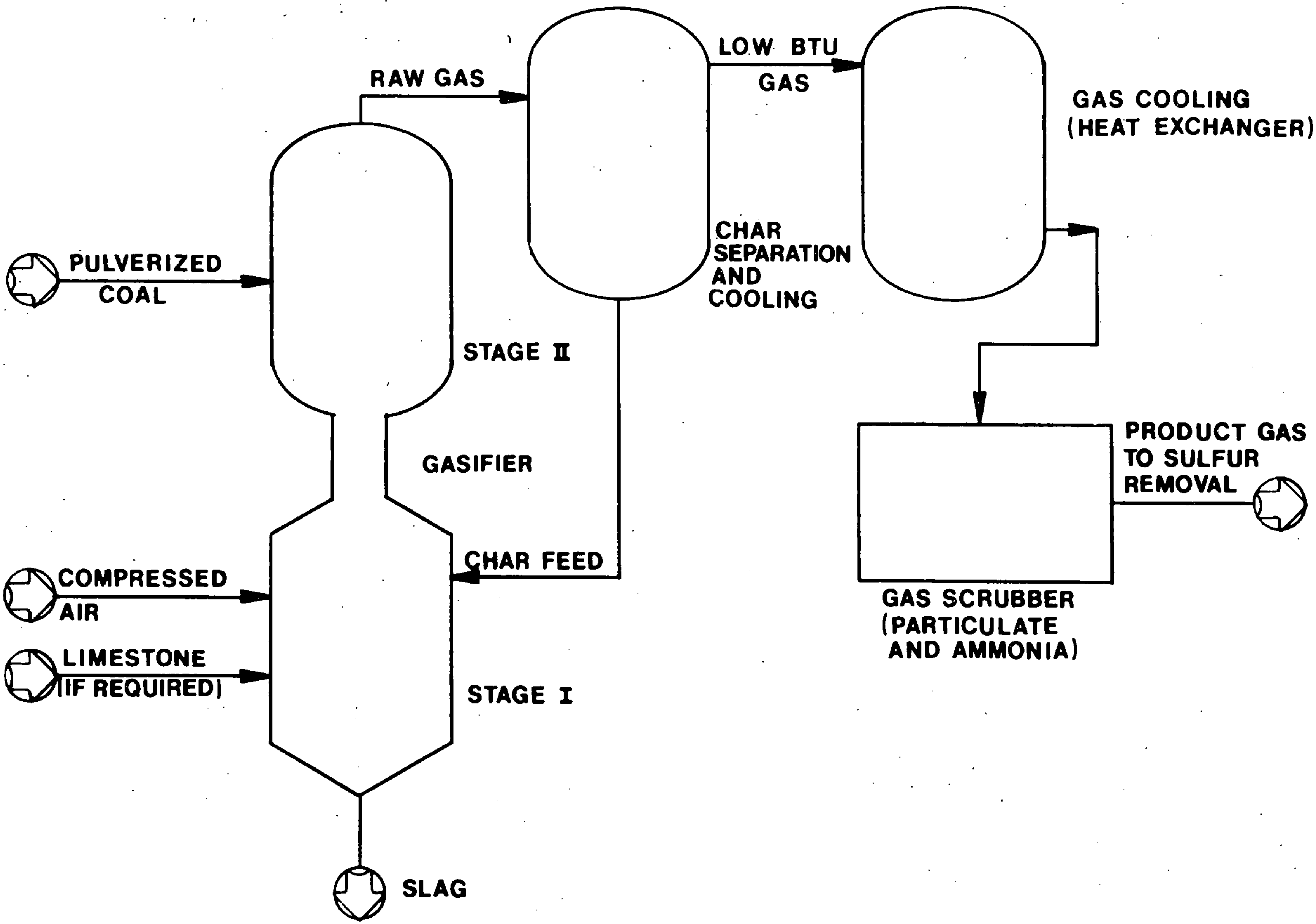


FIGURE 1.4-1

1.6 TEXACO

Type:

Entrained flow gasifier

Licensor:

Texaco Development Corporation
135 East 42nd Street
New York, NY 10017

State of Development:

The Texaco gasifier is a commercially proven process for producing synthesis gas from hydrocarbon feed stocks. Its application to coal gasification, however, is still in the development stage.

Since the early 1950's, the Texaco process has been a commercially proven pressurized process for the production of medium or low-BTU synthesis gas from a wide variety of liquid and gaseous hydrocarbon feeds. The first commercial plant was placed in operation in 1953. Since then, at least 70 plants have been built with a total capacity in excess of a billion cubic feet per day. The capacities of early plants were relatively small, producing 5 to 10 MM SCFD of synthesis gas in several parallel trains. Recent plants have much larger capacities, capable of producing more than 100 MM SCFD of gas in a single train.

Texaco has also been developing the gasifier to make it suitable for coal gasification. During the 1956-1958 period, a 100 TPD, 300 psig, pilot plant at Morgantown, West Virginia, was operated to test West Virginia coals. Currently, Texaco's development work is being done at its Montebello Research Laboratory in California, where a 15 TPD, high-pressure, single-train pilot plant is available to test all types of hydrocarbons, including coals and chars, for synthesis gas manufacture. The pilot unit has been operated at pressures up to the design value of 170 atmospheres (~2500 psig) with liquid feedstocks. Various lignites and bituminous coals have been tested at 350 psig, and facilities for 1200 psig are almost complete.

Description:

The Texaco pilot gasifier is a vertical, cylindrical pressure vessel with a carbon steel shell. Coal reacts with steam and oxygen under slagging conditions in a refractory lined partial oxidation chamber in the upper portion of the gasifier. The resulting gases and molten slag particles flow downward through a water spray chamber and a slag quench bath. Quenching reduces the gas temperature in this zone to a low enough level so that processing in unlined steel equipment is possible.

Steam and oxygen gasify the pulverized coal in the partial oxidation chamber, and the gas formed flows downward. Water is sprayed just beneath the partial oxidation chamber to cool the gas; and, as a result, a large quantity of high pressure steam is generated. The gas is further cooled as it leaves the gasifier through the water in the slag quench bath.

Entrained slag is separated from the gas in the slag quen bath and discharges through the slag pot. Product gas leaving the gasifier is further cleaned in a water scrubber to remove the residual slag particles. The resulting gas is a medium-BTU synthesis gas. The slag-water mixture from the slag pot and the water scrubber is collected and separated. Slag is sent to disposal, while water is recycled either to the slag pot or water scrubber.

An alternate method for cooling the product gas is also available. In this option, the gas leaves the gasifier unquenched at an elevated temperature and passes through a gas cooler where high pressure steam is generated. Selection between the two methods for gas cooling often hinges upon the ultimate disposition of the product gas. The direct water quench method is favored in ammonia or hydrogen plants because the hot gas-steam mixture from the gasifier can be sent directly to shift conversion.

Feed Requirements:[3]

Pulverized coal is required. Lignites and bituminous coals have been tested in the gasifier, with satisfactory results. Pulverized coal is slurried in water and pumped to the gasifier; thus, feed coal of virtually any moisture content can be handled. The gasifier operates at a temperature above the ash fusion temperature.[2]

Operating Conditions:[3]

Temperature in the partial oxidation zone = above ash fusion point
Temperature of gas leaving the gasifier = 400° to 500° F*
Pressure = 300 to 1200 psig

*For the direct quench method of gas cooling.

Gas Produced:

Typical gas composition (dry basis) after gas scrubbing and cooling –

	O_2-Blown Operation[3]
Feed Coal	Illinois #6 Coal
HHV of coal, BTU/lb, dry	13,150
Mole %, CO	37.6
CO_2	20.8
H_2	39.0
CH_4	0.5
H_2S	1.5
N_2 + Ar	0.6
HHV, BTU/SCF, dry	253

By-Products:[3]

Oils or tars are not produced.
Steam generated = N/A

Utility Requirements:

Not Available.

Labor Requirements:

Not Available.

Thermal Efficiency:

Not Available.

Capacity:

A typical commercial Texaco gasifier 9 ft. O.D. and 15 ft. high is projected to gasify approximately 1900 TPD of coal to produce about 100 MM SCFD of medium-BTU gas at 650 psig. Standard combustion-chamber and gasifier designs are also available with nominal shell diameters of 5 ft., 6 ft., 7 ft., and 8 ft.

Commercial experience with oil gasification has shown that a system turndown to 50% of design capacity is possible. The gasifier itself will operate satisfactorily at values as low as 15% of design capacity.[1]

Environmental Considerations:

The granular slag produced in the Texaco gasifier is expected to contain less than 2% unconverted carbon, and can be disposed of by landfill. The water separated in the slag-water separator can be recycled either to form the coal slurry or to cool the gas in the gasifier or the scrubber. Disposal is usually not required.

Remarks:

The Texaco gasifier has been proven on a commercial scale with liquid and gaseous hydrocarbons. Tests for coal have been run on 100 and 15 TPD units, but commercial operation on coal needs to be demonstrated. Hydrogen to carbon monoxide ratio in the gas product is high; a high ratio is desirable if the gas is to be processed to synthesize methane or ammonia.

References:

1. Child, E. T., and C. P. Marion, "Recent Developments in the Texaco Synthesis Gas Generation Process", for presentation at the Fertilizer Association on India, National Seminar, New Delhi, India, December, 1973.
2. Eastman, D., "Preliminary Report on Coal Gasification", presented at the Annual Meeting of the American Institute of Mining and Metallurgical Engineers, New York, February, 1952.
3. Private communications, between Dravo Corporation and Texaco Development Corporation, 1975.

MOLTEN MEDIA GASIFIERS

1.21 AI MOLTEN SALT

Type:

Molten salt gasifier

Developer:

Rockwell International Corporation
Atomics International Division
Post Office Box 309
Canoga Park, CA 91304

State of Development:

The AI Molten Salt coal gasification process has been demonstrated on bench scale and in pilot plant size equipment.

The pilot plant size Molten Salt Test Facility (MSTF) consists of a reactor vessel and supporting equipment for feeding coal and air and combusting the product gas. The reactor vessel is a 4 ft. O.D. (3 ft. I.D.), 10 ft. high stainless steel vessel lined with fused cast alpha-alumina refractory. In a typical pressurized coal gasification test, 1800 lb of Kentucky #9 coal (15% ash, 4% sulfur) was gasified at an average coal feed rate of 470 lb/hr, generating 520 SCFM of low-BTU gas with a heating value of 130-160 BTU/SCF. Process conditions were 3.2 atmospheres (32 psig) pressure, with a melt bed temperature of 1900°-2000°F.[4]

In December 1974, Atomics International, the developer, was awarded a contract by ERDA for the design, construction, and operation of a 120 TPD pilot plant that will produce approximately 15.8 MM SCFD of low-BTU gas. This plant will be located on the site of the Norwalk Harbor Generating Station of Connecticut Light and Power Company.[3,4] The gas produced will be combusted in the power plant boiler. The objective of this pilot plant is to demonstrate the integrated performance of the molten salt process for the production of a clean gas from coal, the recovery of sulfur from the coal in elemental form, and the disposal of the ash. The test operation of the pilot plant is expected to provide the technical information needed for a full-scale plant design. Detailed pilot plant design is scheduled for completion in 1976, with completion of construction in mid 1977.[5]

Description:[6]

The AI Molten Salt gasifier is a vertical cylindrical pressure vessel, lined with fused cast alpha-alumina refractory bricks to resist corrosion from the molten salt. An insulating layer of castable refractory is provided between the vessel wall and the bricks to minimize heat loss.

Coal and sodium carbonate are conveyed into the molten salt bed with air. The coal is partially oxidized and pyrolyzed in the melt, producing a low-BTU fuel gas composed of CO, H_2, CO_2, N_2 and a small fraction of CH_4. The sulfur and the ash from the coal are retained in the melt, eliminating the requirement for sulfur or ash removal from the product gas before use.

The molten salt gasification step is shown schematically in Figure 1.21-1, and it represents the key feature of the AI Molten Salt process. In it, the sodium carbonate melt (1) acts as a dispersing medium for both the coal being gasified and the air used for the gasification; (2) acts as a heat sink, with high heat transfer rates, for absorbing and distributing the heat of oxidation; (3) acts as a heat source for the pyrolysis and distillation of the volatile matter of the coal; (4) reacts chemically with and absorbs the sulfur from the coal; (5) provides an environment in which the sulfur compounds formed act as catalysts for the partial oxidation of the coal; and (6) retains physically the ash present in the coal.

A bleed stream of the molten salt is withdrawn continuously via an overflow to a quench tank where it is contacted with recycled aqueous process liquor. See the schematic process flow sheet for the Norwalk Harbor pilot plant shown in Figure 1.21-2. The soluble salts are dissolved while the insoluble ash particles form a slurry. This slurry flows to clarification and filtration to remove the ash from the salt solution. The separated ash is sent to disposal. The salt solution goes to a regeneration system where the sulfur is removed as H_2S gas from which elemental sulfur is recovered in a Claus plant. The salt is thus converted into sodium carbonate which is recycled to the gasifier.

Feed Requirements:[5]

The process will accept all types of coal. The process allows the use of a complete range of coal particle sizes from 1/4 in. down to fines. There is no requirement for close sizing of coal, removal of fines, or pulverization. The only requirement is for crushing to facilitate pneumatic conveying.

The pilot plant will require the coal to be dried to less than 10% moisture, primarily to prevent plugging or bridging in the solids feed system.

The coal feedstock ash fusion temperatures will not be a major consideration, since the gasification temperature (~1800°F) is below the ash softening temperature of virtually all coals.

Operating Conditions:[1,5]

Melt bed temperature = ~1800°F
Gas outlet temperature = ~1700°F
Gasifier pressure = 1 to 20 atma (0 to 280 psig)

Gas Produced:[5]

Typical gas composition (dry basis) after cooling –

	Air-Blown Operation
Feed Coal	Kentucky #9
HHV of coal, BTU/lb, dry	12,000
Mole %, CO	29.7
CO_2	3.5
H_2	13.2
CH_4	1.5
Sulfur Compounds	$<$ 5 ppm
NH_3	$<$ 5 ppm
N_2	48.0
O_2	1.4
HHV, BTU/SCF, dry	158

Bench scale experiments with O_2 have produced a product gas with a heating value of approximately 300 BTU/SCF.

By-Products:[5]

Oils or tar are not produced.

H_2S is recovered from the salt in the salt regeneration step. It is fed to a Claus plant where elemental sulfur is produced. The amount of sulfur produced depends upon the sulfur content of the feed coal.

Steam is not produced in the gasification-regeneration area.

Utility Requirements:[5]

Estimated, based on Illinois #6 coal (HHV, dry = 12,950 BTU/lb):

Air, lb/lb of coal	3.5
Steam	None
BFW	None
Recycle Na_2CO_3, lb/lb of coal	0.29
Make-Up Na_2CO_3, lb/lb of coal	0.02
Electric Power	Not available for the isolated gasification and regeneration area.

The 120 TPD Norwalk Harbor pilot plant will require 2.5 MW of electric power (for air compression, etc.), 0.5 pound of steam per pound of coal (for sodium carbonate regeneration, etc.), and 2000 GPM of cooling water with a 20° F rise (for gas cooling, regeneration system, etc.). The pilot plant will not have heat recovery and power generating facilities, and the utility requirement numbers do not represent a typical commercial operation.

A 4320 TPD commercial plant will produce approximately 500 MW (net) of electric power and 1440 TPD (net) of low pressure steam. It will require 150,000 GPM of cooling water with a 20° F rise.

Labor Requirements:

he Norwalk Harbor pilot plant gasification-regeneration area, using one gasifier to convert 120 TPD of coal, will require one operator and two helpers, 4 shifts per week, 365 days a year. Battery limits for the gasification-regeneration area are from receipt of sized feed coal to delivery of cooled product gas, and include regeneration of the sodium carbonate and recovery of elemental sulfur.

Thermal Efficiency:[5]

Based on cooled product gas and air-blown operation:

Cold Gas Efficiency = 78%

A 500 MW combined cycle commercial power plant using three 1440 TPD gasifiers will have an overall net station efficiency of 38.8% (net station heat rate of 8800 BTU/KWH) at a gas turbine inlet temperature of 2000° F. This does not allow credit for the available export steam (120,000 lb/hr), which amounts to approximately 2.5% of the gross heat input.

Capacity:[2, 5]

The MSTF has a capacity of 6 to 12 TPD of coal at pressures of up to 60 psig. The Norwalk Harbor pilot plant will have a capacity of 120 TPD of coal at 10 atma (~132 psig).

A 500 MW combined cycle power plant will have three molten salt gasifiers, each with a capacity of 1440 TPD of coal. Each gasifier will be 19 ft. in outside diameter and 50 ft. high, and operate at 20 atma (280 psig).

Environmental Considerations:

The sulfur in the feed coal is removed by reaction with the molten salt and subsequently recovered in elemental form from a Claus plant. The product gas, therefore, does not require further sulfur removal for most applications.

The ash is removed as a moist filter cake. It is washed to remove all but a trace of soluble salts, so that disposal is not expected to be a problem. The ash will be reslurried and piped to an ash pond at the Norwalk Harbor pilot plant site. At other locations it could be hauled to a landfill in a truck or rail car.

Remarks:

The process allows the use of a complete range of coal particle sizes from approximately 1/4 in. down to fines, and it accepts all types of coal. Practically all the sulfur and ash of the coal are retained in the melt, thus minimizing the requirements for product gas cleaning. The sulfur is recovered in elemental form using a Claus plant.

The process has yet to be proven on a commercial scale, but the feasibility, based on the 120 TPD pilot plant operations, should be known by early 1978.

References:

1. "Evaluation of Coal-Gasification Technology, Part II, Low-and Immediate-BTU Fuel Gases", R&D Report No. 74, Interim Report No. 2, prepared for OCR, 1973.
2. "Fuels Technology", A State of the Art Review, prepared by Battelle Columbus Laboratories, Columbus, Ohio, for the National Environmental Research Center, Report No. EPA 650/2-75-034, April, 1975.
3. Howard-Smith, I., and G. J. Werner, *Coal Conversion Technology: A Review,* under the Auspices of Millmerran Coal Pty. Ltd., Brisbane, Australia, May, 1975.
4. "Rockgas: Atomics International's Coal Gasificatic Process", Atomics International, Inc., Brochure, pul lished 1975.
5. Private communications, between Dravo Corporation and Rockwell International Corporation, January, 1976.
6. Trilling C. A., "Coal Gasification by Atomics International's Rockgas Process", paper presented at the ASME Winter Annual Meeting, paper 74-WA/Pwr-11, November 17-22, 1974.

AI MOLTEN SALT GASIFIER - SCHEMATIC DIAGRAM

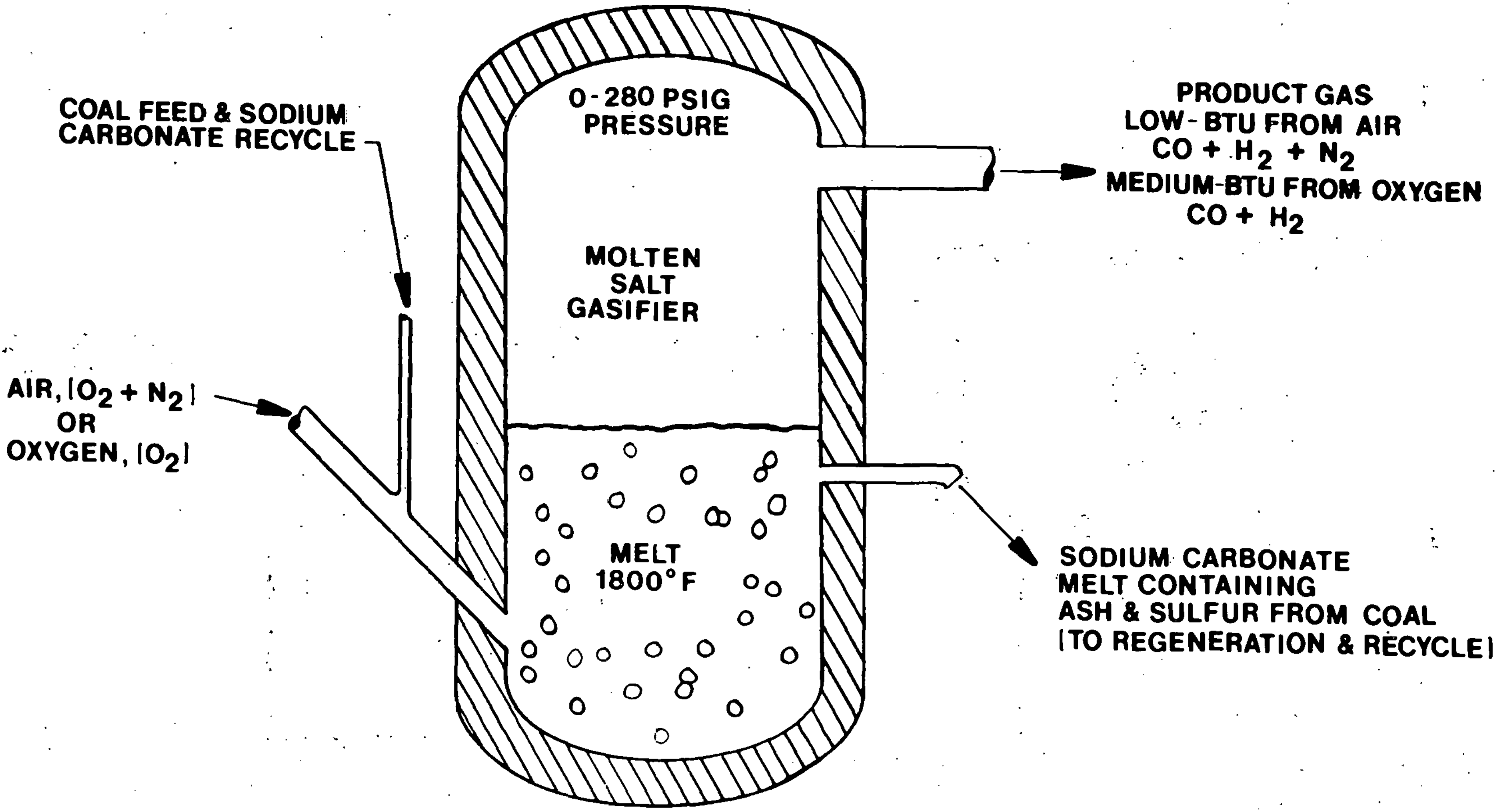


FIGURE 1.21-1

AI MOLTEN SALT COAL GASIFICATION PROCESS

(NORWALK HARBOR PILOT PLANT SET-UP)

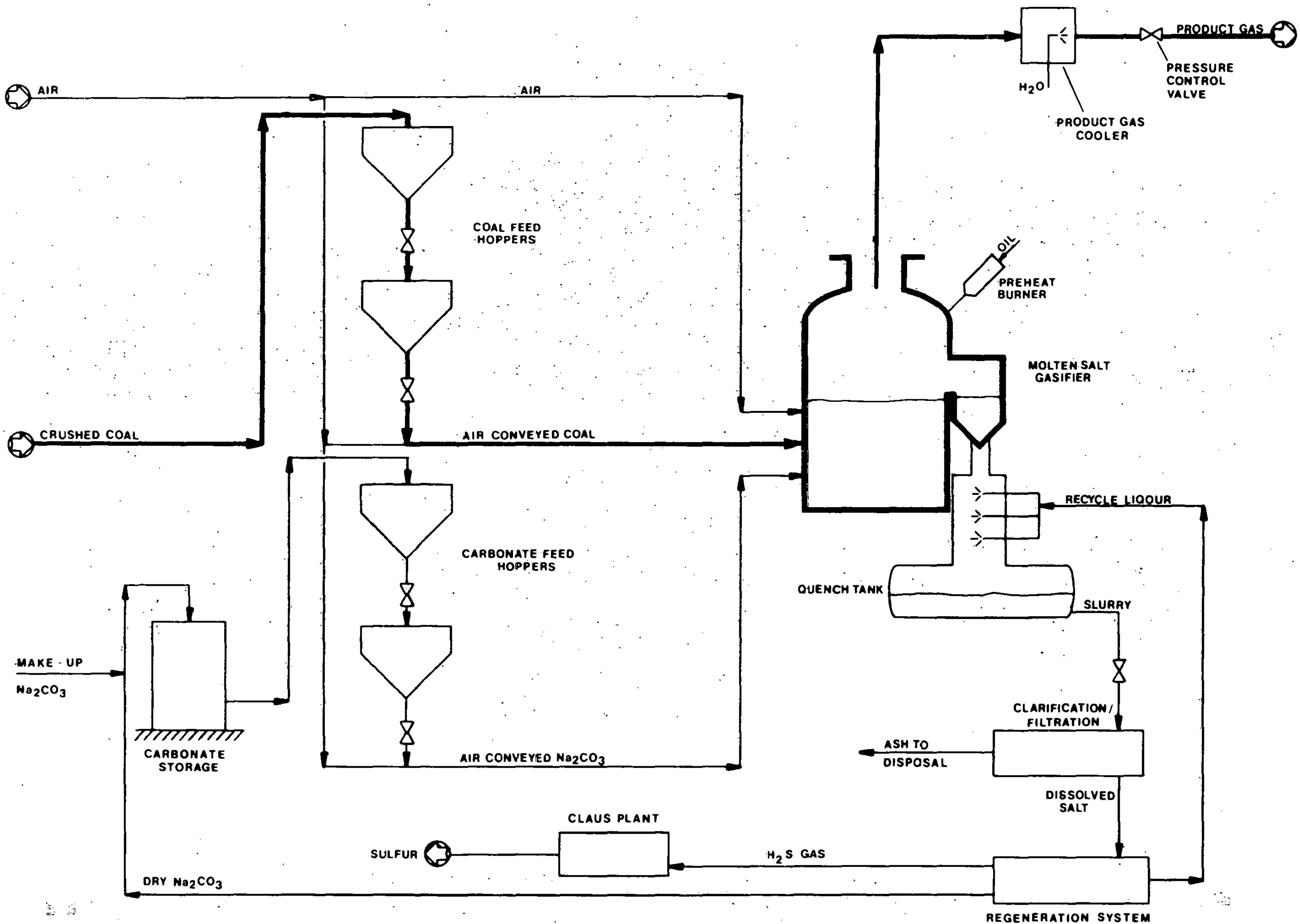


FIGURE 1.21-2

1.22 OTTO-RUMMEL

Type:

Entrained flow slag bath gasifier

Licensor:

Dr. C. Otto and Comp. G.m.b.H.
463 Bochum
Christstrabe 9
West Germany

State of Development:

The Otto-Rummel single-shaft synthesis gas process is a proven process for producing medium- or low-BTU gas from coal, char, or liquid hydrocarbons.

The first pilot-scale Otto-Rummel gasifier was installed by Union Kraftstoff in 1950 based on inventions of R. Rummel. It was located at Wesseling, West Germany, had a 32 in. I.D., and was in operation for several years. A maximum gas output of 3 MM SCFD was recorded. In 1956, a single-shaft gasifier of 6 ft. I.D. was commissioned by Union Kraftstoff at Wesseling, West Germany. This gasifier was designed to produce approximately 13 MM SCFD of medium-BTU gas from 250 TPD of Brown coal with an oxygen blast. The gasifier was also suitable for gasification of liquid fuels.

In 1960, Dr. C. Otto and Company designed an improved version of the single-shaft 6 ft. I.D. gasifier at the Wesseling facility. This gasifier was installed, as had been the older 6 ft. gasifier, within a Winkler plant producing syngas, and performance of both gasifiers was handicapped by some peripheral Winkler equipment which did not meet requirements of the new slagging gasifier. In addition to this, the older 6 ft. gasifier had some process technique difficulties; however the improved 6 ft. gasifier was run satisfactorily for approximately 18 months. In 1964, steam-naphtha reformers went on stream for the production of syngas, and the entire coal gasification plant was shut down.

The 3 gasifiers above were operated at near atmospheric pressure. A 25 atma (~360 psig) demonstration scale gasifier with a 4 ft. 6 in. I.D. is now under construction and is expected to produce 17 MM SCFD of gas. More than 10,000 hours of testing is planned. In addition to the demonstration of high pressure operation, application of the Otto-Rummel technology to different types of feedstocks and production of different types of gases is also planned.

Parallel to the development of the single-shaft gasifier, experimental work was performed on a small double-shaft gasifier in Wesseling in the early 50's.[1] The double-shaft gasifier utilized annular space between two concentric shafts divided into two separate compartments for gasification and combustion, with a common molten slag bath circulating between the compartments. Air was used for combustion of the fuel in the combustion compartment and the heat produced was used for gasification. Performance of the double-shaft pilot gasifier was disappointing because the gas produced contained over 60% nitrogen. Improvements were made to reduce the nitrogen concentration, but the rate of gas production dropped to an unacceptable level.

In spite of the high nitrogen content in the gas produced at the Wesseling pilot gasifier, the British Gas Council was still interested in the development of the double-shaft gasifier. A gasifier with an annulus of 90 in. O.D. and 28 in. I.D. was erected at Bromley, England, and was commissioned in 1962. The Bromley plant had a design capacity of 2 MM SCFD of medium-BTU gas from Midland coal. Technical difficulties in design and problems in operation caused termination of the project.[3]

Description:[4]

The following description pertains to the single-shaft 25 atma (~360 psig) demonstration gasifier now under construction.

It is a vertical cylindrical vessel consisting of 3 stages, and it has a 4 ft. 6 in. I.D. and about 50 ft. height. Stage 1 (at the bottom) is a 6 ft. 6 in. high molten slag vortex chamber, stage 2 (in the middle) is a 20 ft. high reaction zone, and stage 3 (at the top) is a gas cooling section. Stages 1 and 2 have a tube wall construction to recover heat, and nozzles for the injection of coal, steam, oxygen, recycle ash and char are on the side of stage 1.

Dried, pulverized feed coal is pneumatically transported by means of an inert gas to a coal bin. From here it is entrained into recycle gas and injected into the gasifier through the nozzles. (See Figure 1.22-2.) Steam and oxygen are also injected through the same nozzles.

The nozzles are oriented to a downward, oblique, and nearly tangential direction toward the surface of the molten slag bath in stage 1. Momentum of the coal-steam-oxygen mixture makes the slag bath rotate slowly. (See Figure 1.22-1.) This turbulence increases reaction rates. The slag bath acts as a heat shield for the flames from the nozzles directed onto it. The slag also takes part in the gasification reactions. Certain constituents of the slag such as iron oxide are partially reduced and oxidized according to the following reactions:

$$Fe_2O_3 + C \rightarrow 2FeO + CO$$
$$2FeO + 1/2\ O_2 \rightarrow Fe_2O_3$$

The slag thus acts as a heat shield, an oxygen transfer medium, and a promoter of gasification reactions.

All finer coal particles are gasified in stage 1. The rotating gas passes through a throat to stage 2, and, as it does, entrained slag droplets and a portion of the char particles are separated due to the centrifugal action and then flow down along the wall into the slag bath. Unseparated char particles are further gasified in stage 2. The gas then passes to stage 3, where it is quenched by contacting it with recycle gas to solidify the liquid slag droplets before the gas leaves the gasifier. Slag formed in stage 1 is transferred to a slag removal system through a tap hole at the base of the gasifier. In the slag removal system, it is quenched and shattered into a granular form in a water bath, depressurized, discharged, and sent to disposal.

The gas leaving the gasifier contains slag and char particles amounting to 10-30% of the coal feed. It passes through a cyclone and then through a waste heat boiler. Slag and char particles separated in the cyclone and waste heat boiler are pneumatically recycled to the gasifier by means of recycle gas. The gas from the waste heat boiler is contacted with water in a quencher and then cooled in a direct contact water cooler to about 100° F. The resultant gas is a medium-BTU product gas. A low-BTU gas will be produced with air-blown operation.

Water from the cooler is used in the quencher and the sludge formed is decanted in a slurry settling tank. The separated water is recirculated to the cooler after heat exchange with cooling water. A blowdown from this recirculating water is taken to waste water treatment. The settled slurry can be disposed of along with the slag, or it may be recycled. Off-gas from the settling tank is either burned in a thermal oxidizer or recycled.

Feed Requirements:[2]

Pulverized coal, 100% through 16 mesh.
Gasifier will accept all types of coal.

The moisture content of the coal can limit operation by affecting pulverized coal flow – not gasification. Since drying during pulverization produces coals with a low moisture content, coals of virtually any initial moisture content can be handled if they are properly prepared.

Coals having ash fusion points of virtually any temperature can be handled in the Otto-Rummel gasifier. This is due to the maintenance of a slag pool in the base of the gasifier so that fluxing agents can readily be introduced to maintain ash fluidity.

Operating Conditions:[4]

Temperature of slag leaving stage 1 = 2700°-3100° F
Temperature of gas leaving the gasifier = 1500°-1700° F
Pressure = Atmospheric to 25 atma (~360 psig)

Gas Produced:[2, 4]

Typical gas composition (dry basis) after gas scrubbing and cooling –

		O_2-Blown Operation
Feed Coal		Bituminous
HHV of coal, BTU/lb, dry		12,500
Mole %,	CO	53.6
	CO_2	14.0
	H_2	30.7
	CH_4	0.5
	$H_2S + COS$	0.5
	$N_2 + Ar$	0.7
HHV, BTU/SCF, dry		278

By-Products:[4] ¶

Oils or tars are not produced.
Estimated steam generated @ 755 psig, 680° F = 3,63 lb/ton of coal

Utility Requirements:[4] ¶

O_2 (99.5%), lb/lb of coal	1.0
Steam, lb/lb of coal	0.4
BFW, Gal/ton of coal	435
Electric Power, KWH/ton of coal	70*

*From coal crushing through delivery of gas from waste heat boiler.

Labor Requirements:[2]

The gasification area, using a commercial scale gasifier of approximately 850 TPD of coal, requires two operators and three helpers, 4 shifts a week, 365 days a year. Battery limits for the gasification area are from coal bin to delivery of slag and cool product gas from the gas cooler.

Thermal Efficiency:[2] ¶

Based on cooled and scrubbed product gas, O_2-blown operation.

Cold Gas Efficiency = 72%
Overall Thermal Efficiency = 85%

Capacity:[2]

A commercial design of a single-shaft slag bath gasifier operating at 360 psig is projected to gasify about 850 TPD of coal to produce 65 MM SCFD of medium-BTU gas.

The gasifier can be turned down to approximately 50% capacity. The turndown capability of the gasifier will depend on several factors. For example, the product gas quality may change with proportions of steam and oxygen varied to maintain slagging conditions. Also, a certain flow of reactants has to be maintained to impart the necessary kinetic energy to the slag pool to keep it in a turbulent rotational motion.

Environmental Considerations:

Char separated from the product gas is recycled to the gasifier. Granular slag withdrawn from the slag discharge tank contains a maximum of 1% unconverted carbon.[2] It is disposed of by landfill. Inert gas, either N_2 from the oxygen plant or CO_2 from the acid gas removal system, used for conveying the pulverized coal to the coal bin is vented off to the atmosphere through bag filters. Water blowdown from the gas cooling section is treated before disposal. Off-gas from the settling tank is either burned in a thermal oxidizer or recycled.

Remarks:

Although the Otto-Rummel gasifier is not currently in operation, the single-shaft version of the gasifier has been

---

¶ Based on Bituminous coal as in the case of Gas Produce demonstrated in a 250 TPD unit and can be considered commercially proven. Also, a 25 atma (~360 psig) pressure demonstration plant is now under construction. The gasifier accepts all types of coal.

The concept of the double-shaft gasifier using the slag as the oxygen carrier and thus utilizing only air instead of pure oxygen to produce medium-BTU gas is attractive. However, pilot scale plants of the double-shaft gasifier achieved only limited success because of operational and design difficulties.

References:

1. Rummel, R., "Gasification in a Slag Bath", Coke and Gas, pp. 493-501+, December, 1959.
2. Private communications, between Dravo Corporation and Dr. C. Otto and Company G.m.b.H., February, 1964 through January, 1976.
3. Maccormac, M., and Wrobel, J., "The Gasification of Coal in an Experimental Rummel Double-Shaft Slag-Bath Gasifier", Industrial Gas Engineers Journal, pp. 385-399, May, 1965.
4. "Gasification of Solid Fuels in the Rummel/Otto Gasifier (ROG)", Brochure published by Dr. C. Otto and Company G.m.b.H., 1975.

PRINCIPLE OF OTTO-RUMMEL SINGLE-SHAFT GASIFIER

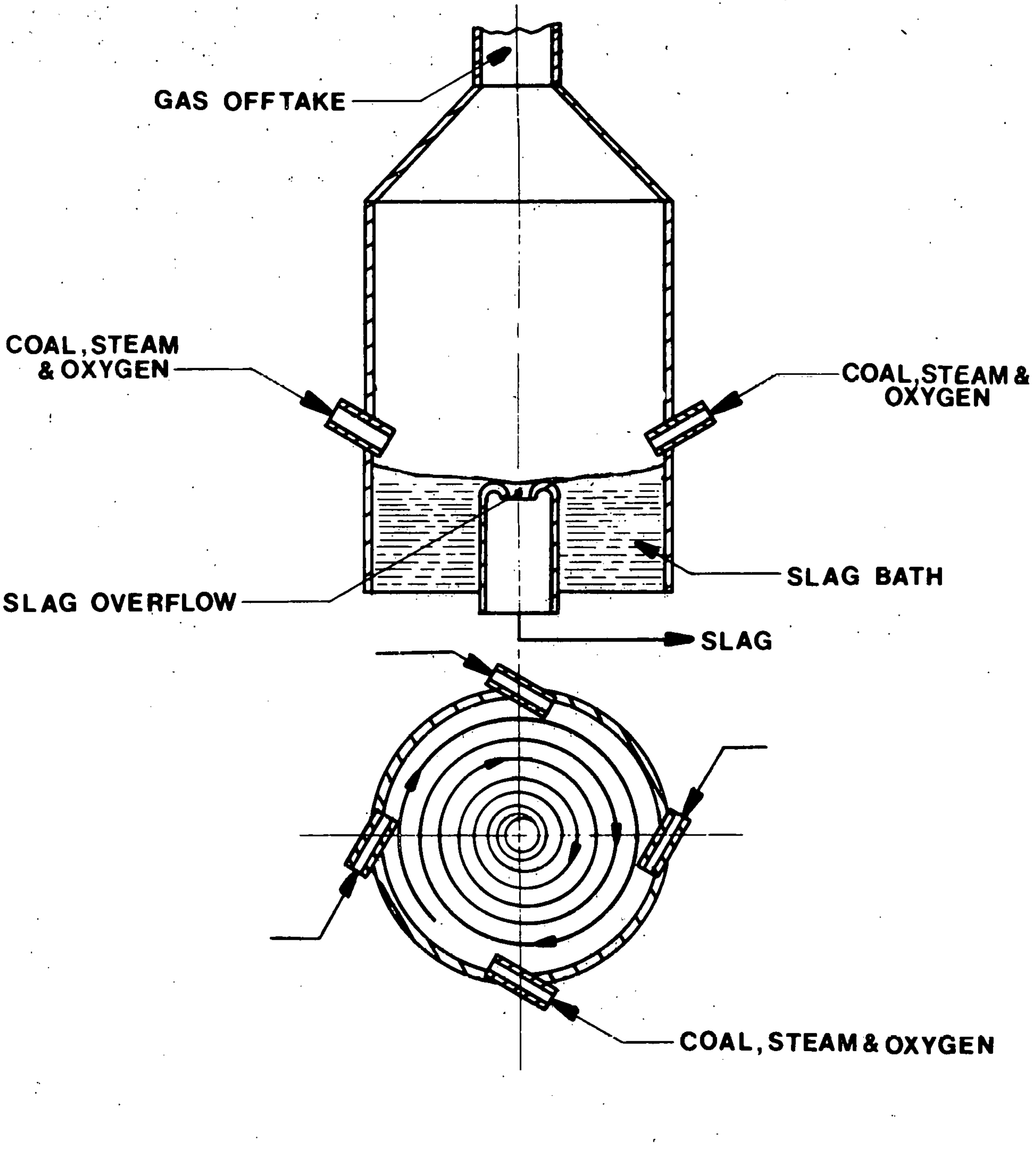


FIGURE 1.22-1

OTTO-RUMMEL COAL GASIFICATION SYSTEM

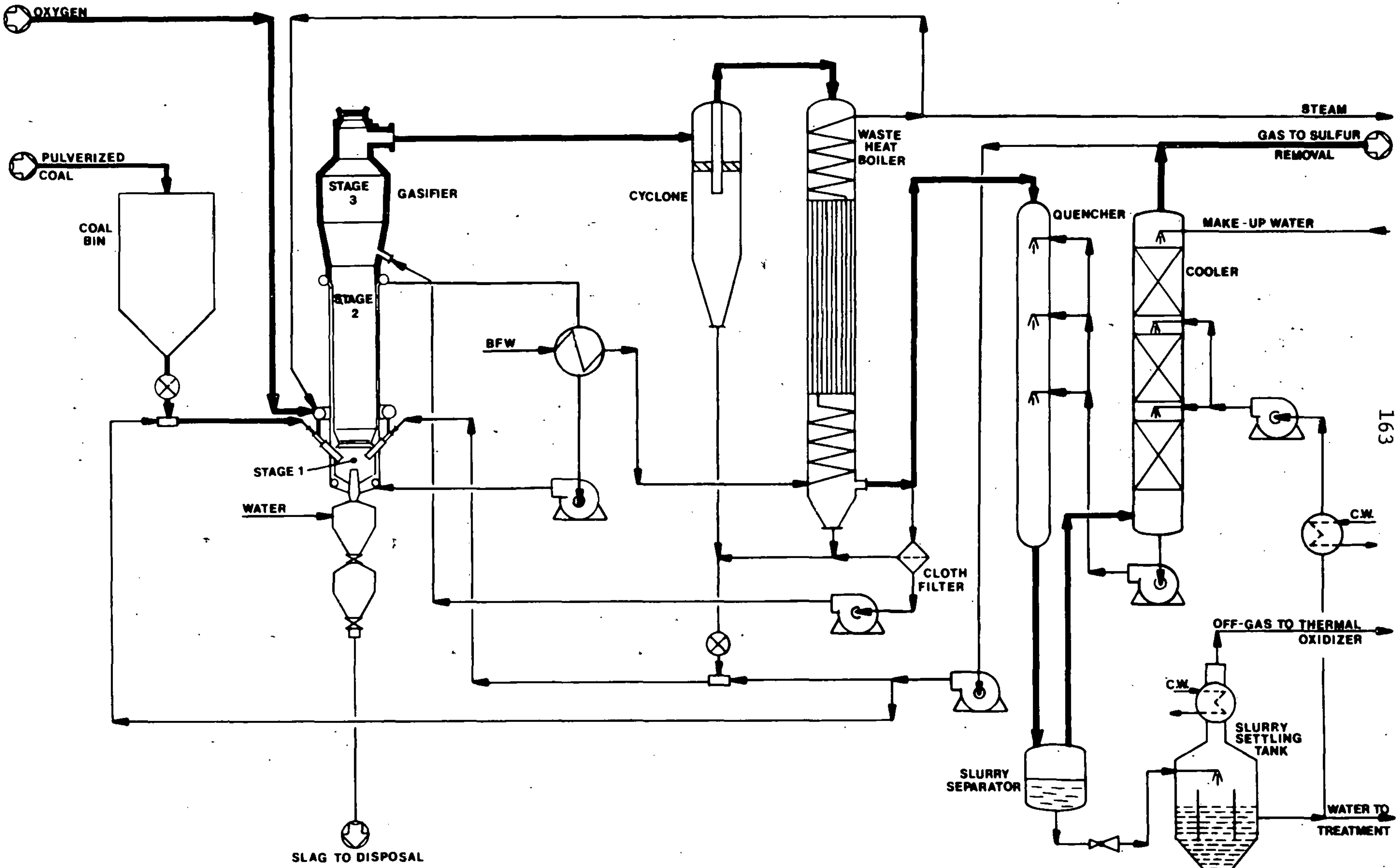


FIGURE 1.22-2

THIS PAGE
WAS INTENTIONALLY
LEFT BLANK

APPENDIX B

METHOD OF FINANCIAL ANALYSIS

APPENDIX B

METHOD OF FINANCIAL ANALYSIS

The comparison of alternative methods for generating electrical power from coal, if it is to be economically meaningful, must be based upon a realistic and consistent method for determining the rate of return on funds to be invested or (given a desired rate of return) on the required cost of power. The method used in this report to determine the costs of electricity, for both the combined-cycle and the conventional pulverized-coal power plants, is one commonly employed in utility-associated analyses.

In essence, this method defines the total cost of electricity per given unit of output (e.g., per kilowatt-hour) as the sum of capital-related expenses, the cost of raw materials, and operating and maintenance charges; each of these charges is considered on an annual basis. Capital-related costs are computed using a fixed capital charge rate applied to the total capital investment, the rate being determined by the financing method chosen, the interest rates, tax rates, and the method of calculating depreciation. The raw-materials charge is simply the cost of raw materials--coal, chemicals, etc.--divided by the net energy output; this charge depends not only on the current prices for raw materials, but also on the over-all conversion efficiency of the plant in question. The operating and maintenance (O&M) charge includes costs for operating labor, labor and materials for continuing maintenance, interim replacement of major components, and expendable supplies. The plant capacity factor selected for a given system influences the O&M charge, as might be anticipated.

Tables B.1, B.2, and B.3 provide details of the procedures used in the computation of the total capital requirements, annual operating costs, and costs of electricity for the alternative power-generation technologies.

Table B.1. Procedure for Calculation of Power Cost, Utility Financing Method

---

Basis

25-year project life
Sum-of-years-digits depreciation of total capital requirement
50% equity, 50% debt
9% interest on debt
12.5% rate of return on equity
48% federal income tax
4% state income tax
Escalation rate and investment tax credit not included
Working capital treated as depreciable capital

Fixed Capital Charge Rate (FCCR)

Using the four equations given in the paper by J. Z. James (Power Engineering, pp. 81-83, April 1977), one obtains

$$\text{FCCR} = 14.7\%$$

Note that property tax and insurance costs have here been included in total operating cost.

Cost of Electricity (COE)

$$\text{COE} = \frac{(\text{Annual Operating Cost}) + (\text{FCCR})(\text{Capital Requirement})}{(\text{Annual Power Production})}$$

Table B.2. Procedure for Calculation of Power Cost Basis for Total Capital Requirement

	Millions of dollars
Total plant investment (TPI)	
Land (number of acres times $2000/acre)	
Physical-plant investment	
Initial costs of catalysts and chemicals	
Paid-up royalties	
TPI	
Total plant cost (TPC)	
A&E home office and fee, 15% of TPI	
TPC	
Contingency, 20% of TPC	
Cost of funds used during construction, $(0.5\ \text{TPI})(0.09\ \frac{Y}{2}) + (0.5\ \text{TPI})(0.125\ \frac{Y}{2})$ where Y is the construction period in years	
Start-up costs (20% of total annual gross operating cost)	
Working capital (coal inventory of 30 days at design rate plus materials and supplies at 0.9% of TPI)	
Total capital requirement	

Table B.3. Procedure for Calculation of Power Cost Basis for Gross and Net Operating Cost (70% Plant-Service Factor)

	Millions of dollars per year
Coal, tons/year at $18/ton	
Catalysts and chemicals	
Purchased water, AF/year at $130/AF	______
Labor	
Operating, men/shift times 6132 at $10/man-hour	
Maintenance, 4.5% of total plant investment (TPI) times 0.6	
Supervision, 20% of operating and maintenance labor	______
Supplies	
Operating, 0.3 times operating labor	
Maintenance, 4.5% of TPI times 0.4	______
Local taxes and insurance, 2.7% of TPI	______
Total gross operating cost	
By-product credits	
Sulfur, millions of standard tons/year (MMST/year) at $22/ST	
Ammonia, MMST/year at $170/ST	
Naphtha, millions of barrels/year (MMbbl/year) at $10/bbl	
Light oil, MMbbl/year at $10/bbl	
Tar, MMbbl/year at $5/bbl	
Phenols, MMbbl/year at $5/bbl	
Char and coal fines, MM tons/year at $16/ton	______
Total by-product credit	______
Total net operating cost	

THIS PAGE

WAS INTENTIONALLY

LEFT BLANK

APPENDIX C

COAL-FIRED STEAM POWER PLANT

APPENDIX C. COAL-FIRED STEAM POWER PLANT

C.1 BACKGROUND

Two reports (202)(245) identified in the literature search provide detailed information concerning large, coal-fired steam power plants. Reference 245 describes an investment cost study of a 1000-megawatt central-station power plant. The steam generator of this plant is a coal-fired, once-through, supercritical, single-reheat type designed to operate at a pressure of 3500 psig and a temperature of 1005°F, with a reheater outlet of 630 psig and 1005°F. Steam is supplied to a tandem compound, six-flow turbine. The feedwater heating cycle includes four low-pressure heaters, a de-aerator, and two high-pressure heaters.

Other systems and equipment in the plant include coal-handling and coal-preparation systems, an ash-handling system, a light-fuel-oil system, generator and switch gear, condensers, a once-through river-water cooling system, a water-treatment system, an auxiliary boiler, precipitators, and the stack. Design coal for the plant is not specified, but gross and net generation, net station heat rate, and thermal efficiency are given.

Reference 202 describes a conceptual design of an 820-megawatt central-power-station plant. The steam generator is a coal-fired, once-through, supercritical, single-reheat type designed to operate at a pressure of 3600 psig and a temperature of 1005°F, with a reheater outlet of 710 psig and 1005°F. Steam is supplied to a tandem compound, four-flow turbine. The feedwater heating cycle has four low-pressure heaters, a de-aerating heater, and two high-pressure heaters.

Other systems and equipment in the plant include coal-handling and coal-preparation systems, an ash-and-solids-handling system, generator and switch gear, condensers, mechanical-draft wet cooling towers and a circulating cooling-water system, a water-treatment system, precipitators, a wet-lime flue-gas-scrubbing system for sulfur-dioxide emission control, a lime-preparation system, and the stack. Design coal for the plant is Illinois No. 6. Gross and net generation, net station heat rate, and thermal efficiency are given for two cases--250°F stack-gas temperature and 175°F stack-gas temperature.

The data given in Reference 202 were used in this assessment report as a basis for comparison with coal-gasification/combined-cycle power plants. This choice was made because the subject steam power plant included a system for control of sulfur-dioxide emissions from the stack. In addition, a wet cooling tower/circulating cooling-water system was included, and it is believed that this type of system is more common than the once-through river-water cooling system. Further, plant-performance calculations were based on Illinois No. 6 coal, which is one of the design coals for this assessment report. The following description of this steam power plant was taken directly from Reference 202 to provide an understanding of the scope of plant operations.

C.2 CYCLE DESCRIPTION

A detailed plant schematic for the 250°F (394 K) stack-temperature case is presented in Fig. C.1. State points and stream flows are shown, where the enthalpy values are keyed to a 32°F (273 K) zero-reference for steam and water and to an 80°F (300 K) zero-reference for air, combustion gases, and solids. The advanced feature of this power system is the use of wet flue-gas scrubbers, with a conventional boiler to generate steam from high-sulfur coal for a conventional steam-turbine cycle and with a single reheat of the steam.

C.2.1 Steam-Turbine-Generator Cycle

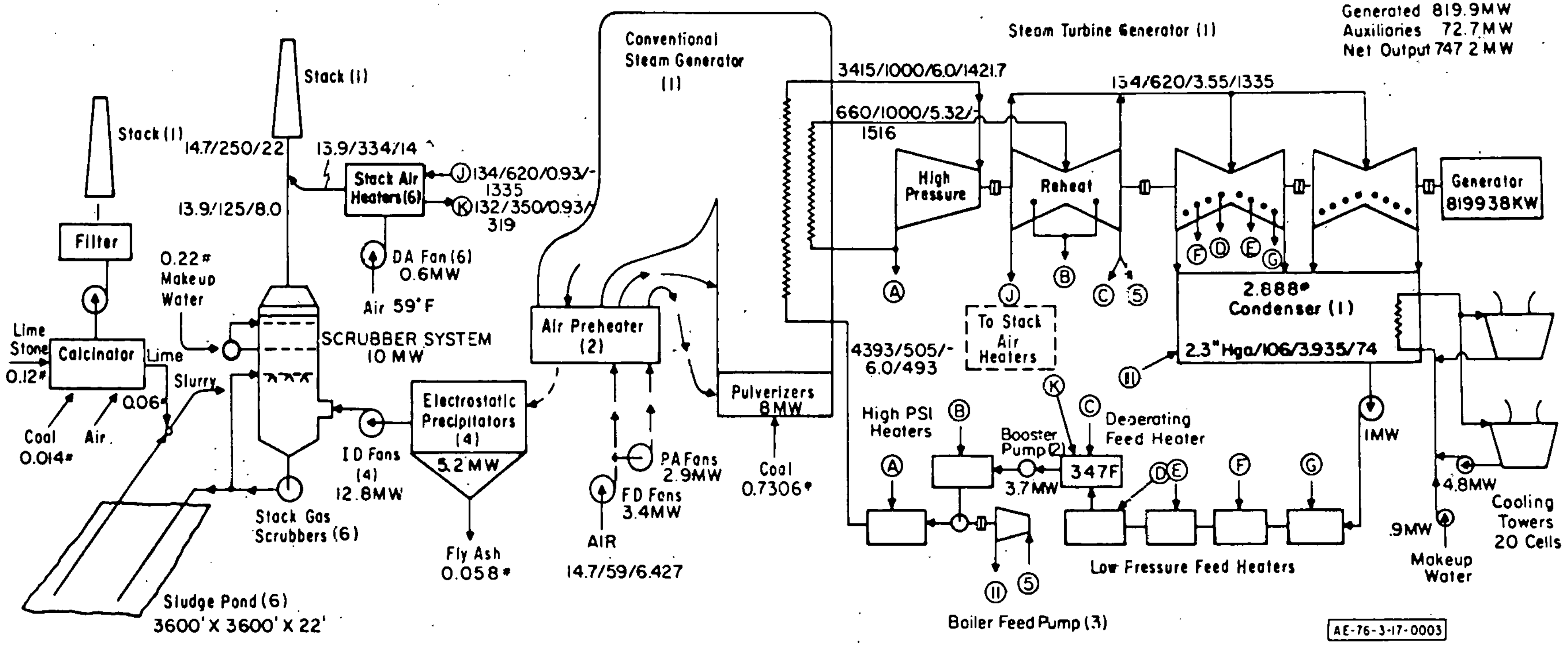
The steam turbine is contained in four shells connected in tandem with a single 820-MW generator. The low-pressure stages have four parallel flows, exhausting downward into a common condenser. The condenser coolant is water-recirculated in a closed circuit to evaporate cooling towers. The regenerative feedwater-heating cycle has four low-pressure feedwater heaters, a de-aerating feedwater heater, and two high-pressure feedwater heaters. Part of the steam exhausted from the high-pressure turbine is used in feedwater heating, while the rest is returned to the boiler to be reheated to 1000°F (811 K). Part of the steam from the reheated turbine exhaust is used for driving the boiler feedpump. The exhausts from the three drive turbines are routed to the main condenser. All other pump drives are driven by electric motors and appear in the detailed account of auxiliary losses. The boiler feedpump and its drive are an integral part of the steam cycle and are fully accounted for in the heat balance for the steam-turbine-generator.

The final feedwater would be at 505°F (536 K) for 100-percent operation. All major components were specified for continuous-performance capability at a flow margin of five percent above the intended plant operating flow. The steam cycle at the valves-wide-open (VWO) point would pass the intended flow, including the five-percent margin, and the designated 510°F (439 K) feed temperature would then exist. It is important in conventional steam systems that the operations be evaluated at the 100-percent operating point, where performance is guaranteed, and not at the specification condition for design with margin.

C.2.2 Conventional Steam Generator

The coal to be fired is dried by the primary air-flow at the eight ball mill pulverizers. Between 15 and 20 percent of the total air is heated to 633°F in the hottest sector of the air preheater as primary air. This air serves to dry the coal, to convey the pulverized coal to the burners, and to consummate the initial combustion process. The remainder of the air is preheated to 585°F (580 K) and delivered to the burners as secondary air.

The water circuitry in the steam generator provides water walls, radiant-energy-absorption surfaces, convection and radiant surfaces for



LEGEND: Pressure/Temperature/Flow Rate/Enthalpy
PSIA/°F/Million Pounds Per Hour/BTU Per Pound
#Million Pounds Per Hour

Fig. C.1. Conventional Steam Cycle with Wet Gas Scrubbers superheating and reheating of steam, and an economizer to bring the flue gas to 740°F (666 K) as it leaves the boiler and enters the air preheater. Slag is removed from the boiler furnace beneath the firing zone, fly ash from a hopper just before the air preheater. These solids, representing 15 and 10 percent of the total ash, respectively, are sluiced to the sludge pond. The electrostatic precipitators, with an efficiency of 98.6 percent, collect another 75 percent of the total ash, leaving only 0.75 percent in the gas flow to the wet scrubbers. The collected fly ash is stored in dry silos for shipment off-site. Induced-draft fans follow the electrostatic precipitators.

C.2.3 Wet Gas Scrubbers

The wet gas scrubbers apply a spray of recirculated hot water that is rich in lime in order to capture sulfur compounds. The remaining fly ash will be washed out of the flue gas also. Following the main reactive spray, there is a demisting spray that recirculates a makeup-water and captured-drift mixture. Carry-over of the slurry and lime are avoided by this means.

C.2.4 Lime and Sludge Systems

A continual removal of sludge and a continual replenishment of lime and water is required. The sludge is flushed to the sludge-settling ponds in a stream, 10 percent of which consists of undissolved solids. The return water from the pond is enriched with lime produced in the coal-fired calcinator from limestone feedstock.

The makeup water moves in a counterflow mode. It is first used in the mist-eliminator recycle wash; the bleedoff replenishes the SO_2-absorber recycle liquids, and ultimately the makeup water becomes part of the sludge and water mixture that accumulates in the settled portion of the sludge pond.

C.2.5 Stack and Reheat System

The flue gas, at 125°F (325 K), leaves the wet scrubber saturated with water vapor and with many constituents at or near their dew-point temperatures. It has been determined that normal gas heaters cannot have suitable service lines when heating such a corrosive gas mixture. The alternative to direct heating is to blend into the flue gas a large flow of air that has been separately heated. Figure C.1 shows 14 Mlb/hr (1764 kg/s) of air heated to 334°F (441 K) blending with 8 Mlb/hr (1008 kg/s) of flue gas to produce a 250°F (394 K) stack temperature. The stack air heaters use steam withdrawn from the steam cycle as their heating medium. The stack and flues are lined to withstand attack from the flue gases.

C.2.6 Overview

The major components of this system are conventional and of proven reliability in utility service. The wet-scrubber system introduces added equipment requiring maintenance and also the need to avoid the corrosive effects of lime and of cool flue gas. The subdivision of scrubber duty into six parallel scrubbers and the subdivision of critical pumping functions in the scrubber system should assure that no more than one sixth of the capacity would be down at any time.

C.3 MAJOR CYCLE COMPONENTS

Components for conventional steam plants are specified for continuous operation with flows five percent greater than required for normal operation. Insofar as Fig. C.1 depicts 100-percent plant operation on a 59°F (288 K) day, the individual specifications for the boiler, turbine, and scrubber will require greater capacities at their design points. The exact matching has been accomplished on the basis of an exact steam-turbine heat balance, which dictates the heat to steam for the boiler, and the boiler efficiency, which in turn dictates the fuel requirement.

This section will consider the specified performance for the steam-turbine-generator, the boiler, the scrubber system, and the heat-rejection system. The latter two are furnished as balance-of-plant equipment. All other balance-of-plant items will be specified in a subsequent section.

C.3.1 Conventional-Furnace Steam Generator

The general layout of the conventional supercritical once-through steam generator is shown in Fig. C.2. Eight ball mill coal pulverizers are located at the base elevation. The burners are arrayed about the radiant furnace section. The combustion gas flows upward over superheater sections, then downward in parallel paths through the reheater and the primary superheater, and finally emerges from the economizer. Figure C.3 presents a preliminary heat-and-mass balance at the specified design flows. The final configuration differed from that shown, in that the induced-draft fans (IDF) were located after the electrostatic precipitators instead of ahead of these units. All other features were the same, and the flows, temperatures, and pressures are correct as shown. The heat to steam for this boiler was 87.1 percent of the fuel's higher heating value.

C.3.2 Steam-Turbine Generator

The heat balance for the steam cycle is presented in Fig. C.4 for operation at the 100-percent-rated-power condition of 820 MW. The rating at the valves-wide-open (VWO) point would be 860 MW. The seven feedwater heaters and the throttle and reheat conditions are typical for supercritical reheat units today. The unusual feature is the extraction of 926,000 lb/hr (117 kg/s) of steam for stack-gas-heating service. The effect on the steam-turbine cycle is as if a separate condenser were located at the 134-psi level. The reduction of steam flow to the low-pressure states reduces generator output and also the condenser and cooling-tower heat-rejection load.

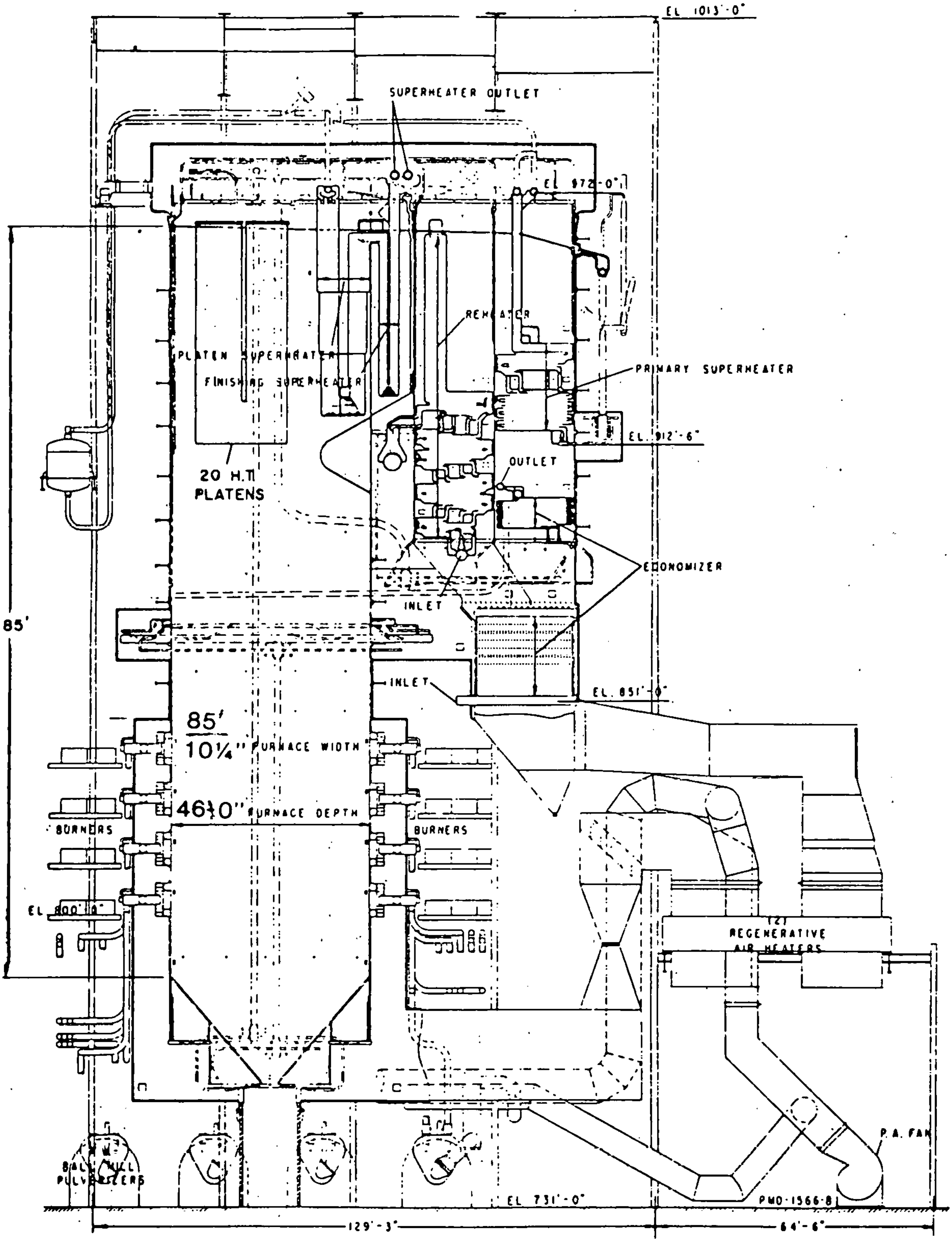


Fig. C.2. ECAS-II Conventional Boiler--Supercritical Once-Through Coal Firing (860 MWe)

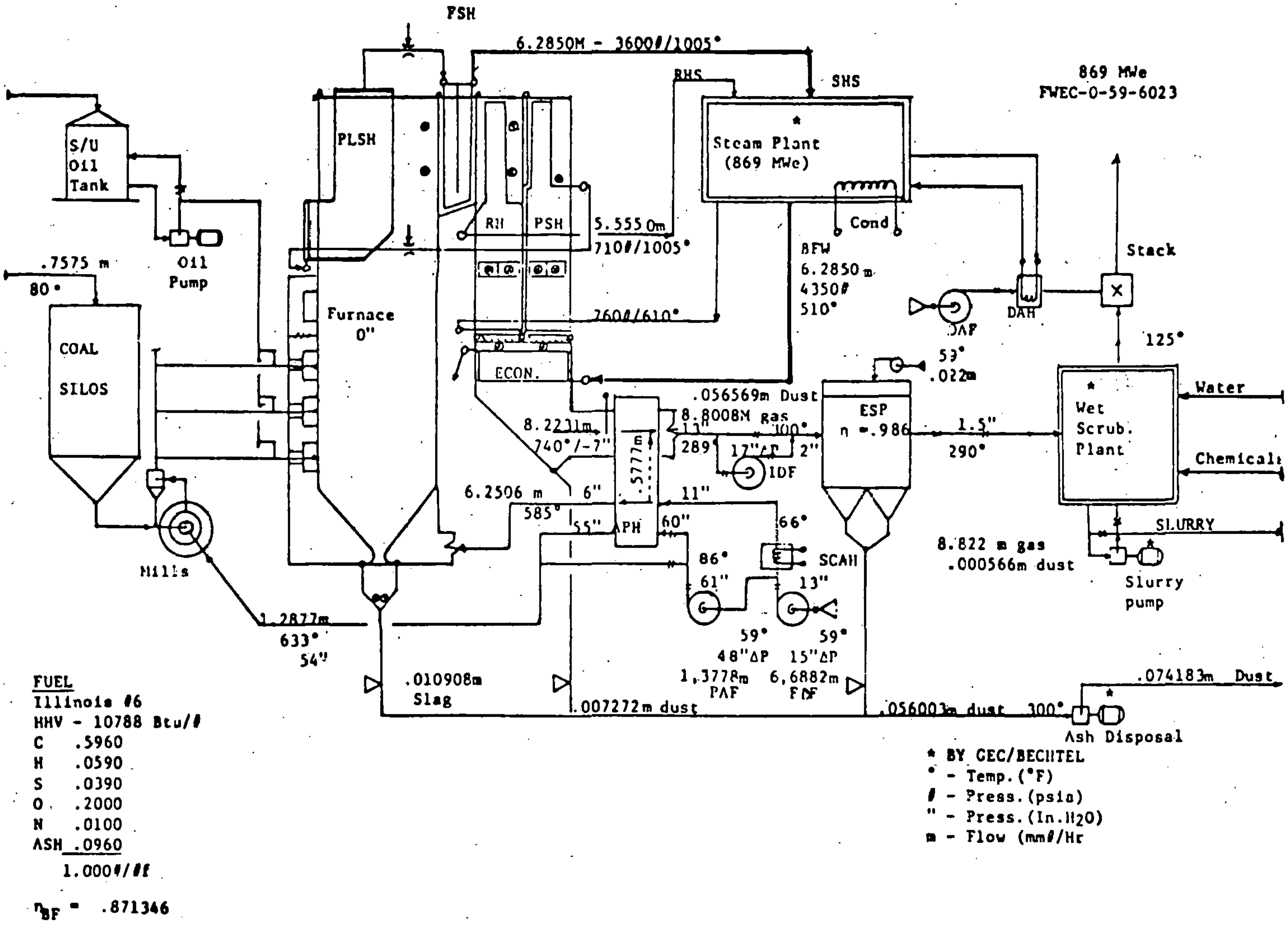
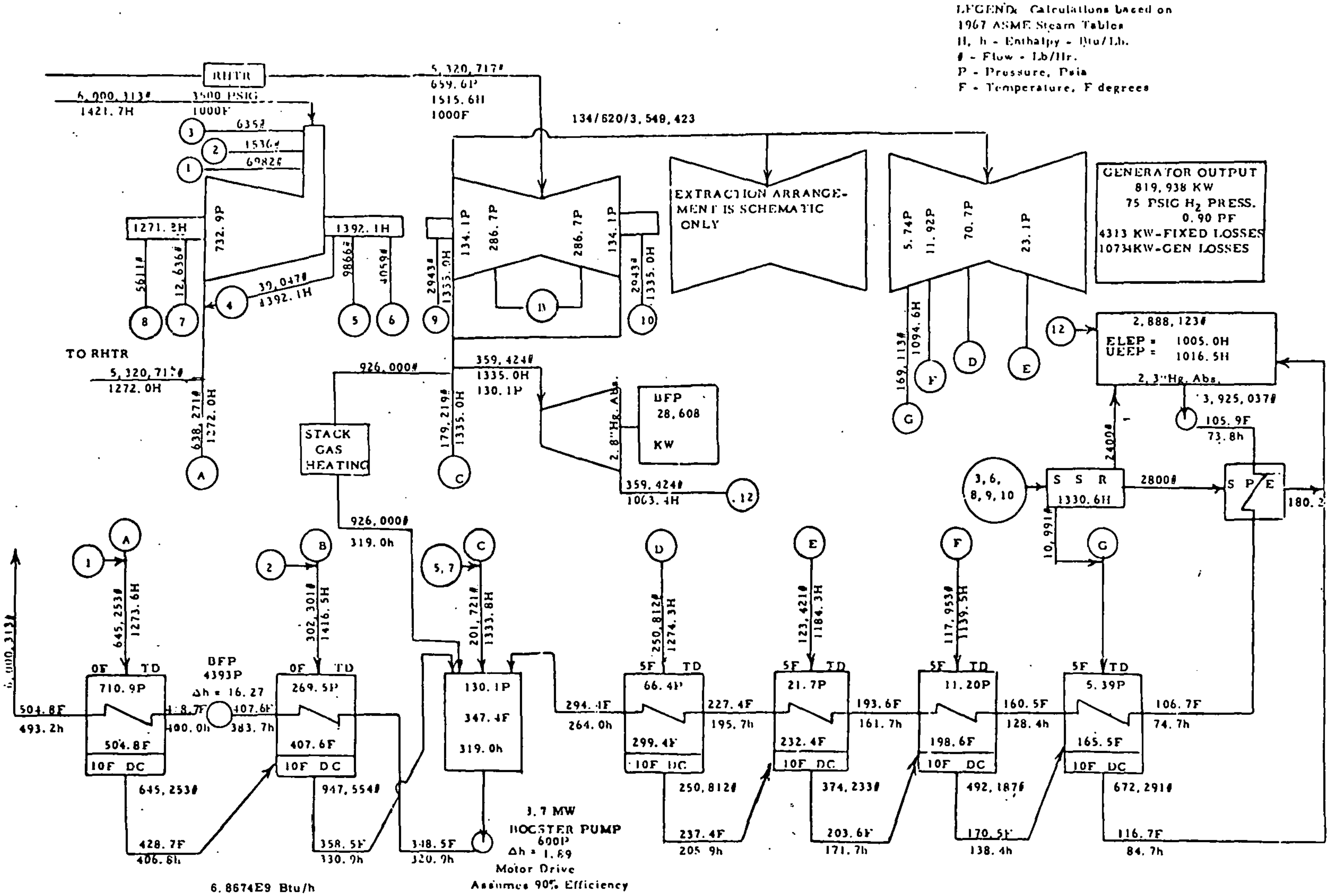


Fig. C.3. Conventional Steam Plant Flow (860 MWe)



VALVE BEST POINT NET HEAT RATE = $\frac{6,000,313(1421.7 - 493.2) + 5,320,717(1515.6 - 1272.0)}{819,938 - 3697}$ = 8414 BTU/KW-H

GROSS HEAT RATE = 8375.54

819,938 KW @ 2.3" Hg. Abs. 0% MU
WITH 15.4% CONTINUOUS EXTRACTION
FOR STACK GAS HEATING
TC4F-33.5" LSB 3600 RPM
3500 PSIG 1000/1000°F
GEN: 992,200 KVA @ 75 PSIG H2 PRESS. & 0.90 PF(HQ)

Fig. C.4. Conventional Furnace with Wet Scrub-250°F Stack

The steam turbine comprises four shells. The high-pressure turbine, the reheat turbine, and two double-flow low-pressure condensing turbines are arranged in tandem with the single generator.

The last-stage turbine buckets are 33.5 inches (851 mm) long. These are the largest buckets applied to 3600-rpm turbines for fossil-fired service. The unit is characterized as "TC4F33.5," indicating tandem compound, four exhaust flows, with 33.5-inch (851-mm) last-stage buckets.

The heat to the steam cycle at 100-percent operating conditions would be 6867.4 MBtu/hr (2.01 GJ/s). The heat input would be 8375.54 Btu/kWh (8.84 kJ/kWh) for generator output.

C.3.3 Stack-Gas-Scrubber System

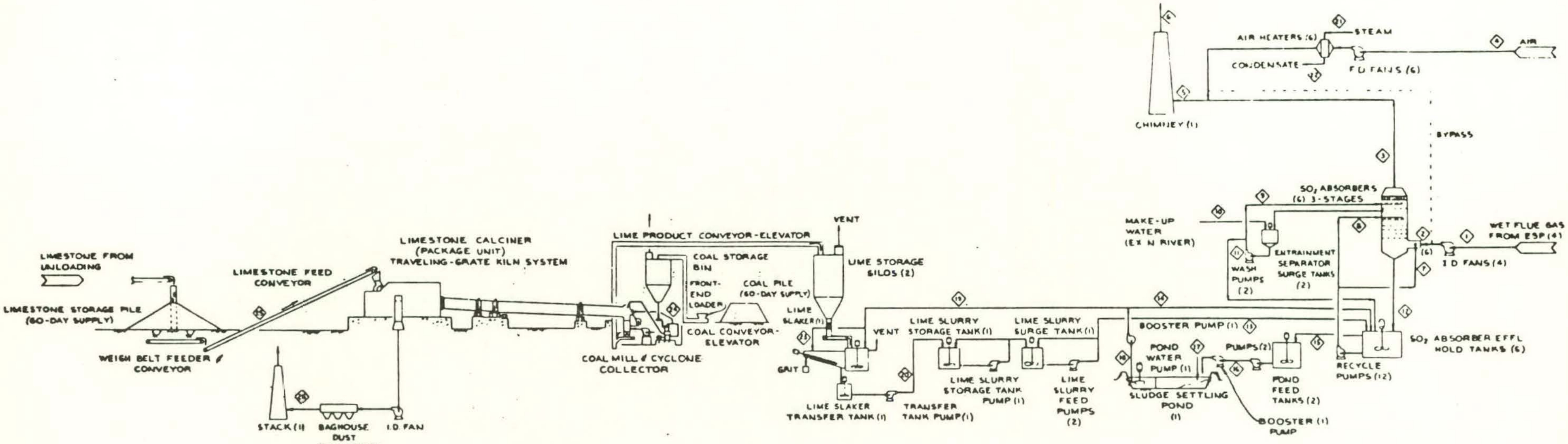
Although all elements of the wet-gas-scrubber system would be furnished as balance-of-plant equipment, the unique aspects of this system demand that it be discussed as a major cycle component.

The entire scrubber system is illustrated in Fig. C.5, along with process flow charts appropriate for operation at the specified five-percent flow margin, using 4.5-percent-sulfur coal. The sulfur capture would be 90 percent. The two process flow charts do not differ with respect to the sulfur-capture system; only the reheating of stack gas to 250°F (394 K) in the upper chart and to 175°F (353 K) in the lower chart are different.

The lime requirement is met by calcining limestone in a rotary kiln fired with coal. There is a 60-day supply of limestone on-site. The coal is stacked in a four-day-storage bin by front-end loaders. The emission requirements for the calciner are met by the use of a baghouse dust collector and a separate stack. No reduction in sulfur gas is expected for the coal fired in the calciner.

The lime product is expected to be in excess of 95-percent available lime. It is stored in silos with a capacity sufficient for five days' operation. With the 1500 tons per day (378 kg/s) of limestone-calcining capacity, this part of the plant need not operate continuously to support plant operations. There should be sufficient time to accomplish all usual maintenance and refurbishment on a scheduled basis. The entire left half of Fig. C.5 represents on-site capital investment and operations that would be eliminated if lime rather than limestone were available for purchase in suitable quantities at a suitable price.

The right half of Fig. C.5 is the scrubbing system that causes lime to react with sulfur in the flue gas to form solids that accumulate in the sludge ponds. The lime replenishment is slaked with pond recycle water to a 16-hour-storage tank. The slaked lime and remaining pond recycle water are discharged to the SO_2-absorber-effluent holding tanks. Table C.1 presents the major parameters of the limestone/lime system considered to this point.



250°F CASE

STREAM NO.	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26
DESCRIPTION	GAS TO I D FAN	GAS TO ABSORBER	GAS TO REHEAT	AIR TO HEATERS	GAS TO STACK	GAS TO ATMOSPHERE	SLURRY-TO PRE-SAT'R	RECYCLE SLURRY TO ABS	MIST ELIM RECYCLE WASH	RAW MAKE-UP WATER	ENTR SEPR BLEED-OFF	SLURRY TO SAE HT	LIME SLURRY TO SAE HT	POND WATER TO SAE HT	SAE HT OVERFLOW	USED SLURRY TO POND	SETTLED USED SLURRY	RECYCLE POND WATER	SLAKE & DILN WATER	LIME SLURRY TRANSFER	STEAM TO AIR HEATER	CONDEN-SATE RTN	LIME TO SLAKER	COAL TO CALINER	LIMESTONE TO CALINER	GAS TO STACK
M LBS./HR	8,178.5	1,363	1,387.5	2,431	22,911	22,911	386.8	11,567	720	229.6	76.5	11,930	66.8	121.2	240.7	722	375.5	1,069	341.8	400.8	160.5	962.8	62.5	14.5	125	203
M ACFM (GPM)	2,644	425	541	551	6,822		(730)	(21,825)	(1,440)	(459)	(153)	(22,508)	(118)	(242)	(454)	(1,362)	(573)	(2,138)	(683)	(709)	(321)	(1926)				74.3
TEMPERATURE, °F	300	312	125	89	250																620	356				500
PRESSURE, IN. WG (PSIG)	-15	10	1	0	0	0															(130.3)	(130.3)				
PARTICULATES, LBS/HR	723	723	3,170		4,338	4,338																				<15
SULFUR DIOXIDE, LBS/HR	67,800	11,300	1,130		6,780	6,780																				<150
UNDISSOLVED SOLIDS, %							10	10				10	20		10	10	40			20						
SPECIFIC GRAVITY							1.06	1.06	1.0	1.0	1.0	1.06	1.13	1.0	1.06	1.06	1.31	1.0	1.0	1.13						
M LBS./HR TOTAL	8,178.5	8,178.5	8,525	14,986	22,911	22,911	2,321	64,401	4,320	459.1	459.1	71,578	400.8	727.2	1444	1444	375.5	1,069	341.8	400.8	962.8	962.8	62.5	14.5	125	203

175°F CASE

STREAM NO.	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26
DESCRIPTION	GAS TO I.D. FAN	GAS TO ABSORBER	GAS TO REHEAT	AIR TO HEATERS	GAS TO STACK	GAS TO ATMOSPHERE	SLURRY-TO PRE-SAT'R	RECYCLE SLURRY TO ABS	MIST ELIM RECYCLE WASH	RAW MAKE-UP WATER	ENTR SEPR. BLEED-OFF	SLURRY TO SAE HT	LIME SLURRY TO SAE HT	POND WATER TO SAE HT	SAE HT OVERFLOW	USED SLURRY TO POND	SETTLED USED SLURRY	RECYCLE POND WATER	SLAKE & DILN WATER	LIME SLURRY TRANSFER	STEAM TO AIR HEATER	CONDEN-SATE RTN	LIME TO SLAKER	COAL TO CALINER	LIMESTONE TO CALINER	GAS TO STACK
M LBS./HR	8,178.5	1,363	1,387.5	844.5	11,592	11,592	386.8	11,567	720	229.6	76.5	11,930	66.8	121.2	240.7	722	375.5	1,069	341.8	(400.8)	35.6	213.4	62.5	14.5	125	203
M ACFM (GPM)	2,644	425	541	153	3,095		(730)	(21,825)	(1,440)	(459)	(153)	(22,508)	(118)	(242)	(454)	(1,362)	(573)	(2,138)	(683)	(709)	(71)	(427)				74.3
TEMPERATURE, °F	300	312	125	59	175																620	356				500
PRESSURE, IN. WG (PSIG)	-15	10	1	0	0	0															(130.3)	(130.3)				
PARTICULATES, LBS/HR	723	723	3,170		4,338	4,338																				<15
SULFUR DIOXIDE, LBS/HR	67,800	11,300	1,130		6,780	6,780																				<150
UNDISSOLVED SOLIDS, %							10	10				10	20		10	10	40			20						
SPECIFIC GRAVITY							1.06	1.06	1.0	1.0	1.0	1.06	1.13	1.0	1.06	1.06	1.31	1.0	1.0	1.13						
M LBS./HR TOTAL	8,178.5	8,178.5	8,525	5,267	11,592	11,592	2,321	69,402	4,320	459.1	459.1	71,578	400.8	727.2	1,444	1,444	375.5	1,069	341.8	400.8	213.4	213.4	62.5	14.5	125	203

REVISED TABLE
ISSUED FOR REPORT
NONE
BECHTEL
SAN FRANCISCO
GE/NASA
ADVANCED ENERGY CONVERSION STUDY
PROCESS FLOW DIAGRAM
WET STACK GAS SCRUBBER 250°
11107 P-606 1

REVISED TABLE
ISSUED FOR REPORT
NONE
BECHTEL
SAN FRANCISCO
GE/NASA
ADVANCED ENERGY CONVERSION STUDY
PROCESS FLOW DIAGRAM
175° STACK GAS TEMP
WET STACK GAS SCRUBBER
11107 P-610 1

Fig. C.5. Process Flow Diagram

Table C.1. Limestone/Lime System Parameters
(Conventional Furnace - Steam Cycle)

Lime product quality	95% available CaO
Limestone/lime product	2 tons/ton
Limestone storage	60-day supply 90,000 tons
Limestone calciner (traveling-grate kiln)	
Nominal production	650 tons/day
Capacity	880 tons/day
Fuel requirements (Ill. No. 6)	5 MBtu/ton lime
Lime storage capacity	5-day supply
Lime slaker capacity	800 tons/day
Slaking temperature	∿ 190°F
Slaked-lime-slurry solids (after dilution)	20% weight
Lime-slurry surge capacity	16 hours

The three-stage SO_2 absorbers operate on flue gas that has been quenched from 300°F (422 K) and saturated with water vapor at 125°F (325 K) by the presaturation sprays at each absorber gas inlet. The flue gas then flows upward through the three absorber stages, each of which comprises a 6-inch (152-mm) bed of spheres. The liquid-to-gas ratio maintains 110 percent of lime-to-sulfur stoichiometric ratio. The effluent wet gas is further washed in the mist-eliminator sprays. These sprays receive all of the fresh makeup water intended for replenishment of the scrubber system. This final wash captures carry-over or large droplets of drift. Table C.2 identifies the parameters of the wet-absorber system and keys the stream functions to Fig. C.5.

The flue gas at 125°F (325 K) and saturated with water vapor is highly corrosive and chemically active. Normal heat exchangers that would reheat the flue gas to an appropriate stack temperature would not withstand the chemical attack of the flue gas. Even the flues and stack must be lined, to avoid attack. The necessary stack temperature is achieved by steam-heating additional air and blending the heated air with the flue gas. This requires six low-head fans and six heaters. Two alternative stack temperatures were examined: 250°F (394 K) and 175°F (353 K). Table C.3 presents the parameters of the blend air and its heat requirements for these alternatives at their 100-percent operating point. The blending technique of gas heating is increasingly inefficient as the stack temperature is increased toward the air temperature of 333°F (440 K); this inefficiency accounts for the great differences between these two alternatives.

The wet-gas-scrubber arrangement connects these several elements with the four induced-draft fans that service the four electrostatic precipitators. There is a total of six absorber and stack-reheater trains.

Table C.2 Wet-Lime-Absorber System Parameters
(Conventional Furnace - Steam Cycle)
(Basis: 90% SO_x Removal for 4.5%-Sulfur Coal)

Parameter	Value or Description
SO_2 absorbers (6)	TCA type[a]
Number of stages	3 (6" of spheres/stage)
Superficial gas velocity	8 ft/s
Total pressure drop	9 in. H_2O
Liquid/gas ratio ◇8 [b]	72 gal/mscf
Presaturation sprays ◇7	2.5 gal/mscf
Mist-eliminator wash sprays ◇9	2 gpm/ft^2
Lime: SO_2 stoichiometric ratio	110%
Absorber hold-tank residence time	5 minutes
Recycle-slurry solids ◇15 ◇8 ◇7	10% weight
Lime-makeup slurry ◇13	20% weight
Spent slurry pond solids ◇17	40% weight

[a] TCA = Turbulent-contact absorber

[b] ◇ = Stream identification number, Fig. C.5

Table C.3 Flue-Gas Heaters for Wet-Scrubber Systems

	Stack-Gas Reheat Temperature	
Parameter	250°F	175°F
Heat duty	971	217
Steam	620 → 356°F	620 → 356°F
Air	333 ← 59°F	333 ← 59°F
Air velocity, ft/min	900	900
Air rate, M lb/hr	14.589	3.267
Pressure drop, in. H_2O	1.5	1.0
Heat-transfer rate, Btu/hr sq-ft °F	5.5	10.4
Finned surface, sq ft	645,000	86,500

The induced-draft fans feed a cross-duct that is normally isolated by dampers from the start-up bypass path. Connecting in a downward fan-like duct are the presaturation spray ducts to each absorber. The redundancy dictated by the size of the absorbers should produce a high level of availability for the scrubber system.

The sludge ponds are the remaining element of the wet-scrubber system. Each pond would measure 3600 feet (1097 m) by 3600 feet (1097 m) across and

22 feet (6.7 m) deep. Six ponds would accommodate 30 years of plant operations. The accumulation rate of solids would equal the solids-delivery rate of 150,000 lb/hr (18.9 kg/s) of calcium sulfite and excess unreacted lime. Because water would accumulate at a rate 50 percent greater, in-situ solids concentration would be 40 percent. It is important to recognize these two accumulations, because the tables in Fig. C.5 represent steady-state balances for the absorbers but nonsteady states for lime, makeup water, and sludge accumulation.

C.4 SYSTEM PERFORMANCE

C.4.1 Performance Integration

Evaluation was made of plant performance on the average 59°F (288 K) day with all equipment operating at 100-percent condition with respect to its design and specification point. To adjust performance data so that an exact integration results, a detailed steam-turbine heat balance had been made at the 100-percent operating point, as presented in Fig. C.4. The required 6867.4 MBtu/hr (1.13 GJ/s) from the boiler are deemed to be provided at the exact boiler efficiency (87.1346) that prevails with the five-percent-margin condition detailed in the boiler heat balance (Fig. C.3). Typically, boiler efficiency improves slightly at reduced firing rates.

In addition to the coal fired at the boiler, the rate of coal usage for calcining was evaluated on the basis that the mass flows of the wet-gas-scrubber process flow diagram (Fig. C.5) represent operation at a five-percent margin above the required 100-percent level. Table C.4 presents the basis and results for the integration into the steam cycle of boiler and wet-gas-scrubber operating flow rates.

Table C.4 Energy Balance--100% Rating, 59°F Day (Conventional Steam Plant - Wet Scrubbers - 250°F Stack)

Parameter	Value
Generated power, kW	819938
Heat-to-steam cycle[a], MBtu/hr	6867.4
HHV of fuel fired[b], MBtu/hr	7881.4
Coal fired at boiler[c], pph	730570
Coal fired at calciner[d], pph	13810
Total coal rate, pph	744380
Effective boiler efficiency, %	85.52
Limestone Feed Rate[d], pph	119050
Scrubber-makeup-water rate, gal/min	917

[a] From 100% steam-cycle heat balance, Fig. C.4.

[b] Boiler efficiency 0.1346 from heat balance, Fig. C.3.

[c] Based on 10788 Btu/pound higher heating value (HHV).

[d] Rates proportioned 1/1.05 for wet scrubber, Fig. C.5.

C.4.2 System Output

For the 100-percent operating point, Table C.5 shows that the 820 MW of generator output was reduced to 747-MW net plant output by the 73 MW required for auxiliaries. The induced-fan power requirement was four MW greater than normal as a result of the additional nine-inch drop in water pressure in the wet-gas scrubbers; the scrubber system itself consumed 10 MW. All other values for auxiliaries are typical of current steam plants. These auxiliary loads consume 8.9 percent of the generator output in the plant.

C.5 PLANT CAPITAL-COST ESTIMATES

The plant capital-cost summary given in Reference 202 for an 869-MWe plant (cycle output), based on mid-1975 costs, is shown in Table C.6.

Table C.5. System Output (Conventional Steam Plant - Wet Scrubbers - 250°F Stack)

Parameter	Output, MW
Steam-cycle output	819.9
Total auxiliary losses	72.7
Net power-plant output (60 Hz AC-500kV)	747.2

Table C.6. Plant Capital-Cost Estimate, Coal-Fired Steam Power Plant (Wet-Stack-Gas Scrubbing--175°-F Stack--Mid-1975 Cost Basis)

Item	Cost,[a] $10^6
Land, improvements, structures	43.4
Coal handling	11.9
Prime-cycle plant equipment	194.8
Electrical plant and instrumentation	46.3
A&E services and contingency	99.6
Total capital cost	396.0
Total capital cost for 546-MWe capacity (cycle output)	335[b]

[a] Reference 202; 820-MWe cycle output

[b] Total plant cost for 869-MWe capacity, mid-1975 basis, was adjusted to a capacity of 546 MWe and mid-1977 cost basis using capacity exponent of 0.7 and escalation factor of 1.17.

The plant, which is based on a reheated-stack-gas temperature of 175°F, was selected for this assessment in preference to a plant designed for 250°-F reheated-stack-gas temperature, because the former is more representative of power plants operated with stack-gas scrubbers.

The plant cost reported in Reference 202 was adjusted to a capacity of 546 MWe and a mid-1977 cost basis, using a capacity exponent of 0.7 and an escalation factor of 1.17.

C.6 PLANT PERFORMANCE SUMMARY

The performance of both the 869-MWe plant (cycle output), as reported in Reference 202, and of a 546-MWe plant (cycle output) as pro-rated from the values obtained for the former is indicated in Table C.7.

C.7 PLANT MATERIAL REQUIREMENTS

Material requirements for a 500-MWe (net output) plant were estimated as follows from Reference 202 for the case of 175°-F stack-gas temperature:

Item	Quantity
Limestone, lb/kWh	0.16
Coal,* lb/kWh	0.936
Water, gal/kWh	0.82

Table C.7. Summary of Performance, Coal-Fired Steam Power Plant (Wet-Stack-Gas Scrubbing--175°F Stack)

Performance Factor	869-MWe Plant[a]	546-MWe Plant
Steam-cycle output, MWe	868.6	546
Auxiliary losses, MWe	73.1	46
Net power-plant output, MWe (60 Hz, AC-500 kV)	795.5	500
Power-plant efficiency, %	33.8	33.8
Coal consumption, lb/kWh	0.936	0.936
Total wastes, lb/kWh	0.25	0.25

[a] Reference 202.

---

*Illinois No. 6 coal with 10,800 Btu/lb HHV

APPENDIX D

BIBLIOGRAPHY AND REFERENCES

APPENDIX D

BIBLIOGRAPHY AND REFERENCES

This bibliography contains the results of the literature survey conducted on LBG/CCPG technology. The product survey is presented in two parts:

(1) All items other than those published by Government sources are assembled by year of publication and then sorted by the last names of the principal authors under each year. This portion of the bibliography, Section D.1, is contained in pages 189 through 229.

(2) All items bearing Government document numbers and obtainable from Government sources are assembled in order by the official document numbers, because titles are sometimes repeated and because this method permits grouping of related items. These references are listed in Section D.2, pages 230 through 263.

An index to the Government reports, by number, appears on pages 264-265, and an author index follows this on pages 266-270. All items cited from the literature have been assigned item numbers, used to compile the indices and to identify the references throughout the text of this report.

A simplified method of listing Government reports has been used, as follows:

> U.S. Government (source), NTIS or GPO (agency selling report), FE-1234-6 (number of the report), 1976 (date of issue); xxx pp (the number of pages gives the price category of the report)
>
> Sample: U.S. Government, NTIS, FE-1514-T4, 1974; 321 pp

The information in each listing should be sufficient to identify the report referenced, should anyone wish to obtain it. The number assigned to each bibliographical entry identifies it for referencing in the text of this report.

D.1 NON-GOVERNMENT SOURCES

For the period before 1970, reference is made to the following article, which includes a good survey of important literature on combined-cycle power plants prior to that date, as well as some selected material from 1970 and 1971:

> Peeler, J.P.K., and Piggott, K.L. (CSIRO, Melbourne, Australia)
> Combined Gas-Turbine/Steam Cycle for Power Generation
> 1. A Literature Survey and Discussion
> Trans. Inst. Eng. Aust., Mech. Chem. Eng. MC8 (2), 125-30 (1972)
> (Note: For Part 2, see Peeler and Piggott, 1972)

In addition ot the literature cited by the above article, the following references should be included. For the years 1970 to date, subsequent listings by year of publication follow.

1.

Weaver, Elmer R.
Formulas and Graphs for Representing the Interchangeability of Fuel Gases
J. Research of the Nat'l Bureau of Standards 46 (3), 213-45 (Research Paper 2193) (1951)

When gas-burning appliances have been adjusted to give satisfaction with a gas of one composition, and are then supplied with gas of a different composition, changes are usually noted in the characteristics of the flames produced. When no change can be seen or measured, the gases are said to be "exactly interchangeable." When undesirable changes do not occur to a greater extent than the person using the term thinks permissible, the gases are usually still called "interchangeable," with the omission of the adverb. No entirely satisfactory method has ever been found for predicting or representing the extent to which different gases depart from exact interchangeability. In this paper a set of six "indexes" is given for specifying and predicting from the composition of any two fuel gases the extent of the effects that occur when one is substituted for another. Four of these indexes are new. Their derivation is given, and their application is shown by a comparison with the results of extensive experimentation by the American Gas Association. They are shown to represent the results of observation somewhat better than any method proposed previously.

2.

Hershey, A.E. (Westinghouse Electric Corp.)
Combustion of Blast-Furnace Gas in Gas Turbines
Proc. Jt. Conf. on Combustion (IMEE and ASME), 347-53 (1955)

3.

Wilson, W.B. and Hafer, A.A.
Combined Steam-Gas Turbine Plants
Proc. Amer. Power Conf. 17, 330-41 (1955)

4.

Gilbert, M. G. and Prigg, J. A. (The Gas Council)
The Prediction of the Combustion Characteristics of Town Gas
Trans. Instn. Gas Engr. 106, 530-589 (1956-1957)
also listed as British Gas Council Res. Comm. GC-35, 1956-57

A method of predicting the combustion characteristics of a gas from its analysis is presented. The method is based upon the methods of Delbourg, in France, and of Weaver, in America. It has been developed and modified for use under British conditions. A number of gases that are used or have been proposed for use in the town gas supply have been examined by the method, and samples of some of these gases have been made up in the laboratory and their characteristics determined. Agreement between the predicted characteristics and those found is reasonably good. The method involves the use of a calculated flame speed and, therefore, cannot be considered as completely satisfactory; check testing of existing appliances therefore remains necessary. Nevertheless, the types of unsatisfactory performance that are liable to occur with a particular gas are indicated and the testing of appliances on samples of the new gas can be reduced to a minimum.

5.

White, A. O.
The Combined Gas Turbine--Steam Turbine Cycle with Supercharged Boiler and Its Fuels
ASME Paper No. 57-A-264, 1957

6.

Buscemi, V. P.
Symposium on the Lake Nasworthy Combined-Cycle Power Station--the Steam and the Gas Turbine-Generators
Proc. Amer. Power Conf. 25, 276-283 (1963)

7.

Andreson, G. E.
Horseshoe Lake Station Unit No. 7 Combined Cycle Steam Generator Design and Operation
National Power Conference, Tulsa, Oklahoma, Sept. 1964; Preprint

8.

George, T. H.
World's First Large Combined Cycle (Steam Turbine--Gas Turbine) Generating Unit--How Is It Doing?
Trans. IEEE, Power Apparatus & Systems PAS84 (12), 1182-1186 (Dec. 1965)
or ASME, IEEE National Power Conf., Tulsa, Oklahoma, Sept. 1965;
Preprint--Paper No. 64-362

Operation of first large combined cycle unit, using modern reheat steam turbine with two shaft gas turbines at Horseshoe Lake Station of Oklahoma Gas & Electric Co.; operational experience shows that expected economy and capability were realized; reliability is expected to improve as result of modifications.

9.
Reti, G. R.
New Combined Cycle for Gas Turbines Offers High Efficiencies
Power Eng. 68 (5), 55-58 (1965)

In combined gas turbine--steam turbine plants, refrigerant cycle follows gas turbine to product maximum performance; regeneration takes place in gas turbine cycle before exhaust gases give up heat to refrigerant; refrigerant picks up heat in intercooler of gas turbine compressor; after heat expands through turbine, refrigerant is condensed; refrigerant pump takes suction from condenser hot-well to repeat cycle; in this cycle, temperatures are, in gas turbine 1500 to 800 F., and in refrigerant cycle 400 to 100 F., in regenerator 800 to 400 F.; efficiencies and future application of system.

10.

Reti, G. R.
Thermodynamic Analysis of New Combined Cycle
Proc. Amer. Power Conf. 27, 521-529 (1965)

Combined cycle uses more than one heat-carrying medium, each within its most favorable temperature range; most common combined cycle is gas turbine--steam turbine combination with waste heat boiler applied after gas turbine; closed refrigerant cycle picks up heat in compressor intercooler, in turbine exhaust-gas heat exchanger, and in cold end of MHD heat recovery duct; refrigerant then enters turbine and expands to condenser pressure, after heat rejection in condenser, refrigerant is pumped back to repeat cycle.

11.

Segeler, C. G. (American Gas Association), Editor-in-Chief
Gas Engineer's Handbook
Industrial Press, N. Y., 1965

12.

Perry, Harry and DeCarlo, Joseph A. (Bureau of Mines)
The Search for Low-Sulfur Coal
ASME Paper No. 66-PWR-3, 1966; 27 pp

For special-purpose coals used in the production of coke, ceramics, and so forth, the sulfur content of the coal is a critical factor, and low-sulfur coals generally are used. Export markets, principally of special-purpose or metallurgical coal, also require coals of low sulfur content. In addition, the increased attention to oxides of sulfur as a harmful air pollutant has resulted in great interest by coal-consuming industries in the availability of low-sulfur coals. The paper discusses the availability of low-sulfur coals, and describes methods of reducing emission of sulfur oxides from furnaces.

13.
Sheldon, R. C.
Application of Exhaust Heat Recovery Combined Cycle
ASME Paper No. 67-PWR-6, Sept. 24-28, 1967; 12 pp

Combined cycle arrangements result in improvements in overall plant heat rates that are economically attractive for base local operation with low steam conditions also offer attractive ways to augment peaking gas turbine output; evaluation of relative worth of these schemes, as well as method for estimating combined cycle heat rates.

14.

Giramonti, A. J. (United Aircraft Research Laboratories)
Discussions of Steam and COGAS Systems with the Babcock & Wilcox Co.
UARL Report UAR-H246, 1969

15.

Schoeberl, Heimo
Experiences with a Blast Furnace Gas Turbine and Its Significance for Energy Supplies
<u>Stahl</u> <u>u</u>. <u>Eisen</u> 89 (6), 281-289 (March 20, 1969) (Ger and Eng)

16.

Berman, P. A. and Lebonette, F. A. (Westinghouse Electric Corp.)
Combined-Cycle Plant Serves Intermediate System Loads Economically
<u>Westinghouse</u> <u>Eng</u>. 30 (6), 168-173 (Nov. 1970)
Paper also presented at ASME-IEEE Joint Power Generation Conference held in Pittsburgh, Pa., Sept. 27-30, 1970
Also reprinted in <u>Combustion</u> 42 (9), 19-23 (March 1971)

A combined-cycle plant is described, in which gas turbines, heat-recovery boilers, and a steam turbine are matched to provide an optimum plant. The plant provides a power level of 230 Mw at a heat rate less than 9400 Btu/kwh. Installed capital cost is kept low by pre-engineered components and packaging techniques.

17.

Biancardi, F. R. and Peters, G. T. (United Aircraft Research Laboratories)
Utility Application for Advanced Gas Turbines to Eliminate Thermal Pollution
ASME Paper No. 70-WA/GT-9, November 1970

Increases in electric power demand during the next 30 years will sharply increase water requirements for condenser cooling and will stimulate the search for alternative solutions to the thermal pollution of our waters. Continuing engineering advances, achieved during extensive research and development efforts on military and commercial gas-turbine applications, could provide the basis for substantially improved power plants that could significantly alleviate thermal pollution. Described are the results of analytical studies to estimate the design technology, performance, and cost characteristics of future fossil- and nuclear-fueled gas-turbine power generation systems and the potential for eliminating thermal pollution.

18.

Ediss, B. G.
Steam Injection Can Improve Gas Turbines
Power 114 (6), 82-84 (1970)

Injecting steam from waste heat into cycle improves output and reliability.

19.

Pirsh, E. A. and Sage, W. L. (Babcock & Wilcox Co.)
Combined Steam Turbine--Gas Turbine Supercharged Cycles Employing Coal Gasification
Amer. Chem. Soc. Div. Fuel Chem. Preprints 14 (2), 39-58 (1970)

20.

Poletavkin, P. G.
Cycles and Thermal Circuits of Steam-Gas Turbine Installations, with Cooling of the Gas During Compression by the Evaporation of Injected Water
High-Temp. 8 (3), 579-84 (May-June 1970)

The investigations conducted to study the thermodynamics of steam-gas turbine showed that for compression ratios of 30 to 300, the injection of water during compression gives a considerable increase in thermal efficiency, up to 40 or 50% for a temperature of the steam-gas mixture at the turbine entrance of 1100 K. Some relationships between the efficiencies of such installations and the cycle parameters are presented. 3 refs.

21.

Robson, F. L. and Giramonti, A. J. (United Aircraft Research Labs)
Advanced-Cycle Power Systems Utilizing Desulfurized Fuels
Amer. Chem. Soc. Div. Fuel Chem. Preprints 14 (2), 79-96 (1970)

22.

Robson, F. L. and Giramonti, A. J. (United Aircraft Research Labs)
An Advanced-Cycle Power System Burning Gasified and Desulfurized Coal
Proc. 1st Seminar on Desulfurization of Fuels and Combustion Gases, Geneva, Switz., Nov. 1970

23.

Robson, F. L. and Giramonti, A. J. (United Aircraft Research Labs)
Nonpolluting Central Power Stations
AAS (Amer. Aero. Soc.) Paper No. 70-083 from AAS/AISS Special Technical Event, Wimrock Farms, Arkansas, Nov. 27-28, 1970
Also reprinted in
Forbes, F. W. and Dergarabedian, P., Editors, Technology Utilization Ideas for the '70 s and Beyond, Amer. Aero. Soc., Tarzana, CA, 1971; pp 29-37

24.
Rudolph, P. F. H. (Lurgi Ges. für Wärmeund Chemotechnik mbH)
New Fossil-Fueled Power Plant Process Based on Lurgi Pressure Gasificatio
of Coal
Amer. Chem. Soc. Div. Fuel Chem. Preprints 14 (2), 13-38 (1970)

25.

Anonymous
Advanced Power Cycles and Nonpolluting Fuels for Utility Power Generation
Gas Turbine Int., 12 (2), 22-4 (March-April 1971)

An advanced-cycled power station using a COGAS power system fueled by a Texaco-type entrained-flow, high temperature gasification system has the potential of generating electric power at busbar costs significantly below those projected for conventional steam power stations while reducing sulfur oxide emissions by over 99%. All advanced-cycle gas turbine power stations considered would incorporate cooling towers, where needed, in both the fuel processing and power systems; thus, these stations would emit essentially no thermal pollution.

26.

Anonymous
Power Plant Integrated with Pressure Gasification of Coal
Combustion 42 (8), 12-13 (Feb. 1971)

Steinkohlen-Elektrizitaet AG, Essen, have worked out the scheme for a combined gasification gas turbine power plant and have decided to build a prototype of such plant in the Kellermann Power Station at Luenen (Westphalia). This unit is scheduled for start-up by the middle of 1971 and will generate 170 Mw. The Kellermann Power Station uses high volatile coal from the Ruhr District. The coal is gasified in a Lurgi pressure gasification plant with air and steam. The generated fuel gas is thoroughly washed in a scrubber to ensure that the fuel gas entering the combustion chamber of the gas turbine is free of dust and alkalies.

27.

Berman P. A. (Westinghouse Electric Corp.)
Operating concept for a 240-Mw Combined Cycle Intermediate Peaking Plant
ASME Paper No. 71-GT-53, 1971; 8 pp

The combined cycle power plant presented in this paper consists of two W501 gas turbines, each exhausting into its own steam generator. The output from both steam generators is fed into a single cylinder steam turbine designed with axial exhaust and generator drive from the high-pressure end to accommodate grade level installation. In the design of the overall plant, the prime objective was to obtain a relatively large block of highly efficient power that could be installed in a minimum of time and cost. Wherever possible, the plant is designed to simplicity of operation. Reliability is recognized to be an extremely important factor in a power plant of this type, since the plant must be capable of going on line with minimum operating attendance. Therefore, the basic design is targeted to allow plant operation at a load of approximately 50% with any single component not operable.

28.

Berman, P. A. and Baker, G. E. (Westinghouse Electric Corp.)
Combined Cycle Packaged Power Plant
<u>Gas Turbine Int</u>. 12 (1), 34-8 (Jan.-Feb. 1971)

Proposed combination plant for loading conditions less than base load but more than peaking includes two gas turbines, two heat recovery boilers, and one steam turbine. Each gas turbine is a complete packaged power generating plant operating at 3600 rpm. Each gas turbine has a heat recovery boiler which utilizes the exhaust gases as preheated combustion air. A burner element provides additional heat energy through combustion of fuel in the gas turbine exhaust gases.

29.

Bund, K., Henney, K. A., and Krieb, K. H.
Combined Gas/Steam Turbine Operated Power Plant Using Pressure Gasification of Coal in the Kellermann Power Station at Luenen
<u>Brenns-Waerme-Kraft</u> 23 (6), 258-262 (1971) (Ger)

The paper describes the arrangement of the gas/steam turbine process used at Luenen, the construction of the plant, and how the pressure gasification process ties-in with the process of the power station. Reference is made to the efficiency on can expect in this plant. 12 refs.

30.

Dibelius, N. R., Hilt, M. B. and Johnson, R. H. (General Electric Co.)
Reduction of Nitrogen Oxides from Gas Turbines by Steam Injection
ASME Paper No. 71-GT-58, 1971; 4 pp

This paper describes the results of tests to determine the effects of steam injection on the production of nitric oxide in gas turbine combustors. When the steam injected into the compressor discharge was 2% of the total air flow, the oxides of nitrogen were reduced to 50% of what they were with no steam injection for a given load in a gas fired machine. When the steam flow was increased to 4% the oxides of nitrogen dropped to 25% of the value with no steam.

31.

Foster-Pegg, R. W. (Struthers Energy Systems, Inc.)
Gas Turbine Heat Recovery Boiler Thermodynamics, Economics and Evaluation
<u>Combustion</u> 42, 8-18 (March 1971)

The most economical recovery of exhaust heat from gas turbines is the theme of the paper. Conventional and heat recovery boilers are compared with respect to differences in operating conditions and their effect on design. Steam costs from conventional and heat recovery boilers are compared with examples given for specific cases. Optimizations of heat recovery boilers for draft loss and approach temperature are illustrated with examples. Finally, the advantages and economic penalties of various optional items associated with heat recovery boilers are discussed.

Originally presented as Paper No. ASME 69-GT-116, at Gas Turbine Conference of March 10-13, 1969.

32.

Henney, K. A. and Krieb, K. H., (Karlheinz Bund Steinkohlen-Elektri A. G.)
Combined Gas/Steam-Turbine Generating Plant with Bituminous Coal, High-Pressure Gasification Plant in Kellermann Power Station at Luenen.
Trans. 8th World Energy Conf., Bucharest, Rom., June 28 - July 2, 1971; Vol. 3, Paper 2.3-71, 20 pp

A plant constructed in West Germany is described. The plant consists essentially of a gas turbine with a gross capability of 74 Mw, to pressure-fired steam generating units with an aggregate steam rate of 340 tons/hr without intermediate superheat, and one steam turbine with a capacity of 96 Mw. The two pressure-fired steam generators are arranged ahead of the gas turbine. The fuel for the gas turbine is a gas produced by the Lurgi process in which coal is gasified at a pressure of 20 atm gage in a mixture of compressed air from the compressor of the gas turbine and of steam. The generator is charged with slightly caking lump coal containing up to 30% mineral matter. It is proposed to build a pilot plant for the removal of sulfur from the gaseous fuel. It is argued that the combination gas/steam process with coal as basic fuel is suitable for economic use on a small scale in countries where the transmission and distribution system has not yet been expanded to a point where larger power stations can be built and where bituminous coal or lignite are available at normal prices. The system is suitable for large units of more than 300 Mw where freedom from atmospheric pollution by dust and sulfur-laden waste gas is a primary concern. It requires a relatively small condenser section so that the consumption of cooling water is appreciably reduced. 12 refs.

33.

Schwieger, R. G.
Future Brightens for Combined-Cycle Plants
Power 115 (10), 105-109 (1971)

Combined-cycle plants, wherein gas turbines, heat-recovery boilers and steam turbines are matched to provide an optimum system have been preengineered with packaged components tailored to meet utility mid-load generation demands.

34.

Schweikhard, W. and Aulds, D.
Oklahoma Utility Buys First PACE Combined-Cycle Plant
Power Eng. 75 (11), 36-39 (1971)

The plant chosen by Public Service Co. is the PACE-260 (Power At Combined Efficiency--260 MW) plant designed and manufactured by the Westinghouse Electric Corp. It consists of two industrial-type gas turbines generating about 50% of the electric output as well as heat to generate steam for a steam turbine to provide the other 50% of the electric-power output.

35.

Sheldon, R. C. and Todd, D. M. (General Electric Co.)
Optimization of the Gas Turbine Exhaust Heat Recovery System
ASME Paper No. 71-GT-79, 1971; 24 pp

In addition to presenting some of the outstanding hardware developments for this application, the basic nature and performance characteristics of these cycles is discussed. Special emphasis is placed on the presentation of the design and physical characteristics of the heat recovery steam generators. The paper also presents several estimating methods to enable the calculations of steam flows, steam turbine performance for heat recovery cycles, heat consumption in the supplementary fired steam generator, and sample calculations illustrating the use of these data.

36.

Smith, H. L. and Budenholzer, R. J. (Westinghouse Electric Corp.)
Cyclic Energy Demands Supplied Economically with Gas Turbines and Combined Cycle Plants
ASME Paper No. 71-GT-71, 1971; 5 pp

This paper presents results of generation addition pattern studies performed to determine the relative merits of steam peaking plants and combined cycle plants in filling these needs. Corresponding optimum addition patterns are established for simple cycle gas turbine and nuclear power plants. The combined cycle and steam peaking plants are shown to be comparable at high cost levels, while the combined cycle shows definite advantage if permitted to burn nondistillate fuel.

37.

Anonymous
Clean Fuel Gas from Coal by Gasification
<u>Chem. Process Eng.</u> 53 (2), 62-63 (1972)

It is shown that the clean fuel gas process based on the pressure gasification of coal yields a gas suitable for burning in furnaces, steam boilers or advanced power cycles. The process includes a scrubbing stage to remove SO_2 and ash down to very low levels.

38.

Boland, C. R. and Patterson, R. D., (Turbo Power and Marine Systems)
A Unique Combined-Cycle System to Meet Utility Intermediate Cycling Loads
<u>Proc. Amer. Power Conf.</u> 34, 302-309 (1972)

39.

Dobner, S. I., Gluckman, M. J., Graff, R. A. and Squires, A. M. (City College of the City Univ. of New York)
Production of Low-Btu Gas from Coal in Combination with Advanced Power Cycles
AIChE, 65th Annual Meeting, New York, Nov. 26-30, 1972; Paper No. 68b

40.
Gard, Manfred (AEG-Telefunken)
Combined Gas and Steam Turbine Power Plants
AEG-Telefunken Prog. (1), 26-32 (1972)

The article describes a combined gas and steam turbine power plant. For smaller units between 30 and 80 MW, the combination of the gas turbine and the steam turbine process is an extremely economical solution. Whereas the gas turbine process shows an overall efficiency of about 32 to 38%, the efficiency of a combined gas and steam turbine plant rises to between 36 and 42%. The efficiency and costs of a combined power plant with a condensing power plant are compared. Diagrams illustrate the layout, heat flow, and the sequence of operation of the combined plant.

41.

Giramonti, Albert J. (United Aircraft Research Laboratories)
Advanced Power Cycles for Connecticut Electric Utility Stations,
Final Report (for The Connecticut Development Commission)
United Aircraft Research Laboratories, East Hartford, Conn.,
UARL Report No. L-971090-2, January 1972

Analytical studies have been performed to define commercially feasible advanced-technology central power stations for Connecticut which would eliminate or significantly reduce utility-caused atmospheric pollution and thermal water pollution. The basic concept investigated represents a combination of (1) advanced-cycle, combined gas and steam (COGAS) base-load power systems, and (2) selected processes for deriving nonpolluting gaseous fuel from high-sulfur residual fuel oil (RFO), which represents the primary fuel for Connecticut power stations. Optimization studies were conducted of integrated fuel processing and power systems to identify the system characteristics which would result in minimum impact on the Connecticut environment while providing minimum-cost electric power. Fuel processing and power system technology considered during these studies was that judged to be appropriate for commercial systems by 1975, with emphasis placed on those processes and designs which have the potential for continued performance improvements and cost reductions during the decade between 1975 and 1985. Characteristics of selected future COGAS power stations are specified in terms of their principal design parameters, and economic comparisons are made between prospective COGAS and steam power stations. In addition, estimates are presented for the total pollutant emission levels in Connecticut associated with power generation, and of the extent to which these emission levels in Connecticut associated with poorer generation, and of the extent to which these emissions could be affected by the utilization of oil-fired COGAS systems.

42.

Matthews, C. W. (Intitute of Gas Technology)
A Design Basis for Utility Gas from Coal
Proc. 3rd Internat'l Conf. on Fluidized Bed Combustion, Hueston Woods, Ohio, Oct. 30-Nov. 1, 1972; pp 229-245

43.

Merz, C. A. and Pakula, T. J. (Turbo Power & Marine Systems, Inc.)
Design and Operational Characteristics of a Combined Cycle Marine Powerplant.
<u>Combustion</u> 43 (11), 15-23 (May 1972)

The subject of this paper is the design and operational characteristics of a 43,000 SHP combined gas turbine and steam turbine marine powerplant, known as COGAS. Based upon the "second generation technology" FT4C-2 marine gas turbine, the combined cycle fuel rate is 0.363 LB/SHP-HR which represents a thermal efficiency of 41 percent. The paper shows how this low fuel rate design can be achieved with simplicity, operational flexibility and minimum environmental effect. 11 refs.

44.

Peeler, J. P. K and Piggott, K. L. (CSIRO, Melbourne, Australia)
Combined Gas Turbine-Steam Cycle for Power Generation—1. A Literature Survey and Discussion
<u>Trans</u>. <u>Inst</u>. <u>Eng</u>. <u>Australia</u>, <u>Mech</u>. <u>Chem</u>. <u>Eng</u>. MC8 (2), 125-130 Nov. 1972

A comprehensive literature survey was carried out on combined cycles incorporating a gas turbine operated in conjunction with a steam cycle. It is proposed that, for ease of classification, the main types of combined cycle be grouped under the titles of exhaust heat and exhaust powered systems. Combined cycles have found application in the process industries and power industry areas, with most systems reporting an improvement in overall cycle efficiency and where costs are discussed, a saving in specific power cost. 38 refs.

45.

Peeler, J. P. K. and Piggott, K. L. (CSIRO, Melbourne, Australia)
Combined Gas Turbine-Steam Cycle for Power Generation
2. Theoretical Study of a Coal Fired System
<u>Trans</u>. <u>Inst</u>. <u>Eng</u>. <u>Aust</u>., <u>Mech</u>. <u>Chem</u>. <u>Eng</u>. MC8 (2), 130-135 (Nov. 1972)

A mathematical model of a carbonizer-gas-turbine-steam cycle, derived on the basis of generalized material and enthalpy balances, was used to calculate the important thermodynamic and cost parameters and hence the energy cost for the combined cycle and its comparative conventional cycle. Use of a digital computer enabled a wide range of variables to be studied. Cycle capacities between 40 and 660 MW were examined. 13 refs.

46.

Robson, Fred L.
Clean Power from Gas Turbine-Based Utility Systems
<u>Combustion</u> 44 (1), 12-17 (July 1972)

The desulfurization of fuels and combustion gases for gas turbine plants is discussed. Operating data on the gas turbine and steamportions of a COGAS system, plus economics of the techniques are presented. Sulfur dioxide is reduced by 95% and thermal pollution by 40 to 60%. 4 refs.

47.
Robson, F. L. (United Aircraft Research Labs)
Fuel Gasification and Advanced Power Cycles - A route to Clean Power
Proc., 3rd Internat'l Conf. on Fluidized Bed Combustion
Hueston Woods, Ohio, Oct. 30-Nov. 1, 1972; pp 205-225

The United States is currently faced with a growing gap between the demand for electrical energy and the supply of economic fuels for generating this energy with minimum environmental impact. The use of advanced power cycles utilizing technological spinoffs from the aerospace industry in conjunction with fuel gasification/desulfurization offers a solution which could prove to be not only technically feasible but economically attractive. A review of one such system, the COmbined Gas And Steam (COGAS) is presented and the technical and economic advantages are enumerated. There are, however, several problem areas, particularly in the interface between the power system and the fuel system which must be resolved before the overall concept becomes a commercially viable one. These problem areas are presented with the intent of provoking thoughtful discussion and perhaps of opening new areas of research among the conference attendees.

48.

Tomlinson, L.
Comparison of Combined Cycle Plants Available Today and Future Trends
Paper, ASME-IEEE Joint Power Generation Conference, Boston
September 10-14, 1972

49.

Wood, B. (Merz and McLellan)
Combined Cycles: A General Review of Achievements
Combustion 43 (10), 12-22 (April 1972)

The gas turbine, if properly matched to the boiler, is usually 15-20 percent of the steam turbine output. Gas is the preferred fuel for the gas turbine, but the boiler may burn any fuel. Such plant is best suited to high load factor duties. The relationship between the two cycles and the question of transition between them is discussed by the aid of a new diagram. Minor variations are possible within each but a clear distinction is to be made between the two basic types, especially in capital cost. 23 refs.

50.

Archer, D. H., Vidt, E. J., Keairns, D. L., Morris, J. P. and Chen, J. L. (Westinghouse Research Labs)
Coal Gasification for Clean Power Production
Symp. Clean Fuels from Coal, Illinois Institute of Technol., Chicago, Sept. 10-14, 1973, IGT, 1973; pp 447-484

Coal gasification, coupled with combined gas and steam turbine generation, provides a basis for a low cost, high efficiency, non-polluting plant. A fluidized bed coal gasification process adapted to power generation has been devised. It uses air and steam for gasification and limestone or dolomite sorbent for desulfurization. 29 refs.

51.
Banchik, I. N.
The Winkler Process for the Production of Low-Btu Gas from Coal
Symp. Clean Fuels from Coal, Ill. Institute of Technol., Chicago, Ill., Sept. 10-14, 1973, I.G.T., 1973; pp 163-178

52.
Clayton, W. H. and Singer, J. G. (Combustion Engineering, Inc.)
Steam Generator Designs for Combined Cycle Applications
Combustion 44 (10), 26-32 (April 1973)

Incorporating a steam generator in a combined-cycle plant offers an area where the boiler designer can expand the technical background developed in the design of units for conventional steam-power plants. The close interaction of the steam generator with the gas and steam turbines necessitates an understanding of the entire cycle in order to provide an optimum plant selection. 10 refs.

53.
Giramonti, A. J. (United Aircraft Research Labs)
Advanced COGAS Power Systems for Low Pollution Emissions
Am. Chem. Soc. Div. Fuel Chem. Prepr. 18 (2), 195-210 (1973)

Analytical studies have been conducted to define commercially feasible, advanced-technology central power stations which would eliminate or significantly reduce utility caused atmospheric pollution and thermal water pollution. The basic concept investigated represents a combination of (1) advanced cycle, COmbined Gas and Steam (COGAS) turbine electric power generation systems based on technology spinoff from the aircraft gas turbine industry, and (2) selected processes for deriving nonpolluting gaseous fuel from high-sulfur residual fuel oil. The results of these studies clearly indicate that advanced COGAS power systems integrated with fuel gasification systems would be more effective than future fossil steam systems in controlling emissions of ash, sulfur oxides, and waste heat. In addition, preliminary calculations indicate that emissions of nitrogen oxides could be reduced up to several orders of magnitude by using low-Btu gasified fuel compared with emissions caused by the combustion of high-Btu fuels. It appears that advanced gas turbine and COGAS power systems using low-But fuels could be fired to higher turbine inlet temperature to improve performance and still emit significantly fewer nitrogen oxides than when operating a low turbine inlet temperature with high-Btu fuels. Furthermore, prospective COGAS systems could produce electricity at lower cost than could be producedby alternative fossil steam systems with comparable air and water pollution controls. Also, despite the relatively high cost of fossil fuels, advanced COGAS power systems should offer a viable alternative to nuclear power systems for future base-load power generation.

Also available--U. S. Gov't, NTIS, CONF-730403-P2, 1973; 16 pp

54.
Gluckman, M. J., Dobner, Samuel, Schumacher, W. J., Alpert, S. B. and Squires, A. M. (City College of the City Univ. of New York)
Production of Low-Btu Fuel Gas from Residual Oil in Combination with Advanced Power Cycles
Preprint, paper presented at ACS Meeting, Dallas, Texas, April 1973; 14 pp

55.
Kollrack, R. and Aceto, L. D. (Pratt and Whitney Aircraft)
The Effects of Liquid Water Addition in Gas Turbine Combustors
J. Air Poll. Control Assn. 23 (2), 116-121 (1973)

It is shown that the addition of liquid water, in quantities equivalent to the mass of fuel consumed, exerts thermal and chemical effects upon the combustion process in a gas turbine engine. The thermal influence is produced by the vaporization and heating of the water and its vapor. These effects have been assessed for mixed combustion and for liquid fuel undergoing vaporization and mixing. 17 refs.

56.
Mikol, W. W. and Yaworsky, Y. J. (Turbo Power and Marine Systems, Inc. and Public Service Electric and Gas Co.)
Complete Automation for Combined-Cycle Operation
Proc. Amer. Power Conf. 35, 638-646 (1973)

57.
Patel, J. G. and Matthews, C. W. (Inst. Gas Technology)
Fluidized-Bed Coal Gasifier as a Load-Following Clean Fuel Source
Amer. Chem. Soc. Div. Fuel Chem. Preprints, 18 (2), 181-193 (April 8-12, 1973)

The concept of a fluidized-bed reactor as a gas producer for a combined-cycle power plant is discussed. It is possible to achieve high carbon utilization in such fluidized-bed reactors by rejection of agglomerated, low-carbon ash produced in the gasifier. It is now the opinion of the people in the electric industry that such systems should be designed for operation in the intermediate load or swing range and to operate satisfactorily they must be capable of load following over a rather wide range. Several methods which could be used to achieve this flexibility are discussed. It appears at this time that, alone and in combination, these methods will enable fluidized-bed gasifiers to perform satisfactorily under the conditions that will be required by the electric industry. The fluidized-bed reactor concept for coal gasification should find practical application in supplying a clean practical fuel produced from coal or utility use for several decades to come.

58.
Pfenninger, H.
Combined Steam and Gas Turbine Power Stations
Brown Boveri Rev. 60 (9), 389-397 (1973)

A combined gas and steam power station consist of a gas turbine unit whose exhaust gases are fed into a boiler which feeds a steam turbine. The boiler may or may not have a supplementary burner. In the latter case it is a purely waste-heat boiler. If the plant operates with minimum excess air in the boiler, total outputs of 400 Mw could be attained with the types of gas turbine available today. Maximum thermal efficiency is achieved in this type of plant not with minimum excess air but with a coefficient of excess air of about 2.5. One advantage of these combined cycle plants is their low cooling water requirement which, in the case of a purely waste-heat boiler, is only about 50% of the conventional steam plant. For given steam conditions in the steam plant the performance of the combined process depends on the pressure ratio of the gas turbine set. This can be optimized relatively simply.

59.
Priddy, A. P. and Sullivan, John J.
Engineering Considerations of Combined Cycles
Combustion 44 (9), 19-25 (March 1973)
or Proc. Amer. Power Conf. 34, 282-291 (1972)

Advantages include low capital costs and heat rates, short construction time, reduced impact upon the environment and independent gas turbine operations. Economically, they can evaluate out as the most attractive generation choice especially in the intermediate load ranges. The range of possible plant capacities, cycle variations, and variety of equipment that are available suggest that the needs of individual utilities with respect to available fuels, capacity requirements, site limitations or available equipment, can be satisfied.

60.
Sage, W. L. (Babcock and Wilcox Co.)
Predicting Performance of a Coal-Fired Air-Blown Gasifier
Amer. Chem. Soc. Div. Fuel Chem. Preprints 18 (2), 211-220
(April 8-12, 1973)

61.
Siegel, H. M. and Kalina, T. (Esso Research & Engineering Co.)
Technology and Cost of Coal Gasification
Mech. Engr. 95, 23-28 (May 1973) or
ASME Paper No. 72-WA/Fu-2, 1972; 9 pp

Describes, in general terms, the technology for manufacturing high Btu substitute natural gas (SNG) and low Btu gas, from coal, by the Lurgi process and by a variety of new presses under development. Economics are presented on the cost of SNG by these routes. The economics of low Btu gas are briefly addressed. Major development problems for the new processes are summarized and potential commercialization dates are discussed. 10 refs.

62.
Singh, P. P., Young, W. E. and Dilmore, J. A. (Combustion Systems Research)
NO_x Emissions from Gas Turbine Combustors
Proc. ASME Air Pollution Control Div. National Symposium, Philadelphia Pa., April 24-25, 1973; Paper No. 10, 23 pp

The nitric oxide formation in a gas turbine combustor was measured as a function of combustor outlet temperature for various conditions. Outlet temperature was varied between 1000°F. and 1800°F. Nitric oxide concentration in the stack gas was measured for inlet temperatures of 200°F. and 600°F, fuel nozzle sizes of five through sixteen gallons per hour, combustor diameters of three and six inches, and fuel types of natural gas, low Btu gas, methanol, and No. 2 fuel oil having both a 0.0079% and 0.20% fixed nitrogen content. For similar test conditions, methanol produced the least nitric oxide for all the fuels tested, and the No. 2 fuel oil with a nitrogen content of 0.2% produced the greatest. CO, CO_2, and hydrocarbon concentrations in the stack gas were also measured. NO_2 and smoke were measured frequently but not continuously.

63.
Wen, C. Y., Bailie, R. C, Lin, C. Y., and O'Brien, W. S. (West Virginia Univ.)
Production of Low Btu Gas Involving Coal Pyrolysis and Gasification
Adv. Chem. Series No. 131, Amer. Chem. Soc., Wash., D.C., 1973; pp 3
or Preprint, ACS meeting, Dallas, Texas, April 9-10, 1973

Experiments involving the pyrolysis of bituminous coal, sawdust, and other carbonaceous feed materials have been performed in a 15-inch diameter, atmospheric, fluidized bed. Data from the pyrolysis experiments are analyzed to generate kinetic and heat-transfer information and to formulate a coal pyrolysis model useful in the design of commercial-sized processes. The model is then applied in forming a conceptual flow-scheme for a relatively low pressure (5-13 atm) electrical-power generation plant. In the conceptual flow-scheme, the low Btu gas is produced in two units, a pyrolyzer and a pyrolysis-char gasifier. The gas is then purified and fed into a combustion chamber; the electricity is generated in an advanced design gas turbine and steam turbine power cycle. 22 refs.

64.
Ahner, D. J., May, T. S. and Sheldon, R. C. (General Electric Co.)
Low-Btu Gasification Combined-Cycle Power Generation
Joint Power Generation Conf., Miami Beach, Fla., Sept. 15-19,
1974; Paper

Uncertainties as to the future sources, quantity, and quality of various fossil fuels, coupled with environmental concerns, increasing costs, and the certain long-term growth in demand for "clean" electric energy are perplexing factors to today's planners in the utility and power generation equipment industries. This paper discusses the characteristics of low Btu gas/combined cycle plants as a means of meeting industry needs in the near term with power equipment now being commercially offered. Data has been obtained from studies conducted both by GE individually, and in conjunction with process engineering firms and licensors. The information presented is based on specific fuel feedstock compositions and includes operation adn control characteristics, cycle arrangements, performance, and combustion and emission characteristics. The low Btu gas/combined cycle plant is shown to be a power generation method that can efficiently provide clean electrical energy from coal and high sulfur heavy oils on a commercial basis by the late 1970's. This approach appears competitive with alternate methods of power for both base-load and mid-range generation.

65.
Anonymous
Coal: Gasification
Mosaic: 5 (2), 29-30 (Sept. 1974)

A fast fluidized bed process for coal gasification is described in which particles in the gas are separated in a cyclone separator and returned to the reactor. By using high temperatures in the production of tars and other undesirable products is minimized. Also, the amount of steam required is reduced and it is converted almost entirely to hydrogen and carbon monoxide. With a combined cycle power plant and advanced turbine design, a conversion efficiency of 50 percent is expected. Alternatively methane and other hydrocarbons could be produced. Air pollution would be minimized: sulfur and fly ash would be converted to hydrogen sulfide and scavenged in a calcined dolomite filter. Sulfur would be recovered.

66.
Armstrong, C. H. (R. W. Beck and Assoc.)
Effect of Recent Advancements in Gas Turbine Technology on Combined-Cycle Efficiency
ASME Paper No. 74-PWR-8, 1974; 5 pp

The efficiency of gas turbine generators has been constantly improving over the past few years, and these changes have also resulted in lower heat rates for combined-cycle power plants. This paper outlines the history of recent improvements, attempts to project the current trends to future efficiency levels, and shows how such projections can be used to help plant utility generation expansion programs. 8 refs.

67.
Berman, P. A. (Westinghouse Electric Corp.)
Construction And Initial Operation of A PACE Combined Cycle Power Plant
ASME Paper No. 74-GT-109, 1974; 9 pp

Describes the construction and initial operation to a 260-MW combined cycle power generating plant consisting of two gas turbines, each with its own heat recovery steam generator. The steam, which is generated at 1200 to 950 deg in each of the boilers, is combined to feed a single cylinder axial exhaust steam turbine. The paper describes the major components and operating cycle, the control system and some of the initial startup problems. 5 refs.

68.
Bloom, Ralph, Jr. and Eddinger, R. Tracy (COGAS Development Co.)
Status of the COGAS Process
Proc. 6th Synthetic Pipeline Gas Symposium, Chicago, Ill., Oct. 28-30, 1974; pp 53-70

69.
Buchet, Eugene (Univ. de Liege, Belgium)
Energetic Analysis of Steam and Gas type Thermal and Nuclear Power Stations
Rev. Gen. Therm. 13 (152-153), 623-636 (Aug.-Sept. 1974) (French)

Evidencing the various classes of losses and the work carried out, the author studies the energy balances of various cycles i.e.: theoretical steam cycles (Rankine's re-superheating or bleeding cycle or a combination of both) actual cycles, theoretical gas cycles (single, recovery type), actual cycles, then oombined gas-steam cycles. He establishes an equivalence between the various theoretical cycles and a Carnot's cycle (definition of an average integrated temperature). In the final section, the author calculates the thermal efficiencies of the various alternatives of the steam cycles used in nuclear power stations (gas cooled reactor, pressurized water reactor, boiling reactor). 5 refs.

70.
Crouch, W. B., Schlinger, W. G., Klapatch, R. D. and Vitti, G. E. (Texaco Inc.)
Recent Experimental Results on Gasification Combustion of Low Btu Gas for Gas Turbines
Combustion 45 (10), 32-35 (April 1974)

A proposed system is presented for low pollution power generation by means of a combined cycle gas turbine system using low Btu fuel gas produced from high sulfur residual oil and solid fuel. Experimental results and conclusions are presented from a cooperative research program involving Texaco, Inc. and Turbo Power and Marine Systems, Inc. whereby high sulfur crude oil residue was partially oxidized with air to produce a 100 to 150 Btu/scf sulfur-free fuel gas for use in a turbine combustor. An FT4 gas turbine combustion chamber test demonstrated that low Btu gas can be efficiently burned with a large reduction in NOx emissions. Gas turbine modifications required to burn low Btu gas are described and projected NOx emission compared to No. 2 fuel oil and natural gas are shown for an FT4 gas turbine. Integration of the gas turbine combined cycle system to a low Btu gasification process is described. The system provides an efficient method of generating electrical power from high sulfur liquid fuels while minimizing emission of air and water pollutants. Presented by the Gas Turbine Division of ASME at the Gas Turbine Conference and Products Show, Zurich, Switzerland Mar 30-Apr 4, 1974 as Paper No. 74-GT-11.

71.
Elgin, D. C. and Perks, H. R. (Scottish Gas Board)
Results of Trials of American Coals in Lurgi Pressure Gasification Plant at Westfield, Scotland
Proc. 6th Synthetic Pipeline Gas Symposium, Chicago, Ill., Oct. 28-30, 1974; pp 249-268

72.
Finger, H. B. (General Electric Co.)
Benefits and Cost of Higher Power Plant Efficiency
Power Eng. 78 (11), 42-45 (1974)

Efficiency can be boosted by going to supercritical pressure and can be improved further with topping cycles and combined cycles. Topping methods described include the mercury-steam cycle, gas turbine-steam turbine combined cycle, alkali metal topping cycle and the magnetohydrodynamics cycle. The gas turbine seems to be a major factor in these topping cycles because of its inherent ability to handle high temperatures with minimum materials problems and because of long experience with it.

73.
Finger, H. B. (General Electric Co.)
Electric Power Plant Efficiency
Proc. Symp. on Energy Prod. and Therm. Efficiency, Oak Brook, Ill., Sept. 10-11, 1973; Publ. Ann Arbor Sci. Publ., Inc., Mich., 1974; pp 130-138

Progress in improving thermal power plant efficiency is discussed. Emphasis is on increased electric power cycle conditions and the gains in efficiency that may still be achievable in steam plants. Effects on reliability indicate the penalties and problems of introducing technological advances too rapidly, the potential or hoped for performance of several advanced power plants are described and compared to the performance of more conventional plants. Data are presented in graphical form.

74.
Grabowski, H. A. (Combustion Engineering, Inc.)
Conservation of Energy Resources and the Optimization of Fossil Fuel Systems
ASME Paper No. 74-WA/Pwr-13,1974; 8 pp

Efficiency of fuel utilization can be realized through the use of fast start-up, two-shift boiler operation and the combined cycles applications. Development of mining technology and the transportation of coal is imperative to the programs for achieving fuel-independent status. Development of clean fuels from coal must be accelerated for immediate use and for the long-range development of new energy processes. Utilization of solid waste with coal offers an attractive energy conservation program. 14 refs.

75.
Grainger, L.
Future Trends in Utilisation of Coal Energy Conversion
Energy Dig. 3 (1), 2-6 (Feb. 1974)

Fluidized combustion for coal energy conversion offers advantages of high heat release rates, high heat transfer rates and thus reduced equipment costs as compared with conventional systems. Coals of high and variable ash content can be used and therefore the amount of energy wasted in a conventional system requiring coal preparation can be reduced. In cycles involving gas turbines for conversion, the coal is first reacted with air and steam to produce a low-Btu gas from which sulfur can be removed after cooling, by conventional techniques. The clean fuel gas is then burnt in a cycle involving gas turbines and steam turbines. Cost reduction and an increased proportion of fuel for conversion to electricity, depend upon industrial gas turbines which can operate at high temperatures. At present this is about 850°C, but is expected to be increased.

76.
Hahn, R. L. and Patterson, R. C.
Low-Btu Gasification of Coal. Phase 1 - An Evaluation for Electric Power Generation
IEEE, ASME, ASCE Joint Power Generation Conf., Miami Beach, Florida, September 1974; pp

77.
Hedley, W. H. and Foley, G. (Monsanto Research Corp.), Editors
Effect of Gas Turbine Efficiency and Fuel Cost on Cost of Producing Electric Power
Proc. Symp. on Energy and the Environment, College Corner, Ohio, Nov. 13, 1974; pp

The relationship between gas turbine efficiencies and fuel costs ranging between 40 and 100 cents per million Btu on the cost of power in mils per kilowatt hour is discussed for power production in a combined cycle gas-turbine system. Improvements in gas turbine efficiency from the present 29% to 37% are envisioned over the next 9 years, which would result in combined cycle efficiencies from 42 to to 54%. Those improvements would reduce power costs (neglecting inflation) from 8 to 6.5 mils per kilowatt hour for 40 cents per million Btu fuel and from 13 to 10.5 mils for 100 cents per million Btu fuel. Power costs are considerably more sensitive to fuel prices than to gas turbine efficiencies, although increasing efficiencies will have a beneficial effect on both costs and quantity of power produced. The research needs in the gas turbine technology are also discussed. The research improvements envisioned which would improve the efficiency of the gas turbine are primarily those which will increase the temperature at which the gas turbines can operate. It is predicted that with adequate funding the R and D effort could be expected to increase the turbine inlet temperature by from 60 to 90°F per year up to 2600°F by 1982, which is enough to increase gas turbine efficiency at the rate of almost 1% per year. R and D will also be required to develop dry control technology for NO/sub x/control so that high inlet temperatures can be utilized without excessive emissions.

Also available -- U. S. Gov't, NTIS, CONF 741179, 1975
or Earley, D. E., Editor, In Energy and the Environment, AIChE, N.Y., 1975; pp 21-23

78.
Hoover, D. Q. (Westinghouse Electric Corp.)
Cost of Inefficiency in the Generation of Electricity
Proc. Symp on Cost of Inefficiency in Fluid Mach. ASME Winter Ann. Meet, New York, NY, Nov. 17-21, 1974, ASME, New York, N. Y., 1975; pp 13-17

In summary: past improvements in power generation efficiency were largely a result of higher steam temperatures; due to material limits and the properties of steam, steam temperatures of fossil units are not likely to increase significantly; due to reactor temperature limits, a similar situation exists in light water reactors; pollution controls will result in decreased efficiency for existing and new plants of conventional design; and, the gas turbine-steam turbine combined cycle offers the most promise for economically increasing power generation efficiency. 2 refs.

79.
Johnson, R. H. and Wilkes, Colin (General Electric Co.)
Environmental Performance of Industrial Gas Turbines
ASME Paper No. 74-GT-23, 1974; 8 pp

At this point in time, everyone is "for the environment" and this is true the world over because the atmosphere is shared by peoples of all nations. Air pollution from hydrocarbon fuel combustion, both worldwide and local, is discussed by reviewing known measurements of contaminants. Application of gas turbines by industry is one way to provide power needs for attaining and maintaining an industrial society. Environmental performance of industrial gas turbines with respect to exhaust emissions and environmental impact is presented for oxides of nitrogen, hydrocarbons, carbon monoxide, particulate matter and visible smoke. Results of recent abatement efforts are also presented together with estimates of potential improvements to show the place of the industrial combustion turbine in a world with growing concern for environmental improvement.

80.
Kamody, John F. and Farnsworth, J. Frank (Koppers Co.)
Gas From the Koppers-Totzek Process for Steam and Power Generation
Ind. Fuel Conf, Purdue Unv., West Lafayette, Indiana, Oct 2-3 1974; 51 p

This paper concentrates on the use of the K-T process for fuel gas production, particularly in regard to steam production. Discussion also includes the use of the gas in combustion gas turbines for power generation. Gas obtained by this process may be also used as fuel in the steel, paper, wood and glass industries as well as synthesis feed gas for various products, such as ammonia, hydrogen, methanol and other chemicals.

81.
Klapatch, R. D. and Vitti, G. E. (Turbo Power & Marine Systems, Inc.)
Gas Turbine Combustor Test Results and Combined Cycle System
Combustion 45 (10) 35-38 (April 1974)

This combustor rig test has demonstrated that low Btu gas can be burned efficiently in a gas turbine. NOx exhaust emissions will be substantially reduced and Co emissions should be equivalent to natural gas firing. An increased capacity fuel induction system, modified combustion chambers, and high compressor air bleeds will be required to operate an industrial gas turbine on low Btu gas. The integrated combined cycle/gasification system can provide the desired flexibility to burn high sulfur oils, coal and/or coke while maintaining acceptable exhaust emission levels. The final step will be the integration of these results into a full engine-gasification system for evaluation in a prototype commercial application. 7 refs.

82.
Klinksiek, David T. and Hsieh, B. C. B. (Gilbert Assoc., Inc.)
Advanced-Cycle Power via Coal Gasification
Proc. Amer. Power Conf. 36, 580-586 (1974)

83.
Koch, H. (BST Brown Boveri-Sulzer Turbomachinery Ltd.)
Investigations and Measures for the Reduction of Gas Turbine Emissions
Sulzer Technical Review (2), 61-67 (1974)

This paper describes two types of combustor for which NO_x and smoke characteristics are presented in terms of lb $NO_x/10^6$ Btu and smoke spot number versus percentage load. The tests were carried out on full scale experimental combustors burning distillate No. 2-GT. Further tests results show NO_x reductions achieved by water and steam injection.

84.
Kovacik, J. M. (General Electric Co.)
Which Energy Systems for Coal-Gasification Plants?
Oil Gas Journal 72 (50), 50-52 (Dec. 16, 1974)

In commercial plants, to produce a pipeline-quality gas from coal heavy-duty turbines, using both gas and steam, can supply the needed energy.

85.
Loeding, J. W. and Patel, J. G. (Institute of Gas Technology)
Coal Gasification As a Source of Power
ASME, 103rd Annual Meeting, Dallas, Texas, Feb. 24-28, 1974; Paper, 15 pp

86.
McCallister, R. A. and Ashley, G. C. (Foster Wheeler Energy Corporation and No. States Power Co.)
Coal Gasification to Produce Low-Btu Fuel for Combined-Cycle Power Generation
Proc. Amer. Power Conf. 36, 292-299 (1974)

87.
Osterle, Fletcher (Carnegie-Mellon Univ.)
Thermodynamic Considerations in the Use of Gasified Coal As A Fuel For Power Conversion Systems
Proc. 7th Annual Frontiers of Power Techn. Conf., Oklahoma State Univ., Stillwater, Okla., Oct 9-10, 1974; Paper No. 14, 8 pp

The gasification process is characterized by the temperature of the power gas leaving the gasifier. At the high end of this temperature range the air flow dominates the steam flow and the combustible power gas is essentially carbon monoxide, whereas at the low end the steam flow dominates the air flow and the combustible power gas is essentially methane. The hydrogen content of the gas is zero at the high temperature end of the scale, rises to a maximum as the temperature is lowered, and drops off again to near zero at the low temperature end. At the high temperatures heat is wasted in the scrubber-cooler and at the low temperatures more heat is required by the gasifier steam generator than is available from the scrubber-cooler. At the low temperatures problems with catalysis are encountered and large water demands are made unless the water condensed out in the scrubber-cooler is reclaimed by evaporation. The gasifier effectiveness is higher at the low temperatures than at the high temperatures.

88.
Patterson, R. Dean (Turbo Power and Marine Systems, Inc.)
Gasification Power Generation System
Proc. Amer. Power Conf. 36, 284-291 (1974)

89.
Perry, M.
The Gasification of Coal
Scientific American 230 (3), 19-25 (1974)

90.
Purh-Westerheide, H. (STEAG)
Kraftwerke Mit Kohledruckvergasung (Power Plants with a Pressurized Gasification of Coal)
VGB Kraftswerkstechnik 54 (8) 532-536 (Aug 1974)

Reasons for development of power plants that use a pressurized coal gasification are outlined. Paper describes the experiences acquired during operation of the 170-MW prototype plant in Luenen, W. Germany. Projected design of a plant with an installed capacity of 800 MW is described.

91.
Schiefer, R. B. and Sullivan, D. A. (General Electric Co.)
Low Btu Fuels for Gas Turbines
ASME Paper No. 74-GT-21, 1974; 9 pp or Gas Turbine Conf. & Product Show, Zurich, Switzerland, March 30-April 1, 1974; 9 pp

The current shortage of conventional gas turbine fuels has created the need for new sources of "clean" fuel. One of the most promising new fuels is low Btu gaseous fuel, such as produced by air injected coal or oil gasifiers or other chemical processes. The various sources of low Btu fuels and their combustion characteristics are discussed. To burn many of the low Btu fuels in the 100-300 Btu/scf range necessitates certain design modifications to the gas turbine originally optimized for high energy fuels. The extent of the modification depends greatly on the low Btu fuel. The impact of low Btu fuels on the gas turbine thermodynamic cycle performance and environmental performance is very encouraging. From the environmental viewpoint, low Btu fuels promise to be "clean" fuels while providing increased output at higher thermal cycle efficiencies than achieved with conventional fuels.

92.
Wilson, W. B and Hefner, W. J. (General Electric Co.)
Economic Selection of Plant Cycles and Fuels for Gas Turbines
ASME Paper No. 74-GT-84, 1974; 13 pp
Combustion 45 (10), 7-16 (April 1974)

Performance characteristics of gas turbines, gas turbine exhaust heat boilers and combined gas-steam turbine cycles, plus the typical heat balance diagrams included in this paper will help the reader visualize economic applications for turbine in different industrial plants. The effect different fuels have on gas turbine maintenance (costs and downtime) and other application parameters are included. The information provided will permit the user to assess his own situation and then select the most economic fuel for a specific gas turbine application

93.
Ahner, D. J. and Boothe, W. A. (General Electric Co.)
Process Systems for Conversion of Difficult Fuels to Synthetic Fuels for Baseload Gas Turbines
ASME Paper No. 75-GT-73, 1975; 8 pp

Rapid changes in the fuel availability and cost picture, coupled with environmental concerns emphasize the need to consider new concepts for power generation by industrial plants and electrical utilities. A number of processes are now being developed to produce clean gaseous and liquid fuels from coal and low-grade petroleum products which offer potential for use in gas turbine-based power generating systems. This paper reviews several of the processes and considers the economic and environmental factors affecting their application to power generation systems.

94.
Ahner, D. J., Sheldon, R. C. and Garrity, J. J. (General Electric Co.)
and Kasper, Stanley (Dravo Corp.)
Economics of Power Generation from Coal Gasification for Combined-Cycle Power Plants
Proc. Amer. Power Conf. 37, 338-351 (1975) or Combustion 47 (10), 26-35 (April 1976)

95.
Alich, John A. Jr., Dickenson, Ronald L., and Korens, Nick (Stanford Res. Inst.)
Suitability of Low-Btu Gas/Combined-Cycle Electric Power Generation for Intermediate Load Service
Combustion 46 (10), 8-16 (April 1975)
Also preprint from AIChE, 67th Annual Meeting, Dec. 1974

This paper deals with the generalized concept of coal and oil gasification for electric power production. The requirements of intermediate load service are discussed. The suitability of gasification components and systems for this type service are summarized. The economics of low-Btu gas/combined-cycle power generation for intermediate load service are compared with alternatives. 17 refs.

96.
Anonymous
Major Research Project to Turn Coal into Gas
IEEE Spectrum 12 (3), 14 (March 1975)

A major research project to turn coal into gas for use in producing electricity will be conducted at Northern States Power Company's Lawerence power plant near Sioux Falls, S. D. The pilot installation will use a coal gasifier to produce a gas with a heat value roughly one sixth that of pipeline natural gas. The gas will be burned in the Lawrence plant's existing boilers to produce electricity. Later, in a so-called combined-cycle process, the gas will be used to fuel a gas turbine to produce electricity and the hot exhaust from the gas turbine will be used to make steam for a conventional steam turbine to generate additional electricity. Net generating capacity of the pilot plant, after the combined cycle has been added, should be about 36 megawatts. Total cost of the project is estimated at $80 to $90 million and initial operation is set for 1979. The project is a joint venture of Northern States Power, the U. S. Office of Coal Research, and Foster Wheeler Energy Corp.

97.
Anonymous
Total Energy Systems and the Gas Turbine Combined Cycle
Electr. Consult. 91 (3), 24 (1975)

One result of soaring fuel prices and the demand for conservation is renewed interest in the gas turbine combined cycle, which joins a gas turbine and a steam turbine, harnessing the power from each. Combined cycles have proven to be practical in the large horsepower (40,000-horse-power range) gas turbines, however, a study is being made of a combined cycle in which a smaller horsepower gas turbine would be coupled with a boiler, condenser, feedwater pump, valving and a steam turbine for a power plant suitable for driving equipment including gas compressors, electrical generators and pumps.

98.
Archer, D. H., Berg, D., and Somers, E. V. (Westinghouse Research Labs)
Fluidized Bed Gasification and Combustion for Power Generation
Trans, Pap. & Discuss., 9th World Energy Conf., Detroit, Mich., Sept. 23-27, 1974; Vol. 5, pp 288-313, 1975

Power plants of advanced design utilizing fluidized bed gasification or combustion of fossil fuels at elevated pressure have the potential to meet SO_2, NO_x, and particulate emission abatement goals at reduced capital costs and increased operating efficiencies. Data indicate that SO_2 reductions of 95%, NO_x reductions of 80-90%, and particulate reductions greater than 99% can be achieved. Projected capital costs are 25% less and power costs 10% less than conventional steam power plants equipped with stack gas scrubbing systems. Overall fluidized bed fuel processing--combined cycle power generating systems which have the potential for achieving these environmental and economic goals can be commercially available before the end of this decade. Equations, diagrams, and tables represent data. 22 refs.

99.
Archer, D. H., Keairns, D. L., and Vidt, E. J.(Westinghouse Research Labs)
Development of a Fluidized Bed Coal Gasification Process for Electric Power Generation
Energy Commun. 1 (12), 115-134 (1975)

A fluidized bed coal gasification process for power generation has been devised. It uses air and steam for gasification and limestone or dolomite for desulfurization. A comprehensive program to demonstrate the process on a commercial scale is underway. A 1200 lb/hr fluidized bed gasification process development plant is being built and preliminary design work on a 50 ton/hr demonstration plant has been initiated. A broad support program is providing data and analyses on the fluidized bed fuel processing system, the sulfur removal system, the particulate removal equipment, the gas turbine and the integrated power generation system. 8 refs.

100.
Ban, Thomas E. (McDowell Wellman Eng.Co.)
Conversion of Solid Fuels to Low-Btu Gas
Energy Sources 2 (1), 11-31 (1975)

Improvement of producer performance could allow gas producers to have strong growth potential in modern economies. Two aspect which deserve attention from research and engineering are (1) capability of utilizing lowest cost coals and (2) capability of enlarging producer gasification capacities. Promising developments involve systems for integrating traveling-grate processes for pretreating and partially gasifying coal prior to subsequent gasification with new enlarged designs of gas producers. Specifically, these would concern a continuous process for conversion of coal to a pelletized and precoked structure for gas production by traveling grates or shaft furnaces of the dry ash or slagging ash species. The purpose of research in this area is to broaden the applications for gas producers to accept a wide variety of low cost fuels and to utilize some of the new processing developments recently perfected in the ferrous metallurgical fields. 10 refs.

101.
Boehman, L. I. and Davison, J. E. (Univ. of Dayton, Ohio)
Performance of a Rich Combustion Refractory Metal Combined Cycle Power Plant.
Proc. 3rd Nat'l Conf. Energy and Environ., Hueston Woods, Ohio, Sept. 29-Oct. 1, 1975; pp 57-63.

A new concept in gas turbine engines is presented in which multiple stages of combustion and refractory metal alloys are used to obtain high turbine inlet temperatures. The oxidizing environment present in conventional engine combustors and turbines is eliminated by utilizing fuel-rich combustion for the first combustor, thus providing a reducing environment for the refractory metal alloy turbine blades. The products of combustion from the first stage of combustion are subsequently burned in a second combustor which can be part of a conventional gas turbine engine or a steam power plant furnace. The results of a feasibility study of the concept are presented. Overall system thermal efficiencies in excess of 50% are shown to be attainable with molybdenum alloys available today.

102.
Foster-Pegg, R. W., Jaeger, H. L. and Leigh, D. C. (Westinghouse Electric Corp.)
Electric Power from Low-Btu Gas in Combined-Cycle Power Plants.
2nd Annual Symp. on Coal Gasification, Liquefaction, and Utilization, Univ. of Pittsburgh, August 5-7, 1975; 66 pp

103.
Fraley, Lowell D. and Kumar, Chintapalli A. (M. W. Kellogg Co.)
Application of Molten Salt Gasification to Combined Cycles.
2nd Symp. Clean Fuels from Coal, I.I.T., Chicago, Ill., June 23-27, 1975; Publ. IGT, Chicago, Ill., 1975; pp 397-410.

The Kellogg Molten Salt process which converts high sulfur coal to clean fuel gas with a heating value of 100 to 150 Btu/SCF with air as a gasification medium is described. When the process, now under development, is integrated with a present day combined power cycle (gas turbine-steam), it could result in a power plant with a heat rate of 8500 to 9500 Btu/kw-hr. Economics and future prospects of the Kellogg gasifier with combined cycle are also examined. 5 refs.

104.
Giramonti, Albert J. and Lessard, Robert D. (United Technologies Research Center)
Advanced Electric Power Systems.
Appl. Energy 1 (4), (Oct. 1975) pp 293-325

Four basic energy sources have been identified for prospective future American utility applications; namely, coal, nuclear, solar and geothermal. Each source must generally be subjected to extensive preprocessing before thermal energy can be delivered in a form useful to an electric power conversion system. Numerous candidate advanced energy conversion systems can be matched to the various energy sources, including steam, open cycle gas turbines, combined cycles, closed cycle gas turbines, MHD, fuel cells, liquid metaltopping, supercritical carbon dioxide topping, and others. Each has advantages and disadvantages which can be ranked and weighted numerically, based on our present knowledge. A tentative selection of promising combinations of energy sources and conversion systems has been made to focus attention on those which satisfy the socio-political requirements and also offer potential profit opportunities for suppliers to the electric utility industry.

105.
Hung, W. S. Y. (Westinghouse Electric Corp.)
Modeling and Measurement of NOx Emissions From Burning Synthetic Coal Gas in Gas Turbine Combustors
ASME Paper No. 75WA/GT-3, 1975; 10 pp

Westinghouse Electric Corp. has developed a diffusion-limited model to simulate the thermal NO_x emission processes in various gas turbine combustors burning synthetic gas made from coal. The model - an extension of one used for fuels containing negligible amounts of fuel-bound nitrogen - predicted NO_x emissions that agree with laboratory data for low-heating-value (100-300 Btu/SCF) gaseous fuels. The analysis has shown that the heating value of a fuel is not necessarily an indicator of its NO_x emissions. The peak temperature resulting from the combustion of the fuel is the primary parameter that determines the NO_x emission level. There are fuels in the 200-300 Btu/SCF range that will burn and generate significant NO_x emissions.

106.
Kumar, C. A., Fraley, L. D., Handman, S. E. (M. W. Kellogg Co.)
Combined power cycle using low Btu gas produced from the Kellogg molten salt coal gasification process
Am. Chem. Soc., Div. Fuel Chem. Preprints 20 (4), 260-269 (1975)

In the recent past, more and more attention has been given to the production of low Btu fuel gas for utilization in a nearby power plant. Even though conventional coal-fired steam cycle power plants are capable of achieving a net heat rate as low as 8600 Btu/kW-hr, most plants operate in the 9100-10000 Btu/kW-hr. Compliance with environmental requirements on stack emissions, however, generally result in heat rates in excess of 10,000 Btu/kW-hr. Thus, there is considerable incentive to go to an alternate source of clean fuel. By incorporating minor changes in the existing combustion chambers, the gas turbine can be operated efficiently on low Btu fuel gas. Integration of the M. W. Kellogg Molten Salt Coal Gasification Process with the gas turbine-steam turbine combined power cycle system provides for an efficient method of generating electrical power from high sulfur coal while minimizing environmental pollution. The Kellogg Molten Salt Process converts the heating value of high-sulfur coal to fuel gas with a lower heating value of 100 to 150 Btu/SCF at a conversion efficiency of around 90 percent, with over 90 percent of sulfur retained by the melt. The fuel gas thus produced is cooled and scrubbed clean of contaminants in equipment integrated with the power generation and melt clean up and recycle systems. This fuel gas when used in conjunction with combined power cycle, using existing equipment, is estimated to generate power at a heat rate of around 9500 to 8500 Btu/net kW-hr depending on the ash content of the coal.

Also available--U. S. Gov't, NTIS, CONF-750806-P2

107.
Kydd, P. H. (General Electric Co.)
Integrated Gasification Gas Turbine
Chem. Eng. Progr. 71 (10), 62-68 (1975) or AIChE, 67th Annual Meeting, Wash., D.C., December 1974; Paper 58d, 31 pp

A simple method of computing the performance of integrated low-Btu gas/gas turbine power plants has been developed. The method has been applied to determine the sensitivity of plant performance to a number of design features and gasifier operating characteristics.

108.
Kydd, P. H. and Day, W. H. (General Electric Co.)
An Ultra High Temperature Turbine for Maximum Performance and Fuels Flexibility
ASME Paper No. 75-GT-81, 1975; 9 pp
Also presented at the Gas Turbine Conf. and Products Show, Texas, Mar. 2-6, 1975

The problems in water-cooled rotors have centered around the high pressures generated in a closed circuit containing water by the high centrifugal field. The present program focusses on open circuit water cooling in which the water has been allowed to exit freely from the bucket tips. This eliminates the leaks and plugging of cooling channels that have been encountered before permits one to distribute the coolant uniformly around the bucket airfoil contour close to the surface. In this way, the thermal gradients and thermal stresses on the airfoil can be held within safe limits. Using this approach a 9.7 in. (24.7 cm) diameter turbine wheel has been built and operated at inlet conditions of 2850 F (1560 C) and 16 atmosphere with tip speeds in excess of 1700 fps (518 m/sec) and with good aerodynamic efficiency. Recent developments in ceramic materials also indicate potntial for use in stationary parts.

109.
Laurendeau, Normand M. (Purdue Univ.)
Theoretical and Practical Concepts Governing Production of Power Gas From Coal
Appl. Energy 1 (14), 293-325 (Oct. 1975)

A survey of current techniques in coal gasification methods is given. The production of power gas is of special interest to the electric power industry, since clean gaseous fuel is mandatory for high temperature operation in both MHD and combined cycle power plants. Acceptable gasification processes should maximize the total heating value (chemical plus sensible) of the power gas, yet minimize major pollutants. Gasification is preferred to liquefaction because increasing prices of both natural gas and electricity warrant the development of a synthetic product, and gaseous fuels alleviate NO_x production. Sulfur may be removed by known absorption or catalytic techniques. 36 refs.

110.
Loeding, J. W. and Patel, J. G. (Institute of Gas Technology)
Coal Gasification Review
Proc. Joint Power Conf., Portland, Oregon, Sept. 28, 1975; 22 pp

At present coal gasification appears to be an attractive means of producing an alternative, nonpolluting source of energy. Once this conclusion is accepted, there are several options which need to be considered. Low Btu gas will be chosen for local and power uses, while high Btu gas will be necessary for pipeling distribution (to minimize distribution costs and use the existing nationwide system). In making either of these gases there exist several options. Many gasification processes are being developed and nine are described briefly, with flowsheets. The particular gasification process chosen will be dictated by the specific need at the time of selection, considering the user's assessment of the technological development of the various process options. Economics, the assumed feedstock, and desired operating options will be weighed heavily. Combined-cycle gas turbine-steam turbine power generation probably holds the greatest potential for the use of low-Btu gasification processes. It promises both capital saving and higher efficiencies than conventional coal-fired steam cycles. Many studies have been concerned with combining conventional steam-and gas-turbine power cycles into systems that yield a greater overall efficiency than the individual steam-or gas-turbine systems.

Also available--U. S. Gov't, NTIS, CONF-7509173-2, 1975

111.
Mitchell, R. W. Stuart (Delf Univ. of Technol, Neth)
Combined Gas/Steam Turbine Total Energy Cycle
Diesel Eng. Users Assoc. Publ. (369), 19 pp (July 1975)

The gas turbine and the steam turbine can be combined to offer attractive power generation cycles, with or without the additonal provision of low pressure process steam. The study was designed to develop some general guidelines for selecting by more analytical means one or two systems likely to provide the highest return on investment and thus worthy of detailed study. 10 refs.

112.
Montgomery, W. O. and Lemezis, S. (Public Serv. Indiana, Plainfield)
Advanced Coal Gasification System for Electric Power Generation
ASME Paper No. 75-Pwr-6, 1975; 5 pp

Continuing a availability of improved generation technology has assisted the utility industry in achieving its past record of holding the rate of increase in customer charges below that experienced by the economy in general. Now that nuclear fission and coal are seen to be the principal primary energy sources in the future, there is need for further improvement in the technology of generating electric power from coal. Application of combined cycles to this purpose awaits development of systems to convert coal into economically acceptable gas turbine fuels. A Government-Industry partnership is now actively developing a multiple-fluidized-bed gasification system to this end. A Process Development Unit described is now starting on a test program aimed at verifying the proposed system and obtaining design data to allow scale-up to practical commercial ratings.

113.
Muehlhaeuser, H., and Eckert, W.
Steam Turbines in Power Stations for Peak and Medium Load
Brown Boveri Rev. 62 (7-8) 285-308, 1975

Electric power systems today have a rapidly increasing need for peak and medium-load generating capacity. It is necessary to know to what extent power stations other than the traditional kinds are suitable for covering loads of this nature. All power stations which use the steam turbine for energy conversion are examined in terms of their operational and economic suitability. Both pure steam stations and also combined steam-gas plant are considered, from the simplest to the most sophisticated. 11 refs.

114.
Papamarcos, J.
Industrial Power Plant: New Options and Problems
Power Eng. 79, 40-47 (1975)

The case for buying power or on-site generation is discussed under the headings: 1. what has changed; 2. prospects for on-site generation; 3. basic considerations; 4. steam cycles; 5. flexibility at lowest price; 6. stack desulfurization; 7. waste fuels; 8. gas turbines and combined cycles; 9. integrated systems; 10. organic cycles.

115.
Pfenninger, H.
Coal as fuel for steam and gas turbines
Brown Boveri Review, 62, 456-465 (1975)

116.
Pillsbury, P. W., Cleary, E. N. G., Singh, P. P., and Chamberlain, R. M.
(Westinghouse Electric Corp.)
Emission Results from Coal Gas Burning in Gas Turbine Combustors
ASME Paper No. 75-GT-44, 1975; 9 pp
J. Eng. Power 98, 88-96 (Jan. 1976)

As part of a continuing experimental development program supported by the U. S. Office of Coal Research, to prepare the gas turbine portion of an integrated gasification and power generation plant, emissions from scaled and full size coal gas combustors have been measured. Fuel used was a mixture of carbon monoxide, hydrogen, carbon dioxide, methane; and nitrogen, blended to match low heating value coal gas from an air-blown gasifier. The results of testing in a full scale, high pressure combustor rig are compared with the small scale work with respect to carbon monoxide and mitrogen oxides emissions, and the implications for design discussed. 5 refs.

117.
Rudolph, Paul F. H. and Bierbach, Herbert H. (Lurgi Mineraloeltechnik, Frankfurt AM, Germ.)
Fuel Gas From Coal
2nd Symp. Clean Fuels from Coal, I.I.T. Chicago, Ill., June 23-27, 1975; pp 85-99

In recent years, serious interest has been focusing on the production of SNG from coal and there is no doubt that this coal conversions route has to play an important role in order to supplement the dwindling resources of natural gas. However, if used as fuel for power stations or for industrial purposes, the substitute for natural gas need not necessarily be SNG but can also be a fuel gas of lower Btu level, with less stringent requirements as to the degree of purity. This paper gives some basic information about the manufacture and utilization of various types of fuel gases from coal. Advantages of the "Fuel Gas from Coal" routes include lower capital requirements and gas production costs, as well as higher efficiencies in the case of combined power cycles using low Btu gas as fuels.

118.
Shaw, Henry (Exxon Research & Engineering Co.)
The Effect of Water on Nitric Oxide Production in Gas Turbine Combustion
ASME Paper No. 75-GT-70, 1975; 9 pp

The NO_x emission index from the combustion of distillate type fuels is a function of the amount of water that is present in the primary zone. A simple analysis based on modified Zeldovich kinetics was used to predict the magnitude of the NO_x reduction due to water. All empirical and theoretical data that were evaluated fit the expression: % NO_x Reduction = $(1 - \exp(C_H H)$ 100, where $C_H = 22 \pm 8$ and H is the absolute humidity. This expression can be used to predict the quantity of water that is required to achieve a desired level of NO_x reduction. Emission data that are collected at varying ambient humidities can thus be corrected to a common reference level. Methanol combustion was used to illustrate a particular application of the semiempirical calculational technique. It was shown that the NO_x emissions from methanol combustion are equivalent to those obtained by adding 8.7 % water to the combustion air of a kerosine type fuel. The NO_x emissions from methanol combustion, on an equal space rate basis, are a factor of 4 lower than from kerosine type fuels. Corrections for ambient temperature and pressure are also required. Thus, in addition to the humidity correction, a technique for correcting NO_x measurements to commonly accepted reference ambient conditions of temperature and pressure is presented in this paper.

119.
Sheer, T. J. (Univ. of the Witwatersrand, Johannesburg, S. Afr.)
Electricity Generation by Combined Cycle Power Stations Incorporating Coal Gasification
S. Afr. Mech. Eng. 25 (11), 350-358 (1975)

With coal likely to remain South Africa's most important source of energy for the purpose of electricity generation for the foreseeable future, ESCOM is investigating the feasibility of more efficient coal-fired power stations. The most promising development in recent years is the combined-cycle power stations, incorporating gas turbines and steam turbines. The two main types of gas/steam-turbine cycles, namely exhaust-boiler cycles and pressurized-boiler cycles, are discussed and examples of prototype plants already in operation in other countries are described. The fuel requirement for these power stations will be clean fuel gas or oil, only the former of which is a practical proposition for South Africa. The production of clean fuel gas from coal is discussed. The biggest advantages associated with combined-cycle power stations incorporating coal gasification will be high thermal efficiencies, minimal air pollution and better recovery of coal from coal deposits. Overall capital costs appear to be comparable with those of conventional power stations. 20 refs.

120.
Stambler, I.
EPRI Gas Turbine Outlook
Gas Turbine World 5, 19-22 (Nov. 1975) or
Combustion 47 (10), 9-12 (April 1976)

The Electric Power Research Institute, Palo Alto, Calif., is funding gas-turbine research and development programs to improve current hardware performance while developing high-temperature technology for future applications in intermediate- and base-load power generation. An EPRI analysis of alternative power-plant designs shows that for future requirements, combined-cycle plants using liquid fuels or intermediate-Btu gas from 2-stage entrained gasifiers promise the lowest costs in intermediate-load service; only combined-cycle versions of advanced coal conversion processes appear competitive with low-sulfur coal and limestone slurry scrubbing. With the rising cost of fuel and other negative factors, large-scale improvements in turbine performance are needed to compensate for the inefficiencies of coal conversion. EPRI wants to raise turbine inlet temperatures to 2800°F with new hot-section technology using new cooling techniques. The water cooling system appears to be the most compatible with coal-derived fuels.

121.
Ahner, D. J., Schulz, R. P., Pier, J. B., and Gluckman, M. (General Electric Co.)
Integrated Low Btu Gasification, Combined Cycle Plant Interface and Power System Control Considerations
ASME Paper No. 76-JPGE/GT-3, 1976; 12 pp

This paper discusses the prospects for integrated low Btu gas/combined cycle power plants in utility type service. The major considerations involved in interfacing the fuels and power plant controls' systems, and methods of operation, are also described. The results of a preliminary power system response capability study are presented. This study utilized computer simulation techniques to model the integrated power plants and their interaction with other types of power generation prime movers on a typical power system grid.

122.
Aleman, D. J. and Smith, J. W. (Babcock & Wilcox Co.)
A Unique Approach to a Combined-Cycle Unit
Part II - Turbine Exhaust Gas Boiler
Proc. Amer. Power Conf. 38, 379-386 (1976)

Part I - see Piwetz, F. W.

123.
Allison, P. R. and Berman, P. A.
PACE 260 at Comanche, the First Two Years
ASME Paper No. 76-GT-109, 1976

124.
Anonymous
Fluid-Bed Technology Advances
Electr. World 186 (2), 39-41 (Dec. 15, 1976)

ERDA has awarded the Curtiss-Wright Corp. a $27.5-million contract to design, build, and operate a non-polluting 13 MW pilot electric generating plant which will fire high sulfur coal in a fluidized bed and will be capable of powering both steam and gas turbines for combined-cycle operation. The contract, process, site, protection of the turbine blades, and the long range goal of developing a design for a 500 MW commercial plant with a combined-cycle thermal efficiency of 40 percent are discussed.

125.
Botts, W. V., Kohl, A. L. and Trilling, C. A. (Atomics International Div.)
Low-Btu Gasification of Coal by Atomics International's Molten Salt Process
Proc. 11th Intersociety Energy Conversion Engng Conf., AIChE, New York, 1976; Vol. 1, pp 280-285

Research and development work conducted to date has demonstrated the basic feasibility of the Molten Salt Coal Gasification Process and indicated it to have a number of key technical advantages over other techniques for converting coal to clean gas. The design of a Process Development Unit (PDU) is well under way under ERDA sponsorship. The PDU program is aimed at demonstrating the performance of a complete integrated system and providing design data for process scale-up and evaluation. Engineering studies to evaluate the applicability of the process to power generation indicate the potential for high efficiency and good economics. The optimum power generation system appears to be a combined cycle involving gasification with air under pressure, combustion of the product gas in a gas turbine, and operation of a waste heat boiler system on the turbine exhaust gas.

Also available--U. S. Gov't, NTIS, CONF-760906-P1, 1976; 6 pp

126.
Crim, W. M. Jr. (Office of Coal Research)
ERDA and the Advanced Power Conversion Program
Mech. Eng. 98 (5), 24-25 (1976)

The mission of the U. S. Energy Research and Development Administration is to develop all energy sources, to make the nation basically self-sufficient in energy, and to protect public health and welfare and the environment. ERDA programs are divided into six major categories: conservation of energy; fossil energy; solar, geothermal, and advanced energy systems; environment and safety; nuclear energy; and national security. The goal of the Advanced Power Systems Program is to develop technology for the demonstration of clean, efficient, reliable, economically feasible methods of converting coal and coal-derived fuels to electrical energy in commercial-size central station power plants at the earliest practical date. Advanced Power Conversion technology programs have been developed in the following areas: (1) open-cycle high performance gas turbine/combined cycle; (2) closed power systems--closed-cycle gas turbine and alkali metal vapor turbine; and (3) advanced support technologies--system studies and evaluation; bearings, seals, rotors, etc.; materials, erosion, corrosion, fireside; instrumentation, controls.

127.
Fleming, D. K., Primack, H. S. (Institute of Gas Technology)
Purification Processes for Coal Gasification
AIChE, 81st Nat'l Meeting, Kansas City, Mo., April 11, 1976;
Paper No. 9c, 33 pp

Coal gasification is being developed to utilize the U. S. coal deposits to satisfy increasing energy requirements. Coal can be gasified to produce a high-Btu pipeline-quality gas; a low-Btu gas suitable for direct combustion or for use in combined-cycle power generation or a synthesis gas for use as a petrochemical-type feedstock. Consequently, more than a score of coal conversion processes are currently under development. In all of these processes, some undesirable components must be removed from the gas prior to end use. Because literally dozens of process are now available for impurity removal, the selection of the optimum purification system becomes a major task. A review of purification processes for gas streams generated in high-Btu coal gasification processes is presented. Special attention is directed to systems for sulfur removal and recovery from the raw product gas and for cleaning up Claus plant tail gas.

Also available--U. S. Gov't, NTIS, CONF-760402-8, 1976

128.
Foster-Pegg, R. W. and Jaeger, H. L. (Westinghouse Electric Corp.)
Low-Btu Gas Powering of Combined-Cycle Plants
Proc. Amer. Power Conf. 38, 362-74 (1976)

129.
Jeffs, E.
Coal-Fired Gas Turbine Pilot Project Gets Under Way
Energy Int. 13 (10), 34-37 (1976)

ERDA has awarded a contract to Curtiss-Wright Power Systems to design, construct, and operate a pilot plant comprising a gas turbine with a fluidized-bed combustor capable of burning high-sulfur coals. The 5-year program covers five phases and the project site is adjacent to Curtiss-Wright's gas turbine plant at Wood Ridge, N.J. The existing coal-fired steam generators were converted to gas about ten years ago. In establishing a basis for the design of a combustor, three options are available, but the one chosen is the split-flow direct cycle in which part of the air flow is diverted to a cooling circuit and the remainder is fed through the bed as combustion air. While this split-flow system is much better for the gas turbine than the adiabatic bed and more controllable than the steam-cooled bed, there are still limits on its performance imposed by the bed. The early experimental work is concerned with heat transfer, materials, and processes. For the long term, the aim of the pilot project is to lay the foundation for a series of commercial plants in the 300- to 500-MW size range in utility service. Since the largest gas turbines commercially available at the present time are at about 100 MW, this represents a significant development all round. But, possibly a start on a prototype plant could be made in as little as three years, with commercial service in the mid eighties.

130.
Krieb, K. H. (KDV-Dev, STEAG, Ger)
KDV Process (High Pressure Coal Gasification) For Power Generation
World Gas Conf., London, Engl, June 7-11, 1976; Vol. 1, Paper IGU/B3-76, 9 pp

A Plant with a rating of 170 MW has been constructed by STEAG at Luenen, (Westphalia, RFG) as a demonstration plant to acquire experience for the layout and design of a 400-MW plant. The 170-MW plant at Luenen consists of 5 LURGI pressure gasifiers, 2 supercharged boilers, one steam turbine of 96 MW and one gas turbine of 74 MW. The results of operational experience after 3500 hours are reported.

131.
Lisauskas, R. A. and Johnson, S. A. (Riley Stoker Corp.)
Coal Processing: NO_x Formation During Gas Combustion
Chem. Eng. Progr. 72 (8), 76-77 (1976)

From a paper presented at the 80th National Meeting of the Amer. Inst. of Chemical Engineers in Boston, Massachusetts, Sept. 7-10, 1975. Complete paper available as referenced in article, 43 pages.

Low Btu gas from a small, fixed-bed coal gasifier was burned in a refractory-lined test furnace. The formation of oxides of nitrogen (NO_x) is discussed with respect to heat input, fuel gas ammonia content, and flue gas oxygen concentrations.

132.
Meyer-Kahrweg, H. (STEAG, Essen)
Combined Gas/Steam Turbine Power Stations with Coal Pressure
Gasification Unit Operating to the STEAG-LURGI System
Proc. 55th Annual Convention of Gas Processors Association, GPA,
Tulsa, Oklahoma, 1976; 131-140 pp

Heat flow diagrams for several German gas/steam turbine power stations are presented. Also included are drawings of pressure gasifiers, gas turbines, and steam generators. A bibliography consisting of 21 references is included.

Also available--U. S. Gov't, NTIS, CONF-760358, 1976; pp 131-140

133.
Papamarcos, John
Combined Cycles and Refined Coal
Power Engineering 80, 34-42 (Dec. 1976)

134.
Piwetz, F. W. (Brown & Root, Inc.)
A Unique Approach to a Combined-Cycle Unit.
Part I - Overall Plant and Control System
Proc. Amer. Power Conf. 38, 375-379 (1976)
Part II - See Aleman, D. J. and Smith, J. W., 1976

135.
Rudolph, Paul F. H. (Lurgi Mineraloeltech, Frankfurt AM, Ger)
Art of Coal Gasification
Int. 4th/Eur. Symp on Chem.React.Eng., Heidelberg, Ger., Apr 6-8, 1976;
Vol. 2, pp 537-560

This survey considers commercially proven processes and those new concepts already developed far enough to be considered second generation candidates.

136.
Shah, R. P., Margaritis, P. J., Rath, L. K., Cherish, P. and Salvador, L. A.
(Westinghouse Research Labs.)
Operation of the Westinghouse Coal Gasification Process Development Unit
Proc. 11th Intersociety Energy Conversion Engineering Conference.,
AIChE, New York, 1976; Vol. 1, pp 294-299

The objective of the Westinghouse Coal Gasification Program is the development of an integrated process which gasifies caking, high-sulfur coals to low-Btu fuel gas which is combusted and expanded through a combined-cycle generating plant. The purpose of work performed as part of the pilot scale work of the PDU is to demonstrate the feasibility of the basic concepts comprising the gasification, devolatilization, desulfurization and waste removal processes, and to demonstrate the system performance and operability. The test results reported herein are evaluations of the devolatilizer reactor system using a variety of coal feedstocks under a range of operating conditions and are a demonstration of the basic feasibility and operability of the devolatizer system with its recirculating fluidized bed concept.

Also available--U. S. Gov't, NTIS, CONF-760906-P1, 1976; 10 pp

137.
Shorthose, N. L. (Rolls-Royce, Ltd.)
Designing Gas Turbines for the Industrial and Marine Field
Symp. on Gas Turbines--Status and Prospects, London, England, Feb. 4-5, 1976; Paper C3/76, pp 27-34

This article describes the design changes found to be necessary when an Aero engine is adapted for industrial and marine use. It shows how the new environments can affect the materials used, and the general behavior of the components. It describes how the configuration of some engines has to be rearranged to suit the new conditions. The design of the power turbine for these engines is discussed, and a mention is made of the trend in gas turbine size, combined cycles, and the combustion of other fuels.

138.
Somers, E. V., Berg, D. and Fickett, A. P. (Westinghouse Electric Corp.)
Advanced Energy Conversion
Annu. Rev. Energy 1, 345-368 (1976)

Advanced energy conversion techniques with potential for coal and nuclear fuel usage, for implementing high thermal efficiency, anf for resource/environmental conformance are reviewed. These include open combined-cycle gas turbine power plants, closed-cycle gas-turbine power plants, magnetohydrodynamic power plants, potassium-steam binary-cycle power plants, low-temperature closed-cycle power plants, and fuel cell power plants. 197 refs.

139.
Unseld, H. and Grothe, F. K. (Chem.Werke Huels, Marl, Ger)
Firing Problems with Combined Gas Turbine/Steam Turbine Units--Changeover of Gas Turbines to Primary Air Operation
VGB Kraftswerkstech. 56 (11), 693-700 (1976)

In the last few years a large number of power plant units have been designed in which a gas turbine serves as an air supply unit for the boiler firing. Some of these plants are already in operation, so that experience is available from different sources. All the combined cycle plants which have been manufactured are equipped with forced draft fans as reserve units. The most undesirable fault is a trip-out of the gas turbine at high load. In order to cope with this fault without interrupting the firing operation of the steam generator, fully automatic changeover from gas turbine operation to primary air operation is necessary. The realization of such a program on both combined cycle units at Heuls Chemical Works Ltd is described. 6 refs.

140.
Wen, C. Y., Bailie, R. C., Lin, C. Y. and O'Brien, W. S. (West Virginia Univ., Morgantown)
Production of Low Btu Gas Involving Coal Pyrolysis and Gasification
Am. Chem. Soc. Div. Fuel Chem. Prepr. 18 (1), 36-55 (1976)

One method of reducing or eliminating the sulfur pollution from coal-fed steam production and electrical power generation plants is to convert the coal to a gaseous fuel in which the sulfur compounds, usually existing as hydrogen sulfide, are easier to be removed than are the oxidized sulfur forms. Experiments involving the pyrolysis of bituminous coal, as well as other carbonaceous feed materials, have been performed in an 18-in.-dia, atmospheric fluidized bed. The experimental results from this work indicate that a low-Btu gas (125-250 Btu/cubic foot) can be generated efficiently, using an air feed, in such a low pressure system. This paper analyzes the data from the pyrolysis experiments in order to generate kinetic and heat transfer information and to formulate a coal pyrolysis model useful in the design of commercial-sized processes. The model is then applied in forming a conceptual flowscheme for a relatively low-pressure (7-13 atmospheres) electrical power generation plant. In the conceptual flowscheme, the low-Btu gas is produced in a two-unit pyrolyzer and pyrolysis char gasifier. The gas is then purified and fed into a combustion chamber, with the electrical power being generated in a combined gas turbine steam-turbine power cycle.

Also available--U. S. Gov't, NTIS, CONF-730403-P1, 1976

141.
Willis, R. H., Chairman
Report of the Committee on Production of Manufactured Gases
13th World Gas Conference, London, June 7-11, 1976;
Preprint IGU/B76, 143 pp

As reported by IGU Committee B on Production of Manufactured Gases, the urgent natural gas requirements of the U.S. are intensifying world interest in the development of new processes and the modification of existing processes for producing substitute natural gas. At least 17 processes are in the advanced stages of development, with major efforts being directed toward coal gasification. The committee describes these processes as well as innovations in the well-established field of oil gasification; approaches for gasifying oil shale, and processes for purifying the product gas. In the area of low-Btu-gas production, process developers hope to reduce costs while increasing specific yields and thermal efficiencies by designing systems that accommodate a wide range of coals. A detailed survey of current low-Btu-gas plants illustrates the various systems in use. The committee also describes some analytical systems for the quality control of raw materials and manufactured gases, reports on various pollution problems caused by gasification processes, and presents statistics on the world's energy resources.

142.
Zabolotny, E. R. and Kuhr, R. W. (Stone and Webster Engineering Corp.)
Waste Treatment Advances: Hot Gas Purification
Chem. Eng. Progr. 72 (10), 69-74 (1976)

The success of a program to demonstrate the feasibility of pressurized fluidized bed boiler combined cycle power plant may depend on developing a very efficient particle collection device capable of operating in both reducing and oxidizing atmospheres at temperatures to about 1500°F and on hydrogen sulfide removal systems. Progress in developing these systems is described. Studies completed to date indicate that the feasibility of hot fuel gas purification in combined-cycle power generation depends upon the type of coal and coal gasification process, demonstration of satisfactory particulate removal system performance, demonstration of satisfactory chemical and mechanical properties of the hot sulfur absorbent in a commercial operating situation, development of a satisfactory hot absorbent regeneration system, and capital cost related factors. Analyses to date support continuation of the hot process development program, promising a typical increment in thermal efficiency of between 1 and 4 percent, which will save about 20 ton/hr of coal at 1,000 MW capacity.

143.
Zahradnik, R. L.
Coal Conversion R&D: What the Government Is Doing
Chem. Eng. Prog. 72 (6), 25-32 (1976)

ERDA's coal conversion and utilization program currently has more than 100 contracts outstanding with a total value in excess of $400 million; 25% of this amount is being contributed by industry. Of the various approaches for converting coal into an improved nonpolluting energy source, liquefaction has advantages in terms of economics and confidence in commercial operability. Specific R&D projects in the liquefaction program are in the areas of hydroliquefaction, solvent extraction, and pyrolysis. The government-supported high-Btu gasification program includes six major projects to improve the process of making pipeline-quality gas from coal. Each of the gasification reactors under study is characterized by important differences in reaction conditions, pretreatment, method of feed, reactor configuration, and heat supply. The technology of converting coal into low-Btu gas could offer a higher conversion efficiency than high-Btu gasification and has great potential for use in gas-steam-turbine combined power cycles. Five major projects are studying this aspect of coal conversion. Research efforts are also being directed toward the development of environmentally acceptable methods of direct coal combustion; three projects contribute to this phase of the program. ERDA's demonstration-plant program includes plans for the 1980-81 operation of a boiler-fuel plant, two pipeline-gas plants, and two fuel-gas plants. Although government funds will cover the design and engineering of these demonstration plants, industry will share 50% of the construction costs.

144.
Anonymous
ERDA Backing 2500°F 10-Mw Design for 1982
Gas Turbine World 7, 41-44 (May 1977)

By applying advanced component technology to small industrial machines, ERDA hopes to leapfrog technology for a 37% simple cycle, 48% combined cycle efficiency plant that can burn heavy oil and synthetic fuels--for production readiness by 1982.

145.
McCaleb, T. L. and Chen, C. L. (Gilbert/Commonwealth Cos.)
Low Btu Gas As an Industrial Fuel
Chem. Eng. Progr. 73 (6), 82-88 (1977)

146.
Neal, Gordon W. (Envirodyne Energy Services)
Advantages of Combined Power/Process Generating Plants
Power Engineering 81, 56-59 (Feb. 1977)

147.
Zaba, T. (BBC Brown, Boveri & Co., Ltd.)
Low-Grade Fuel Used in Gas Turbines
Oil Gas J. 75 (17), 114-118 and 123 (April 25, 1977)

D.2 GOVERNMENT SOURCES

148.

Coward, H.F. and Jones, G.W.
Limits of Flammability of Gases and Vapors
U.S. Government, NTIS, AD-701, 575 (or Bur. Mines Bull. No. 503), 1952; 155 pp

Issued as a result of a cooperative study begun in 1924 between Safety in Mines Research Board of Great Britain and Bureau of Mines. Bulletin contains the most comprehensive listing of the limits of flammability of gases and vapors in air or oxygen yet made available in a single volume. Bulletin explains how flammability limits are determined and some of the theoretical considerations taken into account in such experimentation and presents results of a critical review of all figures published on the limits of flammability of combustible gases and vapors when mixed with air, oxygen, or other "atmosphere."

149.

Zabetakis, M.G.
Flammability Characteristics of Combustible Gases and Vapors
U.S. Government, Bur. Mines, BM Bull. No. 627, 1965; 121 pp

Summarizes limit-of-flammability, auto-ignition, and burning-rate data for more than 200 combustible gases and vapors in air and other oxidants; supplies empirical rules and graphs that can be used to predict similar data for thousands of other combustibles under a variety of environmental conditions. Specific data are presented on the paraffinic, unsaturated, aromatic, and alicyclic hydrocarbons; alcohols, ethers, aldehydes, ketones, and sulfur compounds; and an assortment of fuels, fuel blends, hydraulic fluids, engine oils, and miscellaneous combustible gases and vapors.

150.

Westerstrom, L.W. (Bureau of Mines)
Coal--Bituminous and Lignite
U.S. Government, GPO, Bureau of Mines Minerals Yearbook, 1971; Preprint, 52 pp

A chapter from the 1971 Minerals Yearbook, now out-of-print. Consult the latest edition of the Bureau of Mines Minerals Yearbook for a related and/or similar study.

151.
Zabolotny, Ernest R. et al (Stone & Webster Engineering Corp.) (for EPRI)
Purification of Hot Fuel Gases from Coal or Heavy Oil. Interim Report.
U. S. Gov't, NTIS, EPRI-243-1, Nov. 1974; 96 pp

The work performed in this study involved a review of known technologies for particulate and hydrogen sulfide removal. Several gas purification techniques were selected that show promise of being able to achieve high efficiency performance at elevated temperatures. It is noted that to maximize overall efficiency, gas purification should be accomplished at temperatures allowed by the gas turbine or generated by the gasifier. Hot fuel gas purification systems must be designed to protect the turbine component of a low Btu gas-combined cycle power system and to meet environmental regulations regarding emissions of particulate, sulfur compounds, and nitrogen oxides. Other potential applications for the control systems discussed in this report include cleaning fuel gases generated by fluidized bed boilers, combined cycle systems based on pressurized fluid bed boilers, or conventional power boilers. The overall market for new particulate control technologies is difficult to assess and depends to a great extent on environmental regulations and their timing.

152.
Seamans, R. C. Jr., White, P. C.
Fossil Energy Program Report.
U. S. Gov't., NTIS, ERDA 76-10, 1976; 111 pp

In addition to an executive summary and a glossary, sections dealing with the following topics are included: Carbon Dioxide Acceptor Coal Gasification Process; Bi-Gas Process for the Generation of Pipeline Gas; Pipeline Gas by Hydrogasification (Hygas Process); Steam-Iron System for Production of Hydrogen; Synthane Process; Agglomerating Burner Process; Liquid Phase Methanation Process; Evaluation of High-Btu Gasification Products; Molten Salt Combustion and Gasification Process; Advanced Coal Gasification System for Electric Power Generation; Low-Btu Gasification of Coal for Electricity Generation; Coal Gasification Combined-Cycle System for Electric Power Generation; Low-Btu Fuel Gas; Desulfurization of Low-Btu Producer Gas; Technical and Engineering Services; The Coal Conversion System Technical Data Book; and Computer Modeling of Coal Gasification Reactors.

153.
Energy Research and Development Administration, Office of Fossil Energy
Coal Gasification. Quarterly Report, Oct.-Dec. 1975
U. S. Gov't, NTIS, ERDA-76-30-4, 1976: 100 pp

Progress in U. S. ERDA's research and development programs in coal gasification is reported. This involves pilot plant construction and/or operation for several different processes; brief discussions of results, problems and advantages or disadvantages of each; and engineering support and comparative evaluations. Programs involve projects for high Btu gas production (for pipeline distribution) and low Btu gas production (for power plant usage, including gas cleanup and combined cycle power plants).

154.
Energy Research and Development Administration, Office of Fossil Energy
Coal Power and Combustion. Quarterly Report, April-June 1975
U. S. Gov't, NTIS, ERDA-76-31-2, 1976: 45 pp

Progress in ERDA-sponsored programs in the fluidized-bed combustion of coal is reported, including furnace boiler design, control of sulfur emissions, optimization of operating conditions, gas turbines, and program planning, engineering and coordination. A program for the economic and comparative evaluation of advanced systems for producing power more efficiently is under way (various possibilities such as combined cycles, magnetohydrodynamics, fuel cells).

155.
Bureau of Mines, Morgantown, W. Va.
Economic Analysis of Westinghouse Low- Btu Gasification. Combined-Cycle Power Generating System Producing 134.1 Megawatts. Coal-Dolomite Gas Producer, Indiana Coal SEAM
U. S. Gov't, NTIS, ERDA-76-49, March 1976: 26 pp

The Westinghouse Electric Corporation has conceived and developed a fluidized airblown gas producer which operates at 263 psia and burns a caking coal-dolomite mixture, so that no pretreatment or fuel gas desulfurization is necessary. A fluidized pressurized gasification plant to gasify 47 tons per hour of an Indiana coal mixed with dolomite to provide fuel gas for a combined-cycle power generation system to produce 134.1 Mw net power will require a capital investment of $40,915,400 or $305.11 per kilowatt of net generating capacity. The selling price of power to support a 17-percent capital charge will vary with the cost of coal (15.9 mills/kwhr for $11/ton coal to 17.3 for $15/ton coal). The thermal efficiency of the system is 37.4 percent with the coal heating value at 13,027 Btu's per pound of coal. This is the overall net thermal efficiency and is based on the net power output after deductions for gas production.

156.
Bureau of Mines, Morgantown, W. Va.
Preliminary Economic Analysis of Bureau of Mines Low-Btu Gasification. Combined-Cycle Power Generating System Producing 299.0 Megawatts, Pittsburgh Coal Seam
U. S. Gov't, NTIS, ERDA-76-52 (or FE-2083-4), March 1976; 24 pp

The Bureau of Mines has developed and operated a pilot-plant size, fixed-bed gas producer which operates at 120 psig and burns caking coals; that is, no pretreatment is necessary. The pilot plant data have been supplied by Bureau of Mines personnel and were collected from experimental runs on a highly caking Pittsburgh seam coal. On the basis of the pilot plant data, power costs have been estimated for a full size plant based on July 1975 cost indexes. The evaluation includes sulfur removal, an ammonium sulfate plant, a water-scrubbing system for tar removal, and a combined-cycle power generating plant. A fixed-bed pressure producer gasification plant to gasify 140.4 tons per hour of Pittsburgh seam coal with a combined-cycle power generation system to produce 299 MW net power will require a capital investment of $151,221,200 or $505.76 per kW of net generating capacity. The selling price of power to support a 17-percent capital charge, with the cost of coal a parameter, will vary from 22.4 to 24.3 mills/kW-hr for coal costs varying from $11 to $15/ton.

157.
White, Philip C. (ERDA)
Fossil Energy Research Program of the ERDA, FY 1977
U. S. Gov't, GPO, ERDA 76-63, April 1976; 269 pp

158.
Energy Research and Development Administration, Office of Fossil Energy
Coal Conversion and Utilization. 1975 Technical Report
U. S. Gov't, NTIS, ERDA-76-86, 1976; 221 pp

U. S. ERDA's 1975 programs and progress in coal gasification, coal liquefaction, fluidized-bed combustion and combined power cycles are reviewed. Some related applications or problem areas are also discussed: hydrogen production by the steam-iron process, desulfurization, mathematical modeling, filtration of coal liquids, high temperature dust control and various other combustion projects.

159.
Energy Research and Development Administration, Office of Fossil Energy
Coal Gasification. Quarterly Report, January-March 1976
U. S. Gov't, NTIS, ERDA-76-93-1, 1976; 113 pp

Progress involved with several coal gasification pilot plants is reported, involving high and low Btu gas production and combined-cycle power plants.

160.
Energy Research and Development Administration, Office of Fossil Energy
Coal Gasification. Quarterly Report, April-June 1976
U. S. Gov't, NTIS, ERDA 76-93-2, 1976; 93 pp

In addition to an executive summary and glossary, the following sections are included: Carbon Dioxide Acceptor Coal Gasification Process; Bi-Gas Process for the Generation of Pipeline Gas; Pipeline Gas by Hydrogasification (Hygas Process); Steam-Iron System for Production of Hydrogen; Synthane Process; Agglomerating Burner Process; Liquid Phase Methanation Process; Evaluation of High-Btu Gasification Projects; Molten Salt Combustion and Gasification Process; Advanced Coal Gasification System for Electric Power Generation; Low-Btu Gasification of Coal for Electricity Generation; Coal Gasification Combined-cycle System for Electric Power Generation; Low-Btu Fuel Gas; Desulfurization of Low-Btu Producer Gas; The Coal Conversion Systems Technical Data Book; and Computer Modeling of Coal Gasification Reactors.

161.
Energy Research and Development Administration, Office of Fossil Energy
Coal Power and Combustion. Quarterly Report, January-March 1976
U. S. Gov't, NTIS, ERDA-76-94-1, 1976; 73 pp

ERDA's programs in fluidized-bed combustion, including pressurized fluidized-bed combustion and MIUS, are reviewed. In order to minimize turbine wear and erosion, high temperature dust control studies have been initiated. Other combustion programs include a coal-oil slurry combustion project, solvent-refined coal combustion, anthracite refuse combustion, possible retrofitting with fluidized-bed combustion, potassium topping cycle progress and planning, technical and engineering services in this area.

162.
Skamser, Robert (C. F. Braun & Co.)
Coal Gasification Commercial Concepts Gas Cost Guidelines
U. S. Gov't, NTIS, FE-1235-1, Jan. 1976; 37 pp

The impending shortage of natural gas has led to the development of new processes for the manufacture of synthetic natural gas from coal. A means is need to compare these new processes with each other and with processes using older technology. It is for the purpose of these Guidelines to provide a consistent basis for comparing such processes. Coal analyses, unit prices as of Jan. 1, 1976, environmental requirements, plant size, equipment design guides, and equations for gas costs are included using either utility or private investor financing.

163.
Eyre, I. W. (Gilbert Associates, Inc.)
Participating Surveillance Services for Electric Power Program. 1975 Annual Progress Report for Gasification Programs
U. S. Gov't, NTIS, FE-1236-10, April 1976; 17 pp

Engineering and economic evaluations, feasibility studies and contract surveillance efforts carried out for ERDA in the area of coal conversion and electric power generation are reported.

164.
Gilbert Associates, Inc.
Activities of Gilbert Associates Involving Assistance to the Office of Coal Research Contractors. Monthly Progress Reports for the Period November 1972-December 1973
U. S. Gov't, NTIS, FE-1236-T-1, 1973; 358 pp

The company had a consulting contract with the Office of Coal Research to monitor, review and assist other OCR-sponsored development contracts in coal gasification, magnetohydrodynamics, advanced power cycles (topping and bottoming cycles), desulfurization, etc. The monthly reports to OCR include reports on meetings, inspections, discussions, proposal reviews, special investigations (usually about problems that arose), recommendations, etc. For example, problems with valves and lockhoppers for coal and chars, scrubber operation, certain phases of magnetohydrodynamics and coal gasification problems received continued attention.

165.
Gilbert Associates, Inc.
Activities of Gilbert Associates Involving Assistance to the Office of Coal Research Contractors. Monthly Progress Reports for the Period January-April and July 1974
U. S. Gov't, NTIS, FE-1236-T-2, 1974; 234 pp

The document consists mostly of company reports to the Office of Coal Research in connection with their consulting contract to monitor, review, and assist other OCR-sponsored development contracts in coal gasification, magnetohydrodynamic combined cycles, desulfurization, etc. Recommendations are made with respect to some projects. Two more formal reports are included (1) on coal gasification to provide a low-Btu gas, and (2) on desulfurization of fuel gases limestone (including the related chemistry and regeneration of the limestone).

166.
Westinghouse Electric Corp.
Advanced Coal Gasification System for Electric Power Generation. Multiple-Fluidized-Bed Coal Gasification System Conceptual Design and Cost Estimate, June 1974-June 1975
U. S. Gov't, NTIS, FE-1514-42, June 1975; 234 pp

A conceptual design is presented for a coal gasification system of the size and configuration deemed proper to operate with a large utility-type turbine-generator. Presented are basic design theories, equipment configurations, process flow sheet, principal dimensions, operating principles, and a cost estimate. This report details a complete gasification system that processes 47 tons of coal and 15 tons of dolomite per hour into sulfur-free gaseous fuel having an LHV of 149.9 BTU/SCF at a temperature of 1600°F. This fuel will then operate a Westinghouse 501-D gas turbine, which will generate 95Mw operating at ISO conditions.

167.
Westinghouse Electric Corp.
Advanced Coal Gasification System for Electric Power Generation. Quarterly Progress Report, January-March 1976. Third Quarter, Fiscal Year 1976
U. S. Gov't, NTIS, FE-1514-47, June 2, 1976; 54 pp

Two devolatilization tests were conducted to explore devolatilizer operability over a range of operating conditions using a low-sulfur, mildly caking Indiana coal from the Minnehaha mine of Amax Coal Company. In the first test the system was operated for over 30 hours at temperatures of 1400 to 1800°F and at a pressure of 225 psig with a fluidized bed of char. An analysis indicated that about 94 percent of the volatile matter in the coal was removed. Some fixed carbon was gasified as a consequence of the water vapor content in the inlet gases. The second test provided additional steady-state data on heat and material balances, char characteristics and reactor system operation. Reactor operation was sustained for over 12 days and produced reliable design data. Support work was carried out to investigate operating conditions for the PDU test program, provide troubleshooting capability for PDU operation, obtain data for PDU modifications, analyze and interpret results from PDU operation and develop information for future process development. The coal behavior test program was directed toward obtaining devolatilization data as a function of coal particle size and tests on coals used in the PDU tests. Two tests were run with Canaan dolomite to study its resistance to disintegration resulting from thermal shock in charging, from temperature cycling in the bed, and from partial calcination. Work on solids transport, the intermediate scale test facility and reactor analysis was carried out. Limited gas turbine combustion experiments with oil and low Btu gas are reported.

168.
Westinghouse Electric Corp.
Advanced Coal Gasification System for Electric Power Generation. Development of Full-Size Gas Turbine Combustors Using Synthetic Low-Btu Fuel Gas at 350°F. Technical Status Report, June 1974-July 1976
U. S. Gov't, NTIS, FE-1514-52, July 30, 1976; 135 pp

An important purpose in developing coal gasification systems for low-Btu fuel gas is to make possible the use of coal in combined-cycle electric generating plants for Utility Service. Air-blown gasification systems will not reach their full potential of usefulness unless it has been proved that gas turbine engines of large ratings can be built with integral combustors. The main thrust of the gas turbine combustor development test program was to verify that fact. The technology of burning low heating value gases in slightly modified current gas turbine engine combustors has been demonstrated with 350°F gas, typical of that which would result from coal gasification followed by cleaning with a wet scrubber. Following tests of three fuel injectors and ten combustors over a period of 21 months, a candidate combustor design was identified and considerable data on emissions and performance obtained. The candidate combustor was designed for low smoke emissions in the oil-fired mode, and as a result cannot operate in the low-heating-value gas mode below 50 percent load with many of the gases tested. More work is needed to extend the operating range on some gas compositions below this 50 percent load point. In the 50 percent to 100 percent load range, additional work remains to be done on wall cooling and exit temperature pattern while in the coal gas mode.

169.
Lemezis, S. (Westinghouse Electric Corp.)
Advanced Coal Gasification System for Electric Power Generation. Research and Development Report No. 81, Interim 4
U. S. Gov't, NTIS, FE-1514-53, July 1, 1975-June 30, 1976; 118 pp

This program originally carried along in parallel all the analytical tasks and experiments necessary to evolve a workable advanced coal gasification system for electric power generation; all such work done during the first half of FY 1975 is reported herein. At present, only those tasks directly connected with proving out and characterizing the gasification system embodied in a Process Development Unit are still active. The PDU's devolatilizer unit has successfully demonstrated ability to accommodate both mildly and severely caking feed coals. Testing of full-size gas turbine combustors burning simulated low-Btu fuel gas at 350°F. has been completed. Feasibility of constructing such combustors which fit the space envelope of Utility gas turbines has been established. Test and analytical efforts to both define the required cleanliness of fuel gas streams and to assure contaminant removal down to the required levels were suspended while still inconclusive.

170.
Westinghouse Electric Corp.
Advanced Coal Gasification System for Electric Power Generation.
Office of Coal Research R & D Report No. 81, Interim Report No. 2,
Volumes I and II, July 1, 1973-June 30, 1974
U. S. Gov't, NTIS, FE-1514-T4, 1974; 321 pp

Coal gasification in conjunction with combined gas and steam turbine generation, provides for the economic, efficient, non-polluting, coal-fueled electric power plants that will be increasingly need in the United States. The Westinghouse Electric Corporation is now developing such a system, utilizing a newly devised multiple fluidized-bed gasification process (which employs coal, air, and steam for gasification and limestone/dolomite for desulfurization). The U. S. Office of Coal Research and a Westinghouse-coordinated industrial team are sponsoring this effort. The final product of this effort is a commercial-size Generating Pilot Plant that will operate as part of an existing utility generating station to provide technological verification and economic information for such a system in actual commercial operation.

Note: These reports began under the Office of Coal Research and are now being issued by ERDA as Research and Development Reports.

171.
Data on other reports in this series.
OCR R & D Report No. 81, Interim 1 = PB-136,971/8SL
FE-1514-T7, 1974 (152 pp) is identical with Volume I of FE-1514-T4
FE-1514-T8, 1974 (171 pp) is identical with Volume II of FE-1514-T4

172.
Westinghouse Electric Corp.
Advanced Coal Gasification System for Electric Power Generation.
Research & Development Report No. 81, Interim 3, July 1, 1974-June 30, 1975
U. S. Gov't, NTIS, FE-1514-T9, 1975

see 169. for R & D Report No. 81, Interim 4 = FE-1514-53

173.
Westinghouse Electric Corp.
Advanced Coal Gasification System for Electric Power Generation.
Monthly Progress Reports for the Period January-April 1975
U. S. Gov't, NTIS, FE-1514-T-6, 1975; 423 pp

In this period engineering tests on the coal gasification pilot plant and fuel gas studies (with respect to gas cleanup for gas turbine operation to avoid erosion, corrosion, deposits, etc.) occupied the most attention. The initial engineering tests showed the need for better measuring instruments and control equipment (especially for the rather considerable changes required on start-up). Igniter and thermocouple failures and burner problems required equipment and design changes. Satisfactory, stable operation was not achieved and, in the initial start-up, an explosion resulted from failure of the main flame to ignite and damaged the refractory insulating liners. Fuel gas cleanup studies continued; to avoid tar which fouls heat exchanger surfaces, to remove particulates which cause erosion in gas turbine blades, and to minimize constituents which corrode metals or lead to deposits. Embrittlement of metals (by hydrogen) and carburization problems were investigated. Various desulfurization processes were investigated. Finally, the cost of coal and dolomite was studied (the conclusion was that future price changes were difficult to predict). Many other detailed experimental results are discussed.

174.
Foster Wheeler Energy Corporation
Development Work for an Advanced Coal Gasification System for Electric Generating Plant. Phase II. Quarterly Technical Progress Report, October-December 1975
U. S. Gov't, NTIS, FE-1521-13, April 1976; 35 pp

Efforts involved test runs of the proposed coal pulverizing and drying equipment. Solids feeding systems are being investigated. Material balances (flows) during startup have been calculated. Computer calculations on the water wash and sour water stripping tower, the sulfur removal process (Selexol) and the sulfur recovery system are given. Specifications for various support facilities and environmental protection installations have been issued. Work continued on the conceptual design of a commercial plant, especially with respect to cold flow model tests and computer calculations of effects of transients in the system, including the gas-cleanup system.

175.
Smith, D. E. (Foster Wheeler Energy Corporation)
Development Work for an Advanced Coal Gasification System for Electric Power Generation from Coal Directed Toward a Commercial Gasification Generating Plant. Phase II, Quarterly Technical Progress Report, April-June 1976
U. S. Gov't, NTIS, FE-1521-36, August 1976; 60 pp

Design drawings and specifications were issued for numerous components of coal gasification pilot plant and commercial plants. The flow behavior and entrainment of solids injected into cold flow models were studied further. With a modified configuration, improved entrainment was obtained. The development of models of gas and steam turbine operation was continued, particularly with respect to transients during off-design operation and the control systems required.

176.
Smith, D. E. (Foster Wheeler Energy Corporation)
Development Work for an Advanced Coal Gasification System for Electric Power Generation from Coal Directed Toward a Commercial Gasification Generating Plant. Phase II. Quarterly Technical Progress Report, July-September 1976
U. S. Gov't, NTIS, FE-1521-40, November 1976; 33 pp

Studies of the cold flow model behavior continued, in particular the simulation of slag flow within the lower stage of the gasifier and the ability to influence this flow by varying the geometry of the stage. Glycerol was used as the simulating liquid and several interesting flow characteristics were note. Some of these may be detrimental to operation. The development of a mathematical model of combined gas and steam turbine operation continued, especially with respect to transients and control problems during off-design operation

177.
Smith, D. E. (Foster Wheeler Energy Corp.)
Development Work for an Advanced Coal Gasification System for Electric Power Generation from Coal Directed Toward a Commercial Gasification Generating Plant: Phase II. Quarterly Technical Progress Report, October-December 1976
U. S. Gov't, NTIS, FE-1521-44, Jan. 1977; 10 pp

The draft design report of the pilot plant, which contains all the process and mechanical design work completed to date, is being reviewed and corrected. Work is continuing on the design of a commercial plant, especially in the areas of material balances, process flowsheets, equipment specifications, materials handling, coal drying and injection systems, slag handling system, etc., and in the preparation of a final report. Cold flow model experiments continued with respect to slag entrainment. A final report on transient analysis is being prepared.

178.
Arthur D. Little, Inc.
Benefits/Costs of Advanced Power Cycle Research. A Mid-1974 Analysis. Final Report
U. S. Gov't, NTIS, FE-1756-1, December 1975; 83 pp

The analysis reported here was performed in mid-1974 for what was then the Office of Coal Research (and now part of the United States Energy Research and Development Administration). It was designed as a best-efforts assessment (from available information) of the benefits/costs then of planned Federal R and D programs in advanced power cycle energy systems. Two advanced power cycle technologies were selected for analysis as proxies for the many technologies within the advanced power cycle family: 1) combined cycles (specifically, an integrated gasifier combined cycle system), and 2) magnetohydrodynamics (MHD). The benefits quantified in this report are limited to those defined as the savings to be realized by the Nation as a result of having cheaper energy available through advanced power cycles systems than might be otherwise available in an uncertain future. At a discount rate of 6%, the apparent benefit/cost ratios of Federal R and D related to combined cycles and MHD were 31 and 16, respectively. The uncertainties associated with the analysis requires that these benefit/cost ratios be viewed only as an indication of the level of benefit/cost advantages to be attributed to advanced power cycle research. The sensitivity of the benefit/cost ratios important assumptions such as the price of coal is illustrated through a few sensitivity analyses.

179.
Flynt, F. V. (General Electric Co.)
High Temperature Gas Turbine Engine Component Materials Testing Program. Quarterly Progress Report No. 1, June 27-September 28, 1975
U. S. Gov't, NTIS, FE-1765-4, October 15, 1975; 58 pp

Twenty-one materials have been selected for the Gas Turbine Materials Screening Test program. Specimens are being readied for use. Coal feedstocks for the Initial and Screening Tests involving low-Btu gas have been selected: Illinois No. 6 coal (or equivalent) and North Dakota lignite or Montana Rosebud. COED fuel oil derived from Pittsburgh coal has been selected for use in the Initial Coal-derived Liquid Fuel Tests. Since only 6,000 gallons of this fuel can be made available, 40,000 gallons of "synthetic COED" fuel will be synthesized for use in the balance of the Initial Tests. Test facility requirements have been selected as follows: Initial Tests with Coal-derived Liquid Fuels --General Electric's turbine simulator in Schenectady, and with Low-Btu Gas--MERC's two-atmosphere gasifier in conjunction with a turbine simulator skid; Screening Tests--General Electric's small burner test rigs in Schenectady; and Confirmation Tests with Coal-derived Liquid Fuels--General Electric's turbine simulator in Schenectady, and with Low-Btu Gas--General Electric's turbine simulator in Schenectady, attached to General Electric's GEGAS-D gasifier.

180.
Kaplan, S. M. (General Electric Co.)
High Temperature Gas Turbine Engine Component Materials Testing Program. Task 1. Quarterly Technical Progress Report No. 3, January 3-April 4, 1976
U. S. Gov't, NTIS, FE-1765-13, April 15, 1976; 76 pp

Efforts included: initiation of initial coal derived fuel testing, initiation of screening tests, and delivery of the turbine simulator skid. Two turbine simulator tests were successfully performed; the first test was performed with as-received fuel and the second test involved fuel doped with 3 ppM Na and 3 ppM K. Test results indicated the presence of K- and Na-based corrosive species on test specimens. Investigations indicated that doping of No. 2 distillate fuel with chemicals and/or ash to simulate a coal-derived liquid fuel would not be feasible due to fundamental chemical differences between petroleum-based and coal-based fuels. A search for a coal-fuel base to develop a synthetic coal-derived liquid fuel was initiated, with three candidate fuel bases being identified. Samples of these candidates are currently being evaluated. Shakedown tests of the turbine simulator skid at the Morgantown test facility were initiated in March, and several areas in the test arrangements that needed minor modifications were uncovered. Materials screening tests were initiated using two test conditions established via thermochemical analysis. Two additional test conditions were developed in March. 14 figures, 11 tables.

181.
Dravo Corporation
Handbook of Gasifiers and Gas Treatment Systems, Final Report
U. S. Gov't, NTIS, FE-1772-11, Feb. 1976; 167 pp

The intent of this Handbook is to provide a ready reference on Gasifiers and Gas Treatment Systems that are or may be applicable to coal conversion technology. The Handbook contains sections on twenty-two gasifiers and twenty gas treatment systems, including those presently available in the commercial market as well as those currently under development.

Each section of the Handbook has been reviewed and approved for publication by the supplier. The Handbook is comprised of objective information colledted from various sources and includes data, such as: the state of development, a description of the process, capacity, products, by-products, utilities, environmental considerations, etc. The Handbook is not intended as a comparative evaluation, but rather as an impartial reference on the current technology.

182.
Ralph M. Parsons Co.
Preliminary Design Services Coal Conversion Demonstration Plants. Research and Development Report No. 114, Quarterly Report, January-March 1976
U. S. Gov't, NTIS, FE-1775-4, April 1976; 14 pp

The prime objectives for this work are to develop six conceptual designs/ economic evaluations for coal conversion facilities. One (COED-based pyrolysis) has been completed and published; two (Fischer-Tropsch and Oil/Gas) are in later stages of completion, and two (COG and demonstration facilities complex) are in early-to-intermediate stage of development. This quarterly report summarizes progress made on each of the tasks. This includes completion of conceptual design and economic evaluation of a 40,000-TPD coal mine to provide feed coal to the process plants; completion of the majority of the process designs plus progress on equipment engineering specifications for Fischer-Tropsch and Oil/Gas plants, and progress toward development of a design basis for the multiproduct COG design. One paper was presented on the subject of "Industrial Energy Usage Patterns" which discussed coal conversion's potential role in industrial energy supply and three additional papers were prepared for presentation next quarter.

183.
Caruvana, A. (General Electric Co.)
Development of High Temperature Turbine Subsystem Technology to a "Technology Readiness Status", Phase I. Progress Report for June 1976
U. S. Gov't, NTIS, FE-1806-1, June 7, 1976; 18 pp

Primary emphasis was placed on the preparation of engineering documents to provide the basis for study activities by the many contributors on the interrelated tasks. In parallel the various work statements, subcontracts and Project Funding Authorizations were generated. Preliminary information was generated on overall plant cycle definition, heat balance, performance predictions, gas turbine component sizing and aerodynamic data. The coal handling, drying and storage systems were sized and utility requirements calculated. A preliminary rating of an induced draft cooling tower was prepared. A preliminary review was conducted of Low Temperature Gas Cleanup Systems. The review encompassed various proprietary acid gas removal systems and two particulate and tar removal schemes. The Preliminary System specifies a Benfield Acid Gas Removal Unit and Claus sulfur recovery plant preceded by raw gas quench and followed by a clean gas saturator. Based on a combined cycle configuration with an integrated fixed-bed gasifier, cycle conditions were established for the three reference turbine subsystem designs. Gas flow path sizing, air foil shapes and pitchline velocity distributions were than calculated. Test plants were established for mechanical and physical properties testing of materials identified for use in the preliminary design of water cooled hardware. Also to be evaluated is the behavior of bond joints for various combinations of materials. Advance work was started on the design of the Hot Gas Path Test Stand. Combustor design work will be based on a product low-Btu coal gas composition based on the Illinois No. 6.

184.
Caruvana, A. (General Electric Co.)
Development of High Temperature Turbine Subsystem Technology to a "Technology Readiness Status" Phase I (Quarterly Report for the period June--Sept. 1976)
U. S. Gov'T, NTIS, FE-1806-6, Nov. 1976; 321 pp

The requirements of Overall Plant Design Descriptions (OPDD's) for combined cycle plants utilizing coal-derived low-Btu fuel gas and coal-derived liquid fuel resulted in evaluations of various coal gasification processes including fixed-bed and entrained-bed. An advanced fixed-bed concept was selected which operates at a very low steam to air ratio, achieves a cleaner more tar-free operation and utilizes the coal fines mixed with tar. The Foster-Wheeler (FW) entrained-bed system offers a high throughput with a savings in equipment costs. The availability of an efficient high temperature gas cleanup system would make the overall FW System attractive.

The Benfield System was selected following evaluation of low-temperature gas cleanup systems. Various design concepts are presented which represent the current status of various turbine configurations utilizing different blading cooling concepts. These involve water, steam and/or air cooling. Three combustor conceptual designs are presented including a circular can type, a rectangular can type and an annular combustor. A major study on the controls requirements for a combined cycle plant with a fixed-bed gasifier and a gas cleanup system was completed and included herein.

185.
Carlson, N. G. (United Technologies Corp.)
Development of High-Temperature Subsystem Technology to a Technology Readiness State: Phase I. First Quarterly Technical Progress Report, June-August 1976
U. S. Gov't, NTIS, FE-2292-4, September 1976; 109 pp

The overall objective of the High-Temperature Turbine Technology Program is the development of a 100 megawatt and larger size industrial, high-temperature, open-cycle gas-turbine engine to a state of technology readiness. The industrial gas-turbine engine is intended for use in a combined cycle plant and utilizes a coal-derived fuel. A combined cycle plant consists of an open-cycle gas turbine exhausting into a waste heat boiler that supplies steam to a steam turbine. In turn, both turbines drive electric generators to produce electric power. Because of the operational requirements and the nature of the operating environment and rigorous duty cycle special emphasis is placed on durability. The overall cost of power is the most important criterion used by public utilities for selecting base-load equipment. Also, the lowest cost of power can be attained through careful compromises of capital cost, maintenance cost, and efficiency. Each of these variables is under control of the equipment designer. Parametric analyses have been conducted for identification of systems and equipment and the results have shown the preliminary performance of various gas-turbine engines and steam bottoming cycle systems operating in conjunction with a molten-salt gasifier. A preliminary heat and mass-balance analysis for a power system has indicated an overall efficiency rate of nearly 43 percent. Off-design performance of the gasifier, gas-turbine, and steam bottoming cycle has been defined. Analysis of transient operating modes and identification of control requirements has been started. Effort is being aimed at defining the open-cycle gas-turbine engine, including the effects of various engine components on combined-cycle system performance.

186.
Carlson, N. G. (United Technologies Corp.)
Development of High-Temperature Subsystem Technology to a Technology Readiness State: Phase II. Second Quarterly Technical Progress Report, Sept.-Nov. 1976.
U. S. Gov't, NTIS, FE-2292-7, Sept.-Nov. 1976; 195 pp

187.
Seglin, L. (Econergy Associates)
Preliminary Evaluation of Coal Gasification Processes
U. S. Gov't, NTIS, FE/WAPO-7612-1, March 1, 1976; 70 pp

A preliminary evaluation has been made of 10 coal gasification processes which may be condidates for inclusion in the Modular Coal Gasification Plant now being considered by ERDA. Basic thermodynamic and cost data were developed which, together with available information on the respective processes and the writer's judgment, served as the bases for these evaluations. The evaluations included consideration of relative product costs; magnitude of development problems and development effort required to resolve these, and judgments vis-a-vis chances for technical success. On the basis of these evaluations, recommendations were made as to the preferred gasification processes for inclusion in the Modular Gasification Plant, and the development effort required to improve the chances for technical and economic success of these condidates. General conclusions were: For oxygen blown systems, the lower the gasification temperature, the lower will be the oxygen and acid gas removal costs; air blown systems; such as Battelle/Carbide, offer the greatest potential for lowering the cost of synthesis gas; the best entrained gasification system appears to be Bi-Gas; and the best slag-bath gasification system appears to be Otto-Rummel.

188.
Lewis Research Center, NASA
Comparative Evaluation of Phase I Results from the Energy Conversion Alternatives Study (ECAS)
U. S. Gov't, NTIS, N76-20631, Feb. 1976; 372 pp

Ten advanced energy conversion systems for central-station, base-load electric power generation using coal and coal-derived fuels were studied by NASA at the request of ERDA and NSF. The General Electric Company and the Westinghouse Electric Corporation were selected by competitive bidding to study these systems. Phase I of these contracts was a parametric analysis of each system. The results include performance and economic data, such as plant capital cost and cost of electricity, and emissions and natural resource requirements for selected cases. This report provides a comparative evaluation of the contractor results on both a system-by-system and an overall basis. Ground rules specified by NASA, such as coal specifications, fuel costs, labor costs, method of cost comparison, escalation and interest during construction , fixed charges, emission standards, and environmental conditions, are presented. Each system discussion includes the potential advantages of the system, the scope of each contractor's analysis, typical schematics of systems, comparison of cost of electricity (COE) and efficiency for each contractor, identification and reconciliation of differences, identification of future improvements, and discussion of outside comments. Considerations common to all systems, such as materials and furnaces, are also discussed. Results of selected in-house analyses are presented, in addition to contractor data. The results for all systems are then compared. Maximum efficiency with corresponding COE and capital costs, minimum capital cost with corresponding efficiency and COE and minimum COE with corresponding efficiency and capital costs are tabulated for each system and contractor. Plots of COE against overall energy efficiency for each system and contractor provide an insight into the effects of fuel, bottoming cycle, or gasifier and permit a ready comparison with the advanced coal-fired steam system. The sensitivity of COE to changes in capital costs, construction time, fuel costs, capacity factor, interest rate, escalation rate, and fixed-charge rate is determined as well as sensitivity to comparisons based on different methods of calculating COE.

189.
Corman, J. C. et al (General Electric Co.)
Energy Conversion Alternatives Study (ECAS), General Electric Phase 1.
Volume 1: Executive Summary. Final Report
U. S. Gov't., NTIS, N76-23679/3WE (or NASA CR-134948 , Vol. 1), Feb.
1976; Vol.1 of 7, 54 pp

A data base for the comparison of advanced energy conversion systems for utility applications using coal or coal-derived fuels was developed. Estimates of power plant performance (efficiency), capital cost, cost of electricity, natural resource requirements, and environmental intrusion characteristics were made for ten advanced conversion systems. Emphasis was on the energy conversion system in the context of a base loaded utility power plant. All power plant concepts were premised on meeting emission standard requirements. A steam power plant (3500 psig, 1000 F) with a conventional coal-burning furnace-boiler was analyzed as a basis for comparison. Combined cycle gas/steam turbine system results indicated competitive efficiency and a lower cost of electricity compared to the reference steam plant. The Open-Cycle MHD system results indicated the potential for significantly higher efficiency than the reference steam plant but with a higher cost of electricity.

190.
Beecher, D. T. et al (Westinghouse Research Labs)
Energy Conversion Alternatives Study (ECAS), Westinghouse Phase 1.
Vol. I: Introduction and Summary and General Assumptions. Final Report.
U. S. Gov't, NTIS, N76-23692 (or NASA-CR-134941, Vol. 1),
Feb. 12, 1976; Vol. 1 of 12, 225 pp

Nine advanced energy conversion concepts using coal or coal-derived fuels are summarized. They are; (1) open-cycle gas turbines, (2) combined gas-steam turbine cycles, (3) closed-cycle gas turbines, (4) metal vapor Rankine topping, (5) open-cycle MHD; (6) closed-cycle MHD; (7) liquid-metal MHD; (8) advanced steam; and (9) fuel cell systems. The economics, natural resource requirements, and performance criteria for the nine concepts are discussed.

191.
Thomas, D. E. et al (Westinghouse Research Labs)
Energy Conversion Alternatives Study (ECAS), Westinghouse Phase 1.
Vol. II: Materials Consideration. Final Report
U. S. Gov't, NTIS, N76-23693 (or NASA-CR-13491, Vol. 2)
Feb. 12, 1976; Vol. 2 of 12, 306 pp

Extensive studies are presented which were carried out on material behavior in nine advanced energy conversion systems employing coal and coal-derived fuels. The areas of materials behavior receiving particular attention in this regard are: (1) fireside corrosion and erosion in boiler and heat exhanger materials, (2) oxidation and hot corrosion of gas turbine materials, (3) liquid metal corrosion and mass transport, (4) high temperature steam corrosion, (5) compatability of materials with coal slag and MHD seed, (6) reaction of materials with impure helium, (7) allowable stresses for boiler and heat exchanger materials, (8) environmental effects on mechanical properties, and (9) liquid metal purity control and instrumentation. Such information was then utilized in recommending materials for use in the critical components of the power systems, and at the same time to identify materials problem areas and to evaluate qualitatively the difficulty of solving those problems. Specific materials recommendations for critical components of the nine advanced systems under study are contained in summary tables.

192.
Amos, D. J., Lee, R. M. and Foster-Pegg, R. W. (Westinghouse Research Labs)
Energy Conversion Alternatives Study (ECAS), Westinghouse Phase 1. Volume 5: Combined Gas-Steam Turbine Cycles
U. S. Gov't, NTIS, N76-23696/7ST (or NASA CR-134941, Vol. 5)
February 12, 1976; Vol. 5 of 12, 114 pp

The energy conversion efficiency of gas-steam turbine cycles was investigated for selected combined cycle power plants. Results indicate that it is possible for combined cycle gas-steam turbine power plants to have efficiencies several point higher than conventional steam plants. Induction of low pressure steam into the steam turbine is shown to improve the plant efficiency. Post firing of the boiler of a high temperature combined cycle plant is found to increase net power but to worsen efficiency. A gas turbine pressure ratio of 12 to 1 was found to be close to optium at all gas turbine inlet temperatures that were studied. The coal using combined cycle plant with an integrated low-Btu gasifier was calculated to have a plant efficiency of 43.6%, a capitalization of $497/kw, and a cost of electricity of 6.75 mills/mJ (24.3 mills/kwh). This combined cycle plant should be considered for base load power generation.

193.
Beecher, D. T. et al (Westinghouse Electric Corp.)
Energy Conversion Alternatives Study (ECAS). Westinghouse Phase II, Final Report. Vol. 1 - Summary and Combined Gas-Steam Turbine Plant with an Integrated Low-Btu Gasifier
U. S. Gov't, NTIS, N76- (or NASA CR-134942, Vol. 1), Nov. 1, 1976; Vol. 1 of 3, 497 pp

194.
Beecher, D. T. et al (Westinghouse Electric Corp.)
Energy Conversion Alternatives Study (ECAS). Westinghouse Phase II, Final Report. Vol. 2 - Summary and Combined Gas-Steam Turbine Plant Using Coal Derived Liquid Fuel
U. S. Gov't, NTIS, N76- (or NASA CR-134942, Vol. 2), Nov. 1, 1976; Vol. 2 of 3, 330 pp

195.
Beecher, D. T. et al (Westinghouse Electric Corp.)
Energy Conversion Alternatives Study (ECAS). Westinghouse Phase II, Final Report. Vol. 3 - Summary and Combined Gas-Steam Turbine Plant with Pressurized Fluidized Bed Boilers
U. S. Gov't, NTIS, N76- (or NASA CR-134942, Vol. 3), Nov. 1, 1976; Vol. 3 of 3, 398 pp

The ECAS Phase II report represents a more detailed analysis of the performance, plant layout, capital cost, cost of electricity (COE), natural resource requirements, and emissions of three advanced energy conversion concepts. The concepts studied include two combined gas-steam turbine plants and one advanced steam plant. Development programs are proposed to bring the advanced conversion components to commercial status.

196.
Corman, J. C. and Fox, G. R. (General Electric Company)
Energy Conversion Alternatives Study (ECAS). General Electric Phase II, Final Report. Vol. I - Executive Summary
U. S. Gov't, NTIS, N76- (or NASA CR-134949, Vol. 1), Dec. 1976; 30 pp

197.
Corman, J. C., Robertson, A. S., Stewart, R. D., Cassel, T. A. V. and Johnson, G. G. (General Electric Company)
Energy Conversion Alternatives Study (ECAS). General Electric Phase II, Final Report. Vol. II, Part 1 - Advanced Energy Conversion Systems--Conceptual Designs, Analytical Approach
U. S. Gov't, NTIS, N76- (or NASA CR-134949, Vol. 2, Part 1), Dec. 1976; 74 pp

198.
Brown, D. H., Pomeroy, B. D. and Shah, R. P. (General Electric Company)
Energy Conversion Alternatives Study (ECAS). General Electric Phase II, Final Report. Vol. II, Part 2 - Advanced Energy Conversion Systems--Conceptual Designs, Closed Turbine Cycles
U. S. Gov't, NTIS, N76- (or NASA CR-134949, Vol. 2, Part 2), Dec. 1976; 247 pp

199.
Harris, L. P. and Shah, R. P. (General Electric Company)
Energy Conversion Alternatives Study (ECAS). General Electric Phase II, Final Report. Vol. II, Part 3 - Advanced Energy Conversion Systems--Conceptual Designs, Open Cycle Gas Turbines and Open Cycle MHD
U. S. Gov't, NTIS, N76- (or NASA CR-134949, Vol. 2, Part 3), Dec. 1976; 250 pp

200.
Brown, D. H., Corman, J. C., Johnson, G. G., MacFarland, W. J., Pomeroy, B. D. and Woodford, D. A. (General Electric Company)
Energy Conversion Alternatives Study (ECAS). General Electric Phase II, Final Report. Vol. II, Part 4 - Advanced Energy Conversion Systems--Conceptual Designs, Summary of Results
U. S. Gov't, NTIS, N76- (or NASA CR-134949, Vol. 2, Part 4), Dec. 1976; 70 pp

201.
Bass, R. R., Brown, D. H., Corman, J. C., Harris, L. P., Pomeroy, B. D. and Shah, R. P. (General Electric Company)
Energy Conversion Alternatives Study (ECAS). General Electric Phase II, Final Report. Vol. III - Research and Development Plans and Implementation Assessment
U. S. Gov't, NTIS, N76- (or NASA CR-134949, Vol. 3), Dec. 1976; 328 pp

Phase II of a two-phase study was performed to assist in the development of a data base for the comparison of advanced energy conversion systems for electric utility baseload applications using coal or coal-derived fuels. Conceptual designs were developed for seven systems to permit estimates of power plant efficiency, capital cost, environmental intrusion characteristics, natural resource requirements, and cost of electricity at an assumed capacity factor of 65%. The systems studied were advanced steam with atmospheric fluidized bed (AFB) and pressurized fluidized bed (PFB) heat input subsystems, NASA CR-134949 cont.

a closed helium gas turbine (organic bottoming) with an AFB, a potassium topping cycle with a PFB, a combined cycle gas turbine--water cooled--burning a coal-derived liquid fuel, a combined cycle gas turbine--air cooled--integrated with LBtu gasification, and an open cycle MHD system. A conceptual design for the coal to liquid fuel plant was not a part of the study. An emissions limit target was specified for the power plant conceptual designs. The investigative approach sought to achieve consistency and comparability in the analysis of the systems. Recognized advocate organizations were responsible for the conceptual design, performance estimates, and costing of only those components unique to their respective systems. Wherever possible, common subsystems and components were specified in all systems. A steam power plant (3500/psig/1000 F/1000 F) with a coal-burning radiant furnace and a wet lime stack gas scrubber (stack reheat to 250 F), analyzed in a study using the same groundrules as ECAS, was used as a reference for comparison. All of the systems exhibited an estimated efficiency better than the 32% reference case. Development plans and cost estimates were prepared for the energy conversion portion of the respective systems. An implementation assessment was performed to estimate the potential applicability of the advanced energy conversion systems in electric utility generation systems.

202.
Brown, Dale H. (General Electric Co.) (for EPA)
Conceptual Design and Implementation Assessment of a Utility Steam Plant with Conventional Furnace and Wet Lime Stack Gas Scrubbers
U. S. Gov't, NTIS, NASA CR-134950, 1976; 100 pp

A study was performed to estimate the technical/economic characteristics of a steam power plant (3500 psig, 1000 F/1000 F) with a coal-burning radiant furnace and a wet lime stack gas scrubber to control sulfur emissions. Particulate emissions were controlled by an electrostatic precipitator operating at 300°F. The stack gas from the scrubber was reheated from 125 F to 250 F as a base case, and from 125 F to 175 F as an alternate case. The study was performed on a basis consistent with the General Electric ECAS Phase II evaluation of advanced energy conversion systems for electric utility baseload applications using coal or coal-derived fuels. A conceptual design of the power plant was developed, including the on-site calcination of limestone to lime and the provision of sludge ponds to store the products of flue gas scrubbing. From this design, estimates were derived for power plant efficiency, capital cost, environmental intrusion characteristics, natural resource requirements, and cost of electricity at an assumed capacity factor of 65%. An implementation assessment was performed where factors affecting applicability of the conceptual design power plant in electric utility generation systems were appraised. At 250 F and 175 F stack gas temperatures respectively, the plants showed a cost of electricity of 39.8 and 37.0 mills/kWh and overall plant efficiencies of 32% and 34%.

203.
King, J. M. (United Technologies Corp.)
Energy Conversion Alternatives Study (ECAS). United Technologies Phase II, Final Report. Integrated Coal Gasifier/Molten Carbonate Fuel Cell Powerplant Conceptual Design and Implementation Assessment
U. S. Gov't, NTIS, NASA CR-134955, 1976

204.
Robson, F. L., Giramonti, A. J., Lewis, G. P. and Gruber, G. (United Aircraft Research Labs)
Technological and Economic Feasibility of Advanced Power Cycles and Methods of Producing Nonpolluting Fuels for Utility Power Stations
U. S. Goc't, NTIS, PB-198,392 (or UARL J-970855-13), Dec. 1970; 557 pp

Analytical studies have been made to identify the technical and economic factor that will govern future selection of fuel cleanup processes and advanced-cycle central power stations, which, in combination, will be capable of producing electric power at the lowest possible cost while reducing substantially the emissions of sulfur oxide pollutants resulting from the combustion of high-sulfur coal and residual fuel oil. The technical approach was based upon technology currently available, but possibly not reduced to commercial practice as well as technology judged attainable for commercial use within the next ten and twenty years. This approach included evaluations of current and projected; fossil-fuel desulfurization and conversion processes, current and advanced-cycle central power stations, and integrated fuel cleanup and power stations.

205.
Gluckman, Michael J. (City College, New York. Dept. of Chemical Engineering)
Combined Cycle System Studies
U. S. Gov't, NTIS, PB-228,876/9 (or CCERI-102), July 1973; 15 pp

The report discusses the effects of air compression ratio on the efficiency of combined gas and steam turbine power generating equipment. Described is a partially supercharged superheating system devised to reduce the high stack temperatures experienced from conventional exhaust fired systems when large amounts of saturated steam are introduced into the steam boiler superheating section.

206.
National Academy of Engineering
Evaluation of Coal Gasification Technology
Part II: Low and Medium-Btu Fuel Gases
Office of Coal Research R & D Report No. 74/Int 2
U. S. Gov't. NTIS, PB-234,042/AS (or OCR R&D Report No. 74/Int 2), June 1974

207.
Hedley, William H. (Monsanto Research Corp.)
Effect of Gas Turbine Efficiency and Fuel Cost on Cost of Producing Electric Power
U. S. Gov't, NTIS, PB-234,159/2 (or EPA 650/2-74-041), May 1974; 32 pp

The report gives results of a study of the effect of gas turbine efficiency and fuel cost on the cost of producing electric power. It indicates that combining gas and steam turbines (COGAS Systems) can increase overall power generation efficiency. It tabulates gas turbine efficiencies which must be achieved to produce power at cost of 6-10 mills per kwh, as a function of fuel costs of 40-100 cents per million Btu. Improved gas turbine efficiency of 29-37% is seen over the next 9 years, resulting in combined cycle efficiencies of 42-54%.

208. 209.
Katz, D. L., Briggs, D. E., Lady, E. R., Powers, J. E., Tek, M. R., Williams, B. and Lobo, W. E. (University of Michigan, College of Engineering) (for Electric Power Research Inst.)
Evaluation of Coal Conversion Processes to Provide Clean Fuels (2 Vol.) (Final Report)
U. S. Gov't, NTIS, PB-234,202/OGA and PB-234,203/8GA, (or EPRI 206-0-0, Parts I & II), 1974; Vol. I, 78 pp; Vol. II, 410 pp

Volume I

A review is made of six general methods of coal utilization with elimination of the sulfur prior to or during combustion in an electric power generating plant: fluidized bed combustion, coal beneficiation, pyrolysis, coal gasification, coal dissolution and liquefaction, insitu combustion. The processes in each category were reviewed, analyzed and evaluated. Critical process steps, where additional research must be done before the processes can be considered at the commercial stage of development, were identified. The advantages and disadvantages of 37 processes were identified. Also included are discussions of combined cycle systems, economics, retrofit capabilities, thermodynamics and coal slurry pipelines. These topics give perspective to the general subject of coal use. (modified author abstract)

Volume II

The goals of the project were to investigate the ongoing research and development programs on coal conversion to clean fuels and coal utilization in environmentally acceptable ways for electric power generation, and recommend to EPRI those processes whose development warrants acceleration through EPRI's support. The conduct of the investigation is described with some general concepts and observations made during the seven month study. Part I contains the choices and recommendations for research support by EPRI. Those processes which seem to have the best prerequisites for providing clean fuels from coal at the earliest dates were delineated. The bases for the reasoning behind the choices are given. Coal beneficiation, gasification, liquefaction and fluidized bed combustion were compared and evaluated with regard to their potential integration into the electric power industry.

210.
Brinn, D. G. (British Steel Corp.)
The Gasification of Coal - A Bibliography
U. S. Gov't, NTIS, PB-234,294/7, June 1974; 15 pp

The bibliography consists of some 60 annotated references from the literature maily within the period 1970-1973. The processes considered are: Winkler; Winkler-Flesch; Lurgi; Bi-Gas; Koppers Totzek; Hygas; CO_2 Acceptor; Atgas; Kellogg; Synthane; Westinghouse; Cogas; Stone and Webster; and Hydrane.

211.
Subramaniam, T. K. and Tsaros, C. L. (Institute of Gas Technology)
The Effect of Accounting Factors on the Economics of Synthetic Pipeline Gas
U. S. Gov't, NTIS, PB-235,371/AS (or OCR R & D Report No. 22/Int 5), October 1970

In 1965 the Office of Coal Research adopted a tentative standard for pricing synthetic pipeline gas. This standard has been used by all of our contractors for the sake of uniformity. The standard assumes that a coal-to-pipeline-gas plant is owned by an investor-owned, regulated, utility. It also assumes certain financial factors, including interest rates, which are currently unrealistic.

212.
Ashworth, R. A., Switzer, G. W. Jr. (Gilbert Associates, Inc.)
Low BTU Gasification High Temperature-Low Temperature H_2S Removal Comparison Effect on Overall Thermal Efficiency in a Combined Cycle Power Plant, Office of Coal Research R & D Report No. 79, Interim 1
U. S. Gov't, NTIS, PB-235,780/4ST, January 1974; 65 pp

The report compares the effect of high temperature and low temperature coal gas desulfurization on power plant thermal efficiency. A combined power cycle, gas turbine and steam turbine, was assumed for the coal gasification/power generation process. Material balances, flow sheets with temperature, pressure, energy output, and overall heat balance closure are considered.

213.
Westinghouse Electric Corp. (for Office of Coal Research)
Advanced Coal Gasification System for Electric Power Generation, Office of Coal Research R & D Report No. 81, Interim 1
U. S. Gov't, NTIS, PB-236,971/8SL, May 1974; 250 pp

The objective of this program is to build and operate an advanced gasification system and electric generating plant on an existing electric utility distribution network. The program covers six phases, including the construction and operation of a process development unit (PDU) with a capacity of 1200 lbs/hr and completing the design of a suitable generating pilot plant gasifier and a fuel gas study. Work covered by this report during the first year of the program has been focused and concentrated on Phase I, development of the fluidized-bed gasifier. The latter phases will be concerned with the design, construction and operation of a full-size gasifier and generating pilot plant of about 120 MW. Desulfurization/devolatilization processes, turbine design, and combustor design are also discussed.

OCR R & D Report No. 81, Interim 2 = FE-1514-T-4

214.
Patterson, R. C. et al (Combustion Engineering, Inc.)
Low-Btu Gasification of Coal for Electric Power Generation. OCR R & D Report No. 83, Final Report, Phase 1
U. S. Gov't, NTIS, PB-236,972/AS (or OCR R&D Report No. 83/Int 1), Sept. 1974

215.
Electric Power Research Inst.
Power Generation--Clean Fuels Today (A Seminar sponsored by EPRI)
U. S. Gov't, NTIS, PB-237,661/4GA (or EPRI-SR-1), April 1974; 110 pp

The report gives an overview of reserves and availability of fossil fuels and the problems utilities face in obtaining clean fuel for oil- and gas-fired plants; reviews the status of clean energy production technology; and assesses current government policy on fuel for power generation. A variety of technological options, primarily gasification techniques, to convert oil or coal to clean fuel for electric power generation are presented.

216.
Shore, D., O'Donnell, J. J., Chan, F. K. (Kellogg M. W. Co.)
Evaluation of R and D Investment Alternatives for SOx Air Pollution Control Processes
U. S. Gov't, NTIS, PB-238,263/8ST (or EPA 650/2-74-098), September 1974; 288 pp

The report presents data on sulfur oxide (SOx) emissions from five major source groups: utility plants, industrial boilers, non-ferrous smelters, sulfuric acid plants, and sulfur (Claus) plants. For all source groups studied, the bulk of the SOx emissions comes from a relatively small number of the largest plants. The report also included evaluations of several different sulfur control systems, including stack gas scrubbing (wet limestone process and Wellman/Allied system), substitute natural gas, solvent refined coal, Lurgi gasification with a combined power cycle, and pressurized fluidized-bed combustion with a combined power cycle. Process and cost models and/or economics are presented for each system. Cost models for the stack gas scrubbing processes were applied to existing utility plants in the U. S. and the results analyzed.

217.
KVB Engineering, Inc.
Reduction of NOx Through Staged Combustion in Combined Cycle Supplemental Boilers. Volume I. Systems Optimization Analyses
U. S. Gov't, NTIS, PB-241,463/9ST (or EPRI 224, Vol. 1), February 1975; 79 pp. Vol. 2, see PB-241,464/9ST

This report discusses an investigation directed to control of emissions from supplemental-fired combined cycles with the use of staged combustion in the steam generating portion of the system. A combined cycle, as considered in this report, is the assemby of any number of gas turbines, steam generators, and steam turbines for electric power generation in which the exhaust of the gas turbines is passed through the steam generators. A supplementary-fired combined cycle employs combustion of fuel in the gas turbine exhaust to increase temperatures in the steam system. Staged combustion is achieved by the separation of the exhaust from the gas turbines into two streams prior to entering the steam generator with provisions for primary combustion of fuel in one stream with a deficiency of air. Combustion is completed in a secondary stage by mixing the unfired stream into the products of the fired stream. The use of staged combustion provides conditions favorable for the occurrence of chemical reactions that results in a reduction of mass flow of nitric oxide (NO) present in the gas turbine exhaust. Volume I is concerned with the engineering analysis of combined cycle performance and NOx reduction potential.

218.
KVB Engineering, Inc.
Reduction of NOx Through Staged Combustion in Combined Cycle Supplemental Boilers. Volume II. Experimental Program
U. S. Gov't, NTIS, PB-241,464/9ST (or EPRI 224, Vol. 2), February 1975; 101 pp. Vol. 1, see PB-241,463/9ST

The report describes the experimental program and results of an investigation of staged combustion in combined cycle (steam-gas turbine) electric power generation for the reduction of NOx in the exhaust gases. Several burner configurations were tested, and various flow schemes and air fuel ratios were used.

219.
Waitzman, D. A., Faucett, H. L., Kindahl, E. E., Tomlinson, S. V. and Nichols, D. E.
(Electric Power Research Institute)
Evaluation of Fixed-Bed, Low-Btu Coal Gasification Systems for Retrofitting Power Plants.
U. S. Gov't., NTIS, PB-241,672/5GA (or EPRI-203-1), Feb. 1975; 281 pp

Seven alternative systems are considered: (1) Wellman-Galusha/Benfield System, (2) Wellman-Galusha/Stretford System, (3) Wellman-Galusha/Iron Oxide System, (4) Wellman-Galusha/Iron Oxide/Fines Gasification System, (5) Lurgi/Benfield System, (6) Lurgi/Stretford System, and (7) Lurgi/Iron Oxide System. Provided are conceptual designs and capital and operational cost estimates for six of the systems including associated coal handling, fines removal and sales (or gasification in the Wellman-Galusha/iron oxide/fines gasification system), air compression and boiler modifications. The report estimates the cost of and describes low-Btu, fixed-bed gasification plants that might be operated in the near future on retrofitted power plants, and compares fixed-bed gasification with stack gas cleaning processes.

220.
Southern Research Inst.
A Survey of Technical Information Related to Fine-Particle Control
U. S. Gov't, NTIS, PB-242,383/8GA (or EPRI-259), April 1975; 253 pp

A survey was made of information available on subjects related to fine-particle fly-ash emissions from electric utility power boilers, with special attention to trace elements and other materials associated with fly ash that may affect health when inhaled. Information was obtained on (1) the concentrations and distribution of trace elements in fly ash, (2) the toxicology and epidemiology of fly-ash inhalation, (3) the methods used for measuring the particle-size distribution of fly ash and for determining the contents and nature of trace elements in it, and (4) the effectiveness of emission control devices in the removal of sub-micron particles of fly ash from fuel gas.

This report discusses an investigation directed to control of emissions from supplemental-fired combined cycles with the use of staged combustion in the steam generating portion of the system. A combined cycle, as considered in this report, is the assembly of any number of gas turbines, steam generators, and steam turbines for electric power generation in which the exhaust of the gas turbines is passed through the steam generators. A supplementary-fired combined cycle employs combustion of fuel in the gas turbine exhaust to increase temperatures in the steam system. Staged combustion is achieved by the separation of the exhaust from the gas turbines into two streams prior to entering the steam generator with provisions for primary combustion of fuel in one stream with a deficiency of air. Combustion is completed in a secondary stage by mixing the unfired stream into the products of the fired stream. The use of staged combustion provides conditons favorable for the occurrence of chemical reactions that result in a reduction of mass flow of nitric oxide (NO) present in the gas turbine exhaust. Volume I is concerned with the engineering analysis of combined cycle performance and NOx reduction potential.

221.
Fluor Engineers and Constructors, Inc.
Economics of Air vs. O_2 Pressure Gasification of Coal
U. S. Gov't, NTIS, PB-242,595/7ST (or EPRI-239-1-I), January 1975; 204 pp

Directional economic trends for the alternative use of air or oxygen in coal gasification processes are studied. The processes evaluated are: moving bed, fluidized bed, and entrained bed gasification to produce clean fuel gas. In addition, entrained bed coal gasification is studied in conjunction with a combined cycle power plant.

222.
Aerospace Corporation (for the National Science Foundation)
Power Plant Economic Model Program Description and User's Guide
U. S. Gov't, NTIS, PB 243,625 (or NSF-RA-N-74-209), June 1, 1974

The Aerospace Corporation Power Plant Economic Model was developed to provide an analytic tool for comparing the economics of alternative types of power plants. In addition, by comparing the capital investment requirements and operating costs of alternative solar systems, preferred concepts can be identified. The economic feasibility of these preferred systems can be determined by comparative economic evaluation of these and conventional nuclear and fossil-power plants for identical periods of commercial operations.

223.
Keairns, D. L., Archer, D. H., Hamm, J. R., Jansson, S. A., Lancaster, B. W. (Westinghouse Research Labs.)
Fluidized Bed Combustion Process Evaluation. Phase II. Pressurized Fluidized Bed Coal Combustion Development
U. S. Gov't, NTIS, PB-246,116/8ST (or EPA 650/2-75-027C), September 1975; 480 pp

The report gives results of a program to evaluate and develop pressurized fluidized-bed coal combustion. The historical, technical, and economic aspects of fluidized bed combustion (FBC) systems have been reviewed, systems analyses performed, commercial plant design and cost estimates prepared, and experimental data on the sulfur removal system obtained. Two pressurized FBC power plant systems have provided the basis for the work on system design, performance, economics, and development. The basic design and performance parameters for these two systems are presented. The present work extends the previous work to include collection and analysis of data on critical system parameters (e.g., sulfur removal, spent sorbent disposition, and trace element release); development of process options (e.g., particulate control); and assessment of power plant cycles and component designs (e.g., use of low-temperature gas cleaning, alternative cycles, and gas turbine corrosion/erosion test rig design and construction). The report includes an extensive bibliography.

224.
Leigh, D. C. et al (Kentucky Univ.)
Advanced Coal-Derived Fuel Combined-Cycle Power Plants
U. S. Gov't, NTIS, PB-246,202/6ST, September 1975; 226 pp

The special objectives of this study were the utilization of high-sulfur caking coals typical of Western Kentucky for electric power generation at high efficiencies, to be put in operation in the early 1980's. Various power systems are evaluated against these objectives consistent with environmental considerations and economic criteria.

Also listed as Report 2-PD2-75 of The Institute of Mining and Minerals Research, University of Kentucky, Lexington, Ky, Sept. 1975

225.
Robson, Fred L., Giramonti, Albert J., Blecher William A. (United Technologies Research Center) and Mazzella, Gerald (Foster Wheeler Energy Corp.)
Fuel Gas Environmental Impact: Phase Report
U. S. Gov't, NTIS, PB-249,454/OST (or EPA 600/2-75-078), November 1975; 314 pp

The report gives results of an evaluation of the technical and economic feasibility of: (1) Lurgi-type fixed-bed gasifiers and BCR-type entrained-flow gasifiers in combination with low-and-high-temperature fuel gas cleanup systems; (2) advanced technology combined-cycle power systems; and (3) integrated gasificaion systems, cleanup processes, and power systems. Processes and systems considered were those using technology both currently available for power station configurations which the contractor judged could appear in commercial applications in the 1975-78 time frame (first generation systems) and potentially applicable in the 1980-decade time period (second generation) systems). The results indicate that high-temperature cleanup systems have the potential of improving the efficiency and reducing the capital costs of integrated gasification systems.

226.
Truett, J. Bruce (Mitre Corp.)
Gasification/Combined-Cycle System for Electric Power Generation
U. S. Gov't, NTIS, PB-251,823/1ST (or EPA 600/2-76-085), March 19
50 pp

This report describes a type of gasification/combined cycle system being considered for construction by a consortium of Louisiana cities that own electrical utility systems. The 115 KW system is expected to employ the Texaco Synthesis Gas Generation Process (TSGGP) to produce a fuel gas by partial oxidation of a hydrocarbon feedstock. The gas is cleaned to remove sulfur compunds, ash, and particulates, then burned as fuel for the gas turbine in a combined-cycle power system. The commercially-proven TSGGP process accepts a large variety of hydrocarbons as feedstocks. The initial feedstock for this application is expected to be heavy petroelum residues, although the potential exists for utilization of coal and lignite. Other features of the proposed system include (1) high thermal efficiency (relative to conventional steam generators) resulting in part from efficient recovery of thermal energy from the gasification of feedstock; and (2) extremely low levels of pollutants (SOx, NOx) in emissions to the atmosphere. The five participating municipalities have established a joint commission, "Louisiana Municipal Power Commission" (LAMPCO), which has retained the services of bond counsel and investment banking firms, and is proceeding with plans to implement the proposed power generation facility.

227.
Sawyer, R. F., Brown, N. J., Matthews, R. D., Branch, M. C., Banna, S. M.
et al (University of California, Berkeley) (for EPRI)
The Formation of Nitrogen Oxides from Fuel Nitrogen, Final Report
U. S. Gov't, NTIS, PB-252,462 (or EPRI 223-1), March 1976; 84 pp

This study is a step toward increasing the understanding of the chemistry of fuel nitrogen and oxides of nitrogen reactions in combustion environments. The ability to account quantitatively for all of the nitrogen is essential and has constituted a major part of this effort. The measurement of gaseous nitrogen compounds at low concentrations, 1 to 1000 ppm, in a complex mixture of combustion products is far from trivial. Although the present work fails to provide a complete and unambiguous accounting of all significant nitrogen species, it does represent progress toward that goal. In the following sections the report deals with (a) a review of other studies of fuel-nitrogen chemistry, (b) nitrogen compound measurement, (c) premixed flame experiments.

228.
Teixeira, Donald P., Editor (Electric Power Research Institute)
The Proceedings of the NO_x Control Technology Seminar (held in San Francisco, Calif., Feb. 5-6, 1976)
U. S. Gov't, NTIS, PB-253,661 (or EPRI SR-39), Feb. 1976; 433 pp

On February 5 and 6, 1976, EPRI sponsored a conference in San Francisco on the status of technology for control of oxides of nitrogen from power generation facilities. Coal-fired steam generators, gas turbines and synthetic fuel NO_x emissions were covered during the two-day seminar. Representatives of electric utilities, regulatory agencies, academic institutions, research organizations and other industries were present. The purpose of this Seminar was threefold: first, to acquaint the utility industry with stringent NO_x emission standards for fossil fueled power plants currently under consideration by regulatory bodies; second, to evaluate the current state of the art for NO_x control; and finally, to assess future technical options for NO_x control and, where possible, to present their economic consequences.

229.
Corman, J. C., Fleck, J. J., Fleming, R. B., March, W. D. and Pomeroy, B. D. (General Electric Co.)(for Electric Power Research Inst.)
Comparative Study and Evaluation of Advanced Cycle Systems
U. S. Gov't, NTIS, PB-254,392/4ST (or EPRI AF-158), May 1976; 276 pp

Technical and economic characteristics of various advanced energy conversion systems and research and development requirements, including costs, necessary to establish their commercial feasibility are discussed. Systems studied include recuperative gas turbine, combined cycle gas turbine, advanced steam, closed cycle gas turbine, open cycle magnetohydrodynamics (MHD), closed cycle plasma MHD, liquid metal MHD, thermionic, and fuel cell (low temperature).

230.
Kadlec, P. A., Martins, O. R. (Gilbert Associates, Inc.)
Design Phase Utility Analysis for Gas Turbine and Combined Cycle Plants
U. S. Gov't, NTIS, PB-256,665/1ST, August 12, 1976; 78 pp

The objectives of this study are: (1) to analyze and identify those factors, trends and effects related to the usage of gas turbine (GT) and combined cycle (CC) power plants for base, intermediate and peaking load service as compared to alternate fossil fuel units for both public and privately owned utilities; (2) To forecast the future usage of GT and CC units to supply base, intermediate and peak load needs; (3) To examine and identify the engineering advantages and disadvantages of CC and GT technologies, and arrive at a definition for combined cycle power plants.

231.
Robson, F. L., Blecher, W. A., Colton, C. B. (United Technologies Research Center)
Fuel Gas Environmental Impact
U. S. Gov't, NTIS, PB-257,134/7ST (or EPA 600/2-76-153), June 1976; 287 pp

As they relate to combined cycle power generation, the report gives results of an evaluation of the technical and economic considerations of atmospheric-pressure, oxygen-blown coal gasifiers (Koppers-Totzek) and pressurized, air-blown, partial-oxidation residual-oil gasifiers (Shell/Texaco). It defines the environmental impact of combinations of: (1) fossil fuel gasification systems, (2) low-and high-temperature fuel gas cleanup processes, and (3) advanced cycle power systems.

232.
Ayer, Franklin A., Editor (Research Triangle Inst.)
Symposium Proceedings: Environmental Aspects of Fuel Conversion Technology, II (December 1975, Hollywood, Florida)
U. S. Gov't, NTIS, PB-257,182/6ST (or EPA 600/2-76-149), June 1976; 389 pp

The report covers EPA's second symposium on the environmental aspects of fuel conversion technology. The symposium was conducted at the Diplomat Hotel, Hollywood, Florida, December 15-18, 1975. Its main objective was to review and discuss environmentally related information in the field of fuel conversion technology. Specific topics were environmental probelm definition, process technology, control technology, and process measurements.

233.
Colton, C. B.; Dandavati, M. S.; May, V. B. (Hittman Associates, Inc.)
Low and Intermediate Btu Fuel Gas Cleanup
U. S. Gov't, NTIS, PB-257,182/6 (or EPA 600/2-76-149),
June 1976; pp 193-215

There is a variety of systems presently available and under development to control the emissions from and protect the turbine of a combined cycle power plant burning fuel gas produced by gasifying coal. In the broadest sense, these processes can be characterized as high- and low-temperature processes. Many of these processes have unique features governing their application to specific combinations of coal gasifiers and combined cycle power plants. This paper presents an overview of high- and low-temperature cleanup processes, and addresses the considerations involved in their selection

234.
Salvador, L. A., Vidt, E. J., Holmgren, J. D. (Westinghouse Research Labs.)
Westinghouse Fluidized Bed Combined Cycle Process: Status of Technology and Environmental Considerations.
U. S. Gov't, NTIS, PB-257,182/6 (or EPA-600/2-76-149), June 1976;
pp 133-151

The conversion of coal to a clean, low Btu gas to fuel a combined-cycle power generation plant holds promise of being one of the most economic, efficient, and environmentally acceptable methods of utilizing coal resources to provide the nation's energy needs. Westinghouse Electric Corp. as leader of a government/industry team is developing this power generation system utilizing a multiple-fluidized bed process for devolatilization, desulfurization, and gasification of coal to produce low-Btu fuel for a combined-cycle power generation package. The team is implementing one of the first totally integrated coal conversion programs, from bench-scale to a complete coal to electric power energy conversion package. The program is presently in the design and development phase. Bench-scale development activities are being performed in conjunction with the operation of a 1200 lb/h process development unit (PDU) to evaluate process feasibility and operability. A conceptual design for full-scale generating plant has been completed. The testing has been directed toward a number of technical and environmental considerations including the behavior of high-sulfur, caking coals, ash removal and disposal, sulfur removal and disposal, control of combustion product effluents turbine protection, and product gas cleaning. Operation of the system to provide power in an efficient and environmentally acceptable way is feasible.

235.
Robson, F. L., Blecher, W. A., Giramonti, A. J. (United Technologies Research Center)
Combined-Cycle Power Systems
U. S. Gov't, NTIS, PB-257,182/6 (or EPA 600/2-76-149), June 1976;
pp 359-371

The performance, cost, and emissions of integrated fuel processing/combined-cycle power systems are identified and compared to those of a coal-fired steam station. Of the many types of advanced power systems being proposed as partial solutions to this country's long range energy problem, the Combined Gas And Steam (COGAS) system is the only one currently in the commercial stage, with several thousand Mw already installed in utility systems. The systems now installed and those more advanced versions being proposed require a very clean fuel in order to assure reasonable gas turbine performance and lifetime. While these clean fuels can be produced from coal, the processes are inefficient, typically losing 20 to 30 percent of the original coal heating value. By integrating the fuel processing system with the COGAS power system, much of the inefficiencies which appear as process heat can be recovered, resulting in overall plants having efficiencies, costs, and emissions which are more attractive than present-day conventional coal-fired steam stations.

236.
Blake, David E. (Acurex Corp.)
Particulate Control in Energy Processes Symposium Held at San Francisco, California on May 11-13, 1976
U. S. Gov't, NTIS, PB-260,499/9ST (or EPA 600/7-76-010), September 1976; 577 pp

Methods of control of particulate emission from conventional electric power generation facilities are well developed and reasonably effective. However, several recent developments in combustion technology have significantly increased the difficulty of particulate collection. There is an immediate problem with the rapidly increasing use of low-sulfur, high-ash Western coals. Because of the high mineral content of these coals, ash is produced at higher rates than for high-sulfur (Eastern) anthracite or bituminous coals. Compounding the problem, the low sulfur content decreases the effectiveness of electrostatic precipitators. The most severe problems arise when attempting to switch existing power plants (with precipitators sized for high-sulfur coal) to low-sulfur coals. A longer-range problem with particulate collection exists with several high temperature and pressure energy processes now being developed. In order to obtain maximum efficiency of power generation from coal gasifier or fluidized bed combustion facilities, it is necessary to remove particulates from hot, high pressure streams upstream of the turbines. The symposium, held in San Francisco on May 11-13, 1976, devoted six sessions, two panel discussions, and some 22 papers to consideration of these problems and their solutions. This volume is a collection of the papers presented at the symposium.

237.
Grandys, Kenneth (Illinois State Department of Business and Economic Development)
Coal Conversion Technologies
U. S. Gov't, NTIS, PB-260,664/8ST, September 1, 1975; 34 pp

This report gives the reader a brief overview of the most promising technologies in the fields of coal gasification and liquefaction.

238.
M. W. Kellogg Co.
Comparison of Flue Gas Desulfurization, Coal Liquefaction, and Coal Gasification for Use at Coal-Fired Power Plants
U. S. Gov't., NTIS, PB-264,536/4WE (or EPA-450/3-75-047), April 1975; 158 pp

The report presents a technical and economic comparison of the use of flue gas desulfurization, coal liquefaction, and coal gasification as a means of preventing SO_2 emissions at coal-fired power plants. The report assesses the status of technology, process complexity, process flexibility, environmental effects, installation difficulties, energy conversion efficiency, manpower requirements, and economics of each approach to controlling SO_2 as it would be applied to electric power plants. Three different flue gas desulfurization systems were evaluated as well as one coal liquefaction and one coal gasification process. Two power plant cases are evaluated, an existing 500 MW plant operating at 60 percent load factor and a new 1,000 MW plant operating at 80 percent load factor.

239.
Ashworth, R. A., Vyas, K. C., and Bonamer, D. G. (Arthur G. McKee and Co.)
Utilization of Low and Intermediate Btu Gas from Coal for Iron Ore Pelletizing
U. S. Gov't, NTIS, PB-264,702/2WE (or Bur Mines OFR 36-77)
March 1977; 283 pp

Technical and economic feasibility of gasification of low rank solid fuels to provide fuel gas for firing iron ore pelletizing furnaces in Northern Minnesota are discussed. Comparisons are made of several types of gasifiers, gas characteristics, and economics of large, centrally located gasification plant with gasification facilities at individual pellet plants. Costs of retrofitting to grate-kiln, traveling grate, and shaft type furnaces are compared.

240.
Oak Ridge National Laboratory
Inventory of Energy Research and Development: 1973-1975, Volume II. Serial U
U. S. Gov't, NTIS, PB-265,126/3ST (or NSF-RA-760494),
January 1976; 1344 pp

Volume II contains abstracts in the following subject areas: (1) electric power generation; and (2) energy uses and conservation. The following methods of electric power generation are discussed: fossil fueled and unspecified; fission fueled; hydroelectric; nuclear fusion; MHD and EFD; and direct methods. In the section on energy uses and conservation the following energy uses are treated: heating and cooling; lighting; appliances and equipment; industrial and manufacturing processes; transportation; agricultural; medical; military; and communications.

241.

Fluor Engineers & Constructors, Inc. (for Electric Power Research Inst.)
Economics of Current and Advanced Gasification Process for Fuel Gas Production (Final Report)
U. S. Gov't, NTIS, PB- (or EPRI AF-244), 1976; 247 pp

The purpose of this study was to evaluate for several different gasifiers whether air or oxygen blowing resulted in an economic advantage in fuel gas production from coal. For each technology considered oxidant and steam requirements, fuel gas quantity and composition and gasifier equipment requuurements were obtained from developers representative of that technology. The gasification devices investigated were:

Technology	Pressure	Developer
Moving Bed--Dry Ash	340 psig	Lurgi
Fluidized Bed	340 psig	Institute of Gas Technology
Entrained Bed	Atmospheric	Combustion Engineering

Complete grass roots plants were designed to convert 10,000 tons/day of Illinois No. 6 coal to clean fuel gas. The Moving Bed and Fluidized Bed plants were designed to deliver product fuel gas at 25 psig. This delivery pressure could be increased to 225 psig with minor economic penalties because the gasifiers in these processes operate at pressure. The Entrained Bed plants were designed to deliver product fuel gas at 40 inches water pressure. Increasing the delivery pressure substantially would result in significant economic penalties.

242.

Stone & Webster Engineering Corp. (for Electric Power Research Inst.)
Comparative Evaluation of High and Low Temperature Gas Cleaning for Coal Gasification-Combined Cycle Power Systems (Final Report)
U. S. Gov't., NTIS, PB- (or EPRI AF-416),
April 1977; 152 pp

The purpose of this screening study was to evaluate the incentives for developing hot gas purification technology for application to coal gasification--combined cycle power generating systems. The iron oxide process currently being developed by the Morgantown Energy Research Center for removal of hydrogen sulfide at high temperature (1,000°F) was selected for this study as it was judged to be in a more advanced stage of development than other high temperature absorption processes currently being developed. Process and economic evaluations were performed for five different coal gasification schemes, i.e. air and oxygen blown dry ash, moving bed Lurgi gasifiers; oxygen blown slagging, moving bed gasification currently being developed by the British Gas Corporation; and oxygen and air blown two-stage entrained gasifiers proposed by Foster Wheeler. For each of the above gasification schemes, four complete system flowsheets were developed for converting Illinois #6 coal to electricity via combined cycle power generation. Two of these processing schemes were based on high temperature iron oxide technology with gas turbine inlet temperatures of 1,950°F and 2,400°F. The other two flowsheets for each gasifier incorporated the low temperature Benfield process with gas turbine inlet temperatures of 1,950°F and 2,400°F. The results of this study indicate that there is a large economic incentive for developing hot purification technology for dry ash Lurgi gasification systems. For advanced gasification schemes such as the BGC slagger or the two-stage entrained gasifier, no incentive could be identified for the development of high temperature iron oxide gas cleaning technology. Major technical questions that were raised concerned problems associated with the regeneration of iron sulfide, the fate of trace contaminants such as ammonia and alkali metal vapors in the system, as well as the ability to remove particulates from the gas streams both before and after contact with the iron oxide absorption equipment.

243.
USAEC, Washington, D.C.
Advanced Conversion: C-1-B Advanced Conversion
U. S. Gov't, NTIS, TID-26744, November 11, 1974; 135 pp

Program planning and budgetary constraints are discussed with respect to the following advanced power cycles and systems: (1) high temperature gas turbines; (2) MHD power plants; (3) fuel cell power plants; (4) potassium topping cycle; and (5) combined cycles. The economical aspects of coal gasification, use of waste heat and fuel, and thermionic conversion are also considered.

244.
USAEC, Washington D.C.
Advanced Conversion: C-1-A Summary
U. S. Gov't, NTIS, TID-26745, November 11, 1974; 13 pp

Budget estimates for the development of advanced power cycles were reviewed and determined to be too low to achieve the indicated goals. At present it is not possible to select an advanced cycle system with high confidence because of: (1) substantial technical uncertainties in all attractive options; (2) large uncertainties in development costs and ultimate capital costs; and (3) the uncertainty of the types of fuels which will be developed and supplied in the next few decades. Volume I also contains a summary of the most attractive advanced power cycles.

245.
United Engineers and Constructors Inc.
Coal-Fired Fossil Plant. 1000-MWe Central Station Power Plants Investment Cost Study
U. S. Gov't, GPO, WASH-1230 (Vol. III), June 1972; 88 pp

This report on a 1000 MWe nominally rated Coal-Fired Fossil Plant is one of a series of investment cost studies covering detailed cost and unit quantities performed under AEC contract number AT(30-1)-3032, modification 9. The intent of these studies is to present detailed cost information for a series of 1000 MWe electric generating plants to permit cost comparisons, evaluations and projections based on equivalent assumptions relative to site, labor, performance, and reference dates for cost data.

246.
USAEC, Washington D.C.
Conversion Techniques. Subpanel Report VI Used in Preparing the AEC Chairman's Report to the President
U. S. Gov't, NTIS, WASH-1281-6, November 13, 1973; 355 pp

Improved energy conversion techniques for the reliable generation of electric power and for energy conservation are of great importance, and the goals of this R and D program are to (1) increase the efficiency of use of indigenous energy supplies (coal and uranium as well as new, alternate energy sources), (2) to reduce the environmental impact of this power production, and (3) to reduce the capital cost for construction of new power plants. For the purpose of reaching these goals, the following eight objectives were established: (1) coal gasification: to develop processes for the production and use of clean low-Btu gas from coal in central power stations; (2) gas turbines: to increase the overall efficiency and reliability of power generation by developing high-temperature gas-turbine systems; (3) MHD: to increase the overall efficiency and reliability of power generation by developing MHD power systems; (4) potassium topping cycle: to increase the overall efficiency and reliability of power generation by developing potassium-vapor topping systems; (5) fuel cells: to develop efficient and economical fuel cells for power generation; (6) use of waste heat and fuel: to develop power systems for economical use of heat and fuel presently wasted; (7) advanced concepts: to evaluate, to investigate, and ultimately to develop advanced concepts for energy conversion; and (8) enabling technology: to evolve the basic constituent technologies that enable the substantial improvement of various power systems or that make feasible entirely new concepts for power generation. An implicit constituent of these objectives is to minimize the environmental impact of power generation. These eight objectives represent a significant narrowing of the range of options considered. Under the pressure of severe budgetary constraints, the R and D originally proposed on low-temperature cycles was deferred and converted instead to a study under advanced concepts. Further, the use of waste heat and fuel was confined to the use of solid waste for power generation.

U. S. Government Reports Utilized - By Report Number

Report No.	Item
AD-701,575	148
Bureau of Mines, Bull. 503	148
Bureau of Mines, Bull. 627	149
Bureau of Mines, Minerals Yearbook, 1971	150
Bureau of Mines, OFR 36-77	239
CCERI-102	205
CONF-730403-P1	140
CONF-730403-P2	53
CONF-741179	77
CONF-750806-P2	107
CONF-7509173-2	110
CONF-760358	132
CONF-760402-8	127
CONF-760906-P1	125, 136
EPA 450/3-75-047	238
EPA 600/2-75-078	225
EPA 600/2-76-085	226
EPA 600/2-76-149	232-235
EPA 600/2-76-153	231
EPA 600/7-76-010	236
EPA 650/2-74-041	207
EPA 650/2-74-098	216
EPA 650/2-75-027C	223
EPRI 203-1	219
EPRI 206-0-0, 2 Vol.	208-209
EPRI 223-1	227
EPRI 224, 2 Vol.	217, 218
EPRI 239-1-I	221
EPRI 243-1	151
EPRI 259	220
EPRI AF-158	229
EPRI AF-244	241
EPRI AF-416	242
EPRI SR-1	215
EPRI SR-39	228
ERDA 76-10	152
ERDA 76-30-4	153
EPRI 76-31-2	154
EPRI 76-49	155
EPRI 76-52	156
EPRI 76-63	157
EPRI 76-86	158
EPRI 76-93-1	159
EPRI 76-93-2	160
EPRI 76-94-1	161

Report No.	Item
FE 1235-1	162
FE 1236-10	163
FE 1236-T1	164
FE 1236-T2	165
FE 1514-42	166
FE 1514-47	167
FE 1514-52	168
FE 1514-53	169
FE 1514-T4	170
FE 1514-T6	173
FE 1514-T7	171
FE 1514-T8	171
FE 1514-T9	172
FE 1521-13	174
FE 1521-36	175
FE 1521-40	176
FE 1521-44	177
FE 1756-1	178
FE 1765-4	179
FE 1765-13	180
FE 1772-11	181
FE 1775-4	182
FE 1806-1	183
FE 1806-6	184
FE 2083-4	156
FE 2292-4	185
FE 2292-7	186
FE/WAPO-7612-1	187
N76-20631	188
N76-23679/3WE	189
N76-23692	190
N76-23693	191
N76-23696/7ST	192
NASA CR-134941, Vol. 1, 2, and 5	190 191, 192
NASA CR-134942, Vol. 1-3	193-195
NASA CR-134948, Vol. 1	189
NASA CR-134949, Vol. 1, Vol. 2 (4 parts), Vol. 3	196-201
NASA CR-134950	202
NASA CR-134955	203
NSF-RA-760494	240
NSF-RA-N-74-209	222

U. S. Government Reports Utilized - By Report Number (Cont'd)

Report No.	Item
OCR 22/Int 5	211
OCR 74/Int 2	206
OCR 79/Int 1	212
OCR 81/Int 1	213
OCR 81/Int 2	170-171
OCR 81/Int 3	172
OCR 81/Int 4	169
OCR 83/Int 1	214
PB-198,392	204
PB-228,876/9	205
PB-234,042/AS	206
PB-234,159/2	207
PB-234,202/0GA	208
PB-234,203/8GA	209
PB-234,294/7	210
PB-235,371/AS	211
PB-235,780/4ST	212
PB-236,971/8SL	213
PB-236,972/AS	214
PB-237,661/4GA	215
PB-238,263/8ST	216
PB-241,463/9ST	217
PB-241,464/9ST	218
PB-241,672/5GA	219
PB-242,383/8GA	220
PB-242,595/7ST	221
PB-243,625	222
PB-246,116/8ST	223
PB-246,202/6ST	224
PB-249,454/0ST	225
PB-251,823/1ST	226
PB-252,462	227
PB-253,661	228
PB-254,392/4ST	229
PB-256,665/1ST	230
PB-257,134/7ST	231
PB-257,182/6ST	232-235
PB-260,499/9ST	236
PB-260,664/8ST	237
PB-264,536/4WE	238
PB-264,702/2WE	239
PB-265,126/3ST	240
PB- numbers not yet assigned	241
PB-	242
TID-26744	243
TID-26745	244
UARL-J970855-13	204
WASH-1230	245
WASH-1281-6	246

Author Index

Author Index (Cont'd)

Author Index (Cont'd)

Author Index (Cont'd)

Author Index (Cont'd)

Distribution of ANL/ECT-3, Appendix C

Internal:

F.C. Bennett
W.L. Buck
L. Burris
E.J. Croke
J. Dzingel
W.A. Ellingson
P.S. Farber
J. Fischer
B.L. Graves
L.J. Hoover
H.S. Huang
B.R. Hubble
C.C. Huber
J.L. Humphrey
R.O. Ivins
A.A. Jonke
A.B. Krisciunas
J.A. Lecky
C.D. Livengood (136)
K.S. Macal
W.E. Massey
N.M. O'Fallon
E.G. Pewitt
G.N. Reddy (4)
J.J. Roberts
G.S. Rosenberg
N.F. Sather
W.K. Sinclair
E.B. Smyk
D.G. Streets
T.G. Surles
A. Tevebaugh
S. Vogler
R.W. Weeks
K.E. Wilzbach (50)
S.H. Wong
R.S. Zeno
ANL Contract Copy
ANL Libraries (5)
TIS Files (6)

External:

DOE-TIC (27)
Manager, Chicago Operations and Regional Office, DOE
Chief, Office of Patent Counsel, DOE-CORO
President, Argonne Universities Association
Energy and Environmental Systems Division Review Committee:
    E.E. Angino, U. Kansas
    R.E. Gordon, U. Notre Dame
    W.W. Hogan, Harvard U.
    L.H. Roddis Jr., Charleston, S.C.
    G.A. Rohlich, U. Texas at Austin
    R.A. Schmidt, Booz, Allen, & Hamilton
J.H. Gibbons, Office of Technology Assessment, U.S. Congress
D.E. Kash, USGS, Reston, Va.
G. Abraham, U. Detroit
M. Ardell, McIlvaine Co.
R. Balzhiser, Electric Power Research Inst.
R. Biljetina, Inst. of Gas Technology
L.L. Brothers, U.S. Department of Energy
D.J. DeLaCroix, Babcock & Wilcox Co.
M.J. Deutch, Washington, D.C.
K.A. Duijves, ECN (The Netherlands)
E.R. Frederick, Air Pollution Control Association, Pittsburgh
H. Gollay, Illinois Department of Business and Economic Development
M. Gottlieb, U.S. Department of Energy (15)

A.S. Gupta, Air Products and Chemicals, Inc.
L.C. Headley, Morgantown Energy Technology Center
P.W. House, U.S. Department of Energy
J.L. Jones, SRI International
A.L. Laferriere, Rhode Island College
W. Licht, U. Cincinnati
P. Loquercio, Inst. of Natural Resources, State of Illinois
R.W. Lynch, Sandia Laboratories
G.G. McGlamery, Tennessee Valley Authority
G. Mazzella, Foster Wheeler Energy Corp. (10)
H. Mittelhauser, Mittelhauser Corp.
J. Oxley, Battelle Columbus Laboratories
D.B. Peterson, Energy Resources Conservation and Development
    Commission, Sacramento
F. Robson, United Technologies Research Center
E.S. Rubin, Carnegie-Mellon U.
L.J. Shannon, Midwest Research Inst.
O.J. Tassicker, Electric Power Research Inst.
D. Teixeira, Electric Power Research Inst.
L. Theodore, Manhattan College
R.E. Thompson, KVB, Inc.
C. van der Klein, ECN (The Netherlands)
E.E. Varanini III, Energy Resources Conservation and Development
    Commission, Sacramento
W.E. Wallace Jr., Morgantown Energy Technology Center
V. Weaver, U.S. Department of Energy
F. Witmer, U.S. Department of Energy
J.L. Woodward, Exxon Research and Engineering Co.
W.C. Yee, Tennessee Valley Authority
R.W. Young, C-E Power Systems

☆U.S. GOVERNMENT PRINTING OFFICE: 1980—651-118/2