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Energy Technology Characterizations Handbook:

Environmental Pollution and Control Factors

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U.S. Department of Energy

Assistant Secretary for Environmental
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Washington, D.C. 20545

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FOREWORD

In this third edition of the Handbook, the custom of annual upgrading and augmentation of the environmental characterization information data base that was established with the inaugural and second editions (DOE/EV-0072 and DOE/EP-0028, respectively) is continued. In the Preface to the first edition of the Handbook, the steps to be undertaken in developing an energy-related environmental information base were described. Further work was to be directed at improving several important attributes of the information—its representative character, consistency, validity, and timeliness. Particularly, the information summaries provided in the Handbook were to be augmented by a set of supplementary documents referred to as Environmental Characterization Information Reports (ECIRs), the purpose of which is to present a more explicit treatment of the origin and derivation of the summary information.

The second edition of the Handbook in June 1981 presented the completed portion of the work that was directed at enhancing the quality of the environmental information base. The second edition also included the initial set of four ECIRs on the following key energy systems: Coal-Fired Power Plants—Eastern Coal, Coal-Fired Power Plants—Western Coal, Pressurized Water Reactor Nuclear Power Plant, and Oil Shale Surface Retorting (Paraho Process). These ECIRs were included in the Appendix. They were also published as separate reports and are available from the National Technical Information Service (NTIS).

Work effort expended to upgrade and augment the energy-related environmental information base during FY 1982 and FY 1983 focused on filling some of the gaps in summary data that are evident from perusal of the second edition of the Handbook. Where the appropriate data were available, they were inserted in this third edition, although some data gaps remain. Most of the information deficiencies occur in the environmental control costs and occupational safety and health data blocks. This is, however, expected because many of the environmentally characterized energy systems are not yet fully operational, and experimental data are not sufficient to permit reliable estimates in these areas.

Development of supplementary documents continued during FY 1982 with the development of 13 new ECIRs for a total of 17 ECIRs prepared to date. These newly developed ECIRs have not been previously published as separate Department of Energy (DOE) documents; they are, however, included as an Appendix to this edition of the Handbook. Environmental characterization summaries for 79 energy technologies constitute Part 1. Part 2 contains descriptions of environmental controls that are currently in use or under development and experimentation that are applicable to energy systems for control of air, water, and solid waste pollution. Those data in Part 2 focus on the performance, reliability, and costs of controls and in this Third Edition are limited to coverage of coal-fired electrical power plants, industrial boilers, and synthetic fuel plants (coal and oil shale). Discussions of the applicable environmental control standards are also included.

The specific energy technologies included in Part 1 are categorized in the following general areas: nuclear, synthetic fuels, coal, petroleum, natural gas, solar, geothermal, and hydroelectric. Each technology is characterized in terms of the resources required, costs, residuals released, energy products, and occupational safety and health data. The information is based on a facility of particular size and design, with data presented on the basis of annual quantities or total facility lifetime quantities (e.g., construction materials), as appropriate. In addition, these data are normalized to 10^{12} Btu energy output to facilitate cross-technology comparison and use of these data in computerized data bases.

Plans for continuing work on the information base beyond FY 1983 depend on the availability of funds. The work will emphasize continued development of ECIRs for key technologies and the updating of this Handbook, including expansion of Part 2 to cover environmental controls for other key technologies.

PREFACE

The Environmental Information Handbook Series was conceived and instituted in 1980 to promote the transfer of energy-related environmental information being used within the Department of Energy for policy and planning analyses to interested federal agencies and to the nonfederal sector. The series is meant to be a basic set of reference documents for use in both the public and private sectors. The information is reliable and should assist decisionmaking and research on problems affecting energy and the environment.

This Handbook deals with environmental characterization information for a range of energy supply systems and provides supplementary information on environmental controls applicable to a select group of environmentally characterized energy systems. Environmental residuals, physical resource requirements, and discussion of applicable standards are the principal information provided. The quantitative and qualitative data provided are useful for evaluating alternative policy and technical strategies and for assessing the environmental impact of facility siting, energy production, and environmental controls.

Considerable effort has been expended to provide the information in a useful and comprehensible format. The information base is subject to change and further enhancement as additional or improved information becomes available. User comments are welcomed to improve the quality of information presented and should be sent to Roger Shull, Director, Environmental Assessments Division. Comments will be taken into account in the preparation of later editions.

The development and maintenance of the information is the responsibility of the Environmental Assessments Division. This edition was prepared with the technical services of The Aerospace Corporation and Mueller Associates, Inc., and its subcontractor, Science Applications, Inc.

Peter W. House, Director
Office of Environmental Analysis
Office of Environmental Protection,
Safety, and Emergency Preparedness

EXPLANATORY NOTES

For each energy system summarized in Part 1 of this Handbook, the tabular entries in the "Per 10^{12} Btu Energy Produced" column are expressed in English units. The corresponding annual quantities (used, released, and produced), also expressed in English units, are obtained by multiplying the "Per 10^{12} Btu Energy Produced" entry by the reference energy system's "Annual Energy Production," listed under Facility Operating Parameters. For example, for the Coal-Fired Power Plant-Eastern Coal, 42 tons of particulates are released per 10^{12} Btu of energy produced. This translates to an annual emission level of 500 tons (460 tonnes) for a coal-fired plant producing 12×10^{12} Btu/yr of energy (3.5×10^6 MWh annually).

42 tons/ 10^{12} Btu of Energy Produced	x	12×10^{12} Btu/yr	500 tons/yr
4th columnar entry, Environmental Residuals		"Annual Energy Production," Facility Operating Parameters	2nd columnar entry, Environmental Residuals

The inverse operation applies (division by "Annual Energy Production" expressed in 10^{12} Btu) if the user starts with an annual data entry and wishes to check the corresponding "Per 10^{12} Btu Energy Produced" columnar entry.

In the Resources Used and Costs blocks of the Summary Sheets, total usage and total cost quantities are given for construction materials, land resources, construction personnel, and facility and environmental controls capital costs (when these data are available). With respect to facility and environmental controls capital cost, it is understood that these costs could have been expressed as annualized costs over the projected system lifetime with appropriate use of compound interest factors.

In this third edition of the Handbook, nearly all cost data have been expressed arbitrarily in 1981 dollars employing the widely used and accepted Engineering News Record (ENR) Cost Construction Index (CCI). The ENR-CCI measures the effects of wage-rate and materials-price trends related to construction; however, for consistency in cost data presentation in this Handbook, both construction and operating and maintenance costs (for each category—Facility and Environmental Control Costs) have been converted to 1981 dollars using this index. Although there may be some weakness in using an index number designed specifically to track trends in construction costs to convert operating and maintenance costs from a "reference year" to a specified "current year," it is believed that consistency in cost data presentation is sufficient justification to use this conversion technique. Stated formally, the conversion technique is as follows:

$$C_C = C_R (I_C/I_R)$$

where C_C = current cost in 1981 dollars

C_R = original reference cost in reference year dollars (as specified in the supporting ECIR or other reference source for a given Handbook Summary Sheet topic)

I_C = ENR-CCI value at the current (specified) time of 1981 (the annual average for 1981 of monthly ENR-CCIs equals 3533*)

I_R = ENR-CCI value at the time (year) the reference cost was obtained (as indicated in the supporting ECIR or other source material for the given Handbook Summary Sheet topic). As with I_C , the I_R used in each case is the annual average of monthly ENR-CCIs for the given reference year for costs as cited in the supporting material. (Note: The reference year and actual value of I_R are indicated in the Remarks Column of each Summary Sheet Costs block where conversion has occurred. Refer to the ENR issue cited* for a treatise on ENR cost indexes and a tabulation of ENR-CCIs from 1905 to 1982.)

The original or reference year cost estimates for each energy system can be obtained by solving for C_R from the above equation. Original cost estimates might be desired by users who wish to use other systems that account for cost escalation. Various indexes appear weekly on the Market Trends pages of the McGraw-Hill ENR, and regional cost indexes are published on a bimonthly basis.

The tabular entry "Not Determined" indicates that information was either insufficient or not available to properly quantify that particular entry. In some cases, an explanation is inserted where data are missing.

*Source: Engineering News-Record, Vol. 208, No. 11, McGraw-Hill, Inc., New York, New York, March 18, 1982.

CONTENTS

	<u>Page</u>
FOREWORD	iii
PREFACE	v
PLANATORY NOTES	vii
PART 1. TECHNOLOGY CHARACTERIZATIONS	1
NUCLEAR TECHNOLOGIES	1
Open Pit Uranium Mining	2
Underground Uranium Mining	4
Uranium Milling	6
Uranium Hexafluoride Conversion	9
Uranium Enrichment Gaseous Diffusion	11
Uranium Enrichment Gas Centrifuge	13
Fuel Fabrication Plant	15
Pressurized Water Reactor Nuclear Power Plant	17
Boiling Water Reactor Nuclear Power Plant	19
Commercial High-Level Nuclear Waste Repository	22
Bibliography—Nuclear Technologies	24
SYNTHETIC FUEL TECHNOLOGIES	27
Underground Oil Shale Mining	28
Surface Oil Shale Mining	30
Modified In Situ Shale Retorting	32
Oil Shale Surface Retorting: Paraho Process (Direct Mode)	34
Oil Shale Surface Retorting: Colony TOSCO II Process (Indirect Mode)	36
H-Coal Process	40
Lurgi High-Btu Coal Gasification Plant	42
Solvent Refined Coal II (SRC-II) Plant	45
Indirect Coal Liquefaction Plant (Lurgi Fischer-Tropsch Process)	48
Bibliography—Synthetic Fuel Technologies	51
COAL TECHNOLOGIES	55
Eastern Underground Coal Mining (With Preparation Plant)	56
Eastern Surface Coal Mining (With Preparation Plant)	59
Western Surface Coal Mining (With Preparation Plant)	61
Coal Beneficiation	63
Coal-Oil Mixture Preparation Plant	65
Eastern Coal Unit Train	67
Western Coal Unit Train	69
Eastern Coal Conventional Train	71
Western Coal Conventional Train	73
Barge Transportation—Eastern Coal	75
Barge Transportation—Western Coal	77

CONTENTS (continued)

	<u>Page</u>
COAL TECHNOLOGIES (continued)	
Coal Transportation by Truck—Eastern Coal	79
Slurry Pipeline	81
Atmospheric Fluidized Bed Combustion—Bituminous Coal	83
Atmospheric Fluidized Bed Combustion—Western Subbituminous Coal	85
Coal-Oil Mixture Retrofit Boiler	87
Magnetohydrodynamic System	89
Coal-Fired Power Plant—Eastern Coal	91
Coal-Fired Power Plant—Western Coal	93
High-Voltage Transmission	95
Very High Voltage Transmission	97
Bibliography—Coal Technologies	99
 PETROLEUM TECHNOLOGIES	
Onshore Primary Oil Extraction—Lower 48 States	105
Onshore Enhanced Oil Recovery—Steam Injection—Lower 48 States	106
Offshore Oil Extraction—Lower 48 States	108
Crude Oil Storage in Salt Dome Caverns	110
Oil-Fired Steam Electric Power Plant	112
Bibliography—Petroleum Technologies	114
 NATURAL GAS TECHNOLOGIES	
Onshore Gas Extraction—Lower 48 States	119
Offshore Gas Extraction—Lower 48 States	120
Unconventional Gas Recovery	122
Natural Gas Purification	124
Natural Gas Transmission Pipeline	126
Liquefied Natural Gas Tanker	128
Underground Natural Gas Storage	130
Gas-Fired Steam Electric Power Plant	132
Bibliography—Natural Gas Technologies	134
 SOLAR TECHNOLOGIES	
Residential/Commercial Hot Water Heating—Active System	136
Residential/Commercial Heating—Active System	139
Residential Heating and Cooling—Active System	142
Residential/Commercial Heating—Passive System	144
Residential/Commercial Wind Energy Conversion System	146
Residential Photovoltaic System	148
Residential Wood Stove	150
Low-Temperature Solar Agricultural/Industrial Process Heat System	152
Medium-Temperature Solar Agricultural/Industrial Process Heat System	154
Alcohol Fermentation Plant	156
	158

CONTENTS (continued)

	<u>Page</u>
SOLAR TECHNOLOGIES (continued)	
Methanol From Wood	161
Ethanol From Nonwood Cellulosic Wastes	163
Low-Btu Gas From Pyrolysis (Central Facility)	165
Medium-Btu Biogas From Anaerobic Digestion (Central Facility)	167
Medium-Btu Wood Gasification System (Central Facility)	169
Industrial Wood-Fired Boiler	171
Wood-Fired Steam Electric Plant	173
Wind Energy Conversion System—Electric Utility Application	175
Solar Thermal Power Plant (Central Facility)	177
Solar Photovoltaic Power Plant (Central Utility)	179
Ocean Thermal Energy Conversion	181
Bibliography—Solar Technologies	183
GEOTHERMAL TECHNOLOGIES	
Geothermal—Vapor Dominated System	187
Geothermal Energy Plant (Hydrothermal Flashed Steam)	188
Bibliography—Geothermal Technologies	190
HYDROELECTRIC TECHNOLOGIES	
Small Hydroelectric Plant	195
Large Hydroelectric Plant	196
Pumped Storage System	198
Bibliography—Hydroelectric Technologies	200
PART 2. ENVIRONMENTAL CONTROLS	202
ENVIRONMENTAL CONTROLS FOR COAL-FIRED POWER PLANTS AND INDUSTRIAL BOILERS	203
OVERVIEW	204
AIR POLLUTION CONTROL	206
Electrostatic Precipitators for Particulate Control	206
Fabric Filters (Baghouses) for Particulate Control	211
Wet Scrubbers for Particulate Control	215
Acoustic Agglomeration for Enhancement of Fine Particulate Control	219
Nitrogen Oxide Control	224
Wet Lime and Limestone Scrubbing for Sulfur Dioxide Control	229
Lime Spray-Dry Scrubbers for Sulfur Dioxide Control	233
Sodium Carbonate and Dual Alkali Wet Scrubbing for Sulfur Dioxide Control	237

CONTENTS (continued)

	<u>Page</u>
AIR POLLUTION (continued)	
Scrubbing to Produce Sulfur By-Products for Sulfur Dioxide Control	241
Physical Coal Cleaning for Sulfur Dioxide Control	245
WATER POLLUTION CONTROL	251
Wastewater Control	251
Once-Through Cooling Systems for Thermal Discharge Control	256
Cooling Pond Systems for Thermal Discharge Control	259
Wet Cooling Towers for Thermal Discharge Control	263
Dry Cooling Towers for Thermal Discharge Control	267
SOLID WASTE POLLUTION CONTROL	270
Ash Disposal	270
Nonregenerable Flue Gas Desulfurization Sludge Disposal	274
ENVIRONMENTAL CONTROLS FOR SYNTHETIC FUELS PRODUCTION FROM COAL AND OIL SHALE	279
OVERVIEW AND BACKGROUND	280
AIR POLLUTION CONTROL	285
Rectisol Process for Acid Gas Control	285
Sulfur Control and Recovery	289
Gasifier Lockhopper Vent Gas Control	294
NO _x Control	297
Flaring for Waste Gas Control	301
WATER POLLUTION CONTROL	305
Wastewater Treatment	305
Phenolsolvan Process for Phenol Recovery	309
SOLID WASTE POLLUTION CONTROL	312
Spent Catalyst and Gasifier Ash Disposal	312
Retorted Shale Disposal	317
COSTING PROCEDURE	323
GLOSSARY	328
ACRONYMS AND ABBREVIATIONS	333
APPENDIX. ENVIRONMENTAL CHARACTERIZATION INFORMATION REPORTS	A.1-1
Introduction	A.1-1
Boiling Water Reactor Nuclear Plant	A.2-1

CONTENTS (continued)

Page

APPENDIX. (continued)

Commercial High-Level Nuclear Waste Repository	A.3-1
Indirect Coal Liquefaction Plant (Lurgi Fischer-Tropsch Process)	A.4-1
Colony TOSCO-II Oil Shale Process	A.5-1
Solvent Refined Coal-II (SRC-II) Plant	A.6-1
Lurgi High-Btu Coal Gasification	A.7-1
Eastern Underground Coal Mining	A.8-1
Eastern Surface Coal Mining	A.9-1
Western Surface Coal Mining	A.10-1
Alcohol Fermentation Plant	A.11-1
Residential Wood Stoves	A.12-1
Industrial Wood-Fired Boiler	A.13-1
Geothermal Energy Plant (Hydrothermal Flashed Steam)	A.14-1

PART 1. TECHNOLOGY CHARACTERIZATIONS

NUCLEAR TECHNOLOGIES

Within each Summary Sheet, under "Quantities Used, Released, or Produced", the Reference Energy System columns (English and metric units) list the actual amounts per year for the specific nuclear fuel cycle technology being addressed. The amounts listed in the "Per 10^{12} Btu Energy Produced" column are, however, normalized to the electrical energy produced (output) at the reactor not to the energy produced at the fuel cycle stage presented. For nuclear technologies, it is difficult to quantify the energy content of the product material at each fuel cycle stage (from mining through waste disposal).

Each technology in the fuel cycle is sized to represent a typical real-world plant and may provide enough output product to support a number of reactors. A 1000-MWe Pressurized Water Reactor (PWR) Nuclear Power Plant produces 21×10^{12} Btu of electricity annually; a Boiling Water Reactor produces the same output. To find the number of reactors supported by the product output of a specific fuel cycle stage, divide the annual energy production of that stage (in Btu) by the annual energy produced by the reactor. For example, using the Uranium Milling Summary Sheet:

$$\frac{\text{Annual Energy Production Uranium Milling}}{\text{Annual Energy Production of PWR}} = \frac{68.3 \times 10^{12} \text{ Btu}}{21 \times 10^{12} \text{ Btu}} = 3.25 \text{ reactors}$$

Each stage of the nuclear fuel cycle generates a certain amount of annual product output (e.g., 635 tons of yellowcake at an uranium mill), which supports more than one LWR. The amount listed on each Summary Sheet as "Annual Energy Production" is the Btu equivalent of the annual electricity produced by these LWRs.

OPEN PIT URANIUM MINING

REFERENCE ENERGY SYSTEM

Open pit mining is conducted when the ore body lies under relatively friable material at depths to 120 m. The components of the mining operation include onsite support facilities such as offices and warehouses, mine water pumped into local surface drainage or holding ponds, and mine spoils and ore storage areas.

FACILITY OPERATING PARAMETERS

Size: 528×10^3 tons/yr (actual output)
 Annual Capacity Factor: 80%
 Annual Energy Production*: 115×10^{12} Btu
 Efficiency: 80% (recovery efficiency)
 Lifetime: 20 yr

RESOURCES USED

	Quantities Used			Remarks
	Reference Energy System Annual Usage		Per 10 ¹² Btu Energy Produced *	
	English Units	Metric Units		
<u>Energy</u>				
Electricity	1.32 × 10 ³ MWh	1.32 × 10 ³ MWh	11.5 MWh	
Diesel fuel and lubricants	1.46 × 10 ⁶ gal	5.53 × 10 ⁶ l	12.7 × 10 ³ gal	
<u>Processing Materials</u>				
Explosives		Not Determined		
<u>Water</u>				
Mine water from dewatering	2.00 × 10 ³ acre-ft	2.46 × 10 ⁹ l	17.3 acre-ft	
Sprays for dust control		Not Determined		
	Total Usage			
<u>Construction Materials</u>				
Concrete	16 tons	15 tonnes	0.14 ton	
Total steel and castings	3.73 × 10 ³ tons	3.38 × 10 ³ tonnes	32.40 tons	
Copper, brass, and bronze	46 tons	42 tonnes	0.40 ton	
Aluminum and castings	22 tons	20 tonnes	0.19 ton	
Manganese	17 tons	16 tonnes	0.15 ton	
Chromium	8 tons	7 tonnes	0.07 ton	
Nickel	0.23 ton	0.21 tonne	0.002 ton	
Cast iron	155 tons	141 tonnes	1.35 tons	
<u>Land</u>	300 acres	120 ha	2.6 acres	
<u>Personnel</u>				
Construction (4 yr)	115 workers		1 worker	
Operation and maintenance	400 workers		3.5 workers	

COSTS

	Reference Energy System	Per 10^{12} Btu Energy Produced *	Remarks
<u>Facility</u>		(1981 \$)	
Construction (4 yr)	$\$76.0 \times 10^6$ total	$\$0.662 \times 10^6$ total	Reference year for costs is 1978. 1978 CCI average (I_A) = 2776. See Explanatory Notes Section.
Operation and maintenance	$\$29.2 \times 10^6$ /yr	$\$0.253 \times 10^6$ /yr	
<u>Environmental Controls</u>			
Diversion of surface waters	Not Determined ↓		
Water spraying for dust control			
Revegetation			

*In electrical energy (output) at the reactor; see note on page 1.

OPEN PIT URANIUM MINING

ENVIRONMENTAL RESIDUALS

ENVIRONMENTAL RELEASES				
Quantities Released				
	Reference Energy System		Per 10 ¹² Btu Energy Produced *	Remarks
	Annual Levels			
	English Units	Metric Units		
<u>Air Pollutants</u>				
Particulates	31 tons	28 tonnes	0.27 ton	
Sulfur dioxide	49 tons	45 tonnes	0.43 ton	
Oxides of nitrogen	29 tons	26 tonnes	0.25 ton	
Hydrocarbons	2.3 tons	2.1 tonnes	0.02 ton	
Carbon monoxide	0.12 ton	0.10 tonne	0.001 ton	
Radon and radon daughters	3.37 × 10 ³ Ci	3.37 × 10 ³ Ci	29.3 Ci	
<u>Water Pollutants</u>				
Suspended solids		Not Determined		
Dissolved solids		↓		
Trace elements				
<u>Solid Wastes</u>				
Overburden moved	16 × 10 ⁶ tons	15 × 10 ⁶ tonnes	0.14 × 10 ⁶ tons	

PRODUCTS

	Quantities Produced			Remarks
	Reference Energy System Annual Production		Per 10 ¹² Btu Energy Produced *	
	English Units	Metric Units		
<u>Primary</u>				
Uranium ore	0.53 × 10 ⁶ tons	0.48 × 10 ⁶ tonnes	4.6 × 10 ³ tons	
U ₃ O ₈ concentrate	1.06 × 10 ³ tons	960 tonnes	9.2 tons	

OCCUPATIONAL SAFETY AND HEALTH

Not Determined

*In electrical energy (output) at the reactor; see note on page 1.

UNDERGROUND URANIUM MINING

REFERENCE ENERGY SYSTEM

Operations are for deposits at depths greater than 120 m or when the ore lies under rock requiring blasting. The energy system includes the following onsite support facilities: offices, shops, warehouses, mine spoils area, ore storage, mine shafts, and tunnels.

FACILITY OPERATING PARAMETERS

Size:	0.15×10^6 tons/yr (average ore grade 0.2% U_3O_8)
Annual Capacity Factor:	80%
Annual Energy Production: *	32.6×10^{12} Btu
Efficiency:	80% (recovery efficiency)
Lifetime:	20 yr

RESOURCES USED

	Quantities Used		Per 10 ¹² Btu Energy Produced *	Remarks
	Reference Energy System Annual Usage			
	English Units	Metric Units		
<u>Energy</u>				
Electricity	9.49 × 10 ³ MWh	9.49 × 10 ³ MWh	291 MWh	
Natural gas	36 × 10 ⁶ scf	1.0 × 10 ⁶ m ³	1.1 × 10 ⁶ scf	
Diesel fuel	59 × 10 ³ gal	220 × 10 ³ l	1.8 × 10 ³ gal	
<u>Processing Materials</u>				
Explosives		Not Determined		
<u>Water</u>				
Domestic use	6 acre-ft	8 × 10 ⁶ l	0.2 acre-ft	
Mine water from dewatering		Not Determined		
<u>Total Usage</u>				
<u>Construction Materials</u>				
Concrete	4.79 × 10 ³ tons	4.35 × 10 ³ tonnes	147 tons	
Total steel and castings	3.07 × 10 ³ tons	2.78 × 10 ³ tonnes	94.1 tons	
Copper, brass, and bronze	18 tons	16 tonnes	0.55 ton	
Aluminum and castings	12 tons	11 tonnes	0.37 ton	
Manganese	15 tons	14 tonnes	0.46 ton	
Chromium	2.3 tons	2.1 tonnes	0.07 ton	
Nickel	0.1 ton	0.09 tonne	0.003 ton	
Cast iron	42.4 tons	38.5 tonnes	1.30 tons	
<u>Land</u>	3.9 acres	1.6 ha	0.12 acre	
<u>Personnel</u>				
Construction (3 yr)	36 workers		1.1 workers	
Operation and maintenance	400 workers		12.3 workers	

COSTS

	Reference Energy System	Per 10 ¹² Btu Energy Produced *	Remarks
		(1981\$)	
<u>Facility</u>			
Construction (3 yr)	\$43.6 × 10 ⁶ total	\$1.34 × 10 ⁶ total	Reference year for costs is 1978. 1978 CCI average (I _R) = 2776. See Explanatory Notes Section.
Operation and maintenance	\$17.9 × 10 ⁶ /yr	\$0.549 × 10 ⁶ /yr	
<u>Environmental Controls</u>			
Water spraying for dust control		Not Determined	
Mine water purification/uranium recovery			
Grouting/sealing of mine walls			
Ventilation air			

*In electrical energy (output) at the reactor; see note on page 1.

UNDERGROUND URANIUM MINING

ENVIRONMENTAL RESIDUALS

ENVIRONMENTAL RELEASES

	Quantities Released			
	Reference Energy System Annual Levels		Per 10 ¹² Btu Energy Produced*	Remarks
	English Units	Metric Units		
<u>Air Pollutants</u>				
Particulates	0.33 ton	0.30 tonne	0.01 ton	
Sulfur dioxide	0.7 ton	0.6 tonne	0.02 ton	
Oxides of nitrogen	10 tons	9.5 tonnes	0.32 ton	
Hydrocarbons	1 ton	0.9 tonne	0.03 ton	
Carbon monoxide	6.2 tons	5.6 tonnes	0.19 ton	
Carbon dioxide	620 tons	560 tonnes	19.0 tons	
Aldehydes	0.1 ton	0.09 tonne	0.003 ton	
Organic acids	0.1 ton	0.09 tonne	0.003 ton	
Radon and radon daughters	8.00 × 10 ³ Ci	8.00 × 10 ³ Ci	245 Ci	
<u>Water Pollutants</u>				
Suspended solids	Not Determined ↓			
Dissolved solids				
Radon gas				
Polonium				
Lead				
Bismuth				
Trace elements				
<u>Solid Wastes</u>				
Waste rock	3.9 × 10 ⁶ ft ³	0.11 × 10 ⁶ m ³	0.12 × 10 ⁶ ft ³	

PRODUCTS

	Quantities Produced			Remarks
	Reference Energy System Annual Production		Per 10 ¹² Btu Energy Produced *	
	English Units	Metric Units		
Primary				
Uranium ore	0.15 × 10 ⁶ tons	0.14 × 10 ⁶ tonnes	4.6 × 10 ³ tons	
U ₃ O ₈	300 tons	270 tonnes	9.2 tons	

OCCUPATIONAL SAFETY AND HEALTH

Not Determined

*In electrical energy (output) at the reactor; see note on page 1.

URANIUM MILLING

REFERENCE ENERGY SYSTEM

The model is a uranium mill described by the Nuclear Regulatory Commission in the Final Generic Environmental Impact Statement on Uranium Milling, NUREG-0706, Vol. I-III, September 1980. Tailings control and disposal includes retention basin, clay liner, evaporation pond, in situ solids filtration, and earth cover.

FACILITY OPERATING PARAMETERS

Size:	635 tons/yr uranium concentrate (yellowcake at 90% U_3O_8)
Annual Capacity Factor:	85%
Annual Energy Production: *	68.3×10^{12} Btu
Efficiency:	93% (recovery)
Lifetime:	15 yr

RESOURCES USED

	Quantities Used		Per 10 ¹² Btu Energy Produced *	Remarks
	Reference Energy System Annual Usage			
	English Units	Metric Units		
<u>Feed Materials</u>				
Uranium ore (0.1% uranium)	620 × 10 ³ tons	560 × 10 ³ tonnes	9.1 × 10 ³ tons	
<u>Energy^a</u>				
Electrical	10.8 × 10 ³ MWh	10.8 × 10 ³ MWh	158 MWh	
Natural gas (process heat)	274 × 10 ⁶ scf	7.76 × 10 ⁶ m ³	4.0 × 10 ⁶ scf	
<u>Processing Materials</u>				
Sulfuric acid	28 × 10 ³ tons	25 × 10 ³ tonnes	400 tons	
Sodium chlorite	860 tons	780 tonnes	13 tons	
Ammonium	680 tons	610 tonnes	10 tons	
Flocculent	37 tons	34 tonnes	0.54 ton	
Amine	9 tons	8 tonnes	0.1 ton	
Alcohol	25 tons	22 tonnes	0.4 ton	
Kerosene	280 tons	250 tonnes	4 tons	
Iron	150 tons	140 tonnes	2.2 tons	
<u>Water</u>				
Process water	320 acre-ft	390 × 10 ⁶ l	4.7 acre-ft	
<u>Total Usage</u>				
<u>Construction Materials</u>				
Concrete	250 × 10 ³ ft ³	7.0 X 10 ³ m ³	3.7 × 10 ³ ft ³	
Steel	1.7 × 10 ³ tons	1.6 × 10 ³ tonnes	25 tons	
Copper and aluminum	52 tons	47 tonnes	0.76 ton	
Wood	18 tons	16 tonnes	0.26 ton	
Plastics	18 tons	16 tonnes	0.26 ton	
<u>Land</u>				
Mill operations	120 acres	50 ha	1.8 acres	
Tailings	250 acres	100 ha	3.7 acres	
Uncommitted	370 acres	150 ha	5.4 acres	
Total	740 acres	300 ha	10.9 acres	
<u>Personnel</u>				
Construction (5 yr)	120 workers		1.76 workers	
Operation and maintenance	160 workers		2.34 workers	

*In electrical energy (output) at the reactor; see note on page 1.

URANIUM MILLING

COSTS

	Reference Energy System	Per 10 ¹² Btu Energy Produced *	Remarks
<u>Facility</u>			
	(1981 \$)		
Construction (5 yr)	\$37.1 × 10 ⁶ total	\$0.54 × 10 ⁶ total	
Operation and maintenance	\$ 8.5 × 10 ⁶ /yr	\$0.13 × 10 ⁶ /yr	
<u>Environmental Controls</u>			
Ore crushing/handling			
wet scrubbers	\$155 × 10 ³ total	\$2.3 × 10 ³ total	Total capital costs
	\$18.8 × 10 ³ /yr	\$0.275 × 10 ³ /yr	Operating costs per year
Yellowcake drying			
wet scrubbers	\$50.4 × 10 ³ total	\$0.7 × 10 ³ total	Total capital costs
	\$6.2 × 10 ³ /yr	\$0.091 × 10 ³ /yr	Operating costs per year
Tailings control and disposal	\$13.7 × 10 ⁶ total	\$0.200 × 10 ⁶ total	Includes capital and total operating costs over lifetime

ENVIRONMENTAL RESIDUALS

	Quantities Released			Remarks
	Reference Energy System		Per 10 ¹² Btu Energy Produced *	
	Annual Levels			
	English Units	Metric Units		
<u>Air Pollutants</u>				
Particulates	370 tons	340 tonnes	5.4 tons	
Sulfur dioxide	0.34 ton	0.31 tonnes	5.0 × 10 ⁻³ ton	
Oxides of nitrogen	28 tons	25 tonnes	0.41 tons	
Kerosene	24 tons	22 tonnes	0.35 ton	
Uranium-238, Uranium-234	0.160 Ci	0.160 Ci	2.3 × 10 ⁻³ Ci	
Thorium-230	0.122 Ci	0.122 Ci	1.8 × 10 ⁻³ Ci	
Radon	4.5 × 10 ³ Ci	4.5 × 10 ³ Ci	66 Ci	
<u>Water Pollutants</u>				
Water discharged	326 acre-ft	402 × 10 ⁶ l	4.8 acre-ft	
• Sulfate	13 × 10 ³ tons	12.1 × 10 ³ tonnes	190 tons	
• Iron	440 tons	400 tonnes	6.5 tons	
• Manganese	22 tons	20 tonnes	0.32 ton	
• Selenium	0.88 ton	0.80 tonne	0.01 ton	
Uranium-natural	1.3 Ci	1.3 Ci	19 × 10 ⁻³ Ci	
Radium-226	0.1 Ci	0.1 Ci	1.4 × 10 ⁻³ Ci	
Thorium-230	36 Ci	36 Ci	0.53 Ci	
<u>Solid Wastes</u>				
Tailings	610 × 10 ³ tons	560 × 10 ³ tonnes	9.0 × 10 ³ tons	
Uranium-natural	21.8 Ci	21.8 Ci	0.32 Ci	
Radium-226	156 Ci	156 Ci	2.3 Ci	
Thorium-230	156 Ci	156 Ci	2.3 Ci	
Lead-210, polonium-210, bismuth-210	0.3 Ci	0.3 Ci	4 × 10 ⁻³ Ci	
<u>Thermal Discharge</u>				
Process heat to air	280 × 10 ⁹ Btu	300 × 10 ¹² J	4.1 × 10 ⁹ Btu	

PRODUCTS

	Quantities Produced			Remarks
	Reference Energy System		Per 10 ¹² Btu Energy Produced *	
	Annual Production			
	English Units	Metric Units		
<u>Primary</u>				
Yellowcake (90% U ₃ O ₈)	635 tons	580 tonnes	9.3 tons	
<u>Recoverables/Recyclables</u>				
30% of the tailings liquid	135 acre-ft	166 × 10 ⁶ l	1.99 acre-ft	

*In electrical energy (output) at the reactor; see note on page 1.

URANIUM MILLING

OCCUPATIONAL SAFETY AND HEALTH^b

	Reference Energy System Annual	Per 10 ¹² Btu Energy Produced *	Remarks
<u>Deaths</u>	0.47	0.007	1977 Data
<u>Injuries</u>	34	0.50	↓

^aU.S. Atomic Energy Commission, Environmental Survey of the Uranium Fuel Cycle, WASH-1248, 1974.

^bOak Ridge National Laboratory, An Integrated Assessment of the Impacts Associated with Uranium Mining and Milling, ORNL/TM-6677, July 1979.

*In electrical energy (output) at the reactor; see note on page 1.

URANIUM HEXAFLUORIDE CONVERSION

REFERENCE ENERGY SYSTEM

Conversion of "yellowcake" uranium concentrate into a volatile uranium hexafluoride compound for enrichment by the gaseous diffusion process; uranium hexafluoride conversion by either the dry hydrofluor process or the wet solvent exchange process; offgas treatment to minimize airborne residuals; neutralization and impoundment of liquid wastes.

FACILITY OPERATING PARAMETERS

Size:	5.5×10^3 tons/yr (actual output)
Annual Capacity Factor:	80%
Annual Energy Production: *	655×10^{12} Btu
Efficiency:	100% (recovery efficiency)
Lifetime:	20 yr

RESOURCES USED

	Quantities Used		Per 10 ¹² Btu Energy Produced *	Remarks
	Reference Energy System Annual Usage			
	English Units	Metric Units		
Feed Materials				
Yellowcake (75% U ₃ O ₈)	7.34 × 10 ³ tons	6.66 × 10 ³ tonnes	11.2 tons	
U ₃ O ₈ (purified)	5.5 × 10 ³ tons	5.0 × 10 ³ tonnes	8.4 tons	
Energy				
Electricity	46 × 10 ³ MWh	46 × 10 ³ MWh	71 MWh	
Natural gas	540 × 10 ⁶ scf	15 × 10 ⁶ m ³	0.83 × 10 ⁶ scf	
Processing Materials				
Nitric acid		Not Determined		
Tributylphosphate		↓		
Hexane				
Anhydrous ammonia				
Hydrofluoric acid				
Fluorine				
Water				
Discharged to air	0.28 × 10 ³ acre-ft	0.34 × 10 ⁹ l	0.42 acre-ft	
Discharged to water	1.92 × 10 ³ acre-ft	2.38 × 10 ⁹ l	2.94 acre-ft	
Total	2.20 × 10 ³ acre-ft	2.72 × 10 ⁹ l	3.36 acre-ft	
Total Usage				
Construction Materials				
Concrete	259 × 10 ³ tons	235 × 10 ³ tonnes	395 tons	
Steel and castings	8.19 × 10 ³ tons	7.43 × 10 ³ tonnes	12.5 tons	
Copper, brass, and bronze	120 tons	110 tonnes	0.19 ton	
Aluminum and castings	39 tons	36 tonnes	0.06 ton	
Manganese	39 tons	36 tonnes	0.06 ton	
Chromium	39 tons	36 tonnes	0.06 ton	
Nickel	7 tons	6 tonnes	0.01 ton	
Cast iron	98 tons	89 tonnes	0.15 ton	
Pumps and drivers	7 × 10 ³ hp	5 × 10 ⁶ W	0.01 × 10 ³ hp	
Heat exchangers	30 × 10 ³ ft ³	3 × 10 ³ m ²	0.05 × 10 ³ ft ²	
Nonnuclear pressure vessel	220 tons	200 tonnes	0.33 ton	
Land	65 acres	27 ha	0.10 acre	
Personnel				
Construction (3 yr)	200 workers		0.3 worker	
Operation and maintenance	300 workers		0.4 worker	

*In electrical energy (output) at the reactor; see note on page 1.

URANIUM HEXAFLUORIDE CONVERSION

COSTS

Facility	Reference Energy System	Per 10 ¹² Btu Energy Produced *	Remarks
	(1981 \$)		
Construction (3 yr)	\$70.7 × 10 ⁶ total	\$0.108 × 10 ⁶ total	Reference year for costs is 1978. 1978 CCI average (I _A) = 2776. See Explanatory Notes Section.
Operation and maintenance	\$20.5 × 10 ⁶ /yr	\$0.031 × 10 ⁶ /yr	
<u>Environmental Controls</u>			
Fluorine scrubbers	Not Determined		
Raffinate/waste ponds	↓		
Offgas filters/traps			

ENVIRONMENTAL RESIDUALS

	Quantities Released			Remarks
	Reference Energy System Annual Levels		Per 10 ¹² Btu Energy Produced *	
	English Units	Metric Units		
<u>Air Pollutants</u>				
Sulfur dioxide	850 tons	770 tonnes	1.3 tons	10 CFR 20 specifies allowable levels
Oxides of nitrogen	300 tons	270 tonnes	0.46 ton	
Hydrocarbons	30 tons	20 tonnes	0.04 ton	
Carbon monoxide	7 tons	6 tonnes	0.01 ton	
Fluoride	3.3 tons	3.0 tonnes	0.005 ton	
Uranium	4.1 × 10 ⁻³ Ci	4.1 × 10 ⁻³ Ci	6.2 × 10 ⁻⁶ Ci	
Radon and radon daughters		Not Determined		
<u>Water Pollutants</u>				
Fluoride	790 tons	710 tonnes	1.2 tons	10 CFR 20 specifies allowable levels
Sulfate	140 tons	120 tonnes	0.21 ton	
Nitrate	7 tons	6 tonnes	0.01 ton	
Chloride	7 tons	6 tonnes	0.01 ton	
Sodium ⁺	105 tons	95 tonnes	0.16 ton	
Ammonium	50 tons	40 tonnes	0.07 ton	
Iron	1.3 tons	1.2 tonnes	0.002 ton	
Radium-226	92 × 10 ⁻³ Ci	92 × 10 ⁻³ Ci	0.14 × 10 ⁻³ Ci	
Thorium-230	41 × 10 ⁻³ Ci	41 × 10 ⁻³ Ci	0.063 × 10 ⁻³ Ci	
Uranium	1.2 Ci	1.2 Ci	1.8 × 10 ⁻³ Ci	
<u>Solid Wastes</u>				
Solid chemical effluents (nonvolatile ash containing iron, calcium, magnesium, copper, fluoride)	1.2 × 10 ³ tons	1.1 × 10 ³ tonnes	1.8 tons	
Low and intermediate level radioactive (buried)	24 Ci	24 Ci	36 × 10 ⁻³ Ci	
<u>Thermal Discharge</u>				
Heat discharged to air	0.54 × 10 ¹² Btu	0.57 × 10 ¹⁵ J	0.83 × 10 ⁹ Btu	

PRODUCTS

	Quantities Produced			Remarks
	Reference Energy System Annual Production		Per 10 ¹² Btu Energy Produced *	
	English Units	Metric Units		
	<u>Primary</u>			
Uranium hexafluoride	5.5 × 10 ³ tons	5.0 × 10 ³ tonnes	8.4 tons	

OCCUPATIONAL SAFETY AND HEALTH

Not Determined

*In electrical energy (output) at the reactor; see note on page 1.

URANIUM ENRICHMENT GASEOUS DIFFUSION

REFERENCE ENERGY SYSTEM

Gaseous diffusion enrichment plant using porous barriers and compressors arranged in series to produce uranium hexafluoride enriched to 4% uranium-235; onsite support facilities; tails storage; settling/neutralization ponds; waste burial grounds; feed vaporization and product recovery systems; steam plant.

FACILITY OPERATING PARAMETERS

Size: 12×10^3 tons/yr (enriched uranium-235 as uranium hexafluoride; tails assay 0.2% uranium)

Annual Capacity Factor: 80%

Annual Energy Production:* 2190×10^{12} Btu

Efficiency: 65.4% (recovery efficiency)

Lifetime: 20 yr

RESOURCES USED

	Quantities Used			
	Reference Energy System Annual Usage		Per 10 ¹² Btu Energy Produced*	Remarks
	English Units	Metric Units		
Feed Materials				
Uranium hexafluoride (unenriched)	18 × 10 ³ tons	17 × 10 ³ tonnes	8.4 tons	
Energy				
Electricity	28 × 10 ⁶ MWh	28 × 10 ⁶ MWh	13 × 10 ³ MWh	
Water				
Discharged to air	23 × 10 ³ acre-ft	29 × 10 ⁹ l	11 acre-ft	
Discharged to water bodies (at diffusion plant)	1.8 × 10 ³ acre-ft	22 × 10 ⁹ l	0.8 acre-ft	
Discharged to water bodies (at power plant)	3.07 × 10 ⁶ acre-ft	3.8 × 10 ¹² l	1.4 × 10 ³ acre-ft	
Total Usage				
Construction Materials				
Concrete	1670 × 10 ³ tons	1510 × 10 ³ tonnes	760 tons	
Total steel and castings	723 × 10 ³ tons	656 × 10 ³ tonnes	330 tons	
Copper, brass, and bronze	25.6 × 10 ³ tons	23.3 × 10 ³ tonnes	11.7 tons	
Aluminum and castings	16 × 10 ³ tons	15 × 10 ³ tonnes	7.5 tons	
Manganese	3.9 × 10 ³ tons	3.6 × 10 ³ tonnes	1.8 tons	
Chromium	5.0 × 10 ³ tons	4.6 × 10 ³ tonnes	2.3 tons	
Nickel	0.90 × 10 ³ tons	0.82 × 10 ³ tonnes	0.41 ton	
Cast iron	58.0 × 10 ³ tons	52.7 × 10 ³ tonnes	26.5 tons	
Steam turbogenerators	520 MWe	520 MWe	0.24 MWe	
Pumps and drivers	590 × 10 ³ hp	440 × 10 ⁶ W	0.27 × 10 ³ hp	
Axial compressor	8300 × 10 ³ hp	6200 × 10 ⁶ W	3.8 × 10 ³ hp	
Centrifuge compressors and drivers	22 tons	20 tonnes	0.01 ton	
Heat exchangers	7.9 × 10 ⁶ ft ²	730 × 10 ³ m ²	3.6 × 10 ³ ft ²	
Land				
	Not Determined			
Personnel				
Construction (8 yr)	6.1 × 10 ³ workers		2.8 workers	
Operation and maintenance	2.2 × 10 ³ workers		1.0 worker	

*In electrical energy (output) at the reactor; see note on page 1.

URANIUM ENRICHMENT GASEOUS DIFFUSION

COSTS	Quantities Released		Remarks
	Reference Energy System	Per 10 ¹² Btu Energy Produced *	
<u>Facility</u>	(1981 \$)		
Construction (8 yr)	\$14.7 × 10 ⁹ total	\$6.71 × 10 ⁶ total	Reference year for costs is 1978. 1978 CCI average (I _h) = 2776. See Explanatory Notes Section.
Operation and maintenance	\$0.98 × 10 ⁶ /yr	\$0.448 × 10 ⁶ /yr	
<u>Environmental Controls</u>			
Cooling towers	Not Determined ↓		
Liquid waste systems			
Neutralization pond			
Filters			
Fluorine scrubber			

ENVIRONMENTAL RESIDUALS	Quantities Released		Remarks
	Reference Energy System	Per 10 ¹² Btu Energy Produced *	
	Annual Levels		
<u>Air Pollutants:</u>	English Units	Metric Units	
Particulates	113 × 10 ³ tons	103 × 10 ³ tonnes	51.8 tons
Sulfur dioxide	431 × 10 ³ tons	392 × 10 ³ tonnes	197 tons
Oxides of nitrogen	113 × 10 ³ tons	103 × 10 ³ tonnes	51.8 tons
Hydrocarbons	1.1 × 10 ³ tons	1.0 × 10 ³ tonnes	0.5 ton
Carbon monoxide	2.8 × 10 ³ tons	2.6 × 10 ³ tonnes	1.3 tons
Fluoride	0.044 × 10 ³ tons	0.04 × 10 ³ tonnes	0.02 ton
Uranium	0.18 Ci	0.18 Ci	83 × 10 ⁻⁶ Ci
Technetium-99	0.74 Ci	0.74 Ci	0.34 × 10 ⁻³ Ci
Ruthenium-106	0.010 Ci	0.010 Ci	4.6 × 10 ⁻⁶ Ci
<u>Water Pollutants</u>			
Calcium	700 tons	600 tonnes	0.3 ton
Chloride	900 tons	800 tonnes	0.4 ton
Sodium ⁺	900 tons	800 tonnes	0.4 ton
Sulfate	700 tons	600 tonnes	0.3 ton
Iron	44 tons	40 tonnes	0.02 ton
Nitrate	260 tons	240 tonnes	0.12 ton
Uranium	1.8 Ci	1.8 Ci	0.83 × 10 ⁻³ Ci
Technetium-99	9.6 Ci	9.6 Ci	4.4 × 10 ⁻³ Ci
<u>Solid Wastes:</u>			
Equipment components	Not Determined ↓		
Sludges			
<u>Thermal Discharge</u>			
Heat discharged to water	226 × 10 ¹² Btu	238 × 10 ¹⁵ J	103 × 10 ⁹ Btu
Heat discharged to air	68 × 10 ¹² Btu	72 × 10 ¹⁵ J	31 × 10 ⁹ Btu
<u>Noise Pollution</u>			
In-plant	Not Determined ↓		
Cooling tower			

PRODUCTS	Quantities Produced		Remarks
	Reference Energy System	Per 10 ¹² Btu Energy Produced *	
	Annual Production		
	English Units	Metric Units	
<u>Primary</u>			
Enriched uranium-235	12.0 × 10 ³ tons	10.9 × 10 ³ tonnes	5.49 tons
in uranium hexafluoride			
<u>Byproducts</u>			
Uranium-235 in tails	22 tons	20 tonnes	0.01 ton
			Tails 0.2% uranium

OCCUPATIONAL SAFETY AND HEALTH
Not Determined

*In electrical energy (output) at the reactor; see note on page 1.

URANIUM ENRICHMENT GAS CENTRIFUGE

REFERENCE ENERGY SYSTEM

The gas centrifuge enrichment process uses a system of centrifuges to enrich uranium in uranium-235 to 2-4%. System components include production facilities; feed, product, and tails withdrawal systems; decontamination facilities; recirculating and sanitary water systems; sewage systems; etc.

FACILITY OPERATING PARAMETERS

Size: 10×10^3 tons/yr
(tails assay 0.2%)
Annual Capacity Factor: 80%
Annual Energy Production: * 1821×10^{12} Btu
Efficiency: 65.4%
Lifetime: 20 yr

RESOURCES USED

	Quantities Used		Per 10 ¹² Btu Energy Produced *	Remarks
	Reference Energy System Annual Usage			
	English Units	Metric Units		
<u>Feed Materials</u>				
Uranium hexafluoride	15 × 10 ³ tons	14 × 10 ³ tonnes	8.4 tons	
<u>Energy</u>				
Coal	66.8 × 10 ³ tons	60.7 × 10 ³ tonnes	36.7 tons	Heating and process steam
Gasoline and diesel fuel	208 × 10 ³ gal	786 × 10 ³ l	114 gal	
Electricity	2.0 × 10 ⁶ MWh	2.0 × 10 ⁶ MWh	1.1 × 10 ³ MWh	
<u>Water</u>				
Discharged to air	890 acre-ft	1.1 × 10 ⁹ l	0.49 acre-ft	
Discharged to water	1.82 × 10 ³ acre-ft	2.24 × 10 ⁹ l	1.00 acre-ft	
<u>Total Usage</u>				
<u>Construction Materials</u>				
Concrete	600 × 10 ³ tons	540 × 10 ³ tonnes	330.00 tons	
Steel	280 × 10 ³ tons	250 × 10 ³ tonnes	151.00 tons	
Aluminum	25 × 10 ³ tons	23 × 10 ³ tonnes	14.00 tons	
Copper	4.9 × 10 ³ tons	4.5 × 10 ³ tonnes	2.70 tons	
Zinc	0.22 × 10 ³ tons	0.20 × 10 ³ tonnes	0.12 ton	
Transformer cooling oil	0.33 × 10 ³ tons	0.30 × 10 ³ tonnes	0.18 ton	
Paving materials	1.3 × 10 ³ tons	1.2 × 10 ³ tonnes	0.70 ton	
Miscellaneous metal products	1.2 × 10 ³ tons	1.0 × 10 ³ tonnes	0.63 ton	
<u>Land</u>	840 acres	340 ha	0.46 acre	
<u>Personnel</u>				
Construction (7 yr)	5.1 × 10 ³ workers		2.8 workers	
Operation and maintenance	1.8 × 10 ³ workers		1.0 worker	

COSTS

	Reference Energy System	Per 10 ¹² Btu Energy Produced *	Remarks
<u>Facility</u>			
	(1981 \$)		
Construction (7 yr)	\$5.7 × 10 ⁹ total	\$3.13 × 10 ⁶ total	Reference year for costs is 1975. 1975 CCI average (I _R) = 2212. See Explanatory Notes Section
Operation and maintenance	\$755 × 10 ⁶ /yr	\$0.415 × 10 ⁶ /yr	
<u>Environmental Controls</u>			
Filters	Not Determined		
Liquid waste processing	↓		
Neutralization facilities			
Cooling towers			
Fluorine scrubbers			

* In electrical energy (output) at the reactor; see note on page 1.

URANIUM ENRICHMENT GAS CENTRIFUGE

ENVIRONMENTAL RESIDUALS

	Quantities Released			Remarks
	Reference Energy System		Per 10 ¹² Btu Energy Produced *	
	Annual Levels			
	English Units	Metric Units		
<u>Air Pollutants</u>				
Particulates	40 tons	30 tonnes	0.02 ton	
Sulfur dioxide	840 tons	760 tonnes	0.46 ton	
Oxides of nitrogen	670 tons	610 tonnes	0.37 ton	
Hydrocarbons		Negligible		
Carbon monoxide	18 tons	16 tonnes	0.01 ton	
Uranium (total isotopes)	56 × 10 ⁻³ Ci	56 × 10 ⁻³ Ci	31 × 10 ⁻⁶ Ci	
<u>Water Pollutants</u>				
Condensate				
• Water	3.70 × 10 ³ tons	3.36 × 10 ³ tonnes	2.03 tons	
Aqueous waste				
• Water	560 tons	510 tonnes	0.31 ton	
• Nitric acid	90 tons	80 tonnes	0.05 ton	
• Aluminum nitrate	110 tons	100 tonnes	0.06 ton	
Noncondensable gas				
• Oxides of nitrogen	1.8 tons	1.6 tonnes	0.001 ton	
Radiation				
• Uranium (total isotopes)	6.0 × 10 ⁻³ Ci	6.0 × 10 ⁻³ Ci	3.3 × 10 ⁻⁶ Ci	
<u>Solid Wastes</u>				
Failed rotors		Not Determined		
<u>Thermal Discharge</u>				
Heat dissipated from steam plant	360 × 10 ⁹ Btu	380 × 10 ¹² J	0.2 × 10 ⁹ Btu	
<u>Noise Pollution</u>				
In-plant		Not Determined		

PRODUCTS

	Quantities Produced			Remarks
	Reference Energy System		Per 10 ¹² Btu Energy Produced *	
	Annual Production			
	English Units	Metric Units		
<u>Primary</u>				
Enriched uranium-235 in uranium hexafluoride	1.00 × 10 ³ tons	9.08 × 10 ³ tonnes	5.49 tons	
<u>Byproducts</u>				
Uranium-235 in tails	18 tons	16 tonnes	0.01 ton	0.2% uranium in tails

OCCUPATIONAL SAFETY AND HEALTH

Not Determined

*In electrical energy (output) at the reactor; see note on page 1.

FUEL FABRICATION PLANT

REFERENCE ENERGY SYSTEM

Fuel fabrication is accomplished by chemical conversion of uranium hexafluoride to uranium dioxide and mechanical processing including pellet production and fuel element fabrication loaded in zircalloy or stainless steel tubes, fitted with end caps, and welded.

FACILITY OPERATING PARAMETERS

Size: 990 tons/yr
 Annual Capacity Factor: 80%
 Annual Energy Production: * 619×10^{12} Btu
 Efficiency: 100% (uranium-235 output vs. uranium-235 input)
 Lifetime: 20 yr

RESOURCES USED

	Quantities Used		Per 10 ¹² Btu Energy Produced *	Remarks
	Reference Energy System Annual Usage			
	English Units	Metric Units		
Feed Materials				
Uranium-235 enriched in uranium hexafluoride	3.40 × 10 ³ tons	3.08 × 10 ³ tonnes	5.49 tons	
Energy				
Electricity	44 × 10 ³ MWh	44 × 10 ³ MWh	71 MWh	
Natural gas	93 × 10 ⁶ scf	2.6 × 10 ⁶ m ³	0.15 × 10 ⁶ scf	
Processing Materials				
Aqueous ammonia		Not Determined		
Nitric acid (70%)				
Sodium hydroxide (50%)				
Sulfuric acid (70%)				
Water				
Discharged to water	410 acre-ft	510 × 10 ⁶ l	0.67 acre-ft	
Total Usage				
Construction Materials				
Concrete	46.2 × 10 ³ - 275 × 10 ³ tons	42.0 × 10 ³ - 250 × 10 ³ tonnes	74.70-444.0 tons	
Total steel and castings	7.43 × 10 ³ - 27.8 × 10 ³ tons	6.74 × 10 ³ - 25.3 × 10 ³ tonnes	12.00-45.00 tons	
Copper, brass, and bronze	360 - 3.22 × 10 ³ tons	330 - 2.92 × 10 ³ tonnes	0.59-5.20 tons	
Aluminum and castings	170-885 tons	150-800 tonnes	0.27-1.43 tons	
Manganese	50-130 tons	40-120 tonnes	0.08-0.21 ton	
Chromium	62-93 tons	56-84 tonnes	0.10-0.15 ton	
Nickel	12-18 tons	11-17 tonnes	0.02-0.03 ton	
Cast iron	300-560 tons	280-510 tonnes	0.49-0.90 ton	
Steam turbines	0 - 6.2 × 10 ³ hp	0 - 4.6 × 10 ⁶ W	0-10 hp	
Pumps and drivers	6.2 × 10 ³ - 25 × 10 ³ hp	4.6 × 10 ⁶ - 18 × 10 ⁶ W	10-40 hp	
Heat exchangers	0 - 18 × 10 ³ ft ²	0 - 1.7 × 10 ³ m ²	0-30 ft ²	
Land				
	7.4 acres	3.0 ha	0.012 acre	
Personnel				
Construction (2-3 yr)	400-2.1 × 10 ³ workers		0.7-3.4 workers	
Operation and maintenance	990-2.1 × 10 ³ workers		1.6-3.4 workers	

*In electrical energy (output) at the reactor; see note on page 1.

FUEL FABRICATION PLANT

COSTS

	Reference Energy System	Per 10 ¹² Btu Energy Produced *	Remarks
<u>Facility</u>	(1981 \$)		
Construction (2-3 yr)	$\$248 \times 10^6 - 792 \times 10^6$ total	$\$0.400 \times 10^6 - 1.28 \times 10^6$ total	Reference year for costs is 1978. 1978 CCI average (I_R) = 2776. See Explanatory Notes Section.
Operation and maintenance	$\$177 \times 10^6 - 257 \times 10^6$ /yr	$\$0.287 \times 10^6$ /yr - 0.415×10^6 /yr	
<u>Environmental Controls</u>	(1981 \$)		
High-efficiency particulate aerosol filter system	Not Determined ↓		
Scrubbers and dryers			
Waste lagoons			
Sanitary waste system			

ENVIRONMENTAL RESIDUALS

	Quantities Released			Remarks
	Reference Energy System			
	Annual Levels			
	English Units	Metric Units	Per 10 ¹² Btu Energy Produced *	
<u>Air Pollutants</u>				
Sulfur dioxide	681 tons	618 tonnes	1.10 tons	
Oxides of nitrogen	170 tons	160 tonnes	0.28 ton	
Carbon monoxide	6.2 tons	5.6 tonnes	0.01 ton	
Uranium	5.1 × 10 ⁻³ Ci	5.1 × 10 ⁻³ Ci	8.3 × 10 ⁻⁶ Ci	
<u>Water Pollutants</u>				
Nitrogen as ammonia	280 tons	260 tonnes	0.46 ton	
Nitrogen as nitrate	681 tons	618 tonnes	1.10 tons	
Fluoride	120 tons	110 tonnes	0.19 ton	
Uranium	0.51 Ci	0.51 Ci	0.83 × 10 ⁻³ Ci	
Thorium-234	0.26 Ci	0.26 Ci	0.42 × 10 ⁻³ Ci	
<u>Solid Wastes</u>				
Calcium fluoride	743 tons	674 tonnes	1.20 tons	
Ammonia		Not Determined		
Fluorine		↓		
Sulfur oxide				
Nitrate				
Uranium (buried)	5.9 Ci	5.9 Ci	9.6 × 10 ⁻³ Ci	
<u>Thermal Discharge</u>				
Heat dissipated	200 × 10 ⁹ Btu	300 × 10 ¹² J	0.4 × 10 ⁹ Btu	

PRODUCTS

	Quantities Produced			Remarks
	Reference Energy System Annual Production		Per 10 ¹² Btu Energy Produced *	
	English Units	Metric Units		
<u>Primary</u>				
Uranium (uranium dioxide) fuel elements	990 tons	900 tonnes	1.6 tons	

OCCUPATIONAL SAFETY AND HEALTH

Not Determined

*In electrical energy (output) at the reactor; see note on page 1.

PRESSURIZED WATER REACTOR NUCLEAR POWER PLANT

REFERENCE ENERGY SYSTEM

Pressurized water reactor nuclear-powered electric generating plant using 3.3% enriched uranium-235 fuel; onsite storage of spent reactor fuel; maximum recycling of liquid radioactive wastes; filtration of building exhausts; onsite water treatment of river supply water; natural draft wet cooling towers.

FACILITY OPERATING PARAMETERS

Size: 1×10^3 MWe
 Annual Capacity Factor: 70%
 Annual Energy Production: * 21×10^{12} Btu
 (6.13×10^6 MWh)
 Efficiency: 33%
 Lifetime: 30-40 yr

RESOURCES USED

	Quantities Used		Per 10 ¹² Btu Energy Produced *	Remarks
	Reference Energy System Annual Usage			
	English Units	Metric Units		
<u>Feed Materials</u>				
Uranium fuel (3.3% uranium-235)	26.7 tons	24.2 tonnes	1.27 tons	33% of core annually
<u>Water</u>				
Power plant make-up water	16 × 10 ³ acre-ft	19 × 10 ⁹ l	0.74 × 10 ³ acre-ft	Wet cooling
<u>Total Usage</u>				
<u>Construction Materials</u>				
Concrete	250 × 10 ³ yd ³	190 × 10 ³ m ³	11.9 × 10 ³ yd ³	
Metal conduit	500 × 10 ³ ft	150 × 10 ³ m	24 × 10 ³ ft	
Cable tray	100 × 10 ³ ft	30 × 10 ³ m	4.8 × 10 ³ ft	
Large process pipe	160 × 10 ³ ft	50 × 10 ³ m	7.6 × 10 ³ ft	
Small pipe	200 × 10 ³ ft	60 × 10 ³ m	9.5 × 10 ³ ft	
Wire and cable	7 × 10 ⁶ ft	2.1 × 10 ⁶ m	0.3 × 10 ⁶ ft	
<u>Land</u>				
Site area	1.85 × 10 ³ acres	749 ha	88.1 acres	
Low-level radioactive waste disposal area	0.02 acre	0.008 ha	0.9 × 10 ⁻³ acre	
<u>Personnel</u>				
Construction (9 yr)	2.31 × 10 ³ workers		110 workers	
Operation and maintenance	230 workers		11 workers	

COSTS

	<u>Reference Energy System</u>	<u>Per 10¹² Btu Energy Produced *</u>	<u>Remarks</u>
	(1981 \$)		
<u>Facility</u>	{ Total life cycle costs (excluding ultimate decommissioning and decontamination) $\approx$ 97.0 mills/kWh }		Includes capital, operation and maintenance, and fuel costs for a plant scheduled to begin operation in 1985. Reference year for costs is 1976. 1976 CCI average (I_p) = 2401. See Explanatory Notes Section.
Construction (9 yr)			
Operation and maintenance			
<u>Environmental Controls</u>			Included in facility costs

*In electrical energy (output) at the reactor; see note on page 1.

PRESSURIZED WATER REACTOR NUCLEAR POWER PLANT

ENVIRONMENTAL RESIDUALS

	Quantities Released			
	Reference Energy System Annual Levels			
	English Units	Metric Units	Per 10 ¹² Btu Energy Produced *	Remarks
<u>Air Pollutants</u>				
Noble gases	1.80 × 10 ³ Ci	1.80 × 10 ³ Ci	85.7 Ci	10 CFR 50 and 40 CFR 190 specify individual concentration limits
Carbon-14	6.2 Ci	6.2 Ci	0.30 Ci	
Tritium	800 Ci	800 Ci	38.1 Ci	
Fossil fuel air emissions	53 tons	48 tonnes	2.5 tons	
Airborne water from cooling tower evaporation losses	3.8 × 10 ⁹ gal	14.4 × 10 ⁹ l	0.18 × 10 ⁹ gal	
<u>Water Pollutants</u>				
Activated corrosion and fission products	0.12 Ci	0.12 Ci	0.006 Ci	10 CFR 50 and 40 CFR 190 specify individual concentration limits
Tritium	302 Ci	302 Ci	14.4 Ci	
Total suspended solids		12.9 × 10 ³ mg/l		40 CFR 423 specifies allowable increases in river concentrations
Total dissolved solids		2860 mg/l		
Iron	Metric units are universally used	180 mg/l	Depends on flow, which varies widely	
Chloride		360 mg/l		
Chromium		0.30 mg/l		
Copper		0.73 mg/l		
Zinc		0.84 mg/l		
<u>Solid Wastes</u>				
Low-level solid radwaste	5.83 × 10 ³ Ci (5.90 × 10 ³ ft ³)	5.83 × 10 ³ Ci (167 m ³)	278 Ci (280 ft ³)	
<u>Thermal Discharge</u>				
Heat dissipated to atmosphere	42 × 10 ¹² Btu	44 × 10 ¹⁵ J	2 × 10 ¹² Btu	

PRODUCTS

	Quantities Produced			Remarks
	Reference Energy System Annual Production		Per 10 ¹² Btu Energy Produced *	
	English Units	Metric Units		
Primary				
Electricity	6.1 × 10 ⁶ MWh	6.1 × 10 ⁶ MWh	0.29 × 10 ⁶ MWh	
Recoverables/Recyclables				
Spent nuclear fuel	26.7 tons	24.3 tonnes	1.30 tons	

OCCUPATIONAL SAFETY AND HEALTH

	Reference Energy System Annual	Per 10 ¹² Btu Energy Produced *	Remarks
<u>Deaths</u>	0	0	
<u>Injuries</u>	0.5-3.0	0.02-0.14	
<u>Radiation Exposure</u>	428 man-rem	20.4 man-rem	

*In electrical energy (output) at the reactor; see note on page 1.

BOILING WATER REACTOR NUCLEAR POWER PLANT

REFERENCE ENERGY SYSTEM

General Electric Company's standardized BWR/6 reactor with the Mark III containment design. Natural draft cooling towers. Fuel is 3% enriched uranium-235; onsite storage of liquid radioactive wastes; filtration of building exhausts; onsite water treatment of river supply water; and natural draft wet cooling towers.

FACILITY OPERATING PARAMETERS

Size: 1×10^3 MWe
 Annual Capacity Factor: 70%
 Annual Energy Production: 21×10^{12} Btu
 Efficiency: 33%
 Lifetime: 30-40 yr

RESOURCES USED

	Quantities Used		Per 10 ¹² Btu Energy Produced *	Remarks
	Reference Energy System Annual Usage			
	English Units	Metric Units		
<u>Feed Materials</u>				
Uranium fuel (3.0% enriched uranium-235)	34 tons	31 tonnes	1.6 tons	One-fourth of core annually
<u>Processing Materials</u>	Not Determined			
<u>Water</u>				
Make-up water for cooling towers and miscellaneous plant services	16.9 × 10 ³ acre-ft	21 × 10 ⁹ l	0.8 × 10 ³ acre-ft	Natural draft wet cooling towers used.
	Total Usage			
<u>Construction Materials</u>				
Concrete	4.5 × 10 ⁶ ft ³	130 × 10 ³ m ²	210 × 10 ² ft ³	
Reinforcing steel	17 × 10 ³ tons	15 × 10 ³ tonnes	810 tons	
Structural steel	8.7 × 10 ³ tons	7.9 × 10 ³ tonnes	420 tons	
<u>Land</u>				
Site land requirements, transmission route, disrupted land surface (site), and committed land	3.38 × 10 ³ acres	1.38 ha	161 acres	For two 1250-MWe units with cooling towers
<u>Personnel</u>				
Construction (9 yr)	2.3 × 10 ³ workers		110 workers	
Operation and maintenance	230 workers			

COSTS

	Reference Energy System	Per 10 ¹² Btu Energy Produced *	Remarks
		(1981 \$)*	
<u>Facility</u>			Includes capital, fuel, and operation and maintenance plant costs for a plant scheduled to begin operation in 1985.
Construction (9 yr) (with interest during construction)	{ Total life cycle costs (excluding ultimate decommissioning and decontamination) = 108 mills/kWh. }		
Operation and maintenance			
<u>Environmental Controls</u>			Included in facility costs
*Reference year is 1976; 1976 CCI average (I ₀) = 2401. See Explanatory Notes section.			

*In electrical energy (output) at the reactor; see note on page 1.

BOILING WATER REACTOR NUCLEAR POWER PLANT

ENVIRONMENTAL RESIDUALS

	Quantities Released			Remarks
	Reference Energy System Annual Levels		Per 10 ¹² Btu Energy Produced *	
	English Units	Metric Units		
<u>Air Pollutants</u>				
Gaseous radioactive effluents				10 CFR 50 and 40 CFR 190 specify individual concen- tration limits
• Noble gases	11 × 10 ³ Ci	11 × 10 ³ Ci	540 Ci	
• Tritium	110 Ci	110 Ci	5.2 Ci	
• Carbon-14	6.8 Ci	6.8 Ci	0.32 Ci	
• Iodine-131 (elemental)	64 × 10 ⁻³ Ci	64 × 10 ⁻³ Ci	3.0 × 10 ⁻³ Ci	
• Iodine-131 (nonelemental)	140 × 10 ⁻³ Ci	140 × 10 ⁻³ Ci	6.6 × 10 ⁻³ Ci	
Fossil fuel air emissions	210 tons			
Airborne water from cooling tower evaporation losses	3.8 × 10 ⁹ gal	14.4 × 10 ⁹ l	0.18 × 10 ⁹ gal	
<u>Water Pollutants</u>				
Liquid radioactive effluents				10 CFR 50 and 40 CFR 190 specify individual concen- tration limits
• Tritium	35 Ci	35 Ci	1.7 Ci	
• Activation and fission products	0.1 Ci	0.1 Ci	5 × 10 ³ Ci	
Dissolved solids				40 CFR 423 specifies allowable increases in river concentra- tions
• Sulfates	23 tons	21 tonnes	1.1 tons	
• Chlorine	0.9 ton	0.8 tonne	0.04 ton	
• Sodium	11 tons	10 tonnes	0.53 ton	
• Other	5.8 tons	5.3 tonnes	0.28 ton	
<u>Solid Wastes</u>				
Low-level solid radioactive wastes				
• Wet material embedded in concrete	19 × 10 ³ ft ³	530 m ³	900 ft ³	
• Dry material in drums	3.3 × 10 ³ ft ³	94 m ³	160 ft ³	
Water filtration waste products				
• Aluminum hydroxide	10 tons	9.1 tonnes	0.48 ton	
• Settled solids	8 tons	7.3 tonnes	0.38 ton	
<u>Thermal Discharge</u>				
Heat dissipated	61 × 10 ¹² Btu	64 × 10 ¹⁶ J	2.9 × 10 ¹² Btu	
<u>Noise Pollution</u>				
	Negligible			

*In electrical energy (output) at the reactor; see note on page 1.

BOILING WATER REACTOR NUCLEAR POWER PLANT

PRODUCTS

	Quantities Produced			Remarks
	Reference Energy System Annual Production		Per 10 ¹² Btu Energy Produced *	
	English Units	Metric Units		
Primary Electric power	6.13 × 10 ⁹ kWh	6.13 × 10 ⁹ kWh	2.93 × 10 ⁹ kWh	
Byproducts	Not Determined			
<u>Recoverables/Recyclables</u>				
Spent nuclear fuel containing				
• Uranium-235 nuclear fuel				
— Mass	616 lb	280 kg	29.3 lb	
— Energy equivalent	4.3 × 10 ⁹ kWh (14.7 × 10 ²¹ Btu)	4.3 × 10 ⁹ kWh (15.5 × 10 ²⁴ J)	0.21 × 10 ⁹ kWh (0.7 × 10 ²¹ Btu)	
• Fissile plutonium nuclear fuel				
— Mass	396 lb	780 kg	18.8 lb	
— Energy equivalent	3.4 × 10 ⁹ kWh (10.5 × 10 ²¹ Btu)	3.4 × 10 ⁹ kWh (11.1 × 10 ²⁴ J)	1.6 × 10 ⁹ kWh (0.5 × 10 ²¹ Btu)	
• Isotopes for medical and industrial applications	Not Determined			

OCCUPATIONAL SAFETY AND HEALTH

	Reference Energy System Annual	Per 10 ¹² Btu Energy Produced *	Remarks
<u>Deaths</u>	0.0	0.0	
<u>Injuries</u>			
Number	0.51-3.0	0.02-0.14	
Total lost days	14-91	0.67-4.33	
Occupational Radiation Exposure	1.1 × 10 ³ man-rem	53 man-rem	Average collective dose

*In electrical energy (output) at the reactor; see note on page 1.

COMMERCIAL HIGH-LEVEL NUCLEAR WASTE REPOSITORY

REFERENCE ENERGY SYSTEM

Deep Geologic Repository facility capable of handling solidified high-level wastes and transuranic wastes from the reprocessing of spent fuel; located 600-m deep in each of two candidate rock media, salt and basalt; retrievable emplacement for the first 5 yr of operation with optional permanent disposal; packaging facility included in surface operations. Construction time is 10 yr, mining operations taking place during the last 7 yr.

FACILITY OPERATING PARAMETERS

	Repository For Reprocessing Wastes	
	Salt	Basalt
Average Annual Capacity (MTHM):	3,000	3,000
Total Equivalent Capacity (MTHM):	62,000	56,000
Total Electrical Energy Represented:	49×10^{15} Btu	44×10^{15} Btu
Lifetime (yr):	19	18

RESOURCES USED

	Quantities Used				Per 10 ¹² Btu Energy Produced *		Remarks
	Reference Energy System Annual Levels						
	English Units Salt	English Units Basalt	Metric Units Salt	Metric Units Basalt	Salt	Basalt	
Feed Material							
Water	7.1 × 10 ⁶ gal	12 × 10 ⁶ gal	27 × 10 ⁶ l	45 × 10 ⁶ l	1.5 × 10 ³ gal	2.7 × 10 ³ gal	
Energy							
Construction							
• Propane	8.5 × 10 ³ ft ³	14 × 10 ³ ft ³	0.24 × 10 ³ m ³	0.40 × 10 ³ m ³	1.7 ft ³	3.1 ft ³	
• Diesel fuel	0.63 × 10 ⁶ gal	1.1 × 10 ⁶ gal	2.4 × 10 ³ m ³	4.0 × 10 ³ m ³	130 gal	240 gal	
• Gasoline	0.48 × 10 ⁶ gal	0.79 × 10 ⁶ gal	1.8 × 10 ³ m ³	3.0 × 10 ³ m ³	97 gal	179 gal	
• Electricity	1.6 × 10 ⁶ kWh	2.7 × 10 ⁶ kWh	1.6 × 10 ⁶ kWh	2.7 × 10 ⁶ kWh	330 kWh	610 kWh	
Operation							
• Diesel fuel	3.5 × 10 ⁶ gal	3.4 × 10 ⁶ gal	13 × 10 ³ m ³	13 × 10 ³ m ³	1.3 × 10 ³ gal	1.4 × 10 ³ gal	
• Coal	81 × 10 ³ tons	79 × 10 ³ tons	74 × 10 ³ tonnes	72 × 10 ³ tonnes	32 tons	32 tons	
• Electricity	110 × 10 ⁶ kWh	127 × 10 ⁶ kWh	110 × 10 ⁶ kWh	127 × 10 ⁶ kWh	43 × 10 ³ kWh	52 × 10 ³ kWh	
• Steam	870 × 10 ³ tons	860 × 10 ³ tons	790 × 10 ³ tonnes	780 × 10 ³ tonnes	340 tons	350 tons	
Operational Materials							
Concrete	59 × 10 ³ ft ³	63 × 10 ³ ft ³	1.7 × 10 ³ m ³	1.8 × 10 ³ m ³	23 ft ³	25 ft ³	
Steel	4.8 × 10 ³ tons	13 × 10 ³ tons	4.4 × 10 ³ tonnes	12 × 10 ³ tonnes	1.9 tons	5.2 tons	
Total Usage							
Construction Materials							
Concrete	3.9 × 10 ³ ft ³	6.7 × 10 ³ ft ³	110 × 10 ³ m ³	190 × 10 ³ m ³	79 ft ³	150 ft ³	
Steel	20 × 10 ³ tons	33 × 10 ³ tons	18 × 10 ³ tonnes	30 × 10 ³ tonnes	0.41 ton	0.75 ton	
Copper	260 tons	460 tons	240 tonnes	420 tonnes	5.4 × 10 ⁻³ ton	11 × 10 ⁻³ ton	
Zinc	68 tons	120 tons	62 tonnes	110 tonnes	1.4 × 10 ⁻³ ton	2.7 × 10 ⁻³ ton	
Aluminum	51 tons	85 tons	46 tonnes	77 tonnes	1.0 × 10 ⁻³ ton	1.9 × 10 ⁻³ ton	
Lumber	92 × 10 ³ ft ³	155 × 10 ³ ft ³	2.6 × 10 ³ m ³	4.4 × 10 ³ m ³	1.9 ft ³	3.5 ft ³	
Land							
Fenced, restricted	2000 acres	2000 acres	800 ha	800 ha	41 × 10 ⁻³ acre	45 × 10 ⁻³ acre	
Federally controlled	7900 acres	7900 acres	3200 ha	3200 ha	193 × 10 ⁻³ acre	179 × 10 ⁻³ acre	
Surface facilities	400 acres	540 acres	180 ha	220 ha	9.1 × 10 ⁻³ acre	12 × 10 ⁻³ acre	
Personnel							
Construction (10 yr)							
Construction	2.0 × 10 ³ workers	3.8 × 10 ³ workers	—	—	0.22 worker	0.59 worker	
Operation	1.3 × 10 ³ workers	1.5 × 10 ³ workers	—	—	0.39 worker	0.48 worker	

*In electrical energy (output) at the reactor; see note on page 1.

COMMERCIAL HIGH-LEVEL NUCLEAR WASTE REPOSITORY

COSTS

	Reference Energy System		Per 10 ¹² Btu *		Remarks
	Salt	Basalt	Salt	Basalt	
	(May 1981 \$)				
Facility					
Construction (10 yr)	1.6×10^9	3.1×10^9	33×10^3	70×10^3	
Operation and maintenance	1.6×10^9	2.4×10^9	33×10^3	55×10^3	

ENVIRONMENTAL RESIDUALS

	Quantities Released				Per 10 ¹² Btu Energy Produced *		Remarks	
	Reference Energy System Annual Levels							
	English Units Salt	English Units Basalt	Metric Units Salt	Metric Units Basalt	Salt	Basalt		
Air Pollutants								
Radiological								
• Construction							EPA is developing environmental standards that state the public health and environmental requirements to be met for disposal of high level nuclear waste. NRC will use EPA's regulation to set their standards to govern licensing, design, and operation of permanent waste disposal facilities. Tentative time-table for final regulations (FRI) is May 1983.	
—Radon-220	1.1 × 10 ⁻³ Ci	2.0 Ci			0.16 × 10 ⁻⁶ Ci	0.32 × 10 ⁻³ Ci		
—Radon-222	1.6 × 10 ⁻³ Ci	1.7 Ci			0.23 × 10 ⁻⁶ Ci	0.27 × 10 ⁻³ Ci		
—Lead-210	0.13 × 10 ⁻⁶ Ci	0.14 × 10 ⁻³ Ci			19 × 10 ⁻¹² Ci	0.022 × 10 ⁶ Ci		
—Lead-212	1.7 × 10 ⁻⁶ Ci	3.0 × 10 ⁻³ Ci			0.24 × 10 ⁻⁹ Ci	0.47 × 10 ⁻⁶ Ci		
—Lead-214	1.6 × 10 ⁻³ Ci	1.7 Ci			0.23 × 10 ⁻⁶ Ci	0.27 × 10 ⁻³ Ci		
—Bismuth-210	1.6 × 10 ⁻³ Ci	1.7 Ci			0.23 × 10 ⁻⁶ Ci	0.27 × 10 ⁻³ Ci		
• Operation			Negligible					
Fossil fuel combustion								
Products								
• Construction								
—CO	1400 tons	2400 tons	1300 tonnes	2100 tonnes	0.20 ton	0.37 ton		
—Hydrocarbons	63 tons	100 tons	57 tonnes	94 tonnes	9.0 × 10 ⁻³ ton	17 × 10 ⁻³ ton		
—NO _x	270 tons	440 tons	240 tonnes	400 tonnes	0.038 ton	0.070 ton		
—SO _x	16 tons	27 tons	14 tonnes	24 tonnes	2.3 × 10 ⁻³ ton	4.2 × 10 ⁻³ ton		
—Particulates	16 tons	27 tons	14 tonnes	24 tonnes	2.3 × 10 ⁻³ ton	4.2 × 10 ⁻³ ton		
• Operation								
—CO	170 tons	170 tons	150 tonnes	150 tonnes	0.070 ton	0.067 ton		
—Hydrocarbons	58 tons	60 tons	53 tonnes	54 tonnes	0.023 ton	0.024 ton		
—NO _x	990 tons	1000 tons	895 tonnes	940 tonnes	0.35 ton	0.42 ton		
—SO _x	700 tons	670 tons	630 tonnes	610 tonnes	0.27 ton	0.27 ton		
—Particulates	30 tons	29 tons	27 tonnes	27 tonnes	0.011 ton	0.012 ton		
Dust								
• Construction								
—Hoist	1000 tons	1700 tons	930 tonnes	1600 tonnes	0.14 ton	0.278 ton		
—Arid	14,000 tons	23,000 tons	13,000 tonnes	22,000 tonnes	2.0 tons	3.8 tons		
Solid Wastes	2.4 × 10 ⁶ tons	5.0 × 10 ⁶ tons	2.1 × 10 ⁶ tonnes	4.6 × 10 ⁶ tonnes	340 tons	800 tons		
Water Pollutants								
Not Determined								
Thermal Discharge	40 × 10 ⁹ Btu	37 × 10 ⁹ Btu	40 × 10 ⁶ MJ	39 × 10 ⁶ MJ	15 × 10 ⁶ Btu	15 × 10 ⁶ Btu		

OCCUPATIONAL SAFETY AND HEALTH

	Reference Energy System Annual Average		Per 10 ¹² Btu Energy Produced *		Remarks
	Salt	Basalt	Salt	Basalt	
<u>Nonradiological</u>					
Disabling injuries	50	130	0.010	0.029	
Fatalities*	1.0	2.6	0.20 × 10 ⁻³	0.59 × 10 ⁻³	
<u>Radiological</u>					
Construction	0.026 man-rem	890 man-rem	3.7 × 10 ⁻⁶ man-rem	0.14 man-rem	
Operation	7.4 × 10 ³ man-rem	7.2 × 10 ³ man-rem	2.9 man-rem	2.9 man-rem	

*Fatalities include permanent disabling injuries.

*In electrical energy (output) at the reactor; see note on page 1.

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SYNTHETIC FUEL TECHNOLOGIES

UNDERGROUND OIL SHALE MINING

REFERENCE ENERGY SYSTEM

Underground oil shale mine utilizing room and pillar configuration for shale removal. The oil shale is entered through a tunnel dug into the side of a valley where an outcrop appears. Pillars are left in place to provide roof support. The shale is drilled and blasted and transported to a portable underground primary crusher. The crushed shale is then taken above ground by a conveyor system and crushed further. 30 gal of shale oil produced per ton of shale mined.

FACILITY OPERATING PARAMETERS

Size:	73.7 × 10 ³ tons/day raw shale mined
Annual Capacity Factor:	90%
Annual Energy Production:	135.57 × 10 ¹² Btu
Efficiency:	Not determined
Lifetime:	30 yr

RESOURCES USED

	Quantities Used		Per 10 ¹² Btu Energy Produced	Remarks
	Reference Energy System Annual Usage			
	English Units	Metric Units		
<u>Feed Materials</u>				
Raw shale (unmined)	24.2 × 10 ⁶ tons	22.0 × 10 ⁶ tonnes	178.45 × 10 ³ tons	
<u>Energy</u>				
Electricity for mine equipment		Not Determined		
<u>Water</u>				
Mining and crushing	300-450 acre-ft	380 × 10 ⁶ - 550 × 10 ⁶ l	2.3-3.3 acre-ft	
	<u>Total Usage</u>			
<u>Construction Materials</u>				
		Not Determined		
<u>Land</u>	418 acres	169 ha	3.08 acres	
<u>Personnel</u>				
Construction		484 workers	3.57 workers	
Operation and maintenance		Not Determined		

COSTS

	Reference Energy System	Per 10 ¹² Btu Energy Produced	Remarks
<u>Facility</u>		(1981 \$)	
Construction	\$94.6 × 10 ⁶ total	\$0.697 × 10 ⁶ total	Reference year for cost is 1978. 1978 CCI average (I ₈) = 2776. See Explanatory Notes Section.
Operation and maintenance	Not Determined		
<u>Environmental Controls</u>		Not Determined	

UNDERGROUND OIL SHALE MINING

ENVIRONMENTAL RESIDUALS

		Quantities Released		
Reference Energy System				
Annual Levels				
English Units	Metric Units	Per 10 ¹² Btu Energy Produced	Remarks	
<u>Air Pollutants</u>				
Particulates	605 tons	549 tonnes	4.46 tons	
Sulfur dioxide	1.6 tons	1.5 tonnes	0.012 ton	
Oxides of nitrogen	23 tons	21 tonnes	0.17 ton	
Hydrocarbons	2.6 tons	2.4 tonnes	0.019 ton	
Carbon monoxide	14 tons	12 tonnes	0.10 ton	
<u>Water Pollutants</u>				
Saline contamination potential in groundwater				
<u>Solid Wastes</u>				
		Negligible		See oil shale surface retorting
<u>Noise Pollution</u>				
		Not Determined		

PRODUCTS

	Quantities Produced			Remarks
	Reference Energy System Annual Production		Per 10 ¹² Btu Energy Produced	
	English Units	Metric Units		
<u>Primary</u>				
Mined and primary crushed oil shale rock	24.2 × 10 ⁶ tons	22.0 × 10 ⁶ tonnes	178.45 × 10 ³ tons	

OCCUPATIONAL SAFETY AND HEALTH

Not Determined

SURFACE OIL SHALE MINING

REFERENCE ENERGY SYSTEM

In surface oil shale mining, bench configuration is used for overburden removal and shale extraction. Shale is drilled, blasted, and transported by truck from the in-mine site to a primary crushing site. Shale mined is assumed to be 2800 Btu/lb of raw shale or 30 gal/ton shale oil content.

FACILITY OPERATING PARAMETERS

Size:	73.7×10^3 tons/day (raw shale mined)
Annual Capacity Factor:	90%
Annual Energy Production:	135.6×10^{12} Btu
Efficiency:	Not determined
Lifetime:	30 yr

RESOURCES USED

	Quantities Used			Remarks
	Reference Energy System Annual Usage		Per 10 ¹² Btu Energy Produced	
	English Units	Metric Units		
<u>Feed Materials</u>				
Raw shale	24.1 × 10 ⁶ tons	22.0 × 10 ⁶ tonnes	178 × 10 ³ tons	
<u>Energy</u>		Not Determined		
<u>Processing Materials</u>		Not Determined		
<u>Water</u>	300-450 acre-ft	370 × 10 ⁶ – 550 × 10 ⁶ l	2.2-3.3 acre-ft	
	Total Usage			
<u>Construction Materials</u>		Not Determined		
<u>Land</u>	1.44 × 10 ³ acres	582 ha	10.6 acres	
<u>Personnel</u>				
Construction		Not Determined		
Operation and maintenance				

COSTS

	Reference Energy System	Per 10^{12} Btu Energy Produced	Remarks
<u>Facility</u>		(1981 \$)	
Construction	$\$106 \times 10^6$ total	$\$0.781 \times 10^6$ total	Reference year for costs is 1978. 1978 CCI average (I_p) = 2776. See Explanatory Notes Section.
Operation and maintenance	Not Determined		
<u>Environmental Controls</u>			
Water spray to control dust		Not Determined	

SURFACE OIL SHALE MINING

ENVIRONMENTAL RESIDUALS

	Quantities Released			
	Reference Energy System			
	Annual Levels			
	English Units	Metric Units	Per 10 ¹² Btu Energy Produced	Remarks
<u>Air Pollutants</u>				
Particulates	3.0 × 10 ³ tons	2.7 × 10 ³ tonnes	22 tons	
Sulfur dioxide	28 tons	26 tonnes	0.21 ton	
Oxides of nitrogen	400 tons	363 tonnes	2.95 tons	
Hydrocarbons	466 tons	423 tonnes	3.44 tons	
Carbon monoxide	244 tons	222 tonnes	1.80 tons	
<u>Water Pollutants</u>				
Possibility of underground water contamination by saline mine water				
<u>Solid Wastes</u>				
		Negligible		See oil shale surface retorting
<u>Noise Pollution</u>				
		Not Determined		

PRODUCTS

	Quantities Produced			Remarks
	Reference Energy System		Per 10 ¹² Btu Energy Produced	
	Annual Production			
	English Units	Metric Units		
<u>Primary</u>				
Mined and primary crushed oil shale rock	24.1 × 10 ⁶ tons	22.0 × 10 ⁶ tonnes	178 × 10 ³ tons	

OCCUPATIONAL SAFETY AND HEALTH

Not Determined

MODIFIED IN SITU SHALE RETORTING

REFERENCE ENERGY SYSTEM

A modified in situ oil shale retort is comprised of an underground block of oil shale approximately 15–20% of which has been mined by conventional mining techniques to form a cavity at the bottom of the deposit. The material above the cavity is fractured or rubblized after injection and production wells have been drilled on opposing sides of the formation. The rubblized material is ignited to supply heat to the retort and a retorting fluid (hot steam or gas) is passed through the material. Oil mist and liquid is forced up the production well to the surface for further processing.

FACILITY OPERATING PARAMETERS

Size:	102.6 × 10 ³ tons of shale/day retorted in situ 50 × 10 ³ bbl/day of shale produced
Annual Capacity Factor:	90%
Annual Energy Production:	95.3 × 10 ¹² Btu
Efficiency:	61% (thermal overall)
Lifetime:	30 yr

RESOURCES USED

	Quantities Used			Remarks
	Reference Energy System Annual Usage		Per 10 ¹² Btu Energy Produced	
	English Units	Metric Units		
<u>Feed Materials</u>				
Raw shale retorted in situ	33.7 × 10 ⁶ tons	30.6 × 10 ⁶ tonnes	353.8 × 10 ³ tons	
Raw shale mined and placed above ground	11.2 × 10 ⁶ tons	10.2 × 10 ⁶ tonnes	117.9 × 10 ³ tons	
<u>Energy</u>				
	Not Determined			
<u>Water</u>				
Retorting and upgrading	2.12 × 10 ³ acre-ft	2.61 × 10 ⁹ l	22.2 acre-ft	
Power generation	2.32 × 10 ³ acre-ft	2.87 × 10 ⁹ l	24.4 acre-ft	
Revegetation	0.09 × 10 ³ acre-ft	0.1 × 10 ⁹ l	0.9 acre-ft	
Steam injection	2.75 × 10 ³ acre-ft	3.40 × 10 ⁹ l	28.9 acre-ft	
Miscellaneous	0.42 × 10 ³ acre-ft	0.52 × 10 ⁹ l	4.4 acre-ft	
Total	7.70 × 10 ³ acre-ft	9.50 × 10 ⁹ l	80.8 acre-ft	
<u>Total Usage</u>				
<u>Construction Materials</u>				
	Not Determined			
<u>Land</u>	1.41 × 10 ³ – 1.52 × 10 ³ acres	571–617 ha	14.8–16.0 acres	
<u>Personnel</u>				
Construction	2.92 × 10 ³ workers		30.6 workers	
Operation and maintenance	Not Determined			

COSTS

	<u>Reference Energy System</u>	<u>Per 10¹² Btu Energy Produced</u>	<u>Remarks</u>
<u>Facility</u>			
	(1981 \$)		
Construction	\$1.64 × 10 ⁹ total	\$17.1 × 10 ⁶ total	Reference year for cost is 1978. 1978 CCI average (I _R) = 2776. See Explanatory Notes Section.
Operation and maintenance	Not Determined		
<u>Environmental Controls</u>			
	Not Determined		

MODIFIED IN SITU SHALE RETORTING

ENVIRONMENTAL RESIDUALS

ENVIRONMENTAL RESIDUALS

	Quantities Released			Remarks
	Reference Energy System		Per 10 ¹² Btu Energy Produced	
	Annual Levels			
	English Units	Metric Units		
<u>Air Pollutants</u>				
Particulates	3.77 × 10 ³ tons	3.42 × 10 ³ tonnes	39.6 tons	
Oxides of nitrogen	3.21 × 10 ³ tons	2.92 × 10 ³ tonnes	33.7 tons	
Oxides of sulfur	591 tons	536 tonnes	6.21 tons	
Carbon dioxide	953 tons	865 tonnes	10.0 tons	
Hydrocarbons	49 tons	44 tonnes	0.51 ton	
<u>Water Pollutants</u>				
Zero discharge to surface water assumed; however, possibility of underground aquifer contamination exists				
<u>Solid Wastes</u>				
Spent shale	9.43 × 10 ⁶ tons	8.56 × 10 ⁶ tonnes	99.0 × 10 ³ tons	Aboveground retorting
<u>Noise Pollution</u>				
Not Determined				

PRODUCTS

	<u>Quantities Produced</u>			<u>Remarks</u>
	<u>Reference Energy System Annual Production</u>		<u>Per 10¹² Btu Energy Produced</u>	
	<u>English Units</u>	<u>Metric Units</u>		
<u>Primary</u>				
Refined shale oil	16.4 × 10 ⁶ bbl	2.61 × 10 ⁹ l	172.4 × 10 ³ bbl	
<u>Byproducts</u>				
		Not Determined		
<u>Recoverables/Recyclables</u>				
<u>Water</u>		Not Determined		

OCCUPATIONAL SAFETY AND HEALTH

Not Determined

OIL SHALE SURFACE RETORTING: PARAHO PROCESS (DIRECT MODE)

REFERENCE ENERGY SYSTEM

Mine-mouth plant located in the rich oil shale Green River formation; wetting agents, baffled settling chambers, Venturi scrubbers, and baghouse filters for particulate control; Phosam-VV process for ammonia removal (nitrogen oxide control); Stretford process for hydrogen sulfide removal (sulfur dioxide control); onsite solid waste disposal; onsite water treatment for recirculation to minimize discharge and external water requirements; and onsite shale oil upgrading facility. Oil shale facilities are subject to future regulations.

FACILITY OPERATING PARAMETERS

Size: 50×10^3 bbl/day
(syncrude equivalent)
Annual Capacity Factor: 90% (assumed)
Annual Energy Production: 106.4×10^{12} Btu*
Efficiency: 95% (extraction)
Lifetime: 25 yr
*Heating value of upgraded shale oil $\cong 6.48 \times 10^6$ Btu/bbl.

RESOURCES USED

	Quantities Used		Per 10 ¹² Btu Energy Produced	Remarks
	Reference Energy System Annual Usage			
	English Units	Metric Units		
<u>Feed Materials</u>				
Run-of-mine oil shale	29.0 × 10 ⁶ tons	26.4 × 10 ⁶ tonnes	273 × 10 ³ tons	
<u>Energy</u>				
Diesel fuel for onsite equipment	5.16 × 10 ⁶ gal	19.5 × 10 ⁶ l	48.6 × 10 ³ gal	
<u>Processing Materials</u>				
Ammonium nitrate fuel oil (for rubblization)	7.8 × 10 ³ tons	7.1 × 10 ³ tonnes	73 tons	
<u>Water</u>				
Makeup water	36.3 × 10 ³ acre-ft	44.7 × 10 ⁹ l	343 acre-ft	
<u>Total Usage</u>				
<u>Construction Materials</u>				
		Not Determined		
<u>Land</u>				
	6.97 × 10 ³ acres	2.82 × 10 ³ ha	65.5 acres	
<u>Personnel</u>				
Construction (25 yr)	2.3 × 10 ³ workers		22 workers	
Operation and maintenance	1.26 × 10 ³ workers		11.8 workers	

COSTS

	Reference Energy System	Per 10^{12} Btu Energy Produced	Remarks
(1981 \$)			
<u>Facility</u>			
Construction			Reference year for cost is 1979. 1979 CCI average (I_R) = 3003. See Explanatory Notes Section.
Operation and maintenance		Not Determined	
<u>Environmental Controls</u>			
Construction		Not Determined	
Operation and maintenance	$\$14.8 - \27.9×10^6	$\$0.14 - 0.26 \times 10^6$	

OIL SHALE SURFACE RETORTING: PARAHO PROCESS (DIRECT MODE)

ENVIRONMENTAL RESIDUALS

	Quantities Released			Remarks
	Reference Energy System Annual Levels		Per 10 ¹² Btu Energy Produced	
	English Units	Metric Units		
<u>Air Pollutants</u>				
Sulfur dioxide	66 tons	60 tonnes	0.62 ton	
Oxides of nitrogen	1.1 × 10 ³ tons	1 × 10 ³ tonnes	10.3 tons	
Total suspended particulates	56 tons	51 tonnes	0.53 ton	
Nonmethane hydrocarbons	66 tons	60 tonnes	0.62 ton	
Carbon monoxide	394 tons	358 tonnes	3.7 tons	
Particulate from crushing	296 tons	269 tonnes	2.8 tons	
Dust from shale storage		Not Determined		
Particulates from retort	460 tons	418 tonnes	4.3 tons	
Carbon dioxide from retort	4.1 × 10 ⁶ tons	3.7 × 10 ⁶ tonnes	38.5 × 10 ³ tons	
Post-control flue gas constituents				
• Sulfur dioxide	2.9 × 10 ³ tons	2.6 × 10 ³ tonnes	27.2 tons	0.28 lb/10 ⁶ Btu*
• Oxides of nitrogen	2.1 × 10 ³ tons	1.9 × 10 ³ tonnes	19.7 tons	0.2 lb/10 ⁶ Btu*
• Hydrocarbons	0.1 × 10 ³ tons	0.09 × 10 ³ tonnes	0.94 ton	
• Carbon monoxide	1.8 × 10 ³ tons	1.6 × 10 ³ tonnes	16.9 tons	
• Carbon dioxide	1.1 × 10 ⁶ tons	1.0 × 10 ⁶ tonnes	10.3 × 10 ³ tons	
<u>Water Pollutants</u>				
Runoff from shale storage		Negligible		
Runoff from retorted shale	350 acre-ft	433 × 10 ⁶ l	3.28 acre-ft	
Airborne water from cooling tower drift and evaporation	1.37 × 10 ³ acre-ft	1.68 × 10 ⁹ l	12.8 acre-ft	
Total suspended solids		Not Determined		25-400 mg/l**
Biological oxygen demand		↓		30 mg/l**
Oil and grease				10-50 mg/l**
<u>Solid Wastes</u>				
Retorted shale	23 × 10 ⁶ tons	20.9 × 10 ⁶ tonnes	216 × 10 ³ tons	
<u>Thermal Discharge</u>				
		Not Determined		
<u>Noise Pollution</u>				
		Not Determined		

*Regulatory compliance level.
**Colorado water quality standards.

*Regulatory compliance level.

**Colorado water quality standards.

PRODUCTS

	Quantities Produced			Remarks
	Reference Energy System Annual Production		Per 10 ¹² Btu Energy Produced	
	English Units	Metric Units		
Primary				
Syncrude	16.4 × 10 ⁶ bbl	2.6 × 10 ⁹ l	154 × 10 ³ bbl	
Byproducts				
	Not Determined			

OCCUPATIONAL SAFETY AND HEALTH

	Annual	Per 10 ¹² Btu Energy Produced	Remarks
<u>Deaths*</u>	1.2	0.012	
<u>Injuries*</u>	69.4	0.65	

*Sum of underground mining and surface retorting.

OIL SHALE SURFACE RETORTING: COLONY TOSCO II PROCESS (INDIRECT MODE)

REFERENCE ENERGY SYSTEM

Mine-mouth plant located on the Dow West Property near Parachute Creek, Colorado; underground room and pillar mining method is used; gaseous byproduct-fuel-fired utility boiler to provide steam; TOSCO II indirect mode retorting method; onsite state-of-the-art upgrading and prerefining facilities. Environmental controls include wet suppression, baghouse filters, wet scrubbers for particulate control, Claus process for sulfur recovery (H_2S and SO_2 control), Wellman-Lord tail gas incinerator/ SO_2 scrubber, ammonia recovery unit, acid gas removal process; onsite water treatment and recycling facilities; and on-site solid waste disposal through landfill and revegetation.

FACILITY OPERATING PARAMETERS

Size:	47×10^3 bbl/day syncrude equivalent
Annual Capacity Factor:	90%
Annual Energy Production:	86.5×10^{12} Btu* (15.4×10^6 bbl/yr)
Shale Oil Extraction Efficiency:	95%
Upgrading for Shale Oil to Syncrude Efficiency:	90%
Lifetime:	20 yr
*At 5.6×10^{12} Btu/bbl	

RESOURCES USED

	Quantities Used		Per 10 ¹² Btu Energy Produced (syncrude equivalent)	Remarks
	Reference Energy System Annual Usage			
	English Units	Metric Units		
Explosives				
ANFO for rubbleization	6.01 × 10 ³ tons	5.45 × 10 ³ tonnes	70.8 tons	Explosives
Fuel				
Run-of-mine oil shale	22.3 × 10 ⁶ tons	20.2 × 10 ⁶ tonnes	263 × 10 ³ tons	
Byproduct fuel gas for onsite consumption	409 × 10 ³ tons	371 × 10 ³ tonnes	4.82 × 10 ³ tons	
• Hydrogen generation unit				
• Gas oil hydrogenation unit				
• Naphtha hydrogenation unit				
• Delayed coking process				
• Utility boilers				
Byproduct butane/butylene for plant fuel	71.7 × 10 ³ tons	65.0 × 10 ³ tonnes	844 tons	
Byproduct diesel fuel for mine and processed shale disposal operations	125 × 10 ³ gal	19.9 × 10 ⁶ l	1.47 × 10 ³ bbl	
Energy				
Electricity	15.0 × 10 ⁶ kWh	15.0 × 10 ⁶ kWh	173.4 × 10 ³ kWh	
Water				
Make-up water from Colorado River	3.07 × 10 ³ bbl	11.6 × 10 ⁹ l	36.2 × 10 ⁶ gal	
Miscellaneous water input	471 × 10 ⁶ gal	1.78 × 10 ⁹ l	5.55 × 10 ⁶ gal	
Total Usage				
Concrete	110 × 10 ³ yd ³	84.1 × 10 ³ m ³	1.30 × 10 ³ yd ³	
Steel (reinforced, hardworked)	44 × 10 ³ tons	39.6 × 10 ³ tonnes	518 tons	
Land (20 yr)				
Land for mine development, waste disposal facilities and roads/conveyors	5.74 × 10 ³ acres	2.21 ha	63.2 acres	
Personnel				
Construction (3 yr)	2500 to 2700 workers		28.9 to 31.2 workers	
Operation and maintenance	1040 workers		12.0 workers	

OIL SHALE SURFACE RETORTING: COLONY TOSCO II PROCESS (INDIRECT MODE)

COSTS

Facility	Reference Energy System	Per 10 ¹² Btu Energy Produced (1981 \$)	Remarks
Construction (3 yr)	\$1.53 × 10 ⁹ total	\$17.7 × 10 ⁶ total	Reference year for costs is 1975. 1975 CCI average (I ₈) = 2212. See Explanatory Notes Section.
Operation and maintenance	Not Determined		
Environmental Controls	\$49.2 × 10 ⁶ - 98.4 × 10 ⁶ /yr	\$569 × 10 ³ - 1140 × 10 ³ /yr	Control costs estimated at \$2.00 to \$4.00 per barrel of syncrude

ENVIRONMENTAL RESIDUALS

	Quantities Released		Per 10 ¹² Btu Energy Produced (syncrude equivalent)	Remarks
	Reference Energy System Annual Levels			
	English Units	Metric Units		
Air Pollutants*				
Mining and blasting				
• Total suspended solids (TSP)	2.97 tons	2.69 tonnes	0.0350 ton	
• Sulfur dioxide (SO ₂)	—	—	—	
• Nitrogen oxides (NO _x)	982 tons	894 tonnes	11.6 tons	
• Non-methane hydrocarbons (HC)	197 tons	179 tonnes	2.32 tons	
• Carbon monoxide (CO)	1731 tons	1570 tonnes	20.4 tons	
Particulates from crushing	201 tons	182 tonnes	2.37 tons	
Particulates from shale storage**	16.5 tons	15.0 tonnes	0.194 ton	
Particulates from shale moisturizer	868 tons	870 tonnes	11.3 tons	
Total from shale preheater and elutriator				
• TSP	1808 tons	1640 tonnes	21.3 tons	
• SO ₂	573 tons	520 tonnes	6.75 tons	
• NO _x	5622 tons	5099 tonnes	66.2 tons	
• HC ^x	1065 tons	966 tonnes	12.5 tons	
• CO	183 tons	166 tonnes	2.15 tons	
Hydrogen generation reforming furnaces				
• TSP	45.1 tons	40.9 tonnes	0.531 ton	
• SO ₂	107 tons	97.1 tonnes	1.26 tons	
• NO _x	323 tons	293 tonnes	3.8 tons	
• HC ^x	6.24 tons	5.66 tonnes	0.0735 ton	
• CO	39.0 tons	35.4 tonnes	0.459 ton	
Carbon dioxide (CO₂) from CO₂ stripper				
	2.07 × 10 ⁶ tons	1.88 × 10 ⁶ tonnes	24.4 × 10 ³ tons	
Total from naphtha and gas oil hydrogenators:				
• Delayed coker furnaces and reboiler				
— TSP	12.9 tons	11.7 tonnes	0.152 ton	
— SO ₂	31.4 tons	28.5 tonnes	0.370 ton	0.28 lb/10 ⁶ Btu***
— NO _x	92.8 tons	84.2 tonnes	1.09 tons	0.21 lb/10 ⁶ Btu***
— HC	2.31 tons	2.10 tonnes	0.0272 ton	
— CO	12.1 tons	10.9 tonnes	0.143 ton	
SO ₂ from tailgas incineration	372 tons	337 tonnes	4.38 tons	

*Emission following control devices, where applicable.

**No capacity factor.

***Regulatory compliance level.

OIL SHALE SURFACE RETORTING: COLONY TOSCO II PROCESS (INDIRECT MODE)

ENVIRONMENTAL RESIDUALS (Continued)

	Quantities Released			Remarks
	Reference Energy System Annual Levels		Per 10 ¹² Btu Energy Produced (syncrude equivalent)	
	English Units	Metric Units		
<u>Water Discharge and Losses</u>				
Potential runoff from coarse shale storage	652 × 10 ³ tons	2.47 × 10 ⁶ l	7.68 × 10 ³ gal	
Consumptive uses				
• Mining, crushing, moisturizing revegetation, oil/water sludge	980 × 10 ⁶ tons 1.28 × 10 ⁹ gal	3.71 × 10 ⁹ tonnes 4.84 × 10 ⁹ l	11.5 × 10 ⁶ tonnes 15.1 × 10 ⁶ gal	
• Storage and shipping, fire and potable water, hydrotreater, utility and general process consumption, slop oil tank	955 × 10 ⁶ gal	3.77 × 10 ⁹ l	11.7 × 10 ⁶ gal	
Pyrolysis unit and cooling tower evaporation and drift	1.49 × 10 ⁹ gal	5.6 × 10 ⁹ l	17.6 × 10 ⁶ gal	
Coker unit evaporative losses	33.1 × 10 ⁶ gal	120 × 10 ⁶ l	390 × 10 ³ gal	
Miscellaneous losses	47.0 × 10 ⁶ gal	180 × 10 ⁶ l	554 × 10 ³ gal	
<u>Solid Wastes</u>				
Total dust from baghouse filters	66.6 × 10 ³ tons	60.4 × 10 ³ tonnes	784 tons	
Processed shale (dry)	17.5 × 10 ⁶ tons	15.9 × 10 ⁶ tonnes	206 × 10 ³ tons	
Total sludge from wet scrubbers	962 × 10 ³ tons	872 × 10 ³ tonnes	11.3 × 10 ³ tons	
Total trapped residue from DEA filters	386 tons	350 tonnes	4.55 tons	
Total spent catalysts (max. avg.)	437 tons	396 tonnes	5.15 tons	
Total proprietary waste (arsenic content)	360-580 tons (95.4 tons)	327-526 tonnes (86.5 tonnes)	4.24-6.83 tons (1.12 tons)	
Waste flocculent	197 tons	179 tonnes	2.32 tons	
Proprietary coagulant aid	8.21 tons	7.45 tonnes	0.0967 ton	

OIL SHALE SURFACE RETORTING: COLONY TOSCO II PROCESS (INDIRECT MODE)

PRODUCTS

	Quantities Produced		Per 10 ¹² Btu Energy Produced	Remarks
	Reference Energy System Annual Production			
	English Units	Metric Units		
<u>Primary</u>				
Syncrude (upgraded shale oil)	15.4 × 10 ⁶ bbl	2.45 × 10 ⁹ l	178 × 10 ³ bbl	
<u>Byproducts</u>				
Liquid petroleum gas	1.42 × 10 ⁶ bbl	226 × 10 ⁶ l	16.6 × 10 ³ bbl	
Anhydrous ammonia	44.3 × 10 ³ tons	40.2 × 10 ³ tonnes	518 tons	
Liquid sulfur	63.7 × 10 ³ tons	57.8 × 10 ³ tonnes	744 tons	
Coke	263 × 10 ³ tons	239 × 10 ³ tonnes	3.07 × 10 ³ tons	

OCCUPATIONAL HEALTH AND SAFETY

	Reference Energy System Annual	Per 10 ¹² Btu Energy Produced	Remarks
<u>Deaths</u>			
Underground mining	0.92	0.01	
Surface retorting	0.15	0.002	
<u>Injuries</u>			
Underground mining	40.8	0.44	
Surface retorting	17.1	0.180	

H-COAL PROCESS

REFERENCE ENERGY SYSTEM

The reference system is based on conceptual designs and includes mine-mouth coal processing and a conversion plant utilizing mid-western (Illinois No. 6) high sulfur coal to produce liquid hydrocarbon products and other byproducts. Clean process-derived fuel gas is utilized as onsite fuel. Tail gas sulfur recovery is utilized. Solid wastes are returned to the mine. Onsite water treatment and recirculation are utilized to facilitate minimal discharge to surface waters.

FACILITY OPERATING PARAMETERS

Size:	36.5×10^3 bbl/day syncrude, 24.7×10^3 bbl/day naphtha (major energy products)
Annual Capacity Factor:	91.3%
Annual Energy Production:	127.4×10^{12} Btu
Efficiency:	60% (based on total product, byproduct energy content, and onsite power generation)
Lifetime:	20 yr

RESOURCES USED

	Quantities Used		Per 10 ¹² Btu Energy Produced	Remarks	
	Reference Energy System Annual Usage				
	English Units	Metric Units			
<u>Feed Materials</u>					
Run-of-mine mid-western coal	9.28 × 10 ⁶ tons	8.42 × 10 ⁶ tonnes	72.8 × 10 ³ tons	Includes onsite power generation; 11.443 × 10 ³ Btu/lb	
<u>Processing Materials</u>					
	Not Determined				
<u>Water</u>					
Water consumed (make-up)	18.8 × 10 ³ acre-ft	23.3 × 10 ⁹ l	148 acre-ft		
<u>Total Usage</u>					
<u>Construction Materials</u>					
	Not Determined				
<u>Land</u>					
Plant	400 acres	160 ha	3.1 acres		
Solid waste disposal		Not Determined			
<u>Personnel</u>					
Construction		Not Determined			
Operation and maintenance	726 workers		5.7 workers		

COSTS

	Reference Energy System	Per 10 ¹² Btu Energy Produced	Remarks
<u>Facility</u>			
	(1981 \$)		
Construction	\$1.84 × 10 ⁹ total	\$14.4 × 10 ⁶ total	Reference year for cost is 1975. 1975 CCI average (I _p) = 2212. See Explanatory Notes Section.
Operation and maintenance	\$391 × 10 ⁶ /yr	\$3.07 × 10 ⁶ /yr	
<u>Environmental Controls</u>			
	Not Determined		

H-COAL PROCESS

ENVIRONMENTAL RESIDUALS

		Quantities Released		
		Reference Energy System Annual Levels		
	English Units	Metric Units	Per 10 ¹² Btu Energy Produced	Remarks
<u>Air Pollutants</u>				
Sulfur dioxide	9.2 × 10 ³ tons	8.3 × 10 ³ tonnes	72 tons	
Oxides of nitrogen	5.2 × 10 ³ tons	4.7 × 10 ³ tonnes	41 tons	
Particulates	0.56 × 10 ³ tons	0.51 × 10 ³ tonnes	4.4 tons	
Hydrocarbons	0.08 × 10 ³ tons	0.07 × 10 ³ tonnes	0.6 ton	
<u>Water Pollutants</u>				
No direct discharge into any water source				Wastewater disposal method not specified
<u>Solid Wastes</u>				
Total solid waste (dry ton equivalent)	0.937 × 10 ⁶ tons	0.850 × 10 ⁶ tonnes	7.354 × 10 ³ tons	
<u>Thermal Discharge</u>				
		Not Determined		
<u>Noise Pollution</u>				
		Not Determined		

PRODUCTS

	Quantities Produced			Remarks
	Reference Energy System Annual Production		Per 10 ¹² Btu Energy Produced	
	English Units	Metric Units		
<u>Primary</u>				
Syncrude (low sulfur)	12.1 × 10 ⁶ bbl	1.93 × 10 ⁹ l	95.358 × 10 ³ bbl	
Naphtha	8.23 × 10 ⁶ bbl	1.31 × 10 ⁹ l	64.578 × 10 ³ bbl	
<u>Byproducts</u>				
Sulfur	0.40 × 10 ⁶ tons	0.36 × 10 ⁶ tonnes	3.1 × 10 ³ tons	
Ammonia	0.08 × 10 ⁶ tons	0.07 × 10 ⁶ tonnes	0.6 × 10 ³ tons	
Phenols	7.9 × 10 ³ tons	7.2 × 10 ³ tonnes	62 tons	
Electric power	652 × 10 ³ MWh	652 × 10 ³ MWh	5.120 × 10 ³ MWh	
<u>Recoverables/Recyclables</u>				
Recycled water	4.75 × 10 ³ acre-ft	5.86 × 10 ⁹ l	37.3 acre-ft	

OCCUPATIONAL SAFETY AND HEALTH

Not Determined

LURGI HIGH-Btu COAL GASIFICATION PLANT

ENERGY SYSTEM DESCRIPTION

The "SNG From Coal Process Using the Lurgi Dry Ash Gasifier" is Based On the Great Plains Coal Gasification Project To Be Located in Mercer County, North Dakota. The Gasifier, Located at the Mine Mouth, Is To Generate Raw Gases From the Lignite Coal of the Beulah-Hazen Coal Field, Clean and Shift the Raw Gases To Enrich the Hydrogen Content, Remove the Acid Gases From the Stream Prior to Methanation and, Thereby, Produce a Pipeline Quality Synthetic Natural Gas as Its Primary Energy Products. An Onsite Boiler Fueled by Tars, Tar Oils, Naphtha, Phenol, and Tail Gases From the Process Provides the Necessary Process Steam. A Sulfur Recovery Unit Extracts More Than 99 Percent of the Elemental Sulfur From the Acid Gases. This Sulfur and Some Ammonia Are the Marketable By-Products of the Process. Coal Fines From the Coal Preparation Process Are Sent to an Associated But Offsite Basin Power Plant Which Will Also Be Located Near the Mine Mouth and Will Be the Source of Electric Power for the SNG From Coal Plant. Other Onsite Supporting Processes Include an Oxygen Plant, a Wastewater Treatment Plant, and a Gas Liquor Separation Plant.

FACILITY OPERATING PARAMETERS

Facility Size:	2.75 × 10 ⁶ scf/day SNG 977 Btu/scf SNG
Annual Capacity Factor:	91%
Annual Energy Production:	90.6 × 10 ¹² Btu
Process Thermal Conversion Efficiency:	68.1%
Lifetime:	25 yr

RESOURCES USED

RESOURCES USED		Quantities Used		
	Reference Energy System			
	Annual Usage			
Resource	English Units	Metric Units	Per 10 ¹² Btu Energy Produced	Remarks
Run of mine coal	14.2 × 10 ⁶ tons	12.91 × 10 ⁶ tonnes	157 × 10 ³ tons	
Coal to basin electric power plant	5.15 × 10 ⁶ tons	4.68 × 10 ⁶ tonnes	56.8 × 10 ³ tons	
Coal to gasifier	9.06 × 10 ⁶ tons	8.23 × 10 ⁶ tonnes	100 × 10 ³ tons	
Water to ANG plant	2.3 × 10 ⁹ gal	8.7 × 10 ⁹ tonnes	25.4 × 10 ⁶ gal	
Water consumed in process	300 × 10 ⁶ gal	1.1 × 10 ⁶ liters	3.3 × 10 ⁶ gal	
Methanol to rectisol (gal × 10 ⁶)	1.32 × 10 ⁶ gal	5.0 × 10 ⁶ liters	14.6 × 10 ³ gal	
Oxygen to gasifier	1.80 × 10 ⁶ tons	1.64 × 10 ⁶ tonnes	19.9 × 10 ³ tons	
<u>Land</u>				
• Plantsite	535 acres	217 ha	6.0 acres	
• Mining operations	12.5 × 10 ³ acres	5.1 × 10 ³ ha	138 acres	
• Construction and overburden deposit	905 acres	366 ha	10 acres	
• Pipeline	2.19 × 10 ³ acres	887 ha	24.2 acres	
• Water intake, pipeline, railroad spurs and roads	440 acres	178 ha	4.9 acres	
Total	16.57 × 10 ³ acres	6.71 ha	182.9 acres	
<u>Personnel</u>				
Construction (10 yr)	—	1,046 workers	11.5 workers	Peak work force in 10-yr period
Operation and maintenance	—	527 workers	5.8 workers	Average work force clearing operation

COSTS

COSTS	Reference	Per 10 ¹² Btu	Remarks
	Energy System	Energy Produced	
Facility	(1981\$)		
Construction (10 yr)	\$2.4 × 10 ⁹ total	26 × 10 ⁶	Reference year for cost is 1979; 1979 CCI average (I _R) = 30003.
Operation and maintenance	Not Determined		See Explanatory Notes
Environmental Controls	Not Determined		section.

LURGI HIGH-Btu COAL GASIFICATION PLANT

ENVIRONMENTAL RESIDUALS		Quantities Released		Remarks
		Reference Energy System		
		Annual Levels		
Residual or Product	English Units	Metric Units	Per 10 ¹² Btu Energy Produced	
<u>Gaseous Wastes</u>				
<u>Steam Boilers</u>				
SO ₂	4,065 tons	3,687.6 tonnes	44.8 tons	
NO _x	3,109 tons	2,820.4 tonnes	34.3 tons	
HC	239 tons	216.8 tonnes	2.63 tons	
TSP	518 tons	469.9 tonnes	5.71 tons	
CO	438 tons	397.3 tonnes	4.83 tons	
<u>Steam superheaters</u>				
SO ₂	5,102 tons	4,628.4 tonnes	56.3 tons	
NO _x	1,275 tons	1,156.6 tonnes	14.0 tons	
HC	120 tons	108.8 tonnes	1.32 ton	
TSP	159 tons	144.2 tonnes	1.75 ton	
CO	996 tons	903.5 tonnes	10.9 tons	
<u>Gasifier start-up incinerators, intermittent*</u>				
	—	—	—	
<u>Main plant flares, intermittent*</u>				
	—	—	—	
Particulates from gasifier building	110 tons	99.7 tonnes	1.90 ton	
<u>Basin Electric Power Plant</u>				
SO ₂	45.4 × 10 ³ tons	41.2 × 10 ³ tonnes	501.4 tons	
NO _x	18.9 × 10 ³ tons	17.2 × 10 ³ tonnes	208.9 tons	
TSP	3.8 × 10 ³ tons	3.4 × 10 ³ tonnes	41.8 tons	
CO	Negligible	Negligible		
HC	Negligible	Negligible		
Fugitive dust from coal crushing and screening	173 tons	156.9 tonnes	1.90 ton	
Fugitive dust from fines storage silo and transport	35 tons	31.7 tonnes	0.38 ton	
Fugitive dust from coal storage	Not Determined			
Shift catalyst removal — SO ₂	164 tons	148.7 tonnes	1.81 ton	
Process water cooling tower evaporation and drift	7.6 × 10 ⁶ tons	6.9 × 10 ⁶ tonnes	83,885.2 tons	
Gas liquor separator flare — SO ₂	2.3 × 10 ³ tons	2.1 × 10 ³ tonnes	25.4 tons	
Steam in SNG drying vent gas	Negligible	Negligible	Negligible	
Oxygen plant evaporation and drift	1.43 × 10 ⁶ tons	1.30 × 10 ⁶ tonnes	15,783.6 tons	
Stratford plant emission incinerator — SO ₂	3.0 × 10 ³ tons	2.7 × 10 ³ tonnes	33.1 tons	
Stratford plant evaporation	10.0 × 10 ³ tons	9.1 × 10 ³ tonnes	110.3 tons	
Evaporation from ash handling	60 × 10 ³ tons	54.4 × 10 ³ tonnes	66.22 tons	
<u>Liquid Wastes</u>				
Multieffect evaporator waste water	140 × 10 ³ tons	127 × 10 ³ tonnes	1.54 × 10 ³ tons	
Runoff from coal storage	Not Determined			
Boiler blowdown	430 × 10 ³ tons	390 × 10 ³ tonnes	4.7 × 10 ³ tons	
Runoff from water ponds	Not Determined			
Water to mine disposal with ash	140 × 10 ³ tons	127 × 10 ³ tonnes	1.54 × 10 ³ tons	
Miscellaneous plant waste water	1.0 × 10 ⁶ tons	0.91 × 10 ⁶ tonnes	11.0 × 10 ³ tons	

*The emissions from these sources are primarily SO₂ and are released with undetermined frequency. The rates of release respectively are: 1.15 × 10³ lb/hr and 13.33 × 10³ lb/hr.

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LURGI HIGH-Btu COAL GASIFICATION PLANT

ENVIRONMENTAL RESIDUALS (Continued)

Residual or Product	Quantities Released			Regulatory Compliance Levels
	Reference Energy System		Per 10 ¹² Btu Energy Produced	
	Annual Levels			
	English Units	Metric Units		
<u>Solid Wastes</u>				
Miscellaneous plant refuse		Not Determined		
Gasifier ash	586 × 10 ³ tons	532 × 10 ³ tonnes	6,468 tons	
Fly ash from steam production	500 tons	453.5 tonnes	5.51 tons	
Bottom ash from steam production		Not Determined		
Spent catalyst from shift conversion		Not Determined		
Sanitary sewage treatment sludge		Not Determined		
Spent catalyst from methanation		Not Determined		
Evaporator residue		Not Determined		
Raw water treatment sludge and silt		Not Determined		

PRODUCTS

PRODUCTS	Quantities Produced			Remarks
	Reference Energy System		Per 10 ¹² Btu Energy Produced	
	Annual Production			
	English Units	Metric Units		
<u>Primary</u>				
SNG	189 × 10 ³ tons	1.7 × 10 ⁶ tonnes	20.9 × 10 ³ tons	
Ammonia	70.9 × 10 ³ tons	64.3 × 10 ³ tonnes	782 tons	
Sulfur	53.4 × 10 ³ tons	48.4 × 10 ³ tonnes	589 tons	
Coal fines	515 × 10 ³ tons	4.7 × 10 ⁶ tonnes	56.8 × 10 ³ tons	
<u>Byproducts*</u>				
Tar	279 × 10 ³ tons	253 × 10 ³ tonnes	30.9 × 10 ³ tons	*Recycled
Tar oil	93 × 10 ³ tons	84.4 × 10 ³ tonnes	10.3 × 10 ³ tons	
Naphtha	46 × 10 ³ tons	41.7 × 10 ³ tonnes	5.1 × 10 ³ tons	
Phenol	55 × 10 ³ tons	49.9 × 10 ³ tonnes	6.1 × 10 ³ tons	
Stratford tail gas (scf/yr)	133 × 10 ⁹ scf	3.77 × 10 ⁶ m ³	14.7 × 10 ⁹ scf	
Coal lockhopper off-gas (scf/yr)	0.25 × 10 ⁹ scf	7.10 × 10 ⁶ m ³	27.6 × 10 ⁹ scf	

OCCUPATIONAL SAFETY AND HEALTH

	Coal Strip Mine		Plant Operations	
	Annual	Per 10 ¹² Btu	Annual	Per 10 ¹² Btu
Deaths	0.34	0.0037	0.42	0.0046
Accidental Injuries	10.6	0.1169	1.0	0.0110

SOLVENT REFINED COAL II (SRC-II) PLANT

REFERENCE ENERGY SYSTEM

Pretreated coal is mixed with a coal-derived solvent and then hydrogenated in the dissolver. The resulting slurry goes to gas separation for separation of gases, slurry, and light hydrocarbons. Acid gases are sent to sulfur recovery; purified gas is cryogenically processed into LPG, SNG, and recycle H_2 . Some slurry is recycled to coal pretreatment while the remainder is vacuum flashed, and the light fraction from the flash is sent to the fractionator. These light fractions plus the light hydrocarbons are fractionated into naphtha and fuel oil.

FACILITY OPERATING PARAMETERS

Size:	11×10^6 tons/yr
Annual Capacity Factor:	92% (to produce 100×10^3 bbl/day of products on an equivalent petroleum refinery basis)
Annual Energy Production:	181×10^{12} Btu
Efficiency:	71.1%
Lifetime:	20-25 yr

RESOURCES USED

	Quantities Used			Remarks
	Reference Energy System Annual Usage		Per 10 ¹² Btu Energy Produced	
	English Units	Metric Units		
<u>Feed Materials</u>				
Coal	10.1 × 10 ⁶ tons	9.16 × 10 ⁶ tonnes	55.8 × 10 ³ tons	
<u>Energy</u>				
Electricity (overall)	330 × 10 ⁶ kWh	330 × 10 ⁶ kWh	1.82 × 10 ⁶ kWh	
<u>Processing Materials</u>				
Tar acid recovery solvent	1.02 × 10 ³ tons	925 tonnes	5.64 tons	
Tar acid recovery acid	10.8 × 10 ³ tons	9.79 × 10 ³ tonnes	59.7 tons	
Ammonia recovery chemicals	2.44 tons	2.21 tonnes	13.5 × 10 ⁻³ ton	
Acid gas removal amine	278 tons	252 tonnes	1.54 tons	
Hydrogen generation amine	313 tons	284 tonnes	1.73 tons	
Raw water treatment chemicals	4.88 × 10 ³ tons	4.43 × 10 ³ tonnes	27.0 tons	
Cooling tower chemicals	Not Determined			
<u>Water</u>	16.5 × 10 ³ acre-ft	20.4 × 10 ⁹ l	91.3 acre-ft	Raw water, steam, and cooling tower make-up requirements
<u>Total Usage</u>				
<u>Construction Materials</u>				
Concrete	20.3 × 10 ⁶ ft ³	575 × 10 ³ m ³	112 × 10 ³ ft ³	
Steel	100 × 10 ³ tons	90.7 × 10 ³ tonnes	552 tons	
Paving	4.35 × 10 ⁶ ft ²	404 × 10 ³ m ²	24.0 × 10 ³ ft ²	
Railroad trackage	75.0 × 10 ³ ft	22.9 × 10 ³ m	414 ft	
Pipe	5.00 × 10 ⁶ ft	1.52 × 10 ⁶ m	27.6 × 10 ³ ft	
Glass	25.5 × 10 ³ ft ²	2.37 × 10 ³ m ²	141 ft ²	
Wood	10.0 × 10 ⁶ fbm	23.6 × 10 ³ m ³	55.2 × 10 ³ fbm	
Water	1.00 × 10 ⁹ gal	3.79 × 10 ⁹ l	5.52 × 10 ⁶ gal	
Land				
Total	305-2600 acres	124-1050 ha	1.69-14.4 acres	
<u>Personnel</u>				
Construction (3.5 yr)	3100 workers (average)		17.1 workers	
	5400 workers (peak)		29.8 workers	
Operation and maintenance	430-530 workers		2.4-2.9 workers	

SOLVENT REFINED COAL II (SRC-II) PLANT

COSTS

COSTS			
	Reference Energy System	Per 10 ¹² Btu Energy Produced	Remarks
Facility	(1981 \$)		
Construction (3.5 yr)	\$6.26 × 10 ⁹ total	\$34.6 × 10 ⁶ total	
Operation and maintenance	\$486 × 10 ⁶ /yr — \$608 × 10 ⁶ /yr	\$2.69 × 10 ⁶ /yr — \$3.36 × 10 ⁶ /yr	
Environmental Controls	Not Determined		

ENVIRONMENTAL RESIDUALS

Residual or Product	Quantities Released		Per 10 ¹² Btu Energy Produced	Remarks
	Reference Energy System Annual Levels			
	English Units	Metric Units		
Air pollutants				
Coal storage fugitive dust	Not Determined			
Coal sizing dust	2.70 tons	2.45 tonnes	14.9 × 10 ⁻³ ton	
Coal dryer stack particulates	10.2 × 10 ³ tons	9.25 × 10 ³ tonnes	56.4 tons	
Flue gas (total)	4.67 × 10 ⁶ tons	4.24 × 10 ⁶ tonnes	25.8 × 10 ³ tons	
Hydrocarbon vapors	Not Determined			
Sulfur dioxide	3.95 × 10 ³ tons	3.58 × 10 ³ tonnes	21.8 tons	
Nitrogen oxides	259 tons	235 tonnes	1.43 tons	
Carbon monoxide	6.95 tons	6.30 tonnes	38.4 × 10 ⁻³ ton	
Total suspended particulates	31.3 tons	28.4 tonnes	0.173 ton	
Nonmethane hydrocarbons	6.95 tons	6.3 tonnes	38.4 × 10 ⁻³ ton	
Waste gases				
(95% hydrogen)	3.16 × 10 ⁶ tons	2.87 × 10 ⁶ tonnes	17.5 × 10 ³ tons	
Flue gases	354 × 10 ³ tons	321 × 10 ³ tonnes	1.96 × 10 ³ tons	
Sulfur dioxide	960 tons	870 tonnes	5.30 tons	
Nitrogen oxides	4.35 × 10 ³ tons	3.95 × 10 ³ tonnes	24.0 tons	
Carbon monoxide	555 tons	505 tonnes	3.07 tons	
Total suspended particulates	525 tons	475 tonnes	2.90 tons	
Nonmethane hydrocarbons	130 tons	120 tonnes	0.718 ton	
Cooling tower drift and evaporation	7.79 × 10 ⁶ tons	7.07 × 10 ⁶ tonnes	43.0 × 10 ³ tons	
Flare system emissions	Not Determined			
Water Pollutants				
Runoff from coal storage	Not Determined			
Wastewater	2.09 × 10 ³ tons	1.90 × 10 ³ tonnes	11.5 tons	
Wastewater	280 × 10 ³ tons	254 × 10 ³ tonnes	1.55 × 10 ³ tons	
Boiler blowdown	Not Determined			
Cooling tower blowdown	1.96 × 10 ⁶ tons	1.78 × 10 ⁶ tonnes	10.8 × 10 ³ tons	
Wastewater effluent	3.26 × 10 ⁶ tons	2.96 × 10 ⁶ tonnes	18.0 × 10 ³ tons	
Solid Wastes				
Coal cleaning refuse	2.68 × 10 ⁶ tons	2.43 × 10 ⁶ tonnes	14.8 × 10 ³ tons	
Vacuum flash bottoms	474 × 10 ³ tons	430 × 10 ³ tonnes	2.62 × 10 ³ tons	
Slag	430 × 10 ³ tons	390 × 10 ³ tonnes	2.38 × 10 ³ tons	
Sludge	16.9 × 10 ³ tons	15.3 × 10 ³ tonnes	93.3 tons	

SOLVENT REFINED COAL II (SRC-II) PLANT

PRODUCTS

	Quantities Produced			Remarks
	Reference Energy System Annual Production		Per 10 ¹² Btu Energy Produced	
	English Units	Metric Units		
<u>Primary</u>				
Fuel oil	20.6 × 10 ⁶ bbl	3.27 × 10 ⁶ m ³	114 × 10 ³ bbl	
Distillate and naphtha	5.04 × 10 ⁶ bbl	801 × 10 ³ m ³	27.8 × 10 ³ bbl	
SNG	11.4 × 10 ⁹ scf	323 × 10 ⁶ m ³	63.0 × 10 ⁶ scf	
LPG	2.50 × 10 ⁶ bbl	397 × 10 ³ m ³	13.8 × 10 ³ bbl	
<u>Byproducts</u>				
Sulfur	437 × 10 ³ tons	396 × 10 ³ tonnes	2.41 × 10 ³ tons	
Ammonia	20.1 × 10 ³ tons	18.2 × 10 ³ tonnes	111 tons	
Tar acids (phenols)	806 × 10 ³ bbl	128 × 10 ³ m ³	4.45 × 10 ³ tons	
<u>Recoverables/Recyclables</u>				
None				

OCCUPATIONAL SAFETY AND HEALTH

Not Determined

INDIRECT COAL LIQUEFACTION PLANT (LURGI FISCHER-TROPSCH PROCESS)

REFERENCE ENERGY SYSTEM

Mine-mouth plant located in Wyoming, using low sulfur subbituminous coal; utility power plant to provide steam, air separation plant to provide oxygen; Lurgi pressurized dry ash gasifier and Fischer-Tropsch synthesis; environmental controls include electrostatic precipitators for particulate control, SO₂ scrubbers for SO₂ control, Stretford process for sulfur recovery, Lurgi Rectisol process for H₂S removal, Lurgi Phenosolvan process for phenol removal, Chemie Linz/Lurgi process for ammonia recovery; and onsite solid waste disposal and onsite water treatment for recirculation to minimize discharge.

FACILITY OPERATING PARAMETERS

Size:	45 × 10 ³ bbl/day fuel oil equivalent 6 × 10 ⁶ Btu/bbl fuel oil equivalent
Annual Capacity Factor:	92%
Annual Energy Production:	90.7 × 10 ¹² Btu
Process Thermal Efficiency:	57.7%
Lifetime:	30 yr

RESOURCES USED

	Quantities Used		Per 10 ¹² Btu Energy Produced	Remarks
	Reference Energy System Annual Usage			
<u>Feed Materials</u>	English Units	Metric Units		
ROM coal to coal preparation	9.3 × 10 ⁶ tons	8.5 × 10 ⁶ tonnes	10.3 × 10 ⁴ tons	Low sulfur subbituminous
Coal feed to gasifier	7.66 × 10 ⁶ tons	6.97 × 10 ⁶ tonnes	8.4 × 10 ⁴ tons	Well size
Coal feed to power plant	1.67 × 10 ⁶ tons	1.5 × 10 ⁶ tonnes	1.8 × 10 ⁴ tons	Coal fines
Oxygen to gasifier	1.8 × 10 ⁶ tons	1.6 × 10 ⁶ tonnes	2.0 × 10 ⁴ tons	
Steam to gasifier and for power and heating	12.7 × 10 ⁶ tons	11.6 × 10 ⁶ tonnes	14.0 × 10 ⁴ tons	
<u>Processing Materials</u>				
Limestone	12.4 × 10 ³ tons	11.3 × 10 ³ tonnes	137 tons	
Magnetite iron ore feed (catalyst)	27.3 × 10 ³ tons	24.8 × 10 ³ tonnes	301 tons	
<u>Water</u>				
Make-up water	9.82 × 10 ³ acre-ft	12.0 × 10 ³ l	0.11 × 10 ³ acre-ft	For power plant, environmental control and process requirements. Wet cooling used.
<u>Land</u>	Total Usage			
Plant space	630 acres	255 ha	7 acres	Sufficient land required for 30-yr lifetime
Solid waste disposal	252 acres	102 ha	3 acres	
<u>Personnel</u>				
Construction (4 yr)	5200 workers		57.3 workers	
Operation and maintenance	696 workers		7.7 workers	

COSTS

	Reference Energy System	Per 10 ¹² Btu Energy Produced	Remarks
<u>Facility</u>	(1981 \$)		
Construction (4 yr)	\$2.58 × 10 ⁹ total	\$28.5 × 10 ⁶ total	Reference year for costs is 1977. 1977 CCI average (I _p) = 2577. See Explanatory Notes Section.
Operation and maintenance	\$207.7 × 10 ⁶ /yr	\$2.30 × 10 ⁶ /yr	
<u>Environmental Controls</u>	\$239.8 × 10 ⁶ total	\$2.65 × 10 ⁶ /yr	Capital costs

INDIRECT COAL LIQUEFACTION PLANT (LURGI FISCHER-TROPSCH PROCESS)

ENVIRONMENTAL RESIDUALS

	Quantities Released			
	Reference Energy System Annual Levels*		Per 10 ¹² Btu Energy Produced	Remarks
	English Units	Metric Units		
Air Pollutants				
Sulfur dioxide	3.56 × 10 ³ tons	3.23 × 10 ³ tonnes	39.2 tons	**
Oxides of nitrogen	8.55 × 10 ³ tons	7.8 × 10 ³ tonnes	94.0 tons	
Total suspended particulates	0.26 × 10 ³ tons	0.24 × 10 ³ tonnes	2.9 tons	
Nonmethane hydrocarbons	1.6 × 10 ³ tons	1.5 × 10 ³ tonnes	17.6 tons	
Carbon monoxide	3.73 × 10 ³ tons	3.39 × 10 ³ tonnes	41.4 tons	
Carbon dioxide	11.0 × 10 ⁶ tons	10.0 × 10 ⁶ tonnes	12 × 10 ⁴ tons	
Arsenic	36.7-77.2 lb	33.4-70.3 kg	0.40-0.85 lb	
Beryllium	5.07-5.7 lb	4.6-5.2 kg	0.056-0.063 lb	
Cadmium	13.2-33.9 lb	6.0-15.4 kg	0.14-0.37 lb	
Manganese	19.9-24.1 lb	9.0-10.9 kg	0.22-0.27 lb	
Lead	14.9-349 lb.	6.8-158.0 kg	0.164-3.85 lb	
Selenium	11.3 lb	5.1 kg	0.12 lb	
Uranium	14.4 lb	6.5 kg	0.16 lb	
Zinc	64.5 lb	29.2 kg	0.71 lb	
Radium-226	0.73 × 10 ⁻³ Ci/yr		0.008 × 10 ⁻³ Ci/yr	
Airborne water from cooling tower drift and evaporation	2.33 × 10 ⁹ gal	8.85 × 10 ¹² l	257 × 10 ⁵ gal	
Steam in SNG drying unit vent gas	9.10 × 10 ³ tons	8.28 × 10 ³ tonnes	100.0 tons	
Fugitive dust from coal preparation and storage	Not Determined			
Catalyst regeneration offgases	Not Available			
Water Pollutants				
Runoff from coal storage	Not Determined			
Water runoff from water treat- ment ponds	Negligible			
Solid Wastes				
Solid waste from coal preparation	93 × 10 ³ tons	84.8 × 10 ³ tonnes	1025 tons	
Bottom ash (wet) from utility boiler	22.2 × 10 ³ tons	20.3 × 10 ³ tonnes	245 tons	
Fly ash (dry) from precipitator	68.5 × 10 ³ tons	62.3 × 10 ³ tonnes	755 tons	
Limestone sludge from SO ₂ control	23.3 × 10 ³ tons	21.2 × 10 ³ tonnes	257 tons	
Ash from gasifier (wet)	500 × 10 ³ tons	455 × 10 ³ tonnes	5513 tons	
Sludge from wastewater treatment	42 × 10 ³ tons	38.3 × 10 ³ tonnes	463 tons	
Spent catalyst from raw gas shift and Fischer-Tropsch catalyst preparation tailings (iron ore)	Not Available			
Other spent Fischer-Tropsch catalyst	13.6 × 10 ³ tons	12.4 × 10 ³ tonnes	150 tons	
	9.0 × 10 ³ tons	8.2 × 10 ³ tonnes	99.2 tons	

*Based on assumed 92% capacity factor.

**NSPS for this facility do not exist; however, current standards for power plants would apply to the Utility Section of this facility.

INDIRECT COAL LIQUEFACTION PLANT (LURGI FISCHER-TROPSCH PROCESS)

PRODUCTS

	Quantities Produced			
	Reference Energy System Annual Production		Per 10 ¹² Btu Energy Produced	Remarks
	English Units	Metric Units		
Synthetic natural gas	58.2 × 10 ⁹ scf	1.65 × 10 ⁹ m ³	64.2 × 10 ⁷ scf	
Gasoline	4.6 × 10 ⁶ bbl	731 × 10 ³ m ³	5.1 × 10 ⁴ bbl	
Alcohol	0.67 × 10 ⁶ bbl	7.99 × 10 ⁴ m ³	0.74 × 10 ⁴ bbl	
Diesel and heavy fuel oil	0.997 × 10 ⁶ bbl	9.07 × 10 ⁵ m ³	1.1 × 10 ⁴ bbl	
Propane LPG	370 × 10 ³ bbl	4.4 × 10 ⁴ m ³	4079 bbl	
Butane LPG	49 × 10 ³ bbl	5.8 × 10 ³ m ³	540 bbl	
Sulfur	20.5 × 10 ³ tons	18.6 × 10 ³ tonnes	0.22 × 10 ³ tons	
Ammonia	34.2 × 10 ³ tons	31.1 × 10 ³ tonnes	377 tons	
Surplus electrical power	3.3 MWe			
Recovered energy	16 × 10 ¹² Btu		0.018 Btu	
Recovered water for cooling tower make-up	1.89 × 10 ⁹ gal	5.0 × 10 ⁸ l	20.8 × 10 ⁷ gal	

OCCUPATIONAL SAFETY AND HEALTH

	Reference Energy System Annual		Per 10 ¹² Btu Produced		Remarks
	Accidental	Disease	Accidental	Disease	
Deaths	0.36	0.26	0.0040	0.0029	
Injuries	11	—	0.12	—	

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COAL TECHNOLOGIES

EASTERN UNDERGROUND COAL MINING (WITH PREPARATION PLANT)

REFERENCE ENERGY SYSTEM

Underground bituminous mine located in Appalachia; coal preparation plant onsite; rock dusting and water spray inside mine for dust control; water spray in coal preparation plant, on mine roads, and on coal and waste storage piles; drainage ditches and catchment ponds; onsite solid waste disposal; onsite water treatment and recycling to minimize discharge and make-up water requirements. Facilities are subject to Federal and state regulations.

FACILITY OPERATING PARAMETERS

Size:	Coal mine: 1.5×10^6 tons/yr Preparation plant: 1.125×10^6 tons/yr
Annual Capacity Factor:	60-85%*
Annual Energy Production:**	Coal mine: 40.2×10^{12} Btu Preparation plant: 30.2×10^{12} Btu
Efficiency:	75% (preparation plant)
Lifetime:	23 yr

*Industry estimate.

**Heating value of coal = 13,400 Btu/lb.

RESOURCES USED

	Quantities Used			Remarks
	Reference Energy System Annual Usage		Per 10 ¹² Btu* Energy Produced	
	English Units	Metric Units		
<u>Feed Materials</u>				
ROM coal	1.5 × 10 ⁶ tons	1.4 × 10 ⁶ tonnes	49.8 × 10 ³ tons	Assumed to be a 23-yr (or more) supply
<u>Energy</u>				
Diesel fuel	57.3 × 10 ³ gal	216 × 10 ³ l	1.9 × 10 ³ gal	Mine and preparation plant requirements
Electricity	58.9 × 10 ⁶ kWh	58.9 × 10 ⁶ kWh	1.96 × 10 ⁶ kWh	
<u>Water</u>	151 × 10 ⁶ gal	572 × 10 ⁶ l	5.02 × 10 ⁶ gal	Dust control and make-up water; groundwater is unquantifiable
<hr/>				
	Total Usage			
<u>Construction Materials</u>	Not Determined			
<u>Land</u>	7.5 acres	3.0 ha	0.25 acre	Surface construction and preparation plant waste storage
<u>Personnel</u>				
Coal mine	425 workers		14.1 workers	
Preparation plant	12 workers		0.40 worker	

*Entries computed on basis of output from preparation plant throughout the Summary Sheet.

COSTS

COSTS	Reference	Per 10 ¹² Btu	Remarks
	<u>Energy System</u>	<u>Energy Produced</u>	
Facility	(1981 \$)		
Capital			
• Mine	\$82.7 × 10 ⁶ total	\$2.8 × 10 ⁶ total	Reference year for cost is 1978; 1978 CCI average (I _R) = 2776. See Explanatory Notes section and Appendix B.
• Preparation plant	(\$1.8-\$17.1) × 10 ⁶ total	(\$0.06-\$0.56) × 10 ⁶ total	
Operation and maintenance			
• Mine	\$31 × 10 ⁶ /yr	\$1.0 × 10 ⁶ /yr	Notes section and Appendix B.
• Preparation plant	(\$1.0-\$12.7) × 10 ⁶ /yr	(\$0.04-\$0.4) × 10 ⁶ /yr	
Environmental Controls	Included in above costs		

EASTERN UNDERGROUND COAL MINING (WITH PREPARATION PLANT)

COSTS (CONTINUED)

Environmental Controls

Construction		Not Determined	
Operation and maintenance	\$1.10 × 10 ⁶ /yr	\$36.7 × 10 ³ /yr	For treatment (liming) of acid water

ENVIRONMENTAL RESIDUALS

	Quantities Released		Per 10 ¹² Btu Energy Produced	Remarks
	Reference Energy System Annual Levels			
	English Units	Metric Units		
<u>Air Pollutants</u>				
Fugitive dust		Negligible		Regulatory Compliance Standards* by component • Thermal Dryer — Particulates: 0.031 gr/dscf — Opacity: 20% • Pneumatic Coal Cleaning Equipment — Particulates: 0.018 gr/dscf Opacity: 20% • Processing and Conveying Equipment — Opacity: 20%
• Construction of mine		Unquantifiable		
• Exploration		Unquantifiable		
• Installation		Unquantifiable		
• Belt transfer of coal		Negligible		
• Crushing, screening, and washing		No Emissions		
• Coal storage				
<u>Diesel fuel emissions</u>				
• Particulates	0.72 ton	0.65 tonne	0.02 ton	
• Hydrocarbons	0.72 ton	0.65 tonne	0.02 ton	
• Sulfur dioxide	0.89 ton	0.81 tonne	0.03 ton	
• Carbon monoxide	2.5 tons	2.3 tonnes	0.08 ton	
• Oxides of nitrogen	9.4 tons	8.5 tonnes	0.31 ton	
<u>Water Pollutants</u>				
Total dissolved solids				
• Iron				
• Manganese		Unquantifiable		
Total suspended solids				
Liquid wastes/runoff				
<u>Solid wastes</u>				
Portal construction	58 × 10 ³ tons	52.7 × 10 ³ tonnes	1.93 × 10 ³ tons	Occurs once
Waste from mine ventilation	12 × 10 ³ tons	10.9 × 10 ³ tonnes	400 tons	
Waste from preparation plant	375 × 10 ³ tons	390 × 10 ³ tonnes	12.5 × 10 ³ tons	
<u>Subsidence</u>				
		Not Determined		Unlikely for a 90-in. seam at a depth greater than 375 ft
<u>Noise Pollution</u>				
Underground coal mine equipment		85-99 dBA		
Coal preparation plant		75-105 dBA		

*CFR 40 Part 60, Subpart V: Coal Preparation Plants (41 FR 2232)

EASTERN UNDERGROUND COAL MINING (WITH PREPARATION PLANT)

PRODUCTS

	Quantities Produced			Remarks
	Reference Energy System Annual Production		Per 10 ¹² Btu Energy Produced	
	English Units	Metric Units		
Primary				
Coal (cleaned)	1.125 × 10 ⁶ tons	1.020 × 10 ⁶ tonnes	0.037 × 10 ⁶ tons	Represents 75% recovery from ROM coal output

OCCUPATIONAL HEALTH AND SAFETY

	Reference Energy System Annual	Per 10^{12} Btu Energy Produced	Remarks
Deaths			
Underground mine	0.450	0.011	
Coal preparation plant	8.6×10^{-3}	0.210×10^{-3}	
Injuries			
Underground mine	71.5	1.78	
Coal preparation plant	1.12	0.03	

EASTERN SURFACE COAL MINING (WITH PREPARATION PLANT)

REFERENCE ENERGY SYSTEM

Eastern surface mine with seam thickness of 36 in. Contour mining operations with overburden removal by dragline and coal loaded by front-end loaders and transported to cleaning plant by haulage trucks. Additional mining with auger. Onsite coal preparation to yield a product of 6-in. diameter. Open storage of prepared coal. Simultaneous reclamation of stripped land by backfilling.

FACILITY OPERATING PARAMETERS

Size:	Coal mine: 470×10^3 tons/yr Preparation plant: 340,750 tons/yr
Annual Capacity Factor:	Not Determined
Annual Energy Production:*	Coal mine: 12.0×10^{12} Btu Preparation plant: 8.72×10^{12} Btu
Efficiency:	72.5% (preparation plant)
Lifetime:	30 yr
*Heating value of coal = 12,800 Btu/lb.	

RESOURCES USED

	Quantities Used		Per 10 ¹² Btu* Energy Produced	Remarks
	Reference Energy System Annual Usage			
	English Units	Metric Units		
<u>Feed Materials</u>				
ROM coal	470 × 10 ³ tons	426 × 10 ³ tonnes	54.0 × 10 ³ tons	
<u>Energy</u>				
Diesel fuel	1.42 × 10 ⁶ gal	5.40 × 10 ⁶ l	163 × 10 ³ gal	Load condition 50% of the time
Electricity	2.98 × 10 ⁶ kWh	2.98 × 10 ⁶ kWh	0.342 × 10 ⁶ kWh	
<u>Water</u>				
Make-up water	9.4 × 10 ⁶ gal	35.5 × 10 ⁶ l	1.08 × 10 ⁶ gal	Maximum requirement
	Total Usage			
<u>Construction Materials</u>	Not Determined			
<u>Land</u>	320 acres	130 ha	36.7 acres	
<u>Personnel</u>				
Mine	46 workers		5 workers	
Preparation plant	15 workers		2 workers	

*Entries computed on basis of output from preparation plant throughout the Summary Sheet.

COSTS

COSTS	<u>Reference Energy System</u>	<u>Per 10¹² Btu Energy Produced</u>	<u>Remarks</u>
	(1981 \$)		
<u>Facility</u>			
Capital			
• Mine	\$38.7 × 10 ⁶ total	\$4.5 × 10 ⁶ total	Reference year for cost is 1975; 1975 CCI average (I _R) = 2212. See Explanatory Notes section and Appendix B.
• Preparation plant	(\$0.07-\$6.4) × 10 ⁶ total	(\$0.08-\$0.80) × 10 ⁶ total	
Operation and maintenance			
• Mine	(\$9.7-\$13.6) × 10 ⁶ /yr	(\$1.1-\$1.6) × 10 ⁶ /yr	
• Preparation plant	(\$0.38-\$4.8) × 10 ⁶ /yr	(\$0.05-\$0.54) × 10 ⁶ /yr	
<u>Environmental Controls</u>	Included in above costs		

EASTERN SURFACE COAL MINING (WITH PREPARATION PLANT)

ENVIRONMENTAL RESIDUALS

	Quantities Released			Remarks
	Reference Energy System		Per 10 ¹² Btu Energy Produced	
	Annual Levels			
	English Units	Metric Units		
<u>Air Pollutants</u>				
Carbon monoxide	127.3 × 10 ³ lb	57.8 × 10 ³ kg	14.6 × 10 ³ lb	Regulatory Compliance Standards* by component (air pollutants) <ul style="list-style-type: none">• Thermal Dryer<ul style="list-style-type: none">— Particulates: 0.031 gr/dscf— Opacity: 20%• Pneumatic Coal Cleaning Equipment<ul style="list-style-type: none">— Particulates: 0.018 gr/dscf— Opacity: 20%• Processing and Conveying Equipment<ul style="list-style-type: none">— Opacity: 20% Sources individually meet Federal emission standards
Hydrocarbons	39.6 × 10 ³ lb	18.0 × 10 ³ kg	4.54 × 10 ³ lb	
Nitrogen oxides	610 × 10 ³ lb	277 × 10 ³ kg	7.0 × 10 ³ lb	
Aldehydes	9.9 × 10 ³ lb	4.5 × 10 ³ kg	1.13 × 10 ³ lb	
Sulfur oxides	44.4 × 10 ³ lb	20.2 × 10 ³ kg	5.10 × 10 ³ lb	
Particulates	31.5 × 10 ³ lb	14.3 × 10 ³ kg	3.61 × 10 ³ lb	
Fugitive dust		Negligible or Unquantifiable		
<u>Water Pollutants</u>				
Runoff and leachate from storage pile		Unquantifiable		
Unrecycled water from cleaning process				
<u>Solid Waste</u>				
Refuse from coal cleaning	130 × 10 ³ tons	117 × 10 ³ tonnes	14.9 × 10 ³ tons	
<u>Noise Pollution</u>				
		Not Determined		

*CFR 40 Part 60, Subpart V: Coal Preparation Plants (41FR2232).

*CFR 40 Part 60, Subpart V: Coal Preparation Plants (41FR2232).

PRODUCTS

	Quantities Produced			Remarks
	Reference Energy System		Per 10 ¹² Btu Energy Produced	
	Annual Production			
	English Units	Metric Units		
<u>Primary</u>				
Coal (cleaned)	341 × 10 ³ tons	308 × 10 ³ tonnes	39 × 10 ³ tons	Represents approximately a 72% recovery from ROM coal output

OCCUPATIONAL HEALTH AND SAFETY

	Reference Energy System		
	Annual	Per 10 ¹² Btu Energy Produced	Remarks
<u>Deaths</u>			
Mine	0.011	0.0013	
Preparation plant	0.0108	0.0012	
<u>Injuries</u>			
Mine	2.87	0.33	
Preparation plant	1.41	0.16	

WESTERN SURFACE COAL MINING (WITH PREPARATION PLANT)

REFERENCE ENERGY SYSTEM

Western surface mine with seam thickness of 23.1 ft. The overburden thickness is 100 ft (stripping ratio) 4/1 (cover/coal). The overburden removal is done by dragline stripping shovels. Bulldozers are used for backfilling and regrading. There is an onsite preparation plant using a wet method of cleaning the coal, and unit trains are used for final shipment. The capacity and production of this mine are relatively close. Terrain, topography, and overburden thickness limit the mine capacity. The estimated production is 85-90% of capacity.

FACILITY OPERATING PARAMETERS

Size:	Coal mine: 9.7×10^6 tons/yr Preparation plant: 8.73×10^6 tons/yr
Annual Capacity Factor:	85-90%
Annual Energy Production:*	Coal mine: 170×10^{12} Btu Preparation plant: 152×10^{12} Btu
Efficiency:	90% (preparation plant)
Lifetime:	40 yr
*Heating value of coal = 8750 Btu/lb.	

RESOURCES USED

	Quantities Used			Remarks
	Reference Energy System Annual Usage		Per 10 ¹² Btu* Energy Produced	
	English Units	Metric Units		
<u>Feed Materials</u>				
Raw coal in place	9.7 × 10 ⁶ tons	8.8 × 10 ⁶ tonnes	64 × 10 ³ tons	Assumed to be a 40-yr supply
<u>Energy</u>				
Electricity	0.9 × 10 ⁶ kWh	0.9 × 10 ⁶ kWh	6.0 × 10 ³ kWh	For preparation plant
Fuel	3.8 × 10 ⁶ gal	14.5 × 10 ⁶ l	25.0 × 10 ³ gal	
Ammonium nitrate				
Fuel oil mixture	1.25 × 10 ³ tons	1.13 × 10 ³ tonnes	8.2 tons	
<u>Water</u>	Unquantifiable			
<u>Total Usage</u>				
<u>Construction Materials</u>				
Not Determined				
<u>Land</u>				
Mine	20 × 10 ³ acres	8.09 × 10 ³ ha	130 acres	Facilities land includes land for preparation plant and railroad-associated land
Solid waste storage	102 acres	4.05 ha	0.07 acre	
Facilities	16.8 acres	68 ha	0.11 acre	
Mining operations	35 acres	14.2 ha	0.23 acre	
<u>Personnel</u>				
Mine	210 workers		1.4 workers	
Preparation plant	20 workers		0.13 worker	

*Entries computed on basis of output from preparation plant throughout the Summary Sheet.

COSTS

	Reference Energy System	Per 10^{12} Btu Energy Produced	Remarks
		(1981 \$)	
<u>Facility</u>			
Capital			Reference year for cost is 1978; 1978 CCI average (I_R) = 2776. See Explanatory Notes section and Appendix B.
• Mine	$\$251 \times 10^6$ total	$\$1.7 \times 10^6$ total	
• Preparation plant	$(\$15.4-\$148) \times 10^6$ total	$(\$0.10-\$1.0) \times 10^6$ total	
Operation and maintenance			
• Mine	$\leq \$64 \times 10^6/\text{yr}$	$\leq \$0.42 \times 10^6/\text{yr}$	
• Preparation plant	$(\$8.9-\$109) \times 10^6/\text{yr}$	$(\$0.06-\$0.71) \times 10^6/\text{yr}$	
<u>Environmental Controls</u>	Included in above costs		

WESTERN SURFACE COAL MINING (WITH PREPARATION PLANT)

ENVIRONMENTAL RESIDUALS

	Quantities Released			Remarks
	Reference Energy System			
	Annual Levels			
	English Units	Metric Units	Per 10 ¹² Btu Energy Produced	
<u>Air Pollutants</u>				
Carbon monoxide	147 tons	133 tonnes	0.97 ton	Regulatory Compliance Standards* by component (air pollutants) • Thermal Dryer — Particulates : 0.031 gr/dscf — Opacity: 20% • Pneumatic Coal Cleaning Equip- ment — Particulates: 0.018 gr/dscf — Opacity: 20% • Processing and Conveying Equip- ment — Opacity: 20%
Hydrocarbons	47 tons	43 tonnes	0.30 ton	
Oxides of nitrogen	734 tons	667 tonnes	4.8 tons	
Sulfur dioxide	48 tons	44 tonnes	0.32 ton	
Particulates	39 tons	35 tonnes	0.26 ton	
Aldehydes	12 tons	11 tonnes	0.08 ton	
Fugitive dust	107 tons	97 tonnes	0.70 ton	

Water Pollutants

For the Western Surface Mine,
all water used in the mine
activity is recycled. Amount
is unquantifiable.

Solid Waste

Preparation plant	970 × 10 ³ tons	880 tonnes	6.38 tons
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Noise Pollution

Not Determined

*CFR 40 Part 60, Subpart V: Coal Preparation Plants (41FR2232).

PRODUCTS

	<u>Quantities Produced</u>			<u>Remarks</u>
	<u>Reference Energy System</u>		<u>Per 10¹² Btu Energy Produced</u>	
	<u>Annual Production</u>			
	<u>English Units</u>	<u>Metric Units</u>		
<u>Primary</u>				
Coal (cleaned)	8.73 × 10 ⁶ tons	7.92 × 10 ⁶ tonnes	57.4 × 10 ³ tons	Represents approximately a 90% recovery from ROM coal output

OCCUPATIONAL HEALTH AND SAFETY

	Reference Energy System Annual	Per 10 ¹² Btu Energy Produced	Remarks
<u>Deaths</u>			
Surface mine	0.05	0.29 × 10 ⁻³	
Preparation plant	0.014	0.082 × 10 ⁻³	
<u>Injuries</u>			
Surface mine	13.1	0.08	
Preparation plant	1.8	0.01	

COAL BENEFICIATION

REFERENCE ENERGY SYSTEM

The system is comprised of a number of wet circuit coal beneficiation devices including crushers, scalping screens, rotary breaker, vibrating screens, jigs, thickeners, concentrating tables, flotation circuits, and thermal drying. These devices are designed to remove unwanted components from the raw coal, such as ash to improve the energy content or sulfur to reduce the sulfur oxide emissions. The resultant cleaned coal can then be utilized in a manner essentially identical to other unprocessed coal that has not undergone this degree of beneficiation.

FACILITY OPERATING PARAMETERS

Size:	2.857×10^6 tons/yr
Annual Capacity Factor:	83% (based on 230 days/yr of operation)
Annual Energy Production:	55.0×10^{12} Btu
Efficiency:	87.5%
Lifetime:	20 yr

RESOURCES USED

	Quantities Used		Per 10 ¹² Btu Energy Produced	Remarks
	Reference Energy System Annual Usage			
	English Units	Metric Units		
<u>Feed Materials</u>				
Coal (run-of-mine)	2.86 × 10 ⁶ tons	2.59 × 10 ⁶ tonnes	51.945 × 10 ³ tons	
<u>Energy</u>				
Electricity	11 × 10 ⁶ kWh	11 × 10 ⁶ kWh	0.20 × 10 ⁶ kWh	
Oil	32 × 10 ⁹ Btu	34 × 10 ¹² J	0.59 × 10 ⁹ Btu	
<u>Processing Materials</u>		Not Determined		
<u>Water</u>				
Consumptive uses	200 acre-ft	250 × 10 ⁶ l	3.7 acre-ft	
	Total Usage			
<u>Construction Materials</u>		Not Determined		
<u>Land</u>	240 acres	96 ha	4.3 acres	
<u>Personnel</u>				
Construction (1 yr)	440 workers		8.1 workers	
Operation and maintenance	82 workers		1.5 workers	

COSTS

	<u>Reference Energy System</u>	<u>Per 10¹² Btu Energy Produced</u>	<u>Remarks</u>
<u>Facility</u>			
	(1981 \$)		
Construction (1 yr)	\$35.3 × 10 ⁶ total	\$0.63 × 10 ⁶ total	Reference year for costs is 1976. 1976 CCI average (I _p) = 2401. See Explanatory Notes Section.
Operation and maintenance	\$26.5 × 10 ⁶ /yr	\$0.47 × 10 ⁶ /yr	
<u>Environmental Controls</u>			
	Not Determined		

COAL BENEFICIATION

ENVIRONMENTAL RESIDUALS

	Quantities Released			Remarks
	Reference Energy System Annual Levels		Per 10 ¹² Btu Energy Produced	
	English Units	Metric Units		
<u>Air Pollutants</u>				
Particulates	50 tons	40 tonnes	0.9 ton	Regulatory Compliance Standards* by component:
Sulfur dioxide	0.3 ton	0.2 tonne	0.005 ton	
Oxides of nitrogen	33 tons	30 tonnes	0.6 ton	
Hydrocarbons	11 tons	10 tonnes	0.2 ton	
Carbon monoxide	11 tons	10 tonnes	0.2 ton	
<u>Water Pollutants</u>				
Total dissolved solids	1.82 × 10 ³ tons	1.65 × 10 ³ tonnes	33 tons	• Thermal Dryer — Particulates — 0.031 gr/dscf — Opacity—20%
• Iron	0.4 ton	0.3 tonne	0.007 ton	
• Manganese	1.6 tons	1.5 tonnes	0.03 ton	
• Aluminum	2.2 tons	2.0 tonnes	0.4 ton	
• Zinc	0.3 ton	0.2 tonne	0.005 ton	
• Nickel	0.16 ton	0.15 tonne	0.003 ton	• Pneumatic Coal Cleaning Equipment — Particulates — 0.018 gr/dscf — Opacity—20%
Total suspended solids	33 tons	30 tonnes	0.6 ton	
• Iron	3.3 tons	3.0 tonnes	0.06 ton	
Ammonia	3.0 tons	2.0 tonnes	0.05 ton	
Sulfates	990 tons	900 tonnes	18.0 tons	
<u>Solid Wastes</u>				
Course cleaning	0.11 × 10 ³ tons	0.1 × 10 ³ tonnes	0.002 × 10 ³ tons	• Processing and Conveying Equipment — Opacity—20%
Primary cleaning	559 × 10 ³ tons	508 × 10 ³ tonnes	10.16 × 10 ³ tons	
Froth flotation	290 × 10 ³ tons	260 × 10 ³ tonnes	5.3 × 10 ³ tons	
Breaking and sizing	0.11 × 10 ³ tons	0.1 × 10 ³ tonnes	0.002 × 10 ³ tons	
Total	849 × 10 ³ tons	768 × 10 ³ tonnes	15.5 × 10 ³ tons	
<u>Thermal Discharge</u>				
Not Determined				

Not Determined

Noise Pollution

May affect workers but not
nearby receptors

*CFR 40 Part 60, Subpart V: Coal Preparation Plants (41 FR 2232)

PRODUCTS

	Quantities Produced			Remarks
	Reference Energy System Annual Production		Per 10 ¹² Btu Energy Produced	
	English Units	Metric Units		
Primary				
Coal (cleaned)	2.00 × 10 ⁶ tons	1.82 × 10 ⁶ tonnes	36.4 × 10 ³ tons	
Recoverables/Recyclables	Not Determined			

OCCUPATIONAL SAFETY AND HEALTH

Not Determined

COAL-OIL MIXTURE PREPARATION PLANT

REFERENCE ENERGY SYSTEM

The system is composed of a receiving facility for the coarsely ground/beneficiated coal, a storage/surge hopper for this material, a fine crushing facility for the coal, a batch or continuous oil-coal blending system, and a facility to pump the mixture into existing No. 6 fuel oil distribution systems. Emission controls are included for fugitive dust, evaporative losses, and onsite water pollution.

FACILITY OPERATING PARAMETERS

Size:	106.0×10^3 bbl/system day (20×10^3 tons/system day) (mixture 40% coal—60% oil)
Annual Capacity Factor:	85%
Annual Energy Production:	203.65×10^{12} Btu
Efficiency:	99.8% based on $\frac{\text{energy in feed materials}}{\text{energy in mixture} + \text{operating energy}}$
Lifetime:	20 yr

RESOURCES USED

	Quantities Used		Per 10 ¹² Btu Energy Produced	Remarks
	Reference Energy System Annual Usage			
	English Units	Metric Units		
<u>Feed Materials</u>				
Coal (coarsely ground)	2.60 × 10 ⁶ tons	2.36 × 10 ⁶ tonnes	12.8 × 10 ³ tons	13.06 × 10 ³ Btu/lb, 2% sulfur
Oil (No. 6 fuel oil)	23.0 × 10 ⁶ bbl	3.65 × 10 ⁹ l	113 × 10 ³ bbl	18.8 × 10 ³ Btu/lb, 1% sulfur
<u>Energy</u>				
Operating energy (electricity)	92 × 10 ⁶ kWh	92 × 10 ⁶ kWh	0.45 × 10 ⁶ kWh	
<u>Processing Materials</u>				
	Not Determined			
<u>Water</u>				
Consumptive uses	Negligible			
<u>Total Usage</u>				
<u>Construction Materials</u>				
	Not Determined			
<u>Land</u>				
	261 acres	106 ha	1.28 acres	
<u>Personnel</u>				
Construction	300 workers		1.47 workers	
Operation and maintenance	120 workers		0.589 worker	

COSTS

	Reference Energy System	Per 10 ¹² Btu Energy Produced	Remarks
<u>Facility</u>			
	(1981 \$)		Reference year for cost is 1978. 1978 CCI average (I _a) = 2776. See Explanatory Notes Section
Construction	\$153 × 10 ⁶ total	\$0.750 × 10 ⁶ total	
Operation and maintenance	\$21.6 × 10 ⁶ /yr	\$0.102 × 10 ⁶ /yr	
<u>Environmental Controls</u>			
	Not Determined		

COAL-OIL MIXTURE PREPARATION PLANT

ENVIRONMENTAL RESIDUALS

ENVIRONMENTAL RESIDUALS				
	Quantities Released		Per 10 ¹² Btu Energy Produced	Remarks
	Reference Energy System Annual Levels			
	English Units	Metric Units		
<u>Air Pollutants</u>				
Fugitive dust		Not Determined		
Hydrocarbons		↓		
<u>Water Pollutants</u>				
		Not Determined		
<u>Solid Wastes</u>				
		Negligible		
<u>Thermal Discharge</u>				
		Not Determined		

PRODUCTS

	Quantities Produced			Remarks
	Reference Energy System Annual Production		Per 10 ¹² Btu Energy Produced	
	English Units	Metric Units		
<u>Primary</u>				
Coal-oil mixture (delivered to distribution system)	6.2 × 10 ⁶ tons (31.9 × 10 ⁶ bbl)	5.6 × 10 ⁶ tonnes (5.07 × 10 ⁹ l)	30 × 10 ³ tons (157 × 10 ³ bbl)	
<u>Recoverables/Recyclables</u>				
		Not Determined		

OCCUPATIONAL SAFETY AND HEALTH

Not Determined

EASTERN COAL UNIT TRAIN

REFERENCE ENERGY SYSTEM

Typical eastern unit train systems are comprised of 105 cars holding 100 tons each, using four diesel locomotives of 3000 hp each. The train operates between two fixed locations on a dedicated basis. This example assumes a train traveling 700 mi one way and making 90 trips per year. Ten spare cars are reserved for each train system.

FACILITY OPERATING PARAMETERS

Size:	105 cars, 100 tons per car, 10.5×10^3 tons per train (transported)
Annual Capacity Factor:	Not determined
Annual Energy Production:	24.3×10^{12} Btu (coal transported)
Efficiency:	98.26% based on $\frac{\text{energy delivered}}{\text{energy loaded} + \text{energy expanded}}$
Lifetime:	30 yr

RESOURCES USED

	Quantities Used		Per 10 ¹² Btu Energy Produced	Remarks
	Reference Energy System Annual Usage			
	English Units	Metric Units		
<u>Feed Materials</u>				
Coal transported	945 × 10 ³ tons	858 × 10 ³ tonnes	38.9 × 10 ³ tons	
<u>Energy</u>				
Diesel	230 × 10 ⁹ Btu	240 × 10 ¹² J	9.5 × 10 ⁹ Btu	
<u>Total Usage</u>				
<u>Construction Materials</u>				
Aluminum	45.4 tons	41.2 tonnes	1.87 tons	
Brass and bronze casting	18 tons	16 tonnes	0.75 ton	
Chromium	2.4 tons	2.2 tonnes	0.10 ton	
Copper	62.7 tons	56.9 tonnes	2.58 tons	
Iron		Not Determined		
Manganese	32.3 tons	29.3 tonnes	1.33 tons	
Nickel	0.5 ton	0.4 tonne	0.02 ton	
Steel	4.50 × 10 ³ tons	4.08 × 10 ³ tonnes	185.0 tons	
<u>Land</u>				
Land value has been excluded as it cannot be exclusively associated with coal transportation				
<u>Personnel</u>				
Construction		Not Determined		
Operation and maintenance		125 workers	5.16 workers	

COSTS

	Reference Energy System	Per 10^{12} Btu Energy Produced	Remarks
<u>Facility</u>	(1981 \$)		
Construction	$\$10.3 \times 10^6$ total	$\$0.424 \times 10^6$ total	Reference year for costs is 1978. 1978 CCI average (I_p) = 2776. See Explanatory Notes Section.
Operation and maintenance	$\$9.19 \times 10^6/\text{yr}$	$\$0.378 \times 10^6/\text{yr}$	

EASTERN COAL UNIT TRAIN

ENVIRONMENTAL RESIDUALS

	Quantities Released			
	Reference Energy System Annual Levels		Per 10 ¹² Btu Energy Produced	Remarks
	English Units	Metric Units		
<u>Air Pollutants</u>				
Particulates	2.50 × 10 ³ tons	2.27 × 10 ³ tonnes	102.9 tons	
Sulfur dioxide	90 tons	82 tonnes	3.7 tons	
Oxides of nitrogen	78 tons	71 tonnes	3.2 tons	
Hydrocarbons	61 tons	55 tonnes	2.5 tons	
Carbon monoxide	83 tons	75 tonnes	3.4 tons	
Aldehydes	14 tons	13 tonnes	0.6 ton	
<u>Noise Pollution*</u>				
In-cab noise level		> 112 dBA		Federal design
100 ft from moving train		~ 95 dBA		levels:
1000 ft from moving train		~ 75 dBA		55 dBA—residence
Whistle noise at 1000 ft		≤ 85 dBA		75 dBA—open land

*Noise cannot be expressed in terms of energy produced.

*Noise cannot be expressed in terms of energy produced.

PRODUCTS

	Quantities Produced			Remarks
	Reference Energy System		Per 10 ¹² Btu Energy Produced	
	Annual Production			
	English Units	Metric Units		
<u>Primary</u>				
Coal transported	945 × 10 ³ tons	858 × 10 ³ tonnes	38.9 × 10 ³ tons	

OCCUPATIONAL SAFETY AND HEALTH

Not Determined

WESTERN COAL UNIT TRAIN

REFERENCE ENERGY SYSTEM

Typical western unit train systems are comprised of 100 cars each holding 100 tons and four diesel locomotives of 3000 hp each. The train operates between two fixed locations on a dedicated basis. This example assumes a train traveling 700 mi one way and making 90 trips per year. Ten spare cars are reserved for each train system.

FACILITY OPERATING PARAMETERS

Size:	100 cars, 100 tons per car, 10 × 10 ³ tons per train
Annual Capacity Factor:	Not determined
Annual Energy Production:	17.01 × 10 ¹² Btu (coal transported)
Efficiency:	99.69% based on $\frac{\text{energy delivered}}{\text{energy loaded} + \text{energy expended}}$
Lifetime:	30 yr

RESOURCES USED

	Quantities Used			Remarks
	Reference Energy System Annual Usage		Per 10 ¹² Btu Energy Produced	
	English Units	Metric Units		
<u>Feed Materials</u>				
Coal transported	900 × 10 ³ tons	817 × 10 ³ tonnes	52.9 × 10 ³ tons	
<u>Energy</u>				
Diesel	221 × 10 ⁹ Btu	233 × 10 ¹² J	13.0 × 10 ⁹ Btu	
<u>Total Usage</u>				
<u>Construction Materials</u>				
Aluminum	43.2 tons	39.2 tonnes	2.54 tons	
Brass and bronze casting	17.4 tons	15.8 tonnes	1.02 tons	
Chromium	2.2 tons	2.0 tonnes	0.13 ton	
Copper	59.7 tons	54.2 tonnes	3.51 tons	
Iron		Not Determined		
Manganese	30.6 tons	27.8 tonnes	1.80 tons	
Nickel	0.51 ton	0.46 tonne	0.03 ton	
Steel	4.27 × 10 ³ tons	3.88 × 10 ³ tonnes	251 tons	
<u>Land</u>				
Land value has been excluded as it cannot be exclusively associated with coal transportation				
<u>Personnel</u>				
Construction		Not Determined		
Operation and maintenance	120 workers		7.02 workers	

COSTS

	Reference Energy System	Per 10 ¹² Btu Energy Produced	Remarks
		(1981 \$)	
<u>Facility</u>			
Construction	\$9.80 × 10 ⁶ total	\$0.578 × 10 ⁶ total	Reference year for cost is 1978. 1978 CCI average (I _R) = 2776. See Explanatory Notes Section.
Operation and maintenance	\$8.74 × 10 ⁶ /yr	\$0.513 × 10 ⁶ /yr	

WESTERN COAL UNIT TRAIN

ENVIRONMENTAL RESIDUALS

	Quantities Released			Remarks
	Reference Energy System		Per 10 ¹² Btu Energy Produced	
	Annual Levels			
	English Units	Metric Units		
<u>Air Pollutants</u>				
Particulates	2.38 × 10 ³ tons	2.16 × 10 ³ tonnes	140 tons	
Sulfur dioxide	90 tons	80 tonnes	5.0 tons	
Oxides of nitrogen	75 tons	68 tonnes	4.4 tons	
Hydrocarbons	61 tons	56 tonnes	3.6 tons	
Carbon monoxide	78 tons	71 tonnes	4.6 tons	
Aldehydes	14 tons	12 tonnes	0.8 ton	
<u>Noise Pollution*</u>				
In-cab noise level		≥ 112 dBA		Federal design levels:
100 ft from moving train		~ 95 dBA		55 dBA — residence
1000 ft from moving train		~ 75 dBA		75 dBA — open land
Whistle noise at 1000 ft		≤ 85 dBA		

*Noise cannot be expressed in terms of energy produced.

*Noise cannot be expressed in terms of energy produced.

PRODUCTS

	Quantities Produced			Remarks
	Reference Energy System Annual Production		Per 10 ¹² Btu Energy Produced	
	English Units	Metric Units		
	<u>Primary</u>			
Coal transported	900 × 10 ³ tons	817 × 10 ³ tonnes	52.9 × 10 ³ tons	

OCCUPATIONAL SAFETY AND HEALTH

Not Determined

EASTERN COAL CONVENTIONAL TRAIN

REFERENCE ENERGY SYSTEM

A conventional freight train is assumed to be made up of 85 freight cars, 17 of which carry 85 tons each of coal. The train may have multiple destinations and be made up of a mixture of cars from many sources requiring more than one make-up and breakdown during a single trip. This example assumes a 300-mi one-way trip using a diesel-powered locomotive. The train is assumed to make the equivalent of 20 round trips per year.

FACILITY OPERATING PARAMETERS

Size:	29×10^3 tons/yr (transported)
Annual Capacity Factor:	Not determined
Annual Energy Production:	0.745×10^{12} Btu (coal transported)
Efficiency:	98.6% based on $\frac{\text{coal delivered}}{\text{coal loaded} + \text{energy used}}$
Lifetime:	30 yr

RESOURCES USED

	Quantities Used		Per 10 ¹² Btu Energy Produced	Remarks
	Reference Energy System Annual Usage			
	English Units	Metric Units		
<u>Feed Materials</u>				
Coal transported	29.0 × 10 ³ tons	26.4 × 10 ³ tonnes	39.0 × 10 ³ tons	
<u>Energy</u>				
Diesel fuel	8.05 × 10 ⁹ Btu	8.49 × 10 ¹² J	10.8 × 10 ⁹ Btu	
<u>Total Usage</u>				
<u>Construction Materials</u>				
Aluminum	4.20 tons	3.81 tonnes	5.64 tons	
Brass and bronze	2.48 tons	2.25 tonnes	3.33 tons	
Chromium	0.30 ton	0.27 tonne	0.40 ton	
Copper	7.27 tons	6.60 tonnes	9.76 tons	
Iron		Not Determined		
Manganese	4.48 tons	4.07 tonnes	6.02 tons	
Nickel	0.07 ton	0.06 tonne	0.09 ton	
Steel	629 tons	571 tonnes	844 tons	
<u>Land</u>				
Land use value has been excluded as it cannot be exclusively associated with coal transportation				
<u>Personnel</u>				
Construction		Not Determined		
Operation and maintenance	2.91 workers		3.91 workers	

COSTS

	Reference Energy System	Per 10^{12} Btu Energy Produced	Remarks
<u>Facility</u>		(1981 \$)	
Construction	$\$1.24 \times 10^6$ total	$\$1.67 \times 10^6$ total	Reference year for cost is 1978. 1978 CCI average (I_A) = 2776. See Explanatory Notes Section.
Operation and maintenance	$\$0.811 \times 10^6$ /yr	$\$1.09 \times 10^6$ /yr	

EASTERN COAL CONVENTIONAL TRAIN

ENVIRONMENTAL RESIDUALS

	Quantities Released			Remarks
	Reference Energy System		Per 10 ¹² Btu Energy Produced	
	Annual Levels			
	English Units	Metric Units		
<u>Air Pollutants</u>				
Particulates	76.0 tons	69.0 tonnes	102.0 tons	
Sulfur dioxide	1.9 tons	1.8 tonnes	2.6 tons	
Oxides of nitrogen	2.2 tons	2.0 tonnes	2.9 tons	
Hydrocarbons	1.5 tons	1.4 tonnes	2.0 tons	
Carbon monoxide	2.0 tons	1.8 tonnes	2.7 tons	
Aldehydes, etc.	0.4 ton	0.3 tonne	0.5 ton	
<u>Noise Pollution*</u>				
In-cab noise level		> 112 dBA		Federal design levels:
100 ft from moving train		~ 95 dBA		55 dBA — residence
1000 ft from moving train		~ 75 dBA		75 dBA — open land
Whistle noise at 1000 ft		≤ 85 dBA		
*Noise cannot be expressed in terms of energy produced.				

*Noise cannot be expressed in terms of energy produced.

PRODUCTS

Primary	Quantities Produced			Remarks
	Reference Energy System Annual Production		Per 10 ¹² Btu Energy Produced	
	English Units	Metric Units		
Coal transported	29.0 × 10 ³ tons	26.3 × 10 ³ tonnes	38.9 × 10 ³ tons	

OCCUPATIONAL SAFETY AND HEALTH

Not Determined

WESTERN COAL CONVENTIONAL TRAIN

REFERENCE ENERGY SYSTEM

A conventional freight train is assumed to be made up of 85 freight cars, 17 of which carry 85 tons each of coal. The train may have multiple destinations and thus be made up of a mix of cars from many sources requiring more than one make-up and breakdown of the train during a single trip. This example assumes a 300-mi one-way trip using a diesel-powered locomotive. The train is assumed to make the equivalent of 20 round trips per year.

FACILITY OPERATING PARAMETERS

Size:	29×10^3 tons/yr (transported)
Annual Capacity Factor:	Not determined
Annual Energy Production:	0.548×10^{12} Btu (coal transported)
Efficiency:	98.3% based on $\frac{\text{coal delivered}}{\text{coal loaded} + \text{energy consumed}}$
Lifetime:	30 yr

RESOURCES USED

	Quantities Used		Per 10 ¹² Btu Energy Produced	Remarks
	Reference Energy System Annual Usage			
	English Units	Metric Units		
<u>Feed Materials</u>				
Coal transported	29.1 × 10 ³ tons	26.4 × 10 ³ tonnes	53.04 × 10 ³ tons	
<u>Energy</u>				
Diesel fuel	8.06 × 10 ⁹ Btu	8.50 × 10 ¹² J	14.7 × 10 ⁹ Btu	
<u>Total Usage</u>				
<u>Construction Materials</u>				
Aluminum	4.20 tons	3.82 tonnes	7.67 tons	
Brass and bronze	2.48 tons	2.25 tonnes	4.52 tons	
Chromium	0.30 ton	0.27 tonne	0.54 ton	
Copper	7.27 tons	6.60 tonnes	13.27 tons	
Iron		Not Determined		
Manganese	4.48 tons	4.07 tonnes	8.18 tons	
Nickel	0.066 ton	0.060 tonne	0.12 ton	
Steel	6.28 tons	5.71 tonnes	11.47 tons	
<u>Land</u>				
Land use value has been excluded as it cannot be exclusively associated with coal transportation				
<u>Personnel</u>				
Construction		Not Determined		
Operation and maintenance	2.92 workers		5.32 workers	

COSTS

	Reference Energy System	Per 10^{12} Btu Energy Produced	Remarks
<u>Facility</u>			
		(1981 \$)	
Construction	$\$1.24 \times 10^6$ total	$\$2.27 \times 10^6$ total	Reference year for cost is 1978. 1978 CCI average (I_{CI}) = 2776. See Explanatory Notes Section.
Operation and maintenance	$\$0.837 \times 10^6/\text{yr}$	$\$1.53 \times 10^6/\text{yr}$	

WESTERN COAL CONVENTIONAL TRAIN

ENVIRONMENTAL RESIDUALS

	Quantities Released			Remarks
	Reference Energy System Annual Levels		Per 10 ¹² Btu Energy Produced	
	English Units	Metric Units		
<u>Air Pollutants</u>				
Particulates	75.8 tons	68.8 tonnes	138.4 tons	Includes particulates from locomotives and fugitive emissions
Sulfur dioxide	1.9 tons	1.7 tonnes	3.5 tons	
Oxides of nitrogen	2.2 tons	2.0 tonnes	4.0 tons	
Hydrocarbons	1.5 tons	1.3 tonnes	2.7 tons	
Carbon monoxide	2.0 tons	1.8 tonnes	3.7 tons	
Aldehydes, etc.	0.33 ton	0.30 tonne	0.6 ton	
<u>Noise Pollution*</u>				
In cab of locomotive		> 112 dBA		Federal design levels: 55 dBA — residence 75 dBA — open land
100 ft from moving train		~ 95 dBA		
1000 ft from moving train		~ 75 dBA		
Whistle noise at 1000 ft		≤ 85 dBA		
*Noise cannot be expressed in terms of energy produced.				

*Noise cannot be expressed in terms of energy produced.

PRODUCTS

	Quantities Produced			Remarks
	Reference Energy System Annual Production		Per 10 ¹² Btu Energy Produced	
	English Units	Metric Units		
Primary				
Coal transported	29.0 × 10 ³ tons	26.3 × 10 ³ tonnes	52.9 × 10 ³ tons	

OCCUPATIONAL SAFETY AND HEALTH

Not Determined

BARGE TRANSPORTATION — EASTERN COAL

REFERENCE ENERGY SYSTEM

A barge tow system for transporting coal that consists of 15 barges, each with a capacity of 1400 tons. Total capacity of each tow is 21,000 tons of coal per trip. The 15-barge tow system is propelled by a single 4200-hp diesel-fueled towboat. For an average haul distance (one way) of 190 mi, an average speed of 9 mph, and approximately 3 wk reserved annually for maintenance and miscellaneous delays, an estimated 116 round trips are made annually.

FACILITY OPERATING PARAMETERS

Size:	21×10^3 tons/trip (propelled by a 4.2×10^3 hp diesel towboat)
Annual Capacity Factor:	94% (based on an average 3 wk/yr down time)
Annual Energy Production:	62.6×10^{12} Btu (coal transported)
Efficiency:	99.5% based on $\frac{\text{energy transported}}{\text{energy loaded} + \text{energy required}}$
Lifetime:	Not determined*

*Lifetime specified for analogous "Barge Transportation — Western Coal" is 30 years.

RESOURCES USED

	Quantities Used		Per 10 ¹² Btu Energy Produced	Remarks
	Reference Energy System Annual Usage			
	English Units	Metric Units		
<u>Feed Materials</u>				
Coal transported	2.44 × 10 ⁶ tons	2.21 × 10 ⁶ tonnes	38.911 × 10 ³ tons	Heat content = 12.85 × 10 ³ Btu/lb
<u>Energy</u>				
Diesel fuel	284 × 10 ³ Btu	300 × 10 ¹² J	4.53 × 10 ⁹ Btu	
<u>Construction Materials</u>				
Steel	3.82 × 10 ³ tons	3.45 × 10 ³ tonnes	61.0 tons	Includes carbon, alloy and stainless steel requirements
Copper	31.3 tons	28.4 tonnes	0.5 ton	
Aluminum	37.6 tons	34.1 tonnes	0.6 ton	
Manganese	31.3 tons	28.4 tonnes	0.5 ton	
Chromium	6.3 tons	5.7 tonnes	0.1 ton	
Cast iron	106 tons	96.2 tonnes	1.7 tons	
<u>Personnel</u>				
Construction	Not Determined			
Operation and maintenance	31.3 workers		0.5 worker	

COSTS

	<u>Reference Energy System</u>	<u>Per 10¹² Btu Energy Produced</u>	<u>Remarks</u>
<u>Facility</u>		(1981 \$)	
Construction	\$8.02 × 10 ⁶ total	\$0.127 × 10 ⁶ total	Reference year for costs is 1978. 1978 CCI average (I _R) = 2776. See Explanatory Notes Section.
Operation and maintenance	\$2.00 × 10 ⁶ /yr	\$0.032 × 10 ⁶ /yr	
<u>Environmental Controls</u>			
		Not Determined	Excludes diesel fuel costs

BARGE TRANSPORTATION — EASTERN COAL

ENVIRONMENTAL RESIDUALS

ENVIRONMENTAL RECORDS

	Quantities Released		Per 10 ¹² Btu Energy Produced	Remarks
	Reference Energy System			
	Annual Levels			
	English Units	Metric Units		
<u>Air Pollutants</u>				
Particulates	34.4 tons	31.2 tonnes	0.55 ton	
Sulfur dioxide	32.6 tons	29.6 tonnes	0.52 ton	
Oxides of nitrogen	483 tons	438 tonnes	7.71 tons	
Hydrocarbons	38.8 tons	35.2 tonnes	0.62 ton	
Carbon monoxide	105 tons	95.3 tonnes	1.68 tons	
<u>Water Pollutants</u>				
The potential for water quality degradation exists due to shoreline erosion from towboat wake and spillage of coal and/or diesel fuel from the barge and towboat, respectively				

PRODUCTS

	Quantities Produced		Per 10 ¹² Btu Energy Produced	Remarks
	Reference Energy System Annual Production			
	English Units	Metric Units		
	<u>Primary</u>			
Coal transported (same as feed material)	2.44 × 10 ⁶ tons	2.21 × 10 ⁶ tonnes	38.911 × 10 ³ tons	Heat content = 12.85 × 10 ³ Btu/lb

OCCUPATIONAL SAFETY AND HEALTH

Not Determined

BARGE TRANSPORTATION — WESTERN COAL

REFERENCE ENERGY SYSTEM*

A barge tow system for transporting coal consisting of 15 barges, each with a capacity of 1400 tons. Total capacity of each tow is 21,000 tons of coal per trip. The 15-barge tow system is propelled by a single 4200-hp diesel-fueled towboat. For an average haul distance (one way) of 400 mi, average speed of 9 mph, average load/unload time (total) of 10 hr, 1 day layover per trip, and 21 days per year of scheduled maintenance, the system delivers 67.2 trips per year.

*This description and the following quantitative data presentation are based on estimates of how barge transportation of coal could develop in the West.

FACILITY OPERATING PARAMETERS

Size:	21×10^3 tons (coal)/trip (propelled by a 4.2×10^3 hp diesel-fueled towboat)
Annual Capacity Factor:	94% (based on an average of 3 wk/yr downtime)
Annual Energy Production:	26.7×10^{12} Btu (coal transported)
Efficiency:	98.7% based on energy transported energy loaded + energy required
Lifetime:	30 yr

RESOURCES USED

	Quantities Used		Per 10 ¹² Btu Energy Produced	Remarks
	Reference Energy System Annual Usage			
	English Units	Metric Units		
<u>Feed Materials</u>				
Coal transported	1.41 × 10 ⁶ tons	1.28 × 10 ⁶ tonnes	52.911 × 10 ³ tons	Heat content = 9.45 × 10 ³ Btu/lb
<u>Energy</u>				
Diesel fuel	347 × 10 ⁹ Btu	366 × 10 ¹² J	13.0 × 10 ⁹ Btu	Diesel fuel consumed per 10 ¹² Btu of coal transported
<u>Total Usage</u>				
<u>Construction Materials</u>				
Total steel	3.82 × 10 ³ tons	3.46 × 10 ³ tonnes	143.2 tons	Carbon, alloy, and stainless steel
Copper	29.4 tons	26.7 tonnes	1.1 tons	
Aluminum	34.7 tons	31.5 tonnes	1.3 tons	
Manganese	29.4 tons	26.7 tonnes	1.1 tons	
Chromium	2.8 tons	2.5 tonnes	0.1 ton	
Cast iron	104 tons	94.3 tonnes	3.9 tons	
<u>Personnel</u>				
Construction	Not Determined			
Operation and maintenance	32.0 workers		1.20 workers	

COSTS

	Reference Energy System	Per 10 ¹² Btu Energy Produced	Remarks
<u>Facility</u>			
		(1981 \$)	
Construction	\$6.80 × 10 ⁶ total	\$0.255 × 10 ⁶ total	Reference year for costs is 1978. 1978 CCI average (I ₉) = 2776. See Explanatory Notes Section.
Operation and maintenance	\$1.91 × 10 ⁶ /yr	\$0.071 × 10 ⁶ /yr	
<u>Environmental Controls</u>			
	Not Determined		Operating costs exclude diesel fuel costs

BARGE TRANSPORTATION — WESTERN COAL

ENVIRONMENTAL RESIDUALS

ENVIRONMENTAL RELEASES

Quantities Released				
Reference Energy System Annual Levels			Per 10 ¹² Btu Energy Produced	Remarks
English Units	Metric Units			
<u>Air Pollutants</u>				
Particulates*	41.9 tons	38.0 tonnes	1.57 tons	
Sulfur dioxide	39.2 tons	35.6 tonnes	1.47 tons	
Oxides of nitrogen	588 tons	534 tonnes	22.03 tons	
Hydrocarbons	47.0 tons	42.6 tonnes	1.76 tons	
Carbon monoxide	128 tons	116 tonnes	4.79 tons	
<u>Water Pollutants</u>				
The potential for water quality degradation due to spillage of diesel fuel and/or coal exists; shoreline erosion, due to towboat wake, may also lead to increased sedimentation of waterways				
*Particulates are from diesel fuel combustion. Total suspended particulates (windage) from barge transport of coal are projected to be negligible due to low speeds and high moisture content.				

PRODUCTS

	Quantities Produced			Remarks
	Reference Energy System Annual Production		Per 10 ¹² Btu Energy Produced	
	English Units	Metric Units		
Primary				
Coal transported (same as feed material)	1.41 × 10 ⁶ tons	1.28 × 10 ⁶ tonnes	52.911 × 10 ³ tons	Heat content = 9.45 × 10 ³ Btu/lb

OCCUPATIONAL SAFETY AND HEALTH

Not Determined

COAL TRANSPORTATION BY TRUCK—EASTERN COAL

REFERENCE ENERGY SYSTEM

This transport system is assumed to consist of one over-the-road tractor trailer unit capable of carrying 25 tons over a distance of 60 mi round trip. The truck is assumed to operate 240 days/yr on a 10-hr day and make 800 round trips per year or 1.2×10^6 net ton miles.

FACILITY OPERATING PARAMETERS

Size:	20.0×10^3 tons/yr (transported)
Annual Capacity Factor:	27.5% based on $\frac{\text{time-in-use}}{\text{time (24-hr day)}}$
Annual Energy Production:	0.514×10^{12} Btu (coal transported)
Efficiency:	99.9% based on $\frac{\text{coal delivered}}{\text{coal loaded} + \text{fuel consumed}}$
Lifetime:	7 yr

RESOURCES USED

	Quantities Used			Remarks
	Reference Energy System Annual Usage		Per 10 ¹² Btu Energy Produced	
	English Units	Metric Units		
<u>Feed Materials</u>				
Coal transported	20.0 × 10 ³ tons	18.2 × 10 ³ tonnes	38.9 × 10 ³ tons	
<u>Energy</u>				
Diesel fuel	1.61 × 10 ⁹ Btu	1.70 × 10 ¹² J	3.13 × 10 ⁹ Btu	
	Total Usage			
<u>Construction Materials</u>				
Carbon steel	11.6 tons	10.5 tonnes	22.6 tons	
Cast iron	0.31 ton	0.30 tonne	0.6 ton	
Structural steel	2.0 tons	1.8 tonnes	3.8 tons	
Steel plate (<1.5 in. thick)	1.6 tons	1.5 tonnes	3.2 tons	
<u>Personnel</u>				
Construction	Not Determined			
Operation and maintenance	2.5 workers		4.9 workers	

COSTS

	Reference Energy System	Per 10^{12} Btu Energy Produced	Remarks
<u>Facility</u>			
	(1981 \$)		
Construction	$\$0.098 \times 10^6$ total	$\$0.191 \times 10^6$ total	Reference year for costs is 1978. 1978 CCI average (I_R) = 2776. See Explanatory Notes Section.
Operation and maintenance	$\$0.127 \times 10^6/\text{yr}$	$\$0.242 \times 10^6/\text{yr}$	

COAL TRANSPORTATION BY TRUCK—EASTERN COAL

ENVIRONMENTAL RESIDUALS

ENVIRONMENTAL RESIDUALS				
Quantities Released				
	Reference Energy System		Per 10 ¹² Btu Energy Produced	Remarks
	Annual Levels			
	English Units	Metric Units		
<u>Air Pollutants</u>				
Total suspended particulates	18.1 tons	16.4 tonnes	35.16 tons	
Oxides of sulfur	0.15 ton	0.14 tonne	0.29 ton	
Oxides of nitrogen	0.961 ton	0.872 tonne	1.87 tons	
Carbon monoxide	1.52 tons	1.38 tonnes	2.95 tons	
Hydrocarbons	0.24 ton	0.22 tonne	0.47 ton	
Aldehydes	0.02 ton	0.01 tonne	0.03 ton	
Organic acids	0.02 ton	0.01 tonne	0.03 ton	
<u>Noise Pollution</u>				
Not Determined				

PRODUCTS

	Quantities Produced			Remarks
	Reference Energy System		Per 10 ¹² Btu Energy Produced	
	Annual Production			
	English Units	Metric Units		
Primary				
Coal transported	20.0 × 10 ³ tons	18.2 × 10 ³ tonnes	38.9 × 10 ³ tons	

OCCUPATIONAL SAFETY AND HEALTH

Not Determined

SLURRY PIPELINE

REFERENCE ENERGY SYSTEM

The system is comprised of a 38-in.-diameter pipeline through which a 50-50 mixture (by volume) of coal and water is pumped in a manner similar to crude oil. The system includes a slurry preparation plant, pipeline, pumping facilities, dewatering facilities, and in some instances, a storage facility. The assumed system is transporting western subbituminous coal over 1355 mi.

FACILITY OPERATING PARAMETERS

Size:	25.0×10^6 tons/yr
Annual Capacity Factor:	100%
Annual Energy Production:	472.5×10^{12} Btu (coal transported)
Efficiency:	94.2% based on $\frac{\text{energy delivered}}{\text{energy loaded} + \text{energy used}}$
Lifetime:	40 yr

RESOURCES USED

	Quantities Used		Per 10 ¹² Btu Energy Produced	Remarks
	Reference Energy System Annual Usage			
	English Units	Metric Units		
<u>Feed Materials</u>				
Coal transported	25.0 × 10 ⁶ tons	22.7 × 10 ⁶ tonnes	52.91 × 10 ³ tons	Subbituminous
<u>Energy</u>				
Electricity (pumping energy)	5.7 × 10 ⁹ kWh	5.7 × 10 ⁹ kWh	12 × 10 ⁶ kWh	
<u>Processing Materials</u>		Not Determined		
<u>Water</u>				
Consumptive uses	18.4 × 10 ³ acre-ft	22.7 × 10 ⁹ l	38.87 acre-ft	
	Total Usage			
<u>Construction Materials</u>				
Aluminum	633 tons	575 tonnes	1.34 tons	
Brass and bronze	190 tons	170 tonnes	0.40 ton	
Chromium	140 tons	130 tonnes	0.30 ton	
Concrete	1.42 × 10 ⁶ tons	1.29 × 10 ⁶ tonnes	3.017 × 10 ³ tons	
Copper	2.09 × 10 ³ tons	1.90 × 10 ³ tonnes	4.43 tons	
Iron		Not Determined		
Manganese	4.54 × 10 ³ tons	4.13 × 10 ³ tonnes	9.62 tons	
Nickel	14 tons	13 tonnes	0.03 ton	
Steel	608 × 10 ³ tons	552 × 10 ³ tonnes	1.286 × 10 ³ tons	
<u>Land</u>	17.7 × 10 ³ acres	71.5 × 10 ³ ha	37.4 acres	
<u>Personnel</u>				
Construction	5.81 × 10 ³ workers		12.3 workers	
Operation and maintenance	1.07 workers		2.26 × 10 ⁻³ workers	

SLURRY PIPELINE

COSTS

<u>Facility</u>	<u>Quantities Released</u>		<u>Remarks</u>
	<u>Reference Energy System</u>	<u>Per 10¹² Btu Energy Produced</u>	
	(1981 \$)		
Construction	$\$1.50 \times 10^9$ total	$\$3.18 \times 10^6$ total	Reference year for costs is 1978. 1978 CCI average (I_R) = 2776. See Explanatory Notes Section.
Operation and maintenance	$\$108 \times 10^6/\text{yr}$	$\$0.229 \times 10^6/\text{yr}$	
<u>Environmental Controls</u>	Not Determined		

ENVIRONMENTAL RESIDUALS

ENVIRONMENTAL RESOURCES			
	Quantities Released		
	Reference Energy System Annual Levels		
	English Units	Metric Units	Per 10 ¹² Btu Energy Produced
			Remarks
Air Pollutants		Not Determined	
Water Pollutants		Not Determined	

PRODUCTS

	Quantities Produced			Remarks
	Reference Energy System			
	Annual Production			
	English Units	Metric Units	Per 10 ¹² Btu Energy Produced	
Primary				
Coal transported	25.0 × 10 ⁶ tons	22.7 × 10 ⁶ tonnes	52.91 × 10 ³ tons	
Recoverables/Recyclables		Not Determined		

OCCUPATIONAL SAFETY AND HEALTH

Not Determined

ATMOSPHERIC FLUIDIZED BED COMBUSTION – BITUMINOUS COAL

REFERENCE ENERGY SYSTEM

Steam electric power generation facility utilizing a fluidized bed combustion system in which the small pieces of coal are suspended along with similarly sized bed material in a continuously moving mass of air. The bed material referred to as a sorbent and composed of crushed limestone or dolomite is responsible for the capture of a portion of the sulfur dioxide generated during combustion. Other environmental control systems include either a baghouse or electrostatic precipitator and conventional water treatment as necessary. The lower combustion temperatures of the system also serve to minimize nitrogen oxide formation.

FACILITY OPERATING PARAMETERS

Size:	814 MWe (4.6×10^9 kWh/yr)
Annual Capacity Factor:	65%
Annual Energy Production:	15.8×10^{12} Btu
Efficiency:	35.8%
Lifetime:	20 yr

RESOURCES USED

	Quantities Used		Per 10 ¹² Btu Energy Produced	Remarks
	Reference Energy System Annual Usage			
	English Units	Metric Units		
<u>Feed Materials</u>				
Coal (bituminous Illinois No. 6)	2.05 × 10 ⁶ tons	1.86 × 10 ⁶ tonnes	129.5 × 10 ³ tons	10.78 × 10 ³ Btu/lb
<u>Processing Materials</u>				
Limestone (sorbent bed material)	526 × 10 ³ tons	478 × 10 ³ tonnes	33.3 × 10 ³ tons	
<u>Water</u>				
Consumptive uses	2.84 × 10 ³ acre-ft	3.51 × 10 ⁹ l	180 acre-ft	
	<u>Total Usage</u>			
<u>Construction Materials</u>				
		Not Determined		
<u>Land</u>	246 acres	100 ha	15.6 acres	
<u>Personnel</u>				
Approximately same value as conventional power station of equivalent capacity				

COSTS

	<u>Reference Energy System</u>	<u>Per 10¹² Btu Energy Produced</u>	<u>Remarks</u>
<u>Facility</u>			
		(1981 \$)	
Construction	\$564 × 10 ⁶ total	\$35.7 × 10 ⁶ total	Reference year for costs (facility only) is 1980. 1980 CCI average (I _p) = 3237. See Explanatory Notes Section.
Operation and maintenance	\$59.2 × 10 ⁶ /yr	\$3.74 × 10 ⁶ /yr	
<u>Environmental Controls</u>			
Capital	\$44.6 × 10 ⁶ total	\$2.8 × 10 ⁶ total	

ATMOSPHERIC FLUIDIZED BED COMBUSTION—BITUMINOUS COAL

ENVIRONMENTAL RESIDUALS

ENVIRONMENTAL RESIDUALS		Quantities Released		Remarks
Reference Energy System Annual Levels			Per 10 ¹² Btu Energy Produced	
English Units	Metric Units			
<u>Air Pollutants</u>				
Sulfur dioxide	22.8 × 10 ³ tons	20.6 × 10 ³ tonnes	1.44 × 10 ³ tons	
Oxides of nitrogen	5.78 × 10 ³ tons	5.25 × 10 ³ tonnes	366 tons	
Particulates	2.18 × 10 ³ tons	1.98 × 10 ³ tonnes	138 tons	
Hydrocarbons	240 tons	220 tonnes	15 tons	
Carbon monoxide	880 tons	800 tonnes	56 tons	
<u>Water Pollutants</u>				
Same values as conventional power station of equivalent capacity				
<u>Solid Wastes</u>	676 × 10 ³ tons	614 × 10 ³ tonnes	42.8 × 10 ³ tons	
<u>Thermal Discharge</u>	25.4 × 10 ¹² Btu	26.8 × 10 ¹⁵ J	1.6 × 10 ¹² Btu	Cooling towers and stacks
		Not Determined		

PRODUCTS

	Quantities Produced			Remarks
	Reference Energy System Annual Production		Per 10 ¹² Btu Energy Produced	
	English Units	Metric Units		
<u>Primary</u>				
Electricity	4.63 × 10 ⁹ kWh	4.63 × 10 ⁹ kWh	0.293 × 10 ⁹ kWh	
<u>Byproducts</u>				
		Not Determined		
<u>Recoverables/Recyclables</u>				
		Not Determined		

OCCUPATIONAL SAFETY AND HEALTH

Not Determined

ATMOSPHERIC FLUIDIZED BED COMBUSTION — WESTERN SUBBITUMINOUS COAL

REFERENCE ENERGY SYSTEM

Steam electric power generation facility utilizing a fluidized bed combustion system in which the small pieces of coal are suspended along with similarly sized bed material in a continuously moving mass of air. The bed material referred to as a sorbent and composed of crushed limestone or dolomite is responsible for the capture of a portion of the sulfur dioxide generated during combustion. Other environmental control systems include a baghouse filter with greater than 98% efficiency and conventional water treatment facilities as necessary. The lower combustion temperatures of the system also serve to minimize nitrogen oxide formation.

FACILITY OPERATING PARAMETERS

Size:	536 MWe
Annual Capacity Factor:	95%
Annual Energy Production:	15.2×10^{12} Btu
Efficiency:	34.4%
Lifetime:	20 yr

RESOURCES USED

	Quantities Used			Remarks
	Reference Energy System Annual Usage		Per 10 ¹² Btu Energy Produced	
	English Units	Metric Units		
<u>Feed Materials</u>				
Coal (subbituminous western)	2.75 × 10 ⁶ tons	2.50 × 10 ⁶ tonnes	181 × 10 ³ tons	8.05 × 10 ³ Btu/lb
<u>Processing Materials</u>				
Limestone (sorbent bed material)	194 × 10 ³ tons	177 × 10 ³ tonnes	12.8 × 10 ³ tons	
<u>Water</u>				
Consumptive uses	8.86 × 10 ³ acre-ft	10.9 × 10 ⁹ l	583 acre-ft	
	Total Usage			
<u>Construction Materials</u>				
	Not Determined			
<u>Land</u>	442 acres	179 ha	29.1 acres	
<u>Personnel</u>	Approximately same as conventional power station of equivalent capacity			

COSTS

	Reference Energy System	Per 10^{12} Btu Energy Produced	Remarks
<u>Facility</u>		(1981 \$)	
Construction	$\$381 \times 10^6$ total	$\$25.1 \times 10^6$ total	Reference year for costs (facility only) is 1977. 1977 CCI average (I_R) = 2577. See Explanatory Notes Section.
Operation and maintenance	$\$7.42 \times 10^6$ /yr	$\$0.488 \times 10^6$ /yr	
<u>Environmental Controls</u>			
Capital	$\$49.6 \times 10^6$ total	$\$3.3 \times 10^6$ total	

ATMOSPHERIC FLUIDIZED BED COMBUSTION — WESTERN SUBBITUMINOUS COAL

ENVIRONMENTAL RESIDUALS

ENVIRONMENTAL RESIDUALS

	Quantities Released			Remarks
	Reference Energy System Annual Levels		Per 10 ¹² Btu Energy Produced	
	English Units	Metric Units		
<u>Air Pollutants</u>				
Sulfur dioxide	26 × 10 ³ tons	23 × 10 ³ tonnes	1.7 × 10 ³ tons	
Oxides of nitrogen	8.85 × 10 ³ tons	8.03 × 10 ³ tonnes	582 tons	
Particulates	2.22 × 10 ³ tons	2.01 × 10 ³ tonnes	146 tons	
Hydrocarbons	Approximately same values as conventional power			
Carbon monoxide	station of equivalent capacity			
<u>Water Pollutants</u>				
Approximately same values as conventional power station of equivalent capacity				
<u>Solid Wastes</u>				
Dry weight	384 × 10 ³ tons	349 × 10 ³ tonnes	25.3 × 10 ³ tons	
<u>Thermal Discharge</u>		Not Determined		

PRODUCTS

	Quantities Produced			Remarks
	Reference Energy System Annual Production		Per 10 ¹² Btu Energy Produced	
	English Units	Metric Units		
<u>Primary</u>				
Electricity	4.45 × 10 ⁹ kWh	4.45 × 10 ⁹ kWh	0.293 × 10 ⁹ kWh	
<u>Byproducts</u>		Not Determined		
<u>Recoverables/Recyclables</u>		Not Determined		

OCCUPATIONAL SAFETY AND HEALTH

Not Determined

COAL-OIL MIXTURE RETROFIT BOILER

REFERENCE ENERGY SYSTEM

The system is comprised of a conventional oil burning steam electric generating plant that has been modified to accept a 40/60 mixture (by weight) of coal and oil as a fuel source. The conversion will involve modification of fuel handling and storage facilities, soot blowing systems, and environmental control systems for air emissions.

FACILITY OPERATING PARAMETERS

Size:	300 MWe
Annual Capacity Factor:	55%
Annual Energy Production:	5.23×10^{12} Btu
Efficiency:	35%
Lifetime:	Not determined

RESOURCES USED

	Reference Energy System Annual Usage		Per 10 ¹² Btu Energy Produced	Remarks
	English Units	Metric Units		
<u>Feed Materials</u>				
Coal-oil mixture	2.4 × 10 ⁶ bbl	380 × 10 ⁶ l	0.46 × 10 ⁶ bbl	16.504 × 10 ³ Btu/lb, 9.2 lb/gal
<u>Energy</u>				
Sulfur oxide scrubber operation	200 × 10 ⁹ Btu	211 × 10 ¹² J	38.2 × 10 ⁹ Btu	
Electrostatic precipitator	15 × 10 ⁹ Btu	16 × 10 ¹² J	2.9 × 10 ⁹ Btu	
Nitrogen oxide control	30 × 10 ⁹ Btu	32 × 10 ¹² J	5.7 × 10 ⁹ Btu	
<u>Processing Materials</u>				
	Not Determined			
<u>Water</u>				
Consumptive uses	1.36 × 10 ³ acre-ft	1.67 × 10 ⁹ l	260 acre-ft	
	Total Usage			
<u>Construction Materials</u>				
	Not Determined			
<u>Land</u>				
	See coal-oil mixture preparation plant			Requirements are site specific
<u>Personnel</u>				
Construction	60-150 workers		11.5-28.7 workers	
Operation and maintenance	81.0 workers		15.5 workers	

COSTS

	<u>Reference Energy System</u>	<u>Per 10¹² Btu Energy Produced</u>	<u>Remarks</u>
<u>Facility</u>			
		(1981 \$)	
Construction	$\$0.37 \times 10^6$ total	$\$0.072 \times 10^6$ total	Reference year for costs (facility only) is 1980. 1980 CCI average (I_R) = 3237. See Explanatory Notes Section.
Operation and maintenance	$\$4.91 \times 10^6$ /yr	$\$0.939 \times 10^6$ /yr	
<u>Environmental Controls</u>			
ESP/baghouse	$\$13.7 \times 10^6$ total	$\$2.6 \times 10^6$ total	
Operation and maintenance	$\$0.35 \times 10^6$ /yr	$\$0.074 \times 10^6$ /yr	

COAL-OIL MIXTURE RETROFIT BOILER

ENVIRONMENTAL RESIDUALS

	Quantities Released			Remarks
	Reference Energy System Annual Levels		Per 10 ¹² Btu Energy Produced	
	English Units	Metric Units		
<u>Air Pollutants</u>				
Sulfur oxides	6.78 × 10 ³ tons	6.16 × 10 ³ tonnes	1.297 × 10 ³ tons	1.297 × 10 ³ tons*
Nitrogen oxides	3.39 × 10 ³ tons	3.08 × 10 ³ tonnes	648 tons	648 tons*
Particulates	753 tons	684 tonnes	144 tons	144 tons*
Carbon monoxide	210 tons	190 tonnes	40 tons	
Hydrocarbons	94 tons	85 tonnes	18 tons	
<u>Water Pollutants</u>				
	No direct discharge			
<u>Solid Wastes</u>				
Fly ash	14 × 10 ³ tons	13 × 10 ³ tonnes	2.7 × 10 ³ tons	Assumes 10% ash in coal
Bottom ash	4 × 10 ³ tons	3 × 10 ³ tonnes	0.7 × 10 ³ tons	
<u>Thermal Discharge</u>				
Heat loss to air	14 × 10 ¹² Btu	15 × 10 ¹⁵ J	1.2 × 10 ¹² Btu	
<u>Noise</u>				
		46 dBA		
*Regulatory compliance level.				

*Regulatory compliance level.

PRODUCTS

	Quantities Produced			Remarks
	Reference Energy System Annual Production		Per 10 ¹² Btu Energy Produced	
	English Units	Metric Units		
<u>Primary</u>				
Electricity (300 MWe)	1.53 × 10 ⁹ kWh	1.53 × 10 ⁹ kWh	0.293 × 10 ⁹ kWh	
<u>Byproducts</u>				
		Not Determined		
<u>Recoverables/Recyclables</u>				
		Not Determined		

OCCUPATIONAL SAFETY AND HEALTH

Not Determined

MAGNETOHYDRODYNAMIC SYSTEM

REFERENCE ENERGY SYSTEM

Seed material (potassium) is mixed with a finely ground coal, ionized at a high temperature, and passed through a magnetic field to generate electricity. System components include a pulverized coal burner (2-stage combustor), magnetohydrodynamic generators, a seed recovery system, and steam bottoming cycle.

FACILITY OPERATING PARAMETERS

Size:	1.932×10^3 MWe
Annual Capacity Factor:	65% (load factor)
Annual Energy Production:	37.5×10^{12} Btu (11×10^6 MWe)
Efficiency:	49.8%
Lifetime:	Not determined

RESOURCES USED

	Quantities Used			Remarks
	Reference Energy System Annual Usage		Per 10 ¹² Btu Energy Produced	
	English Units	Metric Units		
<u>Feed Materials</u>				
Coal (bituminous)	3.60 × 10 ⁶ tons	3.26 × 10 ⁶ tonnes	95.9 × 10 ³ tons	Illinois No. 6
<u>Energy</u>				
Potassium seed material		Not Determined		Information not available
<u>Water</u>				
Consumptive use	11.5 × 10 ³ acre-ft	14.2 × 10 ⁹ l	306 acre-ft	
	Total Usage			
<u>Construction Materials</u>				
		Not Determined		
<u>Land</u>				
	1.77 × 10 ³ acres	718 ha	47.3 acres	
<u>Personnel</u>				
Construction		Not Determined		
Operation and maintenance				

COSTS

	Reference Energy System	Per 10 ¹² Btu Energy Produced	Remarks
<u>Facility</u>			
		(1981 \$)	Reference year for costs is 1975. 1975 CCI average (I _{RI}) = 2212. See Explanatory Notes Section.
Construction	\$2.24 × 10 ⁹ total	\$59.1 × 10 ⁶ total	
Operation and maintenance	\$60.0 × 10 ⁶ /yr	\$1.60 × 10 ⁶ /yr	
<u>Environmental Controls</u>			
		Not Determined	

MAGNETOHYDRODYNAMIC SYSTEM

ENVIRONMENTAL RESIDUALS

	Quantities Released			Remarks
	Reference Energy System Annual Levels		Per 10 ¹² Btu Energy Produced	
	English Units	Metric Units		
<u>Air Pollutants</u>				
Particulates	1.1 × 10 ³ tons	1.0 × 10 ³ tonnes	30 tons	
Sulfur dioxide	18.8 × 10 ³ tons	17.0 × 10 ³ tonnes	500 tons	
Oxides of nitrogen	11.2 × 10 ³ tons	10.2 × 10 ³ tonnes	300 tons	
<u>Water Pollutants</u>				
Blowdown from cooling and steam system—similar to emission from an electric power station				
<u>Solid Wastes</u>				
Furnace wastes	285 × 10 ³ tons	259 × 10 ³ tonnes	7.60 × 10 ³ tons	
Fly ash	50.2 × 10 ³ tons	45.6 × 10 ³ tonnes	1.34 × 10 ³ tons	
<u>Thermal Discharge</u>				
		Not Determined		
<u>Noise Pollution</u>				
		Not Determined		

PRODUCTS

	Quantities Produced			Remarks
	Reference Energy System Annual Production		Per 10 ¹² Btu Energy Produced	
	English Units	Metric Units		
<u>Primary</u>				
Electrical energy	11.0 × 10 ⁹ kWh	11.0 × 10 ⁹ kWh	0.293 × 10 ⁹ kWh	
<u>Byproducts</u>				
Sulfur	116 × 10 ³ tons	106 × 10 ³ tonnes	3.10 × 10 ³ tons	

OCCUPATIONAL SAFETY AND HEALTH

Not Determined

COAL-FIRED POWER PLANT — EASTERN COAL

REFERENCE ENERGY SYSTEM

The system is composed of a mine-mouth conventional steam electric power plant using typical eastern bituminous coal with no cogeneration. Environmental control systems include an electrostatic precipitator for particulate control and onsite solid waste disposal. An onsite water and recirculation facility is used to minimize liquid discharges from the plant. The plant is assumed to be subject to the current regulations governing such facilities.

FACILITY OPERATING PARAMETERS

Size:	500 MWe
Annual Capacity Factor:	80%
Annual Energy Production:	12×10^{12} Btu
Efficiency:	35%
Lifetime:	30 yr

RESOURCES USED

	Quantities Used		Per 10 ¹² Btu Energy Produced	Remarks
	Reference Energy System Annual Usage			
	English Units	Metric Units		
<u>Feed Materials</u>				
Run-of-mine coal	1.96 × 10 ⁶ tons	1.77 × 10 ⁶ tonnes	0.16 × 10 ⁶ tons	
<u>Processing Materials</u>				
Limestone to sulfur dioxide scrubber	146 × 10 ³ tons	132 × 10 ³ tonnes	12.2 × 10 ³ tons	
<u>Water</u>				
Coal preparation — consumption	58-138 acre-ft	71 × 10 ⁶ – 170 × 10 ⁶ l	4.8-11.5 acre-ft	
Power plant make-up — consumption	8.3 × 10 ³ acre-ft	10 × 10 ⁹ l	0.69 × 10 ³ acre-ft	
<hr/> Total Usage <hr/>				
<u>Construction Materials</u>				
Concrete	75.6 × 10 ³ tons	68.7 × 10 ³ tonnes	5.72 × 10 ³ tons	
Carbon steel	20.6 × 10 ³ tons	18.7 × 10 ³ tonnes	1.56 × 10 ³ tons	
Alloy steel	1.13 × 10 ³ tons	1.0 × 10 ³ tonnes	92 tons	
Stainless steel	368 tons	334 tonnes	27.8 tons	
Copper	627 tons	570 tonnes	48 tons	
Aluminum	191 tons	174 tonnes	14.5 tons	
Manganese	162 tons	147 tonnes	12.2 tons	
Chromium	97 tons	88 tonnes	7.3 tons	
Nickel	15 tons	14 tonnes	1.2 tons	
Cast iron	287 tons	261 tonnes	21.8 tons	
<u>Land</u>				
Coal preparation and associated solid waste disposal	480 acres	194 ha	40 acres	
Power plant and associated solid waste disposal (ash and scrubber sludge)	369 acres	149 ha	30.8 acres	
<u>Personnel</u>				
Construction (5 yr)		1500 workers	125 workers	
Operation and maintenance		160 workers	13.0 workers	

COSTS

	Reference Energy System	Per 10 ¹² Btu Energy Produced	Remarks
<u>Facility</u>	(January 1981\$)		
Construction (5 yr)	\$498 × 10 ⁶ total	\$41.5 × 10 ⁶ total	Exclusive of fuel costs
Operation and maintenance	\$19.6 × 10 ⁶ /yr	\$1.6 × 10 ⁶ /yr	
<u>Environmental Controls*</u>			
Construction	\$136 × 10 ⁶ total	\$11.3 × 10 ⁶ total	Included in Facility Costs, above
Operation and maintenance	\$17.0 × 10 ⁶ /yr	\$1.4 × 10 ⁶ /yr	

*Includes baghouse, scrubbers, NO_x control, H₂O treatment, noise control, and solids handling.

COAL-FIRED POWER PLANT – EASTERN COAL

ENVIRONMENTAL RESIDUALS

ENVIRONMENTAL RESIDUALS			Quantities Released		
			Reference Energy System Annual Levels		
			English Units	Metric Units	Per 10 ¹² Btu Energy Produced
					Remarks
<u>Air Pollutants</u>					
Sulfur dioxide	10.2 × 10 ³ tons	9.26 × 10 ³ tonnes	850 tons	0.6 lb/10 ⁶ Btu*	
Oxides of nitrogen	10.2 × 10 ³ tons	9.26 × 10 ³ tonnes	850 tons	0.6 lb/10 ⁶ Btu*	
Total suspended particulates	500 tons	460 tonnes	42 tons	0.03 lb/10 ⁶ Btu*	
Nonmethane hydrocarbons	220 tons	200 tonnes	18 tons		
Carbon monoxide	720 tons	655 tonnes	60 tons		
Carbon dioxide	3.7 × 10 ⁶ tons	3.4 × 10 ⁶ tonnes	0.3 × 10 ⁶ tons		
Arsenic	225 lb	102 kg	18.8 lb		
Beryllium	9.3 lb	4.2 kg	0.8 lb		
Cadmium	4.1 lb	1.9 kg	0.4 lb		
Manganese	161 lb	74 kg	13.4 lb		
Lead	114 lb	52 kg	9.5 lb		
Selenium	56 lb	25 kg	4.7 lb		
Radium	3.0 × 10 ⁻³ Ci	3.0 × 10 ⁻³ Ci	0.25 × 10 ⁻³ Ci		
<u>Water Pollutants</u>					
Excess water discharge characteristics (estimated max.)					
• Total suspended solids	Metric units	30 mg/l	Depends on	30 mg/l**	
• Oil and grease	are	15.2 mg/l	flow,	1 mg/l**	
• Copper	universally used	0.009 mg/l	which	1 mg/l**	
• Iron		0.009 mg/l	varies		
• Chlorine		30.1 mg/l			
<u>Solid Wastes</u>					
Waste from coal preparation	0.5 × 10 ⁶ tons	0.4 × 10 ⁶ tonnes	0.04 × 10 ⁶ tons		
Bottom ash from boiler (dry)	25 × 10 ³ tons	23 × 10 ³ tonnes	2.1 × 10 ³ tons		
Collected fly ash (dry)	100 × 10 ³ tons	90 × 10 ³ tonnes	8.3 × 10 ³ tons		
Limestone scrubber sludge (dry)	193 × 10 ³ tons	175 × 10 ³ tonnes	16 × 10 ³ tons		
<u>Thermal Discharge</u>					
Heat loss to air	3.6 × 10 ¹² Btu	3.8 × 10 ¹⁵ J	0.3 × 10 ¹² Btu	Heating flue gas	
*NSPS regulatory compliance level for 3.3 percent sulfur coal with heating value at 12,000 Btu/lb.					
**State of Kentucky standards.					

*NSPS regulatory compliance level for 3.3 percent sulfur coal with heating value at 12,000 Btu/lb.

**State of Kentucky standards.

PRODUCTS

PRODUCTS	Quantities Produced			Remarks
	Reference Energy System Annual Production		Per 10 ¹² Btu Energy Produced	
	English Units	Metric Units		
<u>Primary</u>				
Electric power	12 × 10 ¹² Btu	13 × 10 ¹⁵ J	1.0 × 10 ¹² Btu	
<u>Recoverables/Recyclables</u>				
Water to recycle	89.0 acre-ft	110 × 10 ⁶ l	7.42 acre-ft	

OCCUPATIONAL SAFETY AND HEALTH

	Reference Energy System Annual	Per 10 ¹² Btu Energy Produced	Remarks
<u>Deaths</u>			
Preparation plant	0.004-0.005	0.3 × 10 ⁻³ -0.4 × 10 ⁻³	
Power plant	0-0.11	0-9.5 × 10 ⁻³	
<u>Injuries</u>			
Preparation plant	1.9-3.1	0.16-0.26	
Power plant	1.9-2.3	0.16-0.19	

COAL-FIRED POWER PLANT — WESTERN COAL

REFERENCE ENERGY SYSTEM

The system is composed of a conventional steam electric power plant using typical western low-sulfur subbituminous coal supplied by a unit train operation. No cogeneration is included. Environmental control systems include electrostatic precipitators for particulate control, wet lime/limestone scrubbers for sulfur dioxide control, onsite solid waste disposal, and onsite water treatment for water recirculation to eliminate liquid discharges. The plant is assumed to be subject to current regulations.

FACILITY OPERATING PARAMETERS

Size:	500 MWe
Annual Capacity Factor:	80%
Annual Energy Production:	12×10^{12} Btu
Efficiency:	35%
Lifetime:	30 yr

RESOURCES USED

	Quantities Used			
	Reference Energy System Annual Usage		Per 10 ¹² Btu Energy Produced	Remarks
	English Units	Metric Units		
Feed Materials				
Run-of-mine subbituminous coal	2.11 × 10 ⁶ tons	1.92 × 10 ⁶ tonnes	0.18 × 10 ⁶ tons	Low-sulfur coal (0.63% sulfur)
Processing Materials				
Limestone to sulfur dioxide scrubber	32 × 10 ³ tons	29 × 10 ³ tonnes	2.7 × 10 ³ tons	
Fly ash (sludge fixing)	34 × 10 ³ tons	30.8 × 10 ³ tonnes	2.9 × 10 ³ tons	
Water				
Dust control and SO ₂ control make-up	445 acre-ft	0.55 × 10 ⁹ l	37 acre-ft	Quality not critical
Cooling tower make-up water	4.9 × 10 ³ acre-ft	6.1 × 10 ⁹ l	409 acre-ft	Wet cooling only
Total Usage				
Construction Materials				
Concrete	87.5 × 10 ³ tons	79.5 × 10 ³ tonnes	7.29 × 10 ³ tons	
Carbon steel	26.1 × 10 ³ tons	23.7 × 10 ³ tonnes	2.18 × 10 ³ tons	
Alloy steel	1.39 × 10 ³ tons	1.26 × 10 ³ tonnes	116 tons	
Stainless steel	465 tons	423 tonnes	38.8 tons	
Copper	736 tons	669 tonnes	61.3 tons	
Aluminum	231 tons	210 tonnes	19.2 tons	
Manganese	204 tons	185 tonnes	17.0 tons	
Chromium	121 tons	110 tonnes	10.1 tons	
Nickel	18.8 tons	17.1 tonnes	1.6 tons	
Cast iron	341 tons	310 tonnes	28.5 tons	
Land				
Power plant and solid waste disposal (ash and sludge)	5.2 acres	2.1 ha	0.4 acre	Sufficient land needed for a 30-yr lifetime
Personnel				
Construction	Not Determined			
Operation and maintenance				
• Power plant		135 workers	1.7 workers	

COSTS

	Reference Energy System	Per 10 ¹² Btu Energy Produced	Remarks
<u>Facility</u>	(January 1981 \$)		
Construction (5 yr)	\$487 × 10 ⁶ total	\$40.6 × 10 ⁶ total	Exclusive of fuel costs
Operation and maintenance	\$5.4 × 10 ⁶ /yr	\$0.45 × 10 ⁶ /yr	
<u>Environmental Controls*</u>			
Construction	\$115 × 10 ⁶ total	\$9.6 × 10 ⁶ total	Included in Facility Costs, above
Operation and maintenance	\$2.8 × 10 ⁶ /yr	\$0.23 × 10 ⁶ /yr	

*Includes baghouse, scrubbers, NO_x control, H₂O treatment, noise control, and solids handling.

COAL-FIRED POWER PLANT — WESTERN COAL

ENVIRONMENTAL RESIDUALS

	Quantities Released			
	Reference Energy System Annual Levels		Per 10 ¹² Btu Energy Produced	Remarks
	English Units	Metric Units		
<u>Air Pollutants</u>				
Fugitive coal dust (unit train operation)	5.2 × 10 ³ tons	4.7 × 10 ³ tonnes	0.43 × 10 ³ tons	
Sulfur dioxide	7.15 × 10 ³ tons	6.49 × 10 ³ tonnes	0.60 × 10 ³ tons	{<0.6 lb/10 ⁶ Btu* 0.50 lb/10 ⁶ Btu* 0.03 lb/10 ⁶ Btu*
Oxides of nitrogen	10.2 × 10 ³ tons	9.26 × 10 ³ tonnes	0.85 × 10 ³ tons	
Total suspended particulates	0.525 × 10 ³ tons	0.48 × 10 ³ tonnes	0.04 × 10 ³ tons	
Nonmethane hydrocarbons	0.32 × 10 ³ tons	0.29 × 10 ³ tonnes	0.03 × 10 ³ tons	
Carbon monoxide	1.05 × 10 ³ tons	0.95 × 10 ³ tonnes	0.09 × 10 ³ tons	
Carbon dioxide	3.7 × 10 ⁶ tons	3.4 × 10 ⁶ tonnes	0.31 × 10 ⁶ tons	
Arsenic	128 lb	58.1 kg	10.7 lb	
Beryllium		Not Determined		
Cadmium	11.7 lb	5.3 kg	0.98 lb	
Manganese	0.6 lb	0.3 kg	0.05 lb	
Lead	32.1 lb	14.6 kg	2.68 lb	
Selenium	2.0 lb	0.9 kg	0.17 lb	
Uranium	718 lb	326 kg	59.8 lb	
Zinc	286 lb	130 kg	23.8 lb	
Radium-226	1.4 × 10 ⁻³ Ci	1.4 × 10 ⁻³ Ci	0.12 × 10 ⁻³ Ci	
<u>Solid Wastes</u>				
Coal preparation (at mine)	210 × 10 ³ tons	190 × 10 ³ tonnes	17.5 × 10 ³ tons	
Boiler bottom ash (dry)	34 × 10 ³ tons	31 × 10 ³ tonnes	2.8 × 10 ³ tons	
Boiler fly ash (dry)	101 × 10 ³ tons	91.7 × 10 ³ tonnes	8.4 × 10 ³ tons	
Sulfur dioxide scrubber sludge (dry)	43 × 10 ³ tons	39 × 10 ³ tonnes	3.6 × 10 ³ tons	
Total solid waste to onsite disposal	177 × 10 ³ tons	161 × 10 ³ tonnes	14.8 × 10 ³ tons	
<u>Thermal Discharge</u>				
	21.0 × 10 ¹² Btu	22.1 × 10 ¹⁵ J	1.7 × 10 ¹² Btu	Cooling towers and stacks
*NSPS regulatory compliance level (70% reduction) for 0.63 percent sulfur coal with heating value of coal at 8100 Btu/lb.				

*NSPS regulatory compliance level (70% reduction) for 0.63 percent sulfur coal with heating value of coal at 8100 Btu/lb.

PRODUCTS

	Quantities Produced			Remarks
	Reference Energy System Annual Production		Per 10 ¹² Btu Energy Produced	
	English Units	Metric Units		
<u>Primary</u>				
Electricity	12 × 10 ¹² Btu	13 × 10 ¹⁵ J	1.0 × 10 ¹² Btu	
<u>Byproducts</u>				
Fly ash (for sale)	34 × 10 ³ tons	31 × 10 ³ tonnes	2.9 × 10 ³ tons	
<u>Recoverables/Recyclables</u>				
Water to recycle	196 × 10 ⁶ gal	742 × 10 ⁶ l	16.3 × 10 ⁶ gal	Zero-discharge design

OCCUPATIONAL SAFETY AND HEALTH

	Reference Energy System Annual	Per 10 ¹² Btu Energy Produced	Remarks
<u>Deaths</u>			
Power plant	0-0.11	0-9.5 × 10 ⁻³	
<u>Injuries</u>			
Power plant	1.9-2.3	0.16-0.19	

HIGH-VOLTAGE TRANSMISSION

REFERENCE ENERGY SYSTEM

A 345-kV alternating current (a.c.) line, 500 mi long with a right-of-way (ROW) width of 150 ft (18 acres/mi) serving 600-MWe power plant capacity. Typical components include (not exhaustive) stranded aluminum conductors, ground wires, conductor towers and insulators, and land for system ROW. Reference system is a single circuit with three conductors.

FACILITY OPERATING PARAMETERS

Size:	345-kV a.c. line (serving 600-MWe power capacity)
Annual Capacity:	65%
Annual Energy Production:	9.6×10^{12} Btu (2.8×10^9 kWh) (electricity transmitted)
Efficiency:	82%
Lifetime:	Not determined

RESOURCES USED

	Quantities Used		Per 10 ¹² Btu Energy Produced	Remarks
	Reference Energy System Annual Usage			
	English Units	Metric Units		
<u>Feed Materials</u>				
Electricity transmitted	3.4 × 10 ⁹ kWh	3.4 × 10 ⁹ kWh	0.354 × 10 ⁹ kWh	Total electrical input to line to generate output at 82% efficiency
<u>Total Usage</u>				
<u>Construction Materials</u>				
Concrete	27.0 × 10 ³ tons	24.5 × 10 ³ tonnes	2.81 × 10 ³ tons	The listing pertains to typical materials used and is not exhaustive
Steel	24.2 × 10 ³ tons	22.0 × 10 ³ tonnes	2.52 × 10 ³ tons	
Copper	873 tons	792 tonnes	90.9 tons	
Aluminum	4.52 × 10 ³ tons	3.92 × 10 ³ tonnes	450 tons	
Manganese	169 tons	153 tonnes	17.6 tons	
Chromium	17.8 tons	16.2 tonnes	1.86 tons	
Nickel	220 × 10 ⁻³ ton	200 × 10 ⁻³ tonne	22.9 × 10 ⁻³ ton	
Cast iron	99.8 tons	90.6 tonnes	10.4 tons	
<u>Land</u>				
Right-of-way	4.30 × 10 ³ acres	1.74 × 10 ³ ha	447 acres	May be used simultaneously for other purposes
<u>Personnel</u>				
Construction (2 yr)	1.6 × 10 ³ workers		170 workers	No personnel required for system operation
Operation and maintenance	7.2 workers		0.75 worker	

COSTS

	<u>Reference Energy System</u>	<u>Per 10¹² Btu Energy Produced</u>	<u>Remarks</u>
<u>Facility</u>			
	(1981 \$)		Reference year for costs is 1978. 1978 CCI average (I ₉) = 2776. See Explanatory Notes Section.
Construction (2 yr)	\$196 × 10 ⁶ total	\$20.5 × 10 ⁶ total	
Operation and maintenance	\$0.270 × 10 ⁶ /yr	\$0.028 × 10 ⁶ /yr	
<u>Environmental Controls</u>			
	Not Determined		Operating manpower is reported as zero

HIGH-VOLTAGE TRANSMISSION

ENVIRONMENTAL RESIDUALS

	Quantities Released		Per 10 ¹² Btu Energy Produced	Remarks
	Reference Energy System Annual Levels			
	English Units	Metric Units		
<u>Air Pollutants</u>				
Chemical oxidants, such as ozone, may be generated by the corona				
<u>Noise Pollution</u>				
Noise generated by the corona will not be loud enough to cause hearing damage				
<u>Electromagnetic Fields</u>				
Electric and magnetic fields from 345-kV lines may interfere with a few of the most sensitive cardiac pacemakers. Single circuit, 345-kV lines have maximum field strengths of 4.5 to 8 kV/m at 3 ft above the ground. For field strengths of 6 kV/m or more, annoying transient spark discharges may occur in some circumstances. Current research data indicate that subtle biological effects are occurring to laboratory animals at field strengths approaching 12 kV/m (referred to man).				

PRODUCTS

PRODUCTS	Quantities Produced			Remarks
	Reference Energy System Annual Production		Per 10 ¹² Btu Energy Produced	
	English Units	Metric Units		
<u>Primary</u>				
Electricity transmitted (net)	2.81 × 10 ⁹ kWh	2.81 × 10 ⁹ kWh	0.293 × 10 ⁹ kWh	

OCCUPATIONAL SAFETY AND HEALTH

Not Determined

VERY HIGH VOLTAGE TRANSMISSION

REFERENCE ENERGY SYSTEM

A 500-kV alternating current (a.c.) line, 500 mi long with a right-of-way (ROW) width of 175 ft (21 acres/mi) serving 1200-MW power plant capacity. Typical components include (not exhaustive) stranded aluminum conductors, steel ground wires, conductor towers, and insulators. Reference system is single circuit with three conductors.

FACILITY OPERATING PARAMETERS

Size:	500-kV a.c. line (serving 1200-MWe power capacity)
Annual Capacity Factor:	65%
Annual Energy Production:	20.8×10^{12} Btu (6.1×10^9 kWh) (electricity transmitted)
Efficiency:	89%
Lifetime:	Not determined

RESOURCES USED

	Quantities Used		Per 10 ¹² Btu Energy Produced	Remarks
	Reference Energy System Annual Usage			
	English Units	Metric Units		
<u>Feed Materials</u>				
Electricity transmitted	6.84 × 10 ⁹ kWh	6.84 × 10 ⁹ kWh	0.329 × 10 ⁹ kWh	0.329 × 10 ⁹ kWh input to line required to generate 10 ¹² Btu output at 89% efficiency
<hr/> Total Usage <hr/>				
<u>Construction Materials</u>				
Concrete (including cement)	38.1 × 10 ³ tons	34.6 × 10 ³ tonnes	1.832 × 10 ³ tons	
Steel	35.1 × 10 ³ tons	31.8 × 10 ³ tonnes	1.687 × 10 ³ tons	
Copper	2.64 × 10 ³ tons	2.40 × 10 ³ tonnes	127 tons	
Aluminum	11.1 × 10 ³ tons	10.1 × 10 ³ tonnes	534 tons	
Manganese	229 tons	208 tonnes	11 tons	
Chromium	62 tons	57 tonnes	3 tons	
Nickel	2.1 tons	1.9 tonnes	0.1 ton	
Cast iron	125 tons	113 tonnes	6 tons	
<u>Land</u>				
Right-of-way	10.6 × 10 ³ acres	4.30 × 10 ³ ha	509.9 acres	May be used simultaneously for other purposes
<u>Personnel</u>				
Construction (2 yr)	2.28 × 10 ³ workers		109.8 workers	
Operation and maintenance	12.5 workers		0.6 worker	No personnel required for system operation

COSTS

	Reference Energy System	Per 10 ¹² Btu Energy Produced	Remarks
<u>Facility</u>			
		(1981 \$)	Reference year for costs is 1978. 1978 CCI average (I ₉₁) = 2776. See Explanatory Notes Section.
Construction (2 yr)	\$304 × 10 ⁶ total	\$14.6 × 10 ⁶ total	
Operation and maintenance	\$0.476 × 10 ⁶ /yr	\$0.023 × 10 ⁶ /yr	
<u>Environmental Controls</u>			
	Not Determined		

VERY HIGH VOLTAGE TRANSMISSION

ENVIRONMENTAL RESIDUALS

	Quantities Released			Remarks		
	Reference Energy System Annual Levels		Per 10 ¹² Btu Energy Produced			
	English Units	Metric Units				
<u>Air Pollutants</u>						
Chemical oxidants, such as ozone, may be generated by the corona						
<u>Noise Pollution</u>						
Noise generated by the corona will not be loud enough to cause hearing damage						
<u>Electromagnetic Fields</u>						
Electric and magnetic fields from 500-kV lines will probably interfere with some cardiac pacemakers. Single-circuit, 500-kV lines have maximum field strengths of 6 to 7 kV/m at 3 ft above the ground. This is strong enough to result in annoying transient spark discharges under some circumstances. Current research data indicate that subtle biological effects are occurring to laboratory animals at field strengths approaching 12 V/m (referred to man).						

PRODUCTS

	Quantities Produced			Remarks
	Reference Energy System Annual Production		Per 10 ¹² Btu Energy Produced	
	English Units	Metric Units		
<u>Primary</u>				
Electricity transmitted (net)	6.09 × 10 ⁹ kWh	6.09 × 10 ⁹ kWh	0.293 × 10 ⁹ kWh	

OCCUPATIONAL SAFETY AND HEALTH

Not Determined

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PETROLEUM TECHNOLOGIES

The following should be recognized as limitations of the information provided on the summary sheets of this section:

1. The impacts and costs of oil and gas operations vary widely over the period of development. Typically, capital costs will be concentrated in the initial phases of development, and operation and maintenance costs and impacts will be spread over a longer period of time. Annualizing costs and impacts over the life cycle of a project ignores the actual pattern in which they occur.
2. The figures presented in the data sheets apply to specific representative cases. The variation around these cases may be quite extensive. Some costs, such as platforms, will vary geometrically rather than arithmetically. Thus, an 18-well platform in 400 feet of water will be much more than twice as expensive than one in 200 feet of water. Unless production per platform changes in exactly the same proportion, the numbers provided in the data sheets may be unrealistic.
3. The data sheets also do not consider changes in the underlying conditions determining the economic limit for oil and gas development. The rapid escalation of crude oil prices and changes in price/cost relationships will bring formerly uneconomic projects into production. These projects will generally have unit cost characteristics that are very different from the "representative" projects shown on the data sheets. It is likely that for these new projects, the costs per 10^{12} Btu produced will be much higher. The estimates of environmental impact also do not include the fact that many of the new projects will have improved environmental control systems that are not yet defined. For example, new steam Enhanced Oil Recovery projects will be required to have air emission levels that are much lower than the national averages shown on the data sheets.

ONSHORE PRIMARY OIL EXTRACTION — LOWER 48 STATES

REFERENCE ENERGY SYSTEM

400-well production field, 195 unproductive wells (dry holes) are plugged with cement and crimped below ground level. Gathering pipeline routes oil to field processing facility for gas-water-oil separation. Success ratio for exploration wells is 27.4% and for production wells, 67.2%.

FACILITY OPERATING PARAMETERS

Size: 0.1×10^6 bbl/day (250 bbl/well/day)
 Annual Capacity Factor: 100%
 Annual Energy Production: 212×10^{12} Btu
 Efficiency: 30% (oil reservoir recovery)
 Lifetime: 26 yr

RESOURCES USED

	Quantities Used		Per 10 ¹² Btu Energy Produced	Remarks
	Reference Energy System Annual Usage			
	English Units	Metric Units		
<u>Energy</u>				
Electric pumps	1.34 × 10 ¹² Btu	1.41 × 10 ¹⁵ J	6.32 × 10 ⁹ Btu	
Heater treater separators	0.18 × 10 ¹² Btu	0.19 × 10 ¹⁵ J	0.84 × 10 ⁹ Btu	
Diesel fuel for development drilling	1.6 × 10 ¹² Btu	1.7 × 10 ¹⁵ J	7.6 × 10 ⁹ Btu	
<u>Total Usage</u>				
<u>Construction Materials</u>				
Concrete (mixed)	20.0 × 10 ³ tons	18.1 × 10 ³ tonnes	94.3 tons	
Pipe and tubing	72.0 × 10 ³ tons	65.4 × 10 ³ tonnes	339.6 tons	
Reinforcing bars	4.01 × 10 ³ tons	3.64 × 10 ³ tonnes	18.9 tons	
Refined products	700 × 10 ³ tons	635 × 10 ³ tonnes	3.3019 × 10 ³ tons	
Oil country tubular goods	560 × 10 ³ tons	508 × 10 ³ tonnes	2.642 × 10 ³ tons	
Pumps and drivers	3.20 × 10 ³ tons	2.91 × 10 ³ tonnes	15.1 tons	
<u>Water</u>				
Production drilling fluid	10.2 acre-ft*	12.6 × 10 ⁶ l*	0.0482 acre-ft	
<u>Land</u>				
	2.00 × 10 ³ acres	809 ha	9.43 acres	
<u>Personnel</u>				
Construction (7 yr)	2.80 × 10 ³ workers		13.2 workers	
Operation and maintenance	2.0 × 10 ³ workers		9.7 workers	
* Total life cycle values during 7-yr drilling and facility construction period.				

*Total life cycle values during 7-yr drilling and facility construction period.

COSTS

	<u>Reference Energy System</u>	<u>Per 10¹² Btu Energy Produced</u>	<u>Remarks</u>
<u>Facility</u>		(1981 \$)	
Construction (7 yr)	\$3.86 × 10 ⁹ total	\$18.2 × 10 ⁶ total	Reference year for costs is 1978. 1978 CCI average (I _p) = 2776. See Explanatory Notes Section.
Operation and maintenance	\$34.0 × 10 ⁶ /yr	\$0.160 × 10 ⁹ /yr	
<u>Environmental Controls</u>		Not Determined	

ONSHORE PRIMARY OIL EXTRACTION – LOWER 48 STATES

ENVIRONMENTAL RESIDUALS

	Quantities Released			Remarks
	Reference Energy System		Per 10 ¹² Btu Energy Produced	
	Annual Levels			
	English Units	Metric Units		
<u>Air Pollutants</u>				
Oxides of nitrogen	3.94 × 10 ³ tons	3.58 × 10 ³ tonnes	18.6 tons	Air pollutants produced during drilling and production
Carbon monoxide	110 tons	100 tonnes	0.5 ton	
Hydrocarbons	2.25 × 10 ³ tons	2.04 × 10 ³ tonnes	10.6 tons	
Oxides of sulfur	2.88 × 10 ³ tons	2.62 × 10 ³ tonnes	13.6 tons	
Particulates	740 tons	670 tonnes	3.5 tons	
<u>Solid Wastes</u>				
Drilling cuttings, barite, bentonite, and phosphate	200 × 10 ³ tons*	182 × 10 ³ tonnes*	946 tons	
<u>Noise Pollution</u>				
Not Determined				

*Solid wastes are total life cycle values over the 7-yr drilling and facility construction period.

*Solid wastes are total life cycle values over the 7-yr drilling and facility construction period.

PRODUCTS

	Quantities Produced			Remarks
	Reference Energy System Annual Production		Per 10 ¹² Btu Energy Produced	
	English Units	Metric Units		
Primary				
Crude Oil	36.5 × 10 ⁶ bbl	5.81 × 10 ⁹ l	172.4 × 10 ³ bbl	5.8 × 10 ⁶ Btu/bbl

OCCUPATIONAL SAFETY AND HEALTH

	Reference Energy System Annual	Per 10 ¹² Btu Energy Produced	Remarks
<u>Deaths</u>	0.4	0.002	
<u>Injuries</u>	43.0	0.203	
<u>Man-days lost</u>	7.15 × 10 ³	33.745	

ONSHORE ENHANCED OIL RECOVERY—STEAM INJECTION — LOWER 48 STATES

REFERENCE ENERGY SYSTEM

Enhanced oil recovery via continuous injection of steam through special wells. Due to changes in the viscosity and volume (expansion) of oil and possible rock permeability, oil is displaced by water derived from condensed steam. The recovered oil-water-gas mixture is treated in a separation unit. The energy product derived is crude oil with an average heat content of 6.3×10^6 Btu/bbl.

FACILITY OPERATING PARAMETERS

Size: 52.65×10^3 bbl/day of enhanced oil recovery (1382 wells)
Annual Capacity Factor: 70%
Annual Energy Production: 84.7×10^{12} Btu
Efficiency: 10% (of original-oil-in-place)
Lifetime: 15 yr

RESOURCES USED

	Quantities Used		Per 10 ¹² Btu Energy Produced	Remarks
	Reference Energy System Annual Usage			
	English Units	Metric Units		
<u>Feed Materials</u>				
Process steam		Not Determined		Refer to water resources used
<u>Energy</u>		Not Determined		
<u>Processing Materials</u>		Not Determined		
<u>Water</u>				
Process steam	8.64 × 10 ³ acre-ft	10.7 × 10 ⁹ l	102 acre-ft	
	Total Usage			
<u>Construction Materials</u>				
Concrete	127 × 10 ³ tons	115 × 10 ³ tonnes	1.50 × 10 ³ tons	
Total steel	78.0 × 10 ³ tons	70.8 × 10 ³ tonnes	921 tons	
Oil country tubular goods	38.9 × 10 ³ tons	35.4 × 10 ³ tonnes	460 tons	
<u>Land</u>	3.51 × 10 ³ acres	1.42 × 10 ³ ha	41.4 acres	
<u>Personnel</u>				
Construction (2 yr)	280 workers		3.3 workers	
Operation and maintenance	780 workers		9.2 workers	

COSTS

	Reference Energy System	Per 10 ¹² Btu Energy Produced	Remarks
<u>Facility</u>			
		(1981 \$)	
Construction (2 yr)	\$644 × 10 ⁶ total	\$7.60 × 10 ⁶ total	Reference year for costs is 1978. 1978 CCI average (I ₀) = 2776. See Explanatory Notes Section.
Operation and maintenance	\$122 × 10 ⁶ /yr	\$1.44 × 10 ⁶ /yr	
<u>Environmental Controls</u>			
	Not Determined		

ONSHORE ENHANCED OIL RECOVERY—STEAM INJECTION — LOWER 48 STATES

ENVIRONMENTAL RESIDUALS

	Quantities Released			
	Reference Energy System Annual Levels		Per 10 ¹² Btu Energy Produced	Remarks
	English Units	Metric Units		
<u>Air Pollutants</u>				
Particulates	2.0 × 10 ³ tons	1.8 × 10 ³ tonnes	24 tons	15 tons/10 ¹² Btu*
Sulfur dioxide	17.5 × 10 ³ tons	15.9 × 10 ³ tonnes	207 tons	100 tons/10 ¹² Btu*
Oxides of nitrogen	6.0 × 10 ³ tons	5.4 × 10 ³ tonnes	71 tons	500 tons/10 ¹² Btu*
Hydrocarbons	170 tons	150 tonnes	2.0 tons	
Carbon monoxide	350 tons	320 tonnes	4.1 tons	
<u>Water Pollutants</u>				
Hydrocarbons	70-330 tons	60-300 tonnes	0.8-3.9 tons	
<u>Solid Wastes</u>				
Quantities are process and site specific				
<u>Thermal Discharge</u>		Not Determined		
<u>Noise Pollution</u>		Not Determined		

*Regulatory compliance levels.

PRODUCTS

	Quantities Produced			Remarks
	Reference Energy System		Per 10 ¹² Btu Energy Produced	
	Annual Production			
	English Units	Metric Units		
Primary				
Crude oil	34.5 × 10 ⁶ bbl	2.14 × 10 ⁹ l	159 × 10 ³ bbl	Heat content of crude is 6.3 × 10 ⁶ Btu/bbl
<u>Recoverables/Recyclables</u>				
Water		Not Determined		

OCCUPATIONAL SAFETY AND HEALTH

Not Determined

OFFSHORE OIL EXTRACTION — LOWER 48 STATES

REFERENCE ENERGY SYSTEM

The reference energy system is composed of an 18-well offshore platform capable of producing 4×10^3 bbl/day of oil. Wells are drilled to an average depth of 9500 ft. The development well success rate equals $\approx 76\%$. 18 months would be required to complete drilling, but production could be started before that date. Direction drilling techniques are used from the platform. Six dry holes (including three during exploration) are plugged with cement and the casing crimped 15 ft below the sea floor.

FACILITY OPERATING PARAMETERS

Size:	4×10^3 bbl/day per platform
Annual Capacity Factor:	100%
Annual Energy Production:	8.47×10^{12} Btu
Efficiency:	40% (reservoir recovery efficiency)
Lifetime:	15–20 yr

RESOURCES USED

	Quantities Used		Per 10 ¹² Btu Energy Produced	Remarks
	Reference Energy System Annual Usage			
	English Units	Metric Units		
Energy				
Fuel for drilling	572 × 10 ⁹ Btu*	603 × 10 ¹² J*	67.5 × 10 ⁹ Btu	
Prime mover pumps	8.89 × 10 ⁹ Btu	9.38 × 10 ¹² J	1.05 × 10 ⁹ Btu	
Heater treater	53.6 × 10 ⁹ Btu	56.6 × 10 ¹² J	6.33 × 10 ⁹ Btu	
Other production and support requirements	125 × 10 ⁹ Btu	132 × 10 ¹² J	14.8 × 10 ⁹ Btu	
Water				
Drilling mud water (fresh or salt)	0.240 acre-ft*	0.297 × 10 ⁶ l*	28.4 × 10 ⁻³ acre-ft	Assumed 31.5 gal/bbl
Fresh water for workers	1.61 acre-ft	1.98 × 10 ⁶ l	190 × 10 ⁻³ acre-ft	↓
Total Usage				
Construction Materials				
Concrete	Not Determined			
Barite and bentonite	↓			
Steel				
Copper, aluminum, manganese nickel, and chromium				
Iron, steel, aluminum, and brass castings				
Structural steel and steel plates				
Pipe, tubular goods, and valves				
Land				
Water surface area	2.01 × 10 ³ acres	812 ha	237 acres	If 1-mi fishing buffer is included in permit
Personnel				
Construction (1 ½ yr)	45–65 workers		5.3–7.7 workers	
Operation and maintenance	16 workers		1.9 workers	
*Total life cycle values during 1 ½-yr drilling period.				

*Total life cycle values during 1 ½-yr drilling period.

COSTS

	Reference Energy System	Per 10 ¹² Btu Energy Produced	Remarks
<u>Facility</u>			
	(1981 \$)		
Construction (1 ½ yr)	\$71.9 × 10 ⁶ total	\$8.49 × 10 ⁶ total	Reference year for costs is 1978. 1978 CCI average (I _a) = 2776. See Explanatory Notes Section.
Operation and maintenance	\$2.61 × 10 ⁶ /yr	\$0.308 × 10 ⁶ /yr	
<u>Environmental Controls</u>			
	Not Determined		

OFFSHORE OIL EXTRACTION — LOWER 48 STATES

ENVIRONMENTAL RESIDUALS

	Quantities Released			Remarks
	Reference Energy System Annual Levels		Per 10 ¹² Btu Energy Produced	
	English Units	Metric Units		
<u>Air Pollutants</u>				
Oxides of nitrogen	270 tons	245 tonnes	31.92 tons	
Carbon monoxide	58.5 tons	53.1 tonnes	6.91 tons	
Hydrocarbons (exhaust)	21.6 tons	19.6 tonnes	2.55 tons	
Particulates	19.3 tons	17.5 tonnes	2.28 tons	
Oxides of sulfur	100 tons	90.6 tonnes	11.79 tons	
<u>Water Pollutants</u>				
Cadmium	0.204 ton	0.185 tonne	24.1 × 10 ⁻³ ton	
Cyanide	30.0 × 10 ⁻³ ton	27.2 × 10 ⁻³ tonne	3.54 × 10 ⁻³ ton	
Mercury	1.52 × 10 ⁻³ ton	1.38 × 10 ⁻³ tonne	0.18 × 10 ⁻³ ton	
Total organic carbon (including oil)	1.24 × 10 ³ tons	1.12 × 10 ³ tonnes	146.34 tons	
Total suspended solids	219 tons	199 tonnes	25.867 tons	
Total dissolved solids	330 × 10 ³ tons	300 × 10 ³ tonnes	38.977 × 10 ³ tons	
Chlorides	183 × 10 ³ tons	166 × 10 ³ tonnes	21.615 × 10 ³ tons	
<u>Solid Wastes</u>				
Drill cuttings	26.6 × 10 ³ tons*	24.1 × 10 ³ tonnes*	3.136 × 10 ³ tons	9500-ft wells
Drilling muds	4.67 × 10 ³ tons*	4.24 × 10 ³ tonnes*	551.0 tons	
<u>Noise Pollution</u>				
	Not Determined			

*Solid waste values are total life cycle values during the 1½-yr drilling period.

PRODUCTS

	Quantities Produced			Remarks
	Reference Energy System Annual Production		Per 10 ¹² Btu Energy Produced	
	English Units	Metric Units		
Primary				
Crude oil	1.46 × 10 ⁶ bbl	0.232 × 10 ⁹ l	0.172 × 10 ⁶ bbl	

OCCUPATIONAL SAFETY AND HEALTH

	Reference Energy System Annual	Per 10^{12} Btu Energy Produced	Remarks
<u>Deaths*</u>	27.1×10^{-3}	32×10^{-3}	
<u>Injuries*</u>	41.5×10^{-3}	4.9×10^{-3}	

*1970-1977 sum of injuries and fatalities due to blowouts, fire and explosions, and miscellaneous accidents occurring during exploration, development, and production.

CRUDE OIL STORAGE IN SALT DOME CAVERNS

REFERENCE ENERGY SYSTEM

The salt dome caverns are created by leaching with water; the resulting brine is discharged into a large body of water such as the Gulf of Mexico in an environmentally acceptable manner or recovered for use in the chemical industry. These caverns are provided with a cemented casing to protect subsurface water quality and with pipelines to handle water/brine and crude oil.

FACILITY OPERATING PARAMETERS

Size:	60×10^6 bbl (336×10^{12} Btu)
Annual Capacity Factor:	100%
Annual Energy Production:	Annual values for storage not available
Efficiency:	Not determined
Lifetime:	Not determined

RESOURCES USED

	Quantities Used		Per 10 ¹² Btu Energy Produced**	Remarks
	Reference Energy System Annual Usage*			
	English Units	Metric Units		
<u>Feed Materials</u>				
Crude oil stored			178.572 × 10 ³ bbl	
<u>Energy</u>				
Electric power to operate pumps		Not Determined		
<u>Water</u>				
Initial leaching operation			173 acre-ft	56.25 × 10 ⁶ gal
Each pumping operation			24 acre-ft	crude withdrawal
	<u>Total Usage</u>			
<u>Construction Materials</u>				
		Not Determined		
<u>Land</u>			2.4 acres	Site plus pipelines
<u>Personnel</u>				
Construction			0.6 worker	
Operation and maintenance		Not Determined		
*Annual values for storage not available.				
**Energy produced in this case means energy stored.				

COSTS

	Reference Energy System*	Per 10 ¹² Btu Energy Produced**	Remarks
<u>Facility</u>		(1981 \$)	
Construction		\$0.34 × 10 ⁶ total	Reference year for costs is 1976. 1976 CCI average (I _p) = 2401. See Explanatory Notes Section.
Operation and maintenance	Not Determined		
<u>Environmental Controls</u>		Not Determined	
*Annual values for storage not available.			
**Energy produced in this case means energy stored.			

CRUDE OIL STORAGE IN SALT DOME CAVERNS

ENVIRONMENTAL RESIDUALS

	Quantities Released			Remarks
	Reference Energy System Annual Levels*		Per 10 ¹² Btu Energy Produced**	
	English Units	Metric Units		
<u>Air Pollutants</u>				
Hydrocarbons			2.27 tons	
<u>Water Pollutants</u>				
Hydrocarbons		Not Determined		
Brine discharged			196 acre-ft	
• Initial leaching operation			21 acre-ft	
• Each crude oil fill operation				
<u>Solid Wastes</u>		Negligible During Operation		
<u>Noise Pollution</u>		Not Determined		

*Annual values for storage not available.

**Energy produced in this case means energy stored.

*Annual values for storage not available.

**Energy produced in this case means energy stored.

PRODUCTS

	Quantities Produced			Remarks
	Reference Energy System			
	Annual Production*			
	English Units	Metric Units	Per 10 ¹² Btu Energy Produced**	
Primary				
Crude oil stored (same as feed material)			178.572 × 10 ³ bbl	
*Annual values for storage not available.				
**Energy produced in this case means energy stored.				

*Annual values for storage not available.

**Energy produced in this case means energy stored.

OCCUPATIONAL SAFETY AND HEALTH*

Not Determined

*One death and one major injury have occurred to date in connection with the Strategic Petroleum Reserve storage facilities, which now contain over 115 million bbl.

OIL-FIRED STEAM ELECTRIC POWER PLANT

REFERENCE ENERGY SYSTEM

An oil-fired steam electric power plant generating electricity using the same basic unit processes as other fossil-fueled power stations (e.g., coal and natural-gas-fired systems). Basically, the chemical energy in the fuel oil is converted to heat energy in the steam generator (boiler), the output of which drives a turbine/generator (mechanical/electrical energy), which produces electricity. The power plant includes the following environmental control components as part of the total system: electrostatic precipitator, sulfur dioxide scrubber, wastewater treatment system, sludge dewatering system, and a solid waste disposal system.

FACILITY OPERATING PARAMETERS

Size:	800 MWe
Annual Capacity Factor:	55%
Annual Energy Production:	13.15×10^{12} Btu
Efficiency:	34.7%
Lifetime:	35 yr

RESOURCES USED

	Quantities Used		Per 10 ¹² Btu Energy Produced	Remarks
	Reference Energy System Annual Usage			
	English Units	Metric Units		
<u>Feed Materials</u>				
Residual fuel oil No. 6	6.18 × 10 ⁶ bbl	982 × 10 ⁶ l	470 × 10 ³ bbl	Heat content of fuel oil = 6.13 × 10 ⁶ Btu/bbl
<u>Energy</u>				
Average energy requirements for environmental control devices	0.29 × 10 ⁹ kWh	0.29 × 10 ⁹ kWh	0.022 × 10 ⁹ kWh	Total energy requirement is approximately 7.5% of energy generated
<u>Processing Materials</u>				
	Not Determined			
<u>Water</u>				
Cooling tower make-up	3.3 × 10 ³ acre-ft	4.1 × 10 ⁹ l	250 acre-ft	Mechanical draft cooling towers
<u>Construction Materials</u>				
	Total Usage			
Concrete	86.2 × 10 ³ tons	78.3 × 10 ³ tonnes	6.55 × 10 ³ tons	
Carbon steel	25.3 × 10 ³ tons	23 × 10 ³ tonnes	1.92 × 10 ³ tons	
Alloy steel	1.5 × 10 ³ tons	1.4 × 10 ³ tonnes	114 tons	
Stainless steel	565 tons	515 tonnes	43 tons	
Copper	593 tons	540 tonnes	45 tons	
Aluminum	179 tons	163 tonnes	13.6 tons	
Manganese	201 tons	183 tonnes	15.3 tons	
Chromium	140 tons	127 tonnes	10.6 tons	
Nickel	23 tons	21 tonnes	1.7 tons	
Cast iron	372 tons	338 tonnes	28.3 tons	
<u>Land</u>				
	96 acres	39 ha	7.3 acres	When using mechanical draft cooling towers
<u>Personnel</u>				
Construction (5 yr)	1.67 × 10 ³ workers		127 workers	
Operation and maintenance	138 workers		10.5 workers	

COSTS

	Reference Energy System	Per 10^{12} Btu Energy Produced	Remarks
Facility			
	(1981 \$)		
Construction (5 yr)	$\$305 \times 10^6$ total	$\$22.9 \times 10^6$ total	Reference year for costs is 1978. 1978 CCI average (I_R) = 2776. See Explanatory Notes Section.
Operation and maintenance	$\$8.08 \times 10^6$ /yr	$\$0.615 \times 10^6$ /yr	

OIL-FIRED STEAM ELECTRIC POWER PLANT

COSTS (CONTINUED)

Environmental Controls

Capital	$\$46.2 \times 10^6$ total	$\$3.51 \times 10^6$ total	Capital costs assume use of draft evaporative cooling towers; costs applicable to new equipment only, not retrofit cases Costs applicable to new equipment only, not retrofit cases
Operation and maintenance	$\$8.88 \times 10^6/\text{yr}$	$\$0.676 \times 10^6/\text{yr}$	

ENVIRONMENTAL RESIDUALS

	Quantities Released			
	Reference Energy System Annual Levels		Per 10 ¹² Btu Energy Produced	Remarks
	English Units	Metric Units		
<u>Air Pollutants</u>				
Total suspended particulates	5.39 × 10 ³ tons	4.89 × 10 ³ tonnes	410 tons	0.03 lb/10 ⁶ Btu*
Sulfur dioxide	48.9 × 10 ³ tons	44.4 × 10 ³ tonnes	3.72 × 10 ³ tons	0.80 lb/10 ⁶ Btu*
Oxides of nitrogen	5.68 × 10 ³ tons	5.16 × 10 ³ tonnes	432 tons	0.30 lb/10 ⁶ Btu*
Hydrocarbons	130 tons	120 tonnes	9.8 tons	
Carbon monoxide	648 tons	588 tonnes	49.3 tons	
Particulates/arsenic	0.127 ton	0.115 tonne	9.63 × 10 ⁻³ ton	
Particulates/beryllium	0.101 ton	91.8 × 10 ⁻³ tonne	7.69 × 10 ⁻³ ton	
Particulates/cadmium	3.79 tons	3.44 tonnes	0.288 ton	
Particulates/lead	20.2 × 10 ⁻³ ton	18.4 × 10 ⁻³ tonne	1.54 × 10 ⁻³ ton	
Particulates/mercury	0.127 ton	0.115 tonne	9.63 × 10 ⁻³ ton	
Particulates/nickel	37.9 tons	34.4 tonnes	2.88 tons	
Particulates/manganese	0.127 ton	0.115 tonne	9.63 × 10 ⁻³ ton	
Particulates/chromium	0.297 ton	0.270 tonne	22.6 × 10 ⁻³ ton	
Particulates/copper	0.297 ton	0.270 tonne	22.6 × 10 ⁻³ ton	
Particulates/vanadium	0.598 ton	0.543 tonne	45.5 × 10 ⁻³ ton	
<u>Water Pollutants**</u>				
Biochemical oxygen demand	67.8 tons	61.6 tonnes	5.16 tons	
Chemical oxygen demand	509 tons	462 tonnes	38.7 tons	
Total suspended solids	910 tons	826 tonnes	69.2 tons	
Total dissolved solids	5.06 × 10 ³ tons	4.60 × 10 ³ tonnes	385 tons	
Ammonia	0.977 ton	0.887 tonne	74.3 × 10 ⁻³ ton	
<u>Solid Wastes***</u>				
Total solid wastes	216 × 10 ³ tons	196 × 10 ³ tonnes	16.4 × 10 ³ tons	Scrubber sludge and particulate combined
<u>Thermal Discharge</u>				
Total thermal loss	24.7 × 10 ¹² Btu	26.1 × 10 ¹⁵ J	1.88 × 10 ¹² Btu	Stack, cooling water, and miscellaneous losses

*Regulatory compliance level.

**Water pollutants assuming a closed-cycle system.

***With nonregenerative scrubbers; 2% sulfur content is assumed with 90% removal efficiency.

*Regulatory compliance level.

**Water pollutants assuming a closed-cycle system.

***With nonregenerative scrubbers; 2% sulfur content is assumed with 90% removal efficiency.

PRODUCTS

	Quantities Produced			Remarks
	Reference Energy System Annual Production		Per 10 ¹² Btu Energy Produced	
	English Units	Metric Units		
Primary				
Electricity	3.85 × 10 ⁹ kWh	3.85 × 10 ⁹ kWh	0.293 × 10 ⁹ kWh	

OIL-FIRED STEAM ELECTRIC POWER PLANT

OCCUPATIONAL SAFETY AND HEALTH

	Reference Energy System Annual	Per 10^{12} Btu Energy Produced	Remarks
<u>Deaths</u>	23.8×10^{-3}	1.81×10^{-3}	
<u>Injuries</u>	2.27	0.173	
<u>Manyears Lost</u>	0.1	0.01	

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NATURAL GAS TECHNOLOGIES

The following should be recognized as limitations of the information provided on the summary sheets of this section:

1. The impacts and costs of oil and gas operations vary widely over the period of development. Typically, capital costs will be concentrated in the initial phases of development, and operation and maintenance costs and impacts will be spread over a longer period of time. Annualizing costs and impacts over the life cycle of a project ignores the actual pattern in which they occur.
2. The figures presented in the data sheets apply to specific representative cases. The variation around these cases may be quite extensive. Some costs, such as platforms, will vary geometrically rather than arithmetically. Thus, an 18-well platform in 400 feet of water will be much more than twice as expensive than one in 200 feet of water. Unless production per platform changes in exactly the same proportion, the numbers provided in the data sheets may be unrealistic.
3. The data sheets also do not consider changes in the underlying conditions determining the economic limit for oil and gas development. The rapid escalation of crude oil prices and changes in price/cost relationships will bring formerly uneconomic projects into production. These projects will generally have unit cost characteristics that are very different from the "representative" projects shown on the data sheets. It is likely that for these new projects, the costs per 10^{12} Btu produced will be much higher. The estimates of environmental impact also do not include the fact that many of the new projects will have improved environmental control systems that are not yet defined. For example, new steam Enhanced Oil Recovery projects will be required to have air emission levels that are much lower than the national averages shown on the data sheets.

ONSHORE GAS EXTRACTION — LOWER 48 STATES

REFERENCE ENERGY SYSTEM

The reference energy system is composed of 120 gas wells in a single production field. These wells would be drilled to an average depth of 5000 ft with a success ratio of approximately 67%. The total exploration, drilling, and facility construction period would require 5 yr with some wells ready for production prior to this time. Dry holes (60 expected) would be plugged with cement and the casing would be crimped below the surface.

FACILITY OPERATING PARAMETERS

Size:	29.6×10^6 ft ³ /day
Annual Capacity Factor:	100%
Annual Energy Production:	10.8×10^{12} Btu
Efficiency:	70% (50-90%) (gas reservoir recovery)
Lifetime:	15-25 yr

RESOURCES USED

	Quantities Used		Per 10 ¹² Btu Energy Produced	Remarks
	Reference Energy System Annual Usage			
	English Units	Metric Units		
<u>Energy</u>				
Gas processing				
• Sweet gas	3.34 × 10 ¹² Btu	3.52 × 10 ¹⁵ J	309.2 × 10 ⁹ Btu	
• Sour gas	9.72 × 10 ¹² –	10.2 × 10 ¹⁵ –	900 × 10 ⁹ –	
	14.7 × 10 ¹² Btu	15.6 × 10 ¹⁵ J	1.365 × 10 ¹² Btu	
Development drilling (diesel fuel)	779 × 10 ⁹ Btu	822 × 10 ¹² J	72.1 × 10 ⁹ Btu	
<hr/>				
Total Usage				
<hr/>				
<u>Construction Materials</u>				
Cement/concrete	44.4 × 10 ³ tons	40.4 × 10 ³ tonnes	4.116 × 10 ³ tons	
Pipe, tubing, valves	15.0 × 10 ³ tons	13.6 × 10 ³ tonnes	1.392 × 10 ³ tons	
Steel (structural and casings)	17.4 × 10 ³ tons	15.8 × 10 ³ tonnes	1.614 × 10 ³ tons	
Copper, aluminum, manganese, and other metals	364 tons	330 tonnes	33.7 tons	
Bentonite/barite	2.66 × 10 ³ tons	2.41 × 10 ³ tonnes	246 tons	
<hr/>				
<u>Water</u>				
Drilling mud fluid	93.6 acre-ft*	116 × 10 ⁶ l*	8.67 acre-ft	Assumed 31.5 gal/bbl
<hr/>				
<u>Land</u>				
Temporary	511 acres	207 ha	47.36 acres	
Permanent	420 acres	170 ha	38.93 acres	
<hr/>				
<u>Personnel</u>				
Construction (5 yr)	470 workers		43.48 workers	
Operation and maintenance	52.2 workers		4.83 workers	

*Water values are the total life cycle values during 5-yr drilling and facility construction period for 152 wells.

*Water values are the total life cycle values during 5-yr drilling and facility construction period for 152 wells.

COSTS

	<u>Reference Energy System</u>	<u>Per 10¹² Btu Energy Produced</u>	<u>Remarks</u>
<u>Facility</u>			
		(1981\$)	
Construction and drilling (5 yr)	\$148 × 10 ⁶ total	\$13.6 × 10 ⁶ total	Reference year for costs is 1978. 1978 CCI average (I _R) = 2776. See Explanatory Notes Section.
Operation and maintenance	\$6.69 × 10 ⁶ /yr	\$0.620 × 10 ⁶ /yr	
<u>Environmental Controls</u>			
	Not Determined		

ONSHORE GAS EXTRACTION — LOWER 48 STATES

ENVIRONMENTAL RESIDUALS

	Quantities Released			Remarks
	Reference Energy System Annual Levels		Per 10 ¹² Btu Energy Produced	
	English Units	Metric Units		
<u>Air Pollutants</u>				
Oxides of nitrogen	915 tons	830 tonnes	84.7 tons	
Carbon monoxide	20 tons	19 tonnes	1.9 tons	
Hydrocarbons	6.5 tons	5.9 tonnes	0.6 ton	
Oxides of sulfur	15.4 × 10 ³ tons	14.0 × 10 ³ tonnes	1.425 × 10 ³ tons	
Particulates	20 tons	19 tonnes	1.9 tons	
<u>Water Pollutants</u>				
Biochemical oxygen demand	18.5 tons	16.8 tonnes	1.71 tons	Water pollutants from processing plant
Chemical oxygen demand	121 tons	110 tonnes	11.20 tons	
Oil and grease	370 tons	336 tonnes	34.27 tons	
Chromium	1 ton	0.9 tonne	0.09 ton	
Zinc	0.32 ton	0.29 tonne	0.03 ton	
Total dissolved solids	4.94 × 10 ³ tons	4.48 × 10 ³ tonnes	457 tons	
Chloride	925 tons	840 tonnes	85.68 tons	
Sulfate	740 tons	672 tonnes	68.54 tons	
<u>Solid Wastes</u>				
Drill cuttings	36.3 × 10 ³ tons*	33.0 × 10 ³ tonnes*	3.364 × 10 ³ tons	

*Solid waste values are the total life cycle values during 5-yr drilling and facility construction period for 152 5000-ft-deep wells.

*Solid waste values are the total life cycle values during 5-yr drilling and facility construction period for 152 5000-ft-deep wells.

PRODUCTS

	Quantities Produced			Remarks
	Reference Energy System Annual Production		Per 10 ¹² Btu Energy Produced	
	English Units	Metric Units		
	<u>Primary</u>			
Natural gas	10.8 × 10 ⁹ ft ³	0.306 × 10 ⁹ m ³	1.00 × 10 ⁹ ft ³	1000 Btu/scf

OCCUPATIONAL SAFETY AND HEALTH

	Reference Energy System Annual	Per 10 ¹² Btu Energy Produced	Remarks
<u>Deaths</u>	56 × 10 ⁻⁶	5.2 × 10 ⁻⁶	
<u>Injuries</u>	30 × 10 ⁻³	3 × 10 ⁻³	
<u>Man-days lost</u>	0.32	0.030	

OFFSHORE GAS EXTRACTION — LOWER 48 STATES

REFERENCE ENERGY SYSTEM

The reference energy system is composed of an 18-well platform producing 88.722×10^6 ft³ of natural gas (1000 Btu/scf) per day. Many of the wells are deviated with an average depth of 9.6×10^3 ft. Six dry holes are expected and are plugged with cement and the casing crimped 15 ft below the seafloor.

FACILITY OPERATING PARAMETERS

Size:	88.722×10^6 ft ³ /day/ platform
Annual Capacity Factor:	100%
Annual Energy Production:	32.4×10^{12} Btu
Efficiency:	50-90% (recovery efficiency)
Lifetime:	15-25 yr

RESOURCES USED

	Quantities Used		Per 10 ¹² Btu Energy Produced	Remarks
	Reference Energy System Annual Usage			
	English Units	Metric Units		
<u>Energy</u>				
Fuel	0.722 × 10 ¹² Btu*	0.604 × 10 ¹⁵ J*	17.657 × 10 ⁹ Btu	Fuel for 19 wells
Operation and maintenance	35.3 × 10 ⁹ Btu	3.73 × 10 ¹² J	1.091 × 10 ⁹ Btu	
<u>Water</u>				
Drilling mud water	0.241 acre-ft* (2.49 × 10 ³ bbl)*	0.297 × 10 ⁶ l*	7.43 × 10 ⁻³ acre-ft (76.8 bbl)*	Fresh or salt water for 19 wells; assumed 31.5 gal/bbl
Fresh water for workers	1.61 acre-ft (16.7 × 10 ³ bbl)	1.99 × 10 ⁶ l	49.8 × 10 ⁻³ acre-ft (515.3 bbl)	Assumed 31.5 gal/bbl
Total Usage				
<u>Construction Materials</u>				
Not Determined				
<u>Land</u>				
Water surface area	2.01 × 10 ³ acres	814 ha	62.2 acres	If 1-mi fishing buffer included in permit
<u>Personnel</u>				
Construction and drilling (1½ yr)	45.0-65.1 workers		1.39-2.01 workers	
Operation and maintenance	15.9 workers		0.49 worker	
*Total values during the 1½-yr drilling period.				

*Total values during the 1½-yr drilling period.

COSTS

	Reference Energy System	Per 10 ¹² Btu Energy Produced	Remarks
<u>Facility</u>			
		(1981 \$)	
Construction (1½ yr)	$\$71.3 \times 10^6$ total	$\$2.20 \times 10^6$ total	Reference year for costs is 1978. 1978 CCI average (I_R) 2776. See Explanatory Notes Section.
Operation and maintenance	$\$2.61 \times 10^6$ /yr	$\$0.081 \times 10^6$ /yr	Exploration costs not included; includes platform construction plus drilling costs

OFFSHORE GAS EXTRACTION — LOWER 48 STATES

ENVIRONMENTAL RESIDUALS

	Quantities Released			Remarks
	Reference Energy System		Per 10 ¹² Btu Energy Produced	
	Annual Levels			
	English Units	Metric Units		
<u>Air Pollutants</u>				
Oxides of nitrogen	4.92 tons	4.47 tonnes	0.1519 ton	Air pollutants during production
Carbon monoxide	2.03 tons	1.84 tonnes	0.0627 ton	
Hydrocarbons (exhaust)	0.29 ton	0.26 tonne	9.0 × 10 ⁻³ ton	
Oxides of sulfur	10 × 10 ⁻³ ton	9 × 10 ⁻³ tonne	0.3 × 10 ⁻³ ton	
Particulates		Not Determined		
<u>Water Pollutants</u>				
Cadmium	0.203 ton	0.185 tonne	629 × 10 ⁻³ ton	
Cyanide	0.030 ton	0.027 tonne	0.93 × 10 ⁻³ ton	
Mercury	2 × 10 ⁻³ ton	1.5 × 10 ⁻³ tonne	0.05 × 10 ⁻³ ton	
Total organic carbon	1.24 × 10 ³ tons	1.12 × 10 ³ tonnes	38.2 tons	
Total suspended solids	220 tons	200 tonnes	6.8 tons	
Total dissolved solids	330 × 10 ³ tons	300 × 10 ³ tonnes	10.2 × 10 ³ tons	
<u>Solid Wastes</u>				
Drill cuttings	26.6 × 10 ³ tons*	24.1 × 10 ³ tonnes*	820.22 tons	9600-ft well
Drilling muds	4.67 × 10 ³ tons*	4.24 × 10 ³ tonnes*	144.09 tons	
*Solid waste values are total values during the 1½-yr drilling period.				

*Solid waste values are total values during the 1 1/2-yr drilling period.

PRODUCTS

	Quantities Produced			Remarks
	Reference Energy System Annual Production		Per 10 ¹² Btu Energy Produced	
	English Units	Metric Units		
<u>Primary</u>				
Natural gas	32.4 × 10 ⁹ ft ³	0.92 × 10 ⁹ m ³	1 × 10 ⁹ ft ³	1 × 10 ³ Btu/ft ³

OCCUPATIONAL SAFETY AND HEALTH

	Reference Energy System Annual	Per 10 ¹² Btu Energy Produced	Remarks
<u>Deaths*</u>	0.10	3.2 × 10 ⁻³	
<u>Injuries*</u>	0.16	4.9 × 10 ⁻³	

*Sum of injuries and fatalities between 1970-1977, due to blowouts, fire and explosions, and miscellaneous accidents occurring during exploration, development, and production.

UNCONVENTIONAL GAS RECOVERY

REFERENCE ENERGY SYSTEM

One 9000-ft deep well, located in an arid western U.S. setting, employing four stages of hydraulic fracturing. Locale consists of steppes and buttes, sage brush, deer, antelope, and small game in area. "Tight sands" gas deposits are found at depths from 5000 ft to 15,000 ft located in Montana, North and South Dakota, Idaho, Wyoming, Utah, Colorado, Nebraska, New Mexico, Texas, Oklahoma, Arkansas, and Louisiana. Conventional drilling is followed by massive hydraulic fracturing, which may be repeated three times over the 30-yr life of the well.

FACILITY OPERATING PARAMETERS

Size: One well with $0.3 \times 10^6 \text{ ft}^3/\text{day}$ gas output (average)
 Annual Capacity Factor: 60%*
 Annual Energy Production: $0.066 \times 10^{12} \text{ Btu}$
 Lifetime: 30+ yr

*Due to seasonal (summer) low demand, wells are shut in average of 40% of the time.

RESOURCES USED

	Quantities Used		Per 10 ¹² Btu Energy Produced	Remarks
	Reference Energy System Total Usage			
	English Units	Metric Units		
Energy				
Drilling	33.6 × 10 ⁹ Btu	35.4 × 10 ¹² J	509 × 10 ⁹ Btu	3 stimulations in 30-yr lifetime
Fracturing	1.32 × 10 ⁹ Btu	1.39 × 10 ¹² J	20 × 10 ⁹ Btu	
Maintenance		Not Determined		
Processing Materials				
Production tubing	1 mi	1.61 km	15.6 mi	2-in. outside dia.
Water				
Drilling and fracturing	3.07–6.14 acre-ft	3.79 × 10 ⁶ –7.58 × 10 ⁶ l	46.5–93.0 acre-ft	0.921 acre-ft/fracture
Construction Materials				
Sand	375 tons	340 tonnes	5.68 × 10 ³ tons	
Potassium chloride	37.5 tons	34.0 tonnes	568 tons	
Conductor casing	50 ft	15 m	760 ft	20-in. outside dia.
Surface casing	1.00 × 10 ³ ft	305 m	15.2 × 10 ³ ft	12-in. outside dia.
Production casing	9.00 × 10 ³ ft	2.74 × 10 ³ m	136 × 10 ³ ft	9-in. outside dia.
Condensate storage tank	1 unit	1 unit	15.2 units	300-bbl capacity/unit
Oil-gas-water separator	1 unit	1 unit	15.2 units	
Tubing (well head to separator)	50 ft	15 m	760 ft	2-in. outside dia.
“Christmas tree assembly”	1 unit	1 unit	15.2 units	3 valves, pressure gauge, tubing as needed
Land				
Temporary disturbance	4–5 acres	1.6–2.0 ha	61–76 acres	2–4 mo
Road access	2.5 acres	1.0 ha	38 acres	
Personnel				
Construction (70 days drilling)		15 workers/crew	44 workers	
Operation and maintenance		2 workers	30 workers	

COSTS

	Reference Energy System	Per 10^{12} Btu Energy Produced	Remarks
Facility		(1981 \$)	
Construction		Not Determined	Reference year for costs is 1978. 1978 CCI average $(I_p) = 2776$. See Explanatory Notes Section.
Operation and maintenance	$\$8.91 \times 10^3/\text{yr}$	$\$0.135 \times 10^6/\text{yr}$	
Environmental Controls			
Lined fluid pits		Not Determined	15 $\times 10^3$ psi reuseable unit
Noise reduction and containment			
Water sprayed on temporary roads to reduce dust			
Blowout preventer	$\$0.13 \times 10^6 \text{ total}$	$\$1.91 \times 10^6 \text{ total}$	

UNCONVENTIONAL GAS RECOVERY

ENVIRONMENTAL RESIDUALS

ENVIRONMENTAL RESIDUALS

	Quantities Released			
	Reference Energy System Total Levels			
	English Units	Metric Units	Per 10 ¹² Btu Energy Produced	Remarks
Air Pollutants*				
Dust		Not Determined		
Diesel emissions/drilling				
• Oxides of sulfur	18.9 tons	17.2 tonnes	286 tons	Based on extrapolation from one diesel engine (1100 hp) ^c
• Oxides of nitrogen	25.8 tons	23.4 tonnes	391 tons	
• Hydrocarbons	14.8 tons	13.4 tonnes	224 tons	
• Carbon monoxide	22.8 tons	20.7 tonnes	345 tons	
• Particulates	7.25 tons	6.58 tonnes	110 tons	
• Aldehydes	1.2 tons	1.1 tonnes	18 tons	
Diesel emissions/fracturing				
• Oxides of sulfur	0.743 ton	0.674 tonne	11.2 tons	
• Oxides of nitrogen	1.04 tons	0.944 tonne	15.8 tons	
• Hydrocarbons	0.582 ton	0.528 tonne	8.82 tons	
• Carbon monoxide	0.893 ton	0.811 tonne	13.5 tons	
• Particulates	0.286 ton	0.260 tonne	4.33 tons	
• Aldehydes	0.046 ton	0.042 tonne	0.70 ton	
Water Pollutants*				
Erosion of disturbed soils (minimal controls)				
Solid Wastes*				
Drilling mud waste (13 parts/gal mud)	250 tons	227 tonnes	3.79 × 10 ³ tons	No current regulations
Well residue	438 tons	398 tonnes	6.63 × 10 ³ tons	
Noise Pollution **				
Drilling phase		~ 80-90 dBA		
Fracturing (3-4 days)		~ 96 dBA		
*Pollutants produced in drilling and fracturing period (70 days). No residual effects; all are temporary and end with construction phase.				
**Noise cannot be expressed in terms of energy produced.				

*Pollutants produced in drilling and fracturing period (70 days). No residual effects; all are temporary and end with construction phase.

**Noise cannot be expressed in terms of energy produced.

PRODUCTS

	Quantities Produced			Remarks
	Reference Energy System Annual Production		Per 10 ¹² Btu Energy Produced	
	English Units	Metric Units		
<u>Primary</u>				
Natural gas	65.7 × 10 ⁶ scf (65.7 × 10 ⁹ Btu)	1.86 × 10 ⁶ m ³ (69.3 × 10 ¹² J)	995 × 10 ⁶ scf (995 × 10 ⁹ Btu)	1 × 10 ³ Btu/scf
<u>Byproducts</u>				
Condensate (wet gas or casing head gas)	6.2 × 10 ³ bbl (35 × 10 ⁹ Btu)	980 × 10 ³ l (37.0 × 10 ¹² J)	94 × 10 ³ bbl (530 × 10 ⁹ Btu)	200 bbl/wk

OCCUPATIONAL SAFETY AND HEALTH

	Reference Energy System Annual (Industry 1974-1979)	Per 10 ¹² Btu Energy Produced	Remarks
Deaths			
Exploration and production	0.1 per 1000 workers	Not Determined	
Injuries			
Exploration and production (1978)	38 per 1000 workers	Not Determined	
Drilling	279 per 1000 workers	↓	

NATURAL GAS PURIFICATION

REFERENCE ENERGY SYSTEM

Raw natural gas contains gases and liquids such as water, hydrogen sulfide, carbon dioxide, nitrogen, and various hydrocarbons that have to be removed before the natural gas can be placed in the transmission line. The purification process incorporates dehydration and desulfurization processes, carbon dioxide removal, and natural gas liquids separation to provide a suitable product. Major equipment consists of contactors, stills, reboilers, heaters, condensers, pumps and compressors, and auxiliary hardware.

FACILITY OPERATING PARAMETERS

Size:	$250 \times 10^6 \text{ ft}^3/\text{day}$ gas purification plant (heat content $\approx 1000 \text{ Btu}/\text{ft}^3$)
Annual Capacity Factor:	90% (328 days/yr operation)
Annual Energy Production:	$82 \times 10^{12} \text{ Btu}$
Efficiency:	87-92%
Lifetime:	30 yr

RESOURCES USED

	Quantities Used		Per 10 ¹² Btu Energy Produced	Remarks
	Reference Energy System Annual Usage			
	English Units	Metric Units		
<u>Feed Materials</u>				
Sour (acid) gas	91.8 × 10 ⁹ ft ³	2.60 × 10 ⁹ m ³	1.12 × 10 ⁹ ft ³	Assumed 89.5% efficiency, heat content = 1.0 × 10 ³ Btu/ft ³
<u>Energy</u>		Not Determined		Auxiliary energy requirements are process and feed material specific
<u>Processing Materials</u>		Not Determined		
<u>Water</u>				
Boiler make-up	410 acre-ft	506 × 10 ⁶ l	5.0 acre-ft	
	Total Usage			
<u>Construction Materials</u>		Not Determined		
<u>Land</u>	22.6 acres	9.12 ha	0.275 acre	
<u>Personnel</u>		Not Determined		
Construction		Not Determined ↓		
Operation and maintenance				

COSTS

	Reference Energy System	Per 10^{12} Btu Energy Produced	Remarks
<u>Facility</u>			
Construction		Not Determined ↓	
Operation and maintenance			
<u>Environmental Controls</u>		Not Determined	Vent gas from Claus (sulfur recovery) plant may require tail gas cleanup (depends on level of cleanup)

NATURAL GAS PURIFICATION

ENVIRONMENTAL RESIDUALS

ENVIRONMENTAL RECORDS

	Quantities Released			Remarks
	Reference Energy System		Per 10 ¹² Btu Energy Produced	
	Annual Levels			
	English Units	Metric Units		
<u>Air Pollutants</u>				
Particulates	13.3 tons	12.0 tonnes	0.162 ton	
Oxides of nitrogen	3.35 × 10 ³ tons	3.04 × 10 ³ tonnes	40.9 tons	
Sulfur dioxide	0.443 ton	0.40 tonne	5.4 × 10 ⁻³ ton	
Hydrocarbons	29.5 tons	27 tonnes	0.36 ton	
Carbon monoxide	0.295 ton	0.27 tonne	3.6 × 10 ⁻³ ton	
Aldehydes	2.21 tons	2.01 tonnes	0.027 ton	
<u>Water Pollutants</u>				
Condensate stripper bottoms disposal are of environmental concern				

PRODUCTS

	Quantities Produced			Remarks
	Reference Energy System Annual Production		Per 10 ¹² Btu Energy Produced	
	English Units	Metric Units		
<u>Primary</u>				
Clean natural gas	82 × 10 ⁹ ft ³	2.32 × 10 ⁹ m ³	1 × 10 ⁹ ft ³	Assumed 89.5% efficiency, heat content = 1.0 × 10 ³ Btu/ft ³
<u>Byproducts</u>				
Sulfur		Not Determined		
Natural gas liquids		↓		Propane, butane, and other "sweet" hydrocarbons

OCCUPATIONAL SAFETY AND HEALTH

Not Determined

NATURAL GAS TRANSMISSION PIPELINE

REFERENCE ENERGY SYSTEM

A 600-mi underground steel pipeline constructed of 30 in. O.D. $\times$ 0.625 in. thick American Petroleum Institute 5LX60 pipe and operating at 1200 psig maximum allowable pressure. Natural gas is driven by six centrifugal compressors located at 100-mi intervals. The compressors are driven by gas turbines fueled by the natural gas in the pipeline. A metering station is located at each end of the pipeline.

FACILITY OPERATING PARAMETERS

Size:	600×10^6 scf/day
Annual Capacity Factor:	88%
Annual Energy Production:	190.488×10^{12} Btu (natural gas transmitted)
Efficiency:	96.9%
Lifetime:	20 yr

RESOURCES USED

	Quantities Used		Per 10 ¹² Btu Energy Produced	Remarks
	Reference Energy System Annual Usage			
	English Units	Metric Units		
<u>Feed Materials</u>				
Natural gas transmitted	193 × 10 ⁹ scf (196 × 10 ¹² Btu)	5.46 × 10 ⁹ m ³ (207 × 10 ¹⁵ J)	1.0117 × 10 ⁹ scf (1.03 × 10 ¹² Btu)	1.02 × 10 ³ Btu/scf
<u>Energy</u>				
Fuel gas	5.96 × 10 ⁹ scf (6.08 × 10 ¹² Btu)	169 × 10 ⁶ m ³ (6.42 × 10 ¹⁵ J)	31.3 × 10 ⁸ scf (0.03193 × 10 ¹² Btu)	
<u>Water</u>				
Temporary use	328 acre-ft	404 × 10 ⁶ l	1.72 acre-ft	Hydrostatic testing
Well capacity at compressor stations	182 acre-ft	224 × 10 ⁶ l	0.955 acre-ft	
<u>Total Usage</u>				
<u>Construction Materials</u>				
Steel	0.313 × 10 ⁶ tons	0.284 × 10 ⁶ tonnes	1643.25 tons	
<u>Land</u>	12.0 × 10 ³ acres	4.85 × 10 ³ ha	62.91 acres	
<u>Personnel</u>				
Construction	1.32 × 10 ³ workers		6.92 workers	
Operation and maintenance	40 workers		0.21 worker	

COSTS

	<u>Reference Energy System</u>	<u>Per 10¹² Btu Energy Produced</u>	<u>Remarks</u>
<u>Facility</u>		(1981 \$)	Reference year for costs is 1978. 1978 CCI average (I _p) = 2776. See Explanatory Notes Section.
Construction	\$356 × 10 ⁶ total	\$1.87 × 10 ⁶ total	
Operation and maintenance	Not Determined		
<u>Environmental Controls</u>	Not Determined		

NATURAL GAS TRANSMISSION PIPELINE

ENVIRONMENTAL RESIDUALS

	Quantities Released			Remarks
	Reference Energy System		Per 10 ¹² Btu Energy Produced	
	Annual Levels			
	English Units	Metric Units		
<u>Air Pollutants</u>				
Particulates		Not Determined		
Oxides of nitrogen	762 tons	692 tonnes	4.001 tons	
Carbon monoxide	289 tons	262 tonnes	1.518 tons	
Hydrocarbons	52.6 tons	47.7 tonnes	0.2759 ton	
Oxides of sulfur	1.0 ton	0.95 tonne	5.5 × 10 ⁻³ ton	

Water Pollutants

Construction activities, particularly stream crossings, may temporarily increase stream sediment loadings; normal operation should not affect water quality

Noise Pollution*

Construction	
• Right-of-way	90 dBA
• Blasting	121 dBA
Operation	
• Compressor stations (property boundary)	< 60 dBA

*Noise cannot be expressed in terms of energy produced.

PRODUCTS

	Quantities Produced			Remarks
	Reference Energy System		Per 10 ¹² Btu Energy Produced	
	Annual Production			
	English Units	Metric Units		
Primary				
Natural gas transmitted (net)	187 × 10 ⁹ scf (190 × 10 ¹² Btu)	5.30 × 10 ⁹ m ³ (201 × 10 ¹⁵ J)	980.392 × 10 ⁶ scf (1 × 10 ¹² Btu)	

OCCUPATIONAL SAFETY AND HEALTH

Not Determined

LIQUEFIED NATURAL GAS TANKER

REFERENCE ENERGY SYSTEM

A 63,460-dead-weight-ton tanker with five 25,000-m³ insulated cryogenic tanks to hold liquefied methane at -260°F. Ship length, 289 m; beam, 41 m; design draft, 11 m; maximum shaft horsepower, 40,000; 35 crew accommodations; service speed, 20 knots. Ship is double hulled with one propeller.

FACILITY OPERATING PARAMETERS

Size:	125 × 10 ³ m ³ /tanker (2.6 × 10 ⁹ ft ³ /tanker)
Annual Capacity Factor:	95.3%
Annual Energy Production:	31.053 × 10 ¹² Btu (12 trips/yr)
Efficiency:	95.8% (% cargo delivered)
Lifetime:	25 yr

RESOURCES USED

	Quantities Used		Per 10 ¹² Btu Energy Produced	Remarks
	Reference Energy System Annual Usage			
	English Units	Metric Units		
<u>Energy</u>				
Boil-off burned to power tanker	916 × 10 ⁹ Btu	0.966 × 10 ¹⁵ J	29.5 × 10 ⁹ Btu	1.02 × 10 ³ Btu/scf natural gas
Fuel oil to power tanker	857 × 10 ⁹ Btu	0.904 × 10 ¹⁵ J	27.6 × 10 ⁹ Btu	
Boil-off vented	240 × 10 ⁹ Btu	0.253 × 10 ¹⁵ J	7.72 × 10 ⁹ Btu	
<u>Water</u>				
	30.6 × 10 ⁹ gal	116 × 10 ⁹ l	984.25 × 10 ⁶ gal	
<u>Total Usage</u>				
<u>Construction Materials</u>				
Steel	33.9 × 10 ³ tons	30.8 × 10 ³ tonnes	1.092 × 10 ³ tons	
Copper	267 tons	242 tonnes	8.602 tons	
Aluminum	111 tons	101 tonnes	3.575 tons	
Manganese	290 tons	261 tonnes	9.274 tons	
Chromium	1.06 × 10 ³ tons	958 tonnes	34.004 tons	
Nickel	524 tons	475 tonnes	16.864 tons	
Cast iron	115 tons	104 tonnes	3.691 tons	
<u>Personnel</u>				
Construction (3 yr)	2.40 × 10 ³ workers		77.287 workers	
Operation and maintenance	35.0 workers		1.127 workers	

COSTS

	<u>Reference Energy System</u>	<u>Per 10¹² Btu Energy Produced</u>	<u>Remarks</u>
<u>Facility</u>			
	(1981 \$)		
Construction (3 yr)	\$254 × 10 ⁶ total	\$8.20 × 10 ⁶ total	Reference year for costs is 1978. 1978 CCI average (I ₉) = 2776. See Explanatory Notes Section.
Operation and maintenance	\$34.7 × 10 ⁶ /yr	\$1.12 × 10 ⁶ /yr	
<u>Environmental Controls</u>			
	Not Determined		

LIQUEFIED NATURAL GAS TANKER

ENVIRONMENTAL RESIDUALS

		Quantities Released		
Reference Energy System				
Annual Levels				
English Units	Metric Units	Per 10 ¹² Btu Energy Produced	Remarks	
<u>Air Pollutants</u>				
Particulates	75.7 tons	68.7 tonnes	2.438 tons	
Oxides of sulfur	231 tons	209 tonnes	7.424 tons	
Oxides of nitrogen	181 tons	165 tonnes	5.842 tons	
Hydrocarbons	16.3 tons	14.8 tonnes	0.524 ton	
Carbon monoxide	12.6 tons	11.4 tonnes	0.405 ton	
Methane vented	5.17 × 10 ³ tons	4.69 × 10 ³ tonnes	166.52 tons	
<u>Water Pollutants</u>				
Unknown water volume from shipboard boil-off condenser; excess heat rejected to seawater				
<u>Thermal Discharge</u>				
At sea = 5.9°F above ambient				
In port = 7.4°F above ambient				
<u>Noise Pollution</u>				
Not Determined				

PRODUCTS

	Quantities Produced			Remarks
	Reference Energy System Annual Production		Per 10 ¹² Btu Energy Produced	
	English Units	Metric Units		
<u>Primary</u>				
Liquefied natural gas (equivalent to)	669 × 10 ³ tons	608 × 10 ³ tonnes	21.557 × 10 ³ tons	Quantity transported
Natural gas	30.4 × 10 ⁹ scf	0.862 × 10 ⁹ m ³	980.392 × 10 ⁶ scf	

OCCUPATIONAL SAFETY AND HEALTH

Not Determined

UNDERGROUND NATURAL GAS STORAGE

REFERENCE ENERGY SYSTEM

The underground natural gas storage system consists of 50 wells drilled in a depleted gas field of 5000 acres. The system is charged annually in the summer, and gas is withdrawn in the winter. Working capacity (annual deliverability) is 60×10^9 scf and 2×10^9 scf is used as fuel or lost per year. Additional facilities include compressors, metering facilities, scrubbing and dehydration equipment, and 30 mi of 30-in. connecting pipeline.

FACILITY OPERATING PARAMETERS

Size:	60×10^9 scf (annual deliverability)
Annual Capacity Factor:	Not determined
Annual Energy Production:	61.2×10^{12} Btu (natural gas stored)
Efficiency:	96.77%
Lifetime:	50 yr

RESOURCES USED

	Resources Used		Per 10 ¹² Btu Energy Produced	Remarks
	Reference Energy System Annual Usage			
	English Units	Metric Units		
<u>Feed Materials</u>				
Natural gas stored	61 × 10 ⁹ scf	1.7 × 10 ⁹ m ³	1.0 × 10 ⁹ scf	
<u>Energy</u>				
Field use in compressors	1.5 × 10 ⁹ scf	42 × 10 ⁶ m ³	24 × 10 ⁶ scf	
Lost	0.6 × 10 ⁹ scf	20 × 10 ⁶ m ³	9 × 10 ⁶ scf	
<u>Total Usage</u>				
<u>Construction Materials</u>				
Concrete (including cement)	1.92 × 10 ³ tons	1.74 × 10 ³ tonnes	31.314 tons	
Bentonite (in drilling mud)	350 tons	318 tonnes	5.719 tons	
Barite (in drilling mud)	200 tons	182 tonnes	3.268 tons	
Steel	27.1 × 10 ³ tons	24.6 × 10 ³ tonnes	442.569 tons	
Copper	84.6 tons	76.8 tonnes	1.383 tons	
Aluminum	29.2 tons	26.5 tonnes	0.477 ton	
Manganese	203 tons	185 tonnes	3.323 tons	
Chrome	51.5 tons	46.7 tonnes	0.841 ton	
Nickel	4.3 tons	3.9 tonnes	0.071 ton	
Cast iron	370 tons	336 tonnes	6.049 tons	
<u>Land</u>				
Surface land occupied	20.0 acres	8.10 ha	0.327 acres	
Underground lease	5.00 × 10 ³ acres	2.02 × 10 ³ ha	81.700 acres	
Total	5.02 × 10 ³ acres	2.03 × 10 ³ ha	82.027 acres	
<u>Personnel</u>				
Construction (3 yr)	879 workers		14.36 workers	
Operation and maintenance	2.6 workers		0.043 worker	

COSTS

	<u>Reference Energy System</u>	<u>Per 10¹² Btu Energy Produced</u>	<u>Remarks</u>
<u>Facility</u>			
		(1981 \$)	
Construction (3 yr)	\$121 × 10 ⁶ total	\$1.97 × 10 ⁶ total	Reference year for costs is 1978. 1978 CCI average (I _P) = 2776. See Explanatory Notes Section.
Operation and maintenance	\$1.19 × 10 ⁶ /yr	\$19.4 × 10 ³ /yr	
<u>Environmental Controls</u>			
	Not Determined		

UNDERGROUND NATURAL GAS STORAGE

ENVIRONMENTAL RESIDUALS

	Quantities Released			Remarks
	Reference Energy System Annual Levels		Per 10 ¹² Btu Energy Produced	
	English Units	Metric Units		
<u>Air Pollutants</u>				
Particulates		Not Determined		Information not available
Oxides of sulfur	11.6 tons	10.5 tonnes	0.1889 ton	
Oxides of nitrogen	8.38 × 10 ³ tons	7.61 × 10 ³ tonnes	136.98 tons	
Hydrocarbons	578 tons	525 tonnes	9.447 tons	
Carbon monoxide	240 tons	218 tonnes	3.915 tons	

Water Pollutants

Sediments in streams may temporarily increase during construction; defective gas well casings could potentially result in contamination of local aquifers

Solid Wastes

Negligible waste produced

Noise Pollution

Noise during construction would be limited to compressor stations and would probably be less than 60 dBA at property boundary

PRODUCTS

	Quantities Produced			Remarks
	Reference Energy System Annual Production		Per 10 ¹² Btu Energy Produced	
	English Units	Metric Units		
<u>Primary</u>				
Natural gas stored (net)	60.0 × 10 ⁹ scf	1.70 × 10 ⁹ m ³	980.392 × 10 ⁶ scf	

OCCUPATIONAL SAFETY AND HEALTH

Not Determined
(Information not available)

GAS-FIRED STEAM ELECTRIC POWER PLANT

REFERENCE ENERGY SYSTEM

Gas-fired steam electric power plant generating electricity using steam produced in a boiler from heat supplied from natural gas combustion to drive a turbine/generator system that produces electricity.

FACILITY OPERATING PARAMETERS

Size: 800 MWe
 Annual Capacity Factor: 55%
 Annual Energy Production: 13.15×10^{12} Btu
 Efficiency: 37%
 Lifetime: 35 yr

RESOURCES USED

	Quantities Used		Per 10 ¹² Btu Energy Produced	Remarks
	Reference Energy System Annual Usage			
	English Units	Metric Units		
<u>Feed Materials</u>				
Natural gas (fuel)	34.7 × 10 ⁹ ft ³	0.983 × 10 ⁹ m ³	2.64 × 10 ⁹ ft ³	Heat content of fuel is 1.02 × 10 ³ Btu/ft ³
<u>Energy</u>				
Environmental control devices (energy requirements)	<127 × 10 ⁶ kWh	<127 × 10 ⁶ kWh	<9.67 × 10 ⁶ kWh	Less than 3.3% of energy generated
<u>Water</u>				
Once-through (consumptive water use only)	3.00 × 10 ³ acre-ft	3.70 × 10 ⁹ l	228 acre-ft	Cooling towers can also be used as cooling system
<hr/>				
Total Usage				
<hr/>				
<u>Construction Materials</u>				
Not Determined				
<u>Land</u>				
Fixed land area	88.8 acres	35.9 ha	6.75 acres	Includes average of land range given for cooling towers
<u>Personnel</u>				
Construction (4 yr)	1.20 × 10 ³ workers		91.5 workers	
Operation and maintenance	108 workers		8.20 workers	

COSTS

	<u>Reference Energy System</u>	<u>Per 10¹² Btu Energy Produced</u>	<u>Remarks</u>
<u>Facility</u>			
	(1981 \$)		Reference year for costs is 1978. 1978 CCI average (I ₁) = 2776. See Explanatory Notes Section.
Construction (4 yr)	\$186 × 10 ⁶ total	\$14.1 × 10 ⁶ total	
Operation and maintenance	\$6.61 × 10 ⁶ /yr	\$0.503 × 10 ⁶ /yr	
<u>Environmental Controls</u>			
Construction	\$40.0 × 10 ⁶ total	\$3.04 × 10 ⁶ total	
Operation and maintenance	\$0.468 × 10 ⁶ /yr	\$0.036 × 10 ⁶ /yr	

GAS-FIRED STEAM ELECTRIC POWER PLANT

ENVIRONMENTAL RESIDUALS

	Quantities Released			Remarks
	Reference Energy System		Per 10 ¹² Btu Energy Produced	
	Annual Levels			
	English Units	Metric Units		
<u>Air Pollutants</u>				
Total suspended particulates	564 tons	512 tonnes	42.9 tons	
Sulfur dioxide	10.4 tons	9.44 tonnes	0.791 ton	
Oxides of nitrogen	12 × 10 ³ tons	11 × 10 ³ tonnes	0.93 × 10 ³ tons	
Hydrocarbons (as methane)	17.3 tons	15.7 tonnes	1.32 tons	
Carbon monoxide	295 tons	268 tonnes	22.4 tons	
<u>Water Pollutants*</u>				
Biochemical oxygen demand	5.21 tons	4.73 tonnes	0.396 ton	
Chemical oxygen demand	439 tons	399 tonnes	33.4 tons	
Total suspended solids	909 tons	825 tonnes	69.1 tons	
Total dissolved solids	849 tons	771 tonnes	64.6 tons	
Ammonia	0.973 ton	0.883 tonne	0.074 ton	
<u>Thermal Discharge</u>				
Total heat losses (stack, cooling water, and miscellaneous)	23.3 × 10 ¹² Btu	24.5 × 10 ¹⁵ J	1.77 × 10 ¹² Btu	
*Water pollutants from open cycle system only.				

*Water pollutants from open cycle system only.

PRODUCTS

	Quantities Produced			Remarks
	Reference Energy System Annual Production		Per 10 ¹² Btu Energy Produced	
	English Units	Metric Units		
Primary				
Electricity	3.85 × 10 ⁹ kWh	3.85 × 10 ⁹ kWh	0.293 × 10 ⁹ kWh	
<u>Recoverables/Recyclables</u>				
	Not Determined			

OCCUPATIONAL SAFETY AND HEALTH

	Reference Energy System Annual	Per 10 ¹² Btu Energy Produced	Remarks
<u>Deaths</u>	0.023	1.75 × 10 ⁻³	
<u>Injuries</u>	2.20	0.167	
<u>Manyears Lost</u>	0.1	0.01	

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SOLAR TECHNOLOGIES

RESIDENTIAL/COMMERCIAL HOT WATER HEATING — ACTIVE SYSTEM

REFERENCE ENERGY SYSTEM

Denver, Colorado, was selected as the site for the reference residential system, and Indianapolis, Indiana, was selected for the reference commercial hot water system. The design of both systems is the same: solar energy is absorbed by an array of flat-plate collectors and transferred to a storage tank by a water/glycol alcohol solution. Cold make-up water is heated in the solar storage tank and delivered to the auxiliary hot water tank upon demand.

FACILITY OPERATING PARAMETERS

Size:	Residential—50-ft ² collector area with 90 gal of storage Commercial—500-ft ² collector area with 900 gal of storage Systems provide 75% of reference loads
Annual Capacity Factor:	Not determined
Annual Energy Production: (location specific)	Residential— 7.0×10^6 Btu Commercial— 70.0×10^6 Btu
Efficiency:	22%
Lifetime:	20 yr

RESOURCES USED

	Quantities Used		Per 10 ¹² Btu Energy Produced	Remarks*
	Reference Energy System Annual Usage			
	English Units	Metric Units		
<u>Feed Materials</u>				
Solar radiation	32.3 × 10 ⁶ Btu	34.1 × 10 ⁹ J	4.61 × 10 ¹² Btu	R
	323 × 10 ⁶ Btu	341 × 10 ⁹ J	4.61 × 10 ¹² Btu	C
<u>Energy</u>				
Auxiliary	2.3 × 10 ⁶ Btu	2.5 × 10 ⁹ J	330 × 10 ⁹ Btu	R
	23 × 10 ⁶ Btu	25 × 10 ⁹ J	330 × 10 ⁹ Btu	C
Ancillary	700 × 10 ³ Btu	740 × 10 ⁶ J	100 × 10 ⁹ Btu	R
	7.0 × 10 ⁶ Btu	7.4 × 10 ⁹ J	100 × 10 ⁹ Btu	C
<u>Processing Materials</u>				
Coolant replacement (50% water)**	5 gal	19 l	720 × 10 ³ gal	R
	14 gal	53 l	200 × 10 ³ gal	C
<u>Water***</u>				
Coolant replacement**	2.5 gal	9.3 l	350 × 10 ³ gal	R
	7.0 gal	27 l	1.0 × 10 ⁶ gal	C
<hr/> Total Usage <hr/>				
<u>Construction Materials</u>				
Steel	70 × 10 ⁻³ ton	64 × 10 ⁻³ tonne	10 × 10 ³ tons	R
	400 × 10 ⁻³ ton	360 × 10 ⁻³ tonne	57 × 10 ³ tons	C
Glass	40 × 10 ⁻³ ton	36 × 10 ⁻³ tonne	5.7 × 10 ³ tons	R
	400 × 10 ⁻³ ton	360 × 10 ⁻³ tonne	57 × 10 ³ tons	C
Fiberglass	29 × 10 ⁻³ ton	26 × 10 ⁻³ tonne	4.1 × 10 ³ tons	R
	240 × 10 ⁻³ ton	218 × 10 ⁻³ tonne	34 × 10 ³ tons	C
Copper	15 × 10 ⁻³ ton	13 × 10 ⁻³ tonne	2.1 × 10 ³ tons	R
	84 × 10 ⁻³ ton	73 × 10 ⁻³ tonne	12 × 10 ³ tons	C
Coolant (50% glycol)	14 gal	53 l	2.0 × 10 ⁶ gal	R
	40 gal	150 l	570 × 10 ³ gal	C
Aluminum	55 × 10 ⁻³ ton	50 × 10 ⁻³ tonne	7.9 × 10 ³ tons	R
	550 × 10 ⁻³ ton	500 × 10 ⁻³ tonne	79 × 10 ³ tons	C
<u>Land</u>				
Negligible				
<u>Personnel</u>				
Construction	0.018 worker		2.5 × 10 ³ workers	
Operation and maintenance	Not Determined			
*R = Residential				
C = Commercial				
**Replacement every third year.				
***If the collectors were washed, significantly more water would be required; however, washing is not normally done.				

RESIDENTIAL/COMMERCIAL HOT WATER HEATING — ACTIVE SYSTEM

COSTS

	Reference Energy System	Per 10 ¹² Btu Energy Produced	Remarks*
<u>Facility</u>	(1981 \$)		
Construction	$\$2.46 \times 10^3$ total	$\$349 \times 10^6$ total	R Reference year for costs is 1980. 1980
	$\$24.6 \times 10^3$ total	$\$3.49 \times 10^9$ total	C CCI average (I_p) =
Operation and maintenance	$\$24.6/\text{yr}$	$\$3.49 \times 10^6/\text{yr}$	R 3237. See Explanatory
	$\$246/\text{yr}$	$\$34.9 \times 10^9/\text{yr}$	C Notes Section.
R = Residential			
C = Commercial			

ENVIRONMENTAL RESIDUALS

	Quantities Released			Remarks*
	Reference Energy System Annual Levels		Per 10 ¹² Btu Energy Produced	
	English Units	Metric Units		
<u>Water Pollutants</u>				
Chemical oxygen demand**	0.05 lb	0.02 kg	3.75 tons	R
	0.22 lb	0.10 kg	1.55 tons	C
<u>Solid Wastes</u>				
No annual residuals; however, upon decommissioning, the glass, fiberglass, and coolant must be disposed of				
*R = Residential C = Commercial				
**Assumes ultimate disposal of all working fluid in water.				

PRODUCTS

	Quantities Produced		Per 10 ¹² Btu Energy Produced	Remarks*
	Reference Energy System Annual Production			
	English Units	Metric Units		
<u>Primary</u>				
Thermal energy	7.0 × 10 ⁶ Btu	7.4 × 10 ⁹ J	1.0 × 10 ¹² Btu	R
	70 × 10 ⁶ Btu	74 × 10 ⁹ J	1.0 × 10 ¹² Btu	C
<u>Recoverables/Recyclables</u>				
No annual recoverables; however, upon decommissioning, the steel, copper, and aluminum may be economically recoverable				
*R = Residential				
C = Commercial				

OCCUPATIONAL SAFETY AND HEALTH

	Reference Energy System Annual	Per 10 ¹² Btu Energy Produced	Remarks
<u>Deaths/Injuries</u>			
Potential safety hazards exist due to accidental collector overheating and fire		Not Determined	

RESIDENTIAL/COMMERCIAL HEATING — ACTIVE SYSTEM

REFERENCE ENERGY SYSTEM

A typical residence in Denver, Colorado, was selected as the reference system. Solar energy is absorbed by an array of flat-plate solar collectors and transferred by a water and glycol alcohol solution to a storage tank. The stored solar energy is then pumped upon demand through a heat exchanger to provide space heating.

FACILITY OPERATING PARAMETERS

Size: 500-ft² collector area, 900 gal storage, provides 75% of the load of the reference house

Annual Capacity Factor: Not determined

Annual Energy Production: (location specific) 47.5×10^6 Btu*

Efficiency: 30%

Lifetime: 20 yr

*Assumes a 6-month heating season

RESOURCES USED

	Quantities Used		Per 10 ¹² Btu Energy Produced	Remarks
	Reference Energy System Annual Usage			
	English Units	Metric Units		
<u>Feed Materials</u>				
Solar radiation	158 × 10 ⁶ Btu	167 × 10 ⁹ J	3.32 × 10 ¹² Btu	
<u>Energy</u>				
Auxiliary	15.8 × 10 ⁶ Btu	16.7 × 10 ⁹ J	332 × 10 ⁹ Btu	To meet load collector and distribution pumps
Ancillary	4.3 × 10 ⁶ Btu	4.5 × 10 ⁹ J	90 × 10 ⁹ Btu	
<u>Processing Materials</u>				
Coolant (50% water, 50% glycol)	14 gal	53 l	280 × 10 ³ gal	Assumes replace- ment of coolant every 3 yr
Water**	7 gal	27 l	140 × 10 ³ gal	
<hr/> Total Usage <hr/>				
<u>Construction Materials</u>				
Steel	0.40 ton	0.36 tonne	8.4 × 10 ³ tons	
Glass	0.40 ton	0.36 tonne	8.4 × 10 ³ tons	
Fiberglass	0.25 ton	0.22 tonne	5.2 × 10 ³ tons	
Copper	80 × 10 ⁻³ ton	73 × 10 ⁻³ tonne	1.7 × 10 ³ tons	
Coolant (50% glycol)	40 gal	150 l	840 × 10 ³ gal	
Aluminum	0.55 ton	0.50 tonne	11 × 10 ³ tons	
Land				
Negligible				
<u>Personnel</u>				
Construction	Not Determined			
Operation and maintenance	↓			
**If the collectors were washed, significantly more water would be required; however, washing is not normally done.				

**If the collectors were washed, significantly more water would be required; however, washing is not normally done.

COSTS

	<u>Reference Energy System</u>	<u>Per 10¹² Btu Energy Produced</u>	<u>Remarks</u>
<u>Facility</u>			
		(1981 \$)	
Construction (0.3 yr)	\$24.6 × 10 ³ total	\$516 × 10 ⁶ total	Reference year for costs is 1980. 1980 CCI average (I _R) = 3237. See Explanatory Notes Section.
Operation and maintenance	\$246/yr	\$5.13 × 10 ⁶ /yr	
<u>Environmental Controls</u>			
		Not Determined	

RESIDENTIAL/COMMERCIAL HEATING – ACTIVE SYSTEM

ENVIRONMENTAL RESIDUALS

	Quantities Released			Remarks
	Reference Energy System Annual Levels		Per 10 ¹² Btu Energy Produced	
	English Units	Metric Units		
<u>Water Pollutants</u>				
Chemical oxygen demand	0.15 lb	0.07 kg	1.55 tons	Assumes ultimate disposal of all working fluids in water

Solid Wastes

No annual residuals; however, upon decommissioning, such materials as glass, fiberglass, and coolant must be disposed of

PRODUCTS

	Quantities Produced			Remarks
	Reference Energy System Annual Production		Per 10 ¹² Btu Energy Produced	
	English Units	Metric Units		
Primary				
Thermal energy	47.5 × 10 ⁶ Btu	50.1 × 10 ⁹ J	1.00 × 10 ¹² Btu	

Recoverables/Recyclables

No annual recoverables are created; however, upon decommissioning, such construction materials as copper, steel, and aluminum may be economically recoverable

OCCUPATIONAL SAFETY AND HEALTH

Not Determined

RESIDENTIAL HEATING AND COOLING — ACTIVE SYSTEM

REFERENCE ENERGY SYSTEM

A single family residence in Denver, Colorado, was selected as the reference solar heating and cooling system. The system absorbs solar energy with an array of flatplate collectors. A water and glycol alcohol solution transfers the energy to storage through an intermediate heat exchanger. Upon demand, the stored solar energy is pumped through a liquid/air heat exchanger for space heating or to a lithium-bromide absorption chiller for space cooling.

FACILITY OPERATING PARAMETERS

Size:	Collector array — 500 ft ² Storage — 900 gal Provides 75% of the total reference heating and 70% of the cooling load
Annual Capacity Factor:	Not determined
Annual Energy Production:	70.5×10^6 Btu*
Efficiency:*	33% gross, 32% net
Lifetime:	20 yr

*Based on 8 months of operation. Energy output is also highly location specific.

RESOURCES USED

	Quantities Used		Per 10 ¹² Btu Energy Produced	Remarks	
	Reference Energy System Annual Usage				
	English Units	Metric Units			
<u>Feed Materials</u>					
Solar radiation	210 × 10 ⁶ Btu	222 × 10 ⁹ J	3.00 × 10 ¹² Btu	For the 8 mo of operation	
<u>Energy</u>					
Auxiliary	23.5 × 10 ⁶ Btu	24.8 × 10 ⁹ J	0.33 × 10 ¹² Btu	To meet loads to transport and distribute energy	
Ancillary (electric motor)	2.4 × 10 ³ kWh	2.4 × 10 ³ kWh	33.6 × 10 ⁶ kWh		
<u>Processing Materials</u>					
Coolant (50% glycol, 50% water)	14 gal	53 l	200 × 10 ³ gal	Assumes replacement of fluid every third year	
<u>Water*</u>	7 gal	27 l	98 × 10 ³ gal	Replacement of fluid only	
<hr/> Total Usage <hr/>					
<u>Construction Materials</u>					
Steel	0.65 ton	0.59 tonne	9.2 × 10 ³ tons	Negligible	
Glass	0.40 ton	0.36 tonne	5.7 × 10 ³ tons		
Fiberglass	0.25 ton	0.22 tonne	3.5 × 10 ³ tons		
Copper	0.13 ton	0.12 tonne	1.8 × 10 ³ tons		
Coolant (50% glycol)	40 gal	150 l	0.57 × 10 ⁶ gal		
Aluminum	0.55 ton	0.50 tonne	7.8 × 10 ³ tons		
<u>Land</u>					
<u>Personnel</u>					
Construction (0.1 yr)	0.142 worker		2.00 × 10 ³ workers		
Operation and maintenance	Not Determined				

*If the collectors were washed, significantly more water would be required; however, washing is not normally done.

*If the collectors were washed, significantly more water would be required; however, washing is not normally done.

COSTS

	Reference Energy System	(1981 \$)	Per 10 ¹² Btu Energy Produced	Remarks
<u>Facility</u>				
Construction (0.1 yr)	$\$0.027 \times 10^6$ total		$\$382 \times 10^6$ total	Reference year for costs is 1980. 1980 CCI average (I_R) = 3237. See Explanatory Notes Section.
Operation and maintenance	$\$0.000027 \times 10^6$ /yr		$\$0.38 \times 10^6$ /yr	

RESIDENTIAL HEATING AND COOLING – ACTIVE SYSTEM

ENVIRONMENTAL RESIDUALS

ENVIRONMENTAL RESIDUALS				
	Quantities Released			
	Reference Energy System Annual Levels		Per 10 ¹² Btu Energy Produced	Remarks
	English Units	Metric Units		
<u>Water Pollutants</u>				
Chemical oxygen demand	0.3 lb	0.1 kg	2.0 tons	Assumes ultimate disposal of all working fluids in water
<u>Solid Wastes</u>				
No annual residuals; however, upon decommissioning, the glass, fiberglass, and coolant must be disposed of				

PRODUCTS

	<u>Quantities Produced</u>			<u>Remarks</u>
	<u>Reference Energy System</u>		<u>Per 10¹² Btu</u> <u>Energy Produced</u>	
	<u>Annual Production</u>			
	<u>English Units</u>	<u>Metric Units</u>		
<u>Primary</u>				
Thermal energy	70.5 × 10 ⁶ Btu	74.4 × 10 ⁹ J	1.00 × 10 ¹² Btu	
<u>Recoverables/Recyclables</u>				
No annual recoverables; however, upon decommissioning, the steel, copper, and aluminum may be economically recoverable				

OCCUPATIONAL SAFETY AND HEALTH

	Reference Energy System Annual	Per 10 ¹² Btu Energy Produced	Remarks
<u>Deaths/Injuries</u>			
Potential safety hazards exist due to accidental collector overheating and fire		Not Determined	

RESIDENTIAL/COMMERCIAL HEATING — PASSIVE SYSTEM

REFERENCE ENERGY SYSTEM

Denver, Colorado, was selected as the location of the reference passive heating system. The system functions by absorbing solar radiation on a selectively coated vertical wall. The radiation warms the concrete wall, and that warmth is conducted through the wall and then, by natural convection, into the space. The wall thickness is selected to provide the proper thermal capacitance to even out the absorption/release of thermal energy. Orientation of the wall can range from south to southwest. Two glazings and moveable insulation limit heat losses during periods of low or no sun.

FACILITY OPERATING PARAMETERS

Size: 500 ft² aperture, 18-in.-thick concrete wall; provides 75% of reference load

Annual Capacity Factor: Not determined

Annual Energy Production: 47.5×10^6 Btu*

Efficiency: 32%

Lifetime: 20 yr

*Based on a 6-month heating season. Energy output is also highly location specific.

RESOURCES USED

	Quantities Used		Per 10 ¹² Btu Energy Produced	Remarks
	Reference Energy System Annual Usage			
	English Units	Metric Units		
<u>Feed Materials</u>				
Solar energy	150 × 10 ⁶ Btu	160 × 10 ⁹ J	3.2 × 10 ¹² Btu	6-month heating season only
<u>Energy</u>				
Auxiliary	15.8 × 10 ⁶ Btu	16.7 × 10 ⁹ J	330 × 10 ⁹ Btu	To meet heating load
<u>Total Usage</u>				
<u>Construction Materials</u>				
Concrete	56 tons	51 tonnes	1.2 × 10 ⁶ tons	
Glass	0.8 ton	0.7 tonne	17 × 10 ³ tons	
Insulation	100 lb	45 kg	1.1 × 10 ³ tons	
<u>Land</u>				
Negligible				
<u>Personnel</u>				
Construction (0.02 yr)		0.04 worker	820 workers	
Operation and maintenance		Not Determined		

COSTS

	Reference Energy System	Per 10 ¹² Btu Energy Produced	Remarks
<u>Facility</u>			
		(1981 \$)	
Construction (0.02 yr)	$\$9.05 \times 10^3$ total	$\$192 \times 10^6$ total	Reference year for costs is 1977. 1977 CCI average (I_p) = 2577. See Explanatory Notes Section.
Operation and maintenance		Negligible	

RESIDENTIAL/COMMERCIAL HEATING — PASSIVE SYSTEM

ENVIRONMENTAL RESIDUALS

	Quantities Released			Remarks
	Reference Energy System		Per 10 ¹² Btu Energy Produced	
	Annual Levels			
	English Units	Metric Units		
<u>Solid Wastes</u>				
No annual residuals; however, upon decommissioning, the construction materials will need to be disposed of if they are not a structural part of the building				
<u>Thermal Discharge</u>				
Excess heat collected during the summer could be avoided by shading	24.5 × 10 ⁶ Btu	25.8 × 10 ⁹ J	0.51 × 10 ¹² Btu	

PRODUCTS

	Quantities Produced			Remarks
	Reference Energy System Annual Production		Per 10 ¹² Btu Energy Produced	
	English Units	Metric Units		
Primary				
Thermal energy	47.5 × 10 ⁶ Btu	50.1 × 10 ⁹ J	1.00 × 10 ¹² Btu	

OCCUPATIONAL SAFETY AND HEALTH

	Reference Energy System Annual	Per 10^{12} Btu Energy Produced	Remarks
<u>Deaths/Injuries</u>			
Should be similar to standard residential construction		Not Determined	

RESIDENTIAL/COMMERCIAL WIND ENERGY CONVERSION SYSTEM

REFERENCE ENERGY SYSTEM

A three-blade, horizontal axis rotor, 25 ft in diameter, intercepts the wind and begins to produce electricity at wind speeds of 8 mph. Maximum rated capacity is attained from 26 mph to 50 mph. Beyond 50 mph, the machine automatically stops rotating to protect itself.

The direct current generated is converted to alternating current and tied directly to the utility grid.

FACILITY OPERATING PARAMETERS

Size:	3 blades, 25 ft in diameter, 15 kWe capacity*
Annual Capacity Factor:	22%
Annual Energy Production:	98.7×10^6 Btu* (28.9×10^3 kWh)
Efficiency:	Varies with wind speed—up to 45%
Lifetime:	30 yr

*Low Wind Regime (12-15 mph at 30-ft elevation). Greater energies delivered when machine is in higher wind regimes.

RESOURCES USED

	Quantities Used		Per 10 ¹² Btu Energy Produced	Remarks
	Reference Energy System Annual Usage			
	English Units	Metric Units		
<u>Feed Materials</u>				
Wind		Not Determined		Minimum (cut in) wind speed is 8 mph and maximum (cut out) wind speed is 50 mph
<u>Water</u>				
Wind energy conversion systems may use pumped water as a storage medium				
	Total Usage			
<u>Construction Materials</u>				
Concrete	0.60 ton	0.55 tonne	6.1 × 10 ³ tons	
Steel	0.22 ton	0.20 tonne	2.2 × 10 ³ tons	
Copper	4.8 × 10 ⁻³ ton	4.4 × 10 ⁻³ tonne	48 tons	
Fiberglass		Negligible		
Lead	7.5 tons	6.8 tonnes	76 × 10 ³ tons*	Present only if batteries are used as storage medium
<u>Land</u>				
Tower base	5.2 × 10 ⁻³ acre	2.1 × 10 ⁻³ ha	52 acres	Does not consider wake
<u>Personnel</u>				
Construction		0.053 worker	530 workers	
Operation and maintenance		Not Determined		
*Unrealistically high; not all systems would use lead-acid batteries, and different types of batteries or other types of storage might be used.				

*Unrealistically high; not all systems would use lead-acid batteries, and different types of batteries or other types of storage might be used.

COSTS

	Reference Energy System	Per 10^{12} Btu Energy Produced	Remarks
<u>Facility</u>		(1981 \$)	
Construction	$\$159 \times 10^3$ total	$\$1.61 \times 10^3$ total	Reference year for costs is 1972. 1972 CCI average (I_{1972}) = 1753. See Explanatory Notes Section.
Operation and maintenance		Not Determined	
<u>Environmental Controls</u>		Not Determined	

RESIDENTIAL/COMMERCIAL WIND ENERGY CONVERSION SYSTEM

ENVIRONMENTAL RESIDUALS

	Quantities Released			
	Reference Energy System		Per 10 ¹² Btu Energy Produced	Remarks
	Annual Levels			
	English Units	Metric Units		
Solid Wastes				
No annual residuals; however, upon decommissioning, the concrete and fiberglass must be disposed of				
Noise Pollution				
Some problems with low frequency noise have been noted but it is not felt to be significant; sound vibrations are also potential sources of electromagnetic interference				

PRODUCTS

	Quantities Produced			Remarks
	Reference Energy System Annual Production		Per 10 ¹² Btu Energy Produced	
	English Units	Metric Units		
Primary				
Electricity	28.9 × 10 ³ kWh	28.9 × 10 ³ kWh	0.293 × 10 ⁹ kWh	
Recoverables/Recyclables				
No annual recoverables; however, when decommissioning, the steel, copper, and lead (if present) may be economically recoverable				

OCCUPATIONAL SAFETY AND HEALTH

	Reference Energy System Annual	Per 10 ¹² Btu Energy Produced	Remarks
Deaths			
		Not Determined	
Injuries			
Wind energy conversion systems are characterized by safety hazards associated with mechanical stress in rotor blades and tower; the stresses may result in catastrophic failure of those members			

RESIDENTIAL PHOTOVOLTAIC SYSTEM

REFERENCE ENERGY SYSTEM

Phoenix, Arizona, was designated as the location for the reference residential photovoltaic system. Solar radiation strikes silicon photovoltaic cells contained within roofing shingles. This creates a direct current, which is then transformed to an alternating current by an inverter. The alternating current is then supplied to the house load or returned to the utility grid. The utility grid provides backup power, and there is no onsite storage. (Systems located elsewhere might have different collector areas but would otherwise be very similar. One possible variation would be to use photovoltaic modules composed of solar cells attached to other mounting materials (glass or metal). The energy output of the system is dependent on the net collector area, cell efficiency, and geographic location.)

FACILITY OPERATING PARAMETERS

Size:	904-ft ² net collector area 8.5 kWp (peak)
Annual Capacity Factor:	30%
Annual Energy Production:	69.4 × 10 ⁶ Btu (20,340 kWh – some returned to utility grid)
Efficiency:	10% (varies with cell temperature and composition)
Lifetime:	30 yr

RESOURCES USED

	Quantities Used		Per 10 ¹² Btu Energy Produced	Remarks
	Reference Energy System Annual Usage			
	English Units	Metric Units		
<u>Feed Materials</u>				
Solar energy	675 × 10 ⁶ Btu	713 × 10 ⁹ J	9.7 × 10 ¹² Btu	
<u>Energy</u>				
Auxiliary	400 kWh	400 kWh	5.8 × 10 ⁶ kWh	Net electrical energy purchased (total delivered from utility minus total returned to utility)
<u>Water</u>				
Negligible (if washing of photo- voltaic array is performed, an estimated 500 gal/yr is required)				
	Total Usage			
<u>Construction Materials</u>				
Plastic (Lexan)	1.1 tons	1.0 tonne	16 × 10 ³ tons	
Silicon*	35 × 10 ⁻³ ton	32 × 10 ⁻³ tonne	500 tons	
Aluminum	1.9 × 10 ⁻³ ton	1.7 × 10 ⁻³ tonne	28 tons	
Silver	1.2 × 10 ⁻³ ton	1.1 × 10 ⁻³ tonne	17 tons	
Solder (60/40 lead/tin)	9.7 × 10 ⁻³ ton	8.8 × 10 ⁻³ tonne	140 tons	
Carbon steel	63 × 10 ⁻³ ton	57 × 10 ⁻³ tonne	900 tons	
Silicon steel	190 × 10 ⁻³ ton	170 × 10 ⁻³ tonne	2.7 × 10 ³ tons	
Copper	67 × 10 ⁻³ ton	61 × 10 ⁻³ tonne	960 tons	
Plastics (polyester and phenolic)	3.8 × 10 ⁻³ ton	3.4 × 10 ⁻³ tonne	54 tons	
Zinc	350 × 10 ⁻⁶ ton	320 × 10 ⁻⁶ tonne	5 tons	
Exotics (boron, phosphorus)	590 × 10 ⁻¹² ton	540 × 10 ⁻¹² tonne	8.5 × 10 ⁻⁶ ton	
Tantalum pentoxide	154 × 10 ⁻⁶ ton	140 × 10 ⁻⁶ tonne	2.2 tons	
<u>Personnel</u>				
Construction (0.04 yr)	0.04 worker		575 workers	
Operation and maintenance		Not Determined		

*Silicon is the most common material used for solar cells. However, alternate materials such as cadmium sulfide or gallium arsenide are available.

RESIDENTIAL PHOTOVOLTAIC SYSTEM

COSTS

	Reference Energy System	Per 10 ¹² Btu Energy Produced	Remarks
<u>Facility</u>		(1981 \$)*	
Construction (0.04 yr)	\$12.0 × 10 ³ - 19.6 × 10 ³ total	\$174 × 10 ⁶ - 277 × 10 ⁶ total	Reference year for costs is 1980. 1980 CCI average (I _{av}) = 3237. See Explanatory Notes Section.
Operation and maintenance		Not Determined	

*These costs reflect Department of Energy price goals (in 1981 \$). Current prices (in 1981) are significantly higher with an 8.5-kWp system today costing approximately \$136,000. Actual costs have been decreasing rapidly.

ENVIRONMENTAL RESIDUALS

ENVIRONMENTAL RESIDUALS		Quantities Released		
Reference Energy System				
Annual Levels				
English Units	Metric Units	Per 10 ¹² Btu Energy Produced		Remarks
<u>Air Pollutants</u>				
There is a potential for accidental high voltage arcing, which will generate ozone and fumes from burned plastics				
<u>Solid Wastes</u>				
No annual residuals; however, upon decommissioning, such construction materials as plastic, silicon, solder, zinc, and exotics must be disposed of				
<u>Thermal Discharge</u>				
Inverter heat loss	10.4 × 10 ⁶ Btu	11.0 × 10 ⁹ J	150 × 10 ⁹ Btu	

PRODUCTS

RECOVERABLES

	Quantities Produced			Remarks
	Reference Energy System Annual Production		Per 10 ¹² Btu Energy Produced	
	English Units	Metric Units		
<u>Primary</u>				
Electrical energy	20.3 × 10 ³ kWh	20.3 × 10 ³ kWh	0.297 × 10 ⁹ kWh	
<u>Recoverables/Recyclables</u>				
No annual recoverables; however, upon decommissioning, such materials as aluminum, silver, steel, and copper may be economically recoverable				

OCCUPATIONAL SAFETY AND HEALTH

	Annual	Per 10 ¹² Btu Energy Produced	Remarks
<u>Deaths and Injuries</u>			
Manufacturing of photovoltaic cells involves many toxic materials; their handling, storage, and transport involves potential health hazards			

RESIDENTIAL WOOD STOVE

ENERGY SYSTEM DESCRIPTION

Wood Stove for Residential Space Heating; Provides 24×10^6 Btu/yr of Heat To Meet Approximately 50 Percent of Annual Space Heating Needs of a Home in Tennessee; Welded Steel Construction With Firebrick Lined Firebox; Two Cords of Green Wood Seasoned for a Year to 20 Percent Moisture Content; Onsite Wood Storage and Ash Disposal; Free Wood Collected From Public Land.

FACILITY OPERATING PARAMETERS

Size:	3.28 ft ³ firebox
Annual Capacity Factor:	32% (2800 hr)
Annual Energy Production:	24×10^6 Btu
Efficiency:	50%
Lifetime:	20 yr

RESOURCES USED

Resource	Quantities Used			Remarks
	Reference Energy System Annual Levels*		Per 10 ¹² Btu Energy Produced	
	English Units	Metric Units		
<u>Fuel</u>				
Harvested wood supply	12.4 × 10 ³ lb	5.62 × 10 ³ kg	517 × 10 ⁶ lb	50 percent moisture content
Seasoned wood supply	7.73 × 10 ³ lb	3.51 × 10 ³ kg	322 × 10 ⁶ lb	20 percent moisture content
Gasoline	22.5 gal	85.2 liters	938 × 10 ³ gal	
<u>Land**</u>				
Forest land	12.4 acres	5.02 ha	517 × 10 ³ acres	Public land
Storage land	2.94 × 10 ⁻³ acres	1.19 × 10 ⁻³ ha	123 acres	Stove owner's land
<u>Construction Materials**</u>				
Steel	300 lb	136 kg	12.5 × 10 ⁶ lb	1/4 in. and 5/16 in. thickness
Cast iron	22 lb	9.98 kg	917 × 10 ³ lb	Door
Firebrick	78 lb	35.4 kg	3.25 × 10 ⁶ lb	Firebox liner
Water	None			

*Based on assumed 2800 hr/yr at low firing rate.

**One-time acquisition; not an annual requirement.

COSTS

Facility Capital Cost	Reference Energy System	Per 10 ¹² Btu Energy Produced	Remarks
(1982 \$)			
Wood stove and accessories	\$960 total	40.0×10^6 total	
Brick chimney	\$879 total	36.7×10^6 total	

RESIDENTIAL WOOD STOVE

ENVIRONMENTAL RESIDUALS AND PRODUCTS

	Quantities Released			
	Reference Energy System Annual Levels*			
<u>Residual or Product</u>	<u>English Units</u>	<u>Metric Units</u>	<u>Per 10¹² Btu Energy Produced</u>	<u>Remarks</u>
<u>Investing Emissions</u>	Not Determined			
<u>Vehicle Emissions</u>				
Carbon monoxide	14.3 lb	6.49 kg	596 × 10 ³ lb	
Nitrogen oxides	1.83 lb	0.830 kg	76.3 × 10 ³ lb	
Hydrocarbons	1.35 lb	0.612 kg	56.3 × 10 ³ lb	
<u>Flue Gas Emissions</u>				
Particulates	27.1 lb	12.3 kg	1.13 × 10 ⁶ lb	
Condensable organics	30.9 lb	14.0 kg	1.29 × 10 ⁶ lb	
Nitrogen oxides	4.64 lb	2.10 kg	193 × 10 ³ lb	
Carbon monoxide	1.38 × 10 ³ lb	626 kg	57.5 × 10 ⁶ lb	
Sulfur dioxide	1.55 lb	0.703 kg	64.6 × 10 ³ lb	
Polycyclic organic matter	2.16 lb	0.980 kg	90.1 × 10 ³ lb	
<u>Indoor Air Pollutants</u>	Not Determined			
<u>Water Pollutants</u>				
Erosion	930 lb	422 kg	38.8 × 10 ⁶ lb	Contributes to water pollution
Runoff from wood storage	965 gal	3.65 × 10 ³ liters	40.2 × 10 ⁶ gal	
<u>Solid Waste</u>				
Wood ash	155 lb	70.3 kg	6.46 × 10 ⁶ lb	
<u>Product</u>				
Heat	24 × 10 ⁶ Btu	25.3 × 10 ⁹ joules	1 × 10 ¹² Btu	
*Based on assumed 2800 hr/yr at low firing rate.				

*Based on assumed 2800 hr/yr at low firing rate.

SAFETY AND HEALTH

	Annual		Per 10 ¹² Btu Energy Produced	
	Injuries	Deaths	Injuries	Deaths
Harvesting	4.06 × 10 ⁻³	25 × 10 ⁻⁶	169	1.04
Transportation	158 × 10 ⁻⁶	2.69 × 10 ⁻⁶	6.59	112 × 10 ⁻³
Fires	150 × 10 ⁻⁶	17.2 × 10 ⁻⁶	6.26	717 × 10 ⁻³
Burns	643 × 10 ⁻⁶	—	26.8	—

LOW-TEMPERATURE SOLAR AGRICULTURAL/INDUSTRIAL PROCESS HEAT SYSTEM

REFERENCE ENERGY SYSTEM

A commercial laundry in Indianapolis, Indiana, was designated as the reference process and location for low-temperature solar industrial process heat. The process temperatures range from 120°F to 212°F.

Solar energy is absorbed by a flatplate collector array and transferred to storage by a heat exchanger. A glycol alcohol solution circulates through the collector to prevent freezing. The heated water is delivered to the load from a solar storage tank, through an auxiliary tank.

FACILITY OPERATING PARAMETERS

Size: 500-ft² collector area, 900-gal storage, provides 50% of the reference load

Annual Capacity Factor: Not determined

Annual Energy Production: 65×10^6 Btu*

Efficiency: 28% (gross), 27% (net)

Lifetime: 20 yr

*Annual energy production and system efficiency will vary with available solar radiation, location, and with daily load schedule.

RESOURCES USED

	Quantities Used		Per 10 ¹² Btu Energy Produced	Remarks
	Reference Energy System Annual Usage			
	English Units	Metric Units		
<u>Feed Materials</u>				
Solar radiation	231 × 10 ⁶ Btu	244 × 10 ⁹ J	3.6 × 10 ¹² Btu	
<u>Energy</u>				
Ancillary (electricity)	2.9 × 10 ³ kWh	2.9 × 10 ³ kWh	45 × 10 ⁶ kWh	A 50% solar fraction is assumed
Auxiliary	65 × 10 ⁶ Btu	69 × 10 ⁹ J	1.0 × 10 ¹² Btu	
<u>Processing Materials</u>				
Coolant (50% glycol and 50% water)	13 gal	51 l	207 × 10 ³ gal	Annual usage for replacement of fluid every 3 yr
<u>Water</u>				
	12 × 10 ³ gal	45 × 10 ³ l	186 × 10 ³ gal	Used for collector washing if per- formed; very small quantity used for coolant mixture replacement
<u>Total Usage</u>				
<u>Construction Materials</u>				
Steel	0.40 ton	0.36 tonne	6.2 × 10 ³ tons	
Glass	0.40 ton	0.36 tonne	6.2 × 10 ³ tons	
Fiberglass	0.25 ton	0.22 tonne	3.8 × 10 ³ tons	
Copper	80 × 10 ⁻³ ton	73 × 10 ⁻³ tonne	1.2 × 10 ³ tons	
Coolant	40 gal	153 l	620 × 10 ³ gal	
Aluminum	0.55 ton	0.50 tonne	8.5 × 10 ³ tons	
<u>Land</u>				
		Negligible		
<u>Personnel</u>				
Construction (0.3 yr)		Not Determined		
Operation and maintenance				

COSTS

	<u>Reference Energy System</u>	<u>Per 10¹² Btu Energy Produced</u>	<u>Remarks</u>	
<u>Facility</u>				
Construction (0.3 yr)	$\$24.6 \times 10^3$ total	(1981 \$)	Reference year for costs is 1980. 1980 CCI average (I_p) = 3237. See Explanatory Notes Section.	
Operation and maintenance	$\$246/\text{yr}$	$\$378 \times 10^6$ total $\$3.82 \times 10^6/\text{yr}$		
<u>Environmental Controls</u>				
A double wall heat exchanger may be used to increase isolation of the process fluid from the glycol solution should this be desired or required by code				

LOW-TEMPERATURE SOLAR AGRICULTURAL/INDUSTRIAL PROCESS HEAT SYSTEM

ENVIRONMENTAL RESIDUALS

	Quantities Released			Remarks
	Reference Energy System		Per 10 ¹² Btu Energy Produced	
	Annual Levels			
	English Units	Metric Units		
<u>Water Pollutants</u>				
Chemical oxygen demand (COD)	0.15 lb	0.07 kg	1.2 tons	Assumes ultimate disposal of all working fluid in water

Use of surfactants, detergents, or other compounds in collector washing water also contributes to COD, but quantitative data are not available, and the COD does not reflect these pollutants

Solid Wastes

No annual residuals; however, upon decommissioning, such construction materials as glass, fiberglass, and possibly some portion of the metals must be disposed of

Thermal Discharge

Thermal discharges from the collector array, piping, and storage are unavoidable; those losses are a very low-grade heat and are not always detrimental

PRODUCTS

	Quantities Produced			Remarks
	Reference Energy System Annual Production		Per 10 ¹² Btu Energy Produced	
	English Units	Metric Units		
Primary				
Thermal energy	65 × 10 ⁶ Btu	69 × 10 ⁹ J	1.0 × 10 ¹² Btu	

Recoverables/Recyclables

No annual recoverables; however, upon decommissioning, some fraction of the metals may be economically recoverable

OCCUPATIONAL SAFETY AND HEALTH

Not Determined

MEDIUM-TEMPERATURE SOLAR AGRICULTURAL/INDUSTRIAL PROCESS HEAT SYSTEM

REFERENCE ENERGY SYSTEM*

A pulp mill in Madison, Wisconsin, was selected as the reference system. Solar energy is reflected and concentrated (maximum concentration ratio: 50:1) by a 500-ft² array of compound parabolic concentrating collectors. The array tracks the altitude of the sun. An aromatic alcohol transfers solar energy from the collector to a pressurized storage tank via a heat exchanger. Upon demand, the hot, pressurized storage water is passed through a throttling valve, flashed to steam and applied to the load. Condensate and make-up water return to storage.

*The reference system has been normalized to a 500-ft² collector area. To provide a large percentage of the purchased energy load of a typically sized wood pulp application, a solar array would have to be unrealistically large (634,000 ft² for a 50-percent solar fraction on a purchased energy load of 270×10^9 (Btu/yr)).

FACILITY OPERATING PARAMETERS

Size: 500-ft² collector area
900-gal pressurized storage

Annual Capacity Factor: Not determined

Annual Energy Production: 65×10^6 Btu*

Efficiency: 25% (gross)*

Lifetime: 20 yr

*Annual energy production and system efficiency are dependent on available insolation, geographic location, and daily load schedules.

RESOURCES USED

RESOURCES USED

	Quantities Used*		Per 10 ¹² Btu Energy Produced	Remarks
	Reference Energy System Annual Usage			
	English Units	Metric Units		
<u>Feed Materials</u>				
Solar energy	267 × 10 ⁶ Btu	281 × 10 ⁹ J	4.10 × 10 ¹² Btu	
<u>Energy</u>				
Ancillary*		Not Determined		
Auxiliary*, **		↓		
<u>Processing Materials</u>				
Coolant	13 gal	51 l	207 × 10 ³ gal	For replacement every 3 yr
<u>Water</u>	12 × 10 ³ gal	45 × 10 ³ l	186 × 10 ⁶ gal	Used for collector washing if performed
Total Usage				
<u>Construction Materials</u>				
Steel	4.0 tons	3.6 tonnes	62 × 10 ³ tons	
Glass	0.40 ton	0.36 tonne	6.2 × 10 ³ tons	
Aluminum	0.35 ton	0.32 tonne	5.4 × 10 ³ tons	
Fiberglass	0.40 ton	0.36 tonne	6.2 × 10 ³ tons	
Coolant (aromatic alcohol)	40 gal	151 l	620 × 10 ³ gal	
Copper	80 × 10 ⁻³ ton	73 × 10 ⁻³ tonne	1.2 × 10 ³ tons	
<u>Land</u>				
Assume 1.3 times collector area for ground-mounted arrays				
<u>Personnel</u>				
Construction		Not Determined		
Operation and maintenance		↓		
*The reference system was normalized to 500-ft ² collector area. However, a solar fraction is not available, and thus, the corresponding ancillary and auxiliary energy requirements are not known.				
**In addition to purchased energy, wood pulp mills typically burn wood residues for energy.				

MEDIUM-TEMPERATURE SOLAR AGRICULTURAL/INDUSTRIAL PROCESS HEAT SYSTEM

COSTS

	Reference Energy System	Per 10^{12} Btu Energy Produced	Remarks
<u>Facility</u>	(1981 \$)		Reference year for costs is 1980. 1980 CCI average $(I_p) = 3237$. See Explanatory Notes Section.
Construction	$\$27.3 \times 10^3$ total	$\$415 \times 10^6$ total	
Operation and maintenance	$\$273/\text{yr}$	$\$4.15 \times 10^6/\text{yr}$	
<u>Environmental Controls</u>			
A double-walled heat exchanger may be used to help prevent contamination of one working fluid by another if this is desired			

ENVIRONMENTAL RESIDUALS

	<u>Quantities Released</u>			<u>Remarks</u>
	<u>Reference Energy System</u>			
	<u>Annual Levels</u>			
	<u>English Units</u>	<u>Metric Units</u>	<u>Per 10¹² Btu Energy Produced</u>	
<u>Water Pollutants</u>				
The bulk of the chemical oxygen demand would come from detergents in collector washing water and from herbicides used to keep ground-mounted arrays free from weeds and brush				
<u>Solid Wastes</u>				
No annual solid wastes; however, upon decommissioning, such construction materials as glass, fiberglass, and possibly some portion of the metals must be disposed of				
<u>Thermal Discharge</u>				
Excessive heat may be discharged as a fail-safe during system malfunction; other heat losses are of low grade and are negligible				

PRODUCTS

	<u>Quantities Produced</u>			<u>Remarks</u>
	<u>Reference Energy System</u>		<u>Per 10¹² Btu</u> <u>Energy Produced</u>	
	<u>Annual Production</u>			
	<u>English Units</u>	<u>Metric Units</u>		
<u>Primary</u>				
Thermal energy	65 × 10 ⁶ Btu	69 × 10 ⁹ J	1.0 × 10 ¹² Btu	
<u>Recoverables/Recyclables</u>				
No annual recoverables; however, upon decommissioning, some fraction of the metals may be economically recoverable				

OCCUPATIONAL SAFETY AND HEALTH

Not Determined

ALCOHOL FERMENTATION PLANT

REFERENCE ENERGY SYSTEM

The fermentation plant is designed to produce 50×10^6 gal/yr of 99.5 volume percent (199 proof) ethanol from corn along with Distillers' Dried Grain with Solubles (DDGS), a commercial animal feed. Process heat requirements are obtained by burning high-sulfur, Illinois No. 6 coal. Particulates and SO_x emissions in the boiler flue gas are removed by a flue gas scrubbing system employing ammonia as the sorbent, and wastewater is treated in a two-stage activated sludge treatment facility prior to disposal.

FACILITY OPERATING PARAMETERS

Size:	50×10^6 gal/yr
Annual Capacity Factor:	90%
Overall Plant Efficiency:	68.9%
Annual Energy Production:	3.78×10^{12} Btu
Lifetime:	20 yr

RESOURCES USED

	Quantities Used		Per 10^{12} Btu Energy Produced	Remarks
	Reference Energy System Annual Usage*			
	English Units	Metric Units		
<u>Feed Materials</u>				
Corn	544 × 10 ³ tons	494 × 10 ³ tonnes	144 × 10 ³ tons	
<u>Fuel</u>				
Coal	97.9 × 10 ³ tons	88.9 × 10 ³ tonnes	25.9 × 10 ³ tons	
<u>Water</u>				
Process water	330 × 10 ⁶ gal	1250 × 10 ⁶ l	87.3 × 10 ⁶ gal	
Raw water make-up	83.1 × 10 ⁶ gal	315 × 10 ⁶ l	22.0 × 10 ⁶ gal	
Cooling tower make-up	280 × 10 ⁶ gal	1060 × 10 ⁶ l	74.1 × 10 ⁶ gal	
<u>Processing Materials</u>				
Air input to amylase production	223 × 10 ³ tons	202 × 10 ³ tonnes	59.0 × 10 ³ tons	
Yeast	396 tons	360 tonnes	105 tons	
Iodine sterilizing solution	7.92 × 10 ³ gal	30.0 × 10 ³ l	2.1 × 10 ³ gal	
Hydrocarbon solvent	9.03 × 10 ³ gal	34.2 × 10 ³ l	2.39 × 10 ³ gal	
Denaturant	1.00 × 10 ⁶ gal	3.79 × 10 ⁶ l	264 × 10 ³ gal	
Air input to dryer	652 × 10 ³ tons	592 × 10 ³ tonnes	173 × 10 ³ tons	
Anhydrous ammonia	3.04 × 10 ³ tons	2.76 × 10 ³ tonnes	804 tons	
Air input to boiler	1.10 × 10 ⁶ tons	1.00 × 10 ⁶ tonnes	291 × 10 ³ tons	
<u>Water treatment chemicals</u>				
• Sodium chloride	396 tons	360 tonnes	105 tons	
• Lime	792 tons	719 tonnes	210 tons	
• Sludge polymer	7.9 tons	7.17 tonnes	2.09 tons	
<u>Land</u>	50.0 acres	20.2 ha	13.2 acres	
<u>Personnel</u>				
Operation	159 workers		42.1 workers	

*Assumes a 90% capacity factor.

ALCOHOL FERMENTATION PLANT

COSTS

Facility	Reference Energy System	Per 10 ¹² Btu Energy Produced	Remarks
	(1981 \$)*		
Construction (total)	\$69.7 × 10 ⁶ total	\$18.4 × 10 ⁶ total	
Operation and maintenance (annual)	\$61.5 × 10 ⁶ /yr	\$16.2 × 10 ⁶ /yr	
Environmental controls (capital)**	\$9.07 × 10 ⁶ total	\$2.40 × 10 ⁶ total	
Operation and Maintenance	Not Determined		

*Operating cost estimate for 1983 plant startup.

**These costs have been included in the above estimates for total construction (capital) costs.

ENVIRONMENTAL RESIDUALS

	Quantities Released		Per 10 ¹² Btu Energy Produced	Remarks
	Reference Energy System Annual Levels*			
	English Units	Metric Units		
Air Pollutants				
Particulates from grain cleaning	163 tons	148 tonnes	43.1 tons	
Emissions from starch conversion	Negligible			
Emissions from enzyme production	Negligible			
Emissions from fermentation				
• Ethanol	1.80 × 10 ³ tons	1.63 × 10 ³ tonnes	476 tons	
• Water vapor	2.48 × 10 ³ tons	2.25 × 10 ³ tonnes	656 tons	
• Carbon dioxide	170 × 10 ³ tons	154 × 10 ³ tonnes	45.0 × 10 ³ tons	
Distillation/dehydration pollutants				
• Carbon dioxide	2.81 × 10 ³ tons	2.55 × 10 ³ tonnes	743 tons	
• Water vapor	41.2 tons	37.4 tonnes	10.9 tons	
Emissions from product handling	Negligible			
Emissions from raw chemical storage	Negligible			
Scrubber emissions				
• Sulfur dioxide	947 tons	860 tonnes	250 tons	1.25 × 10 ³ tons*
• Particulates	104 tons	94.4 tonnes	27.5 tons	104 tons**
• Nitrogen oxides	726 tons	659 tonnes	192 tons	730 tons**
• Water vapor	120 × 10 ³ tons	109 × 10 ³ tonnes	31.8 tons	
Dust from DDGS handling	5.31 tons	4.82 tonnes	1.41 tons	
Inert dust from coal handling	49.0 tons	44.5 tonnes	13.0 tons	
Cooling tower evaporative and drift losses	242 × 10 ⁶ gal	916 × 10 ⁶ l	64.0 × 10 ⁶ gal	

*A capacity factor of 90% is assumed.

**Federal regulatory compliance levels.

ALCOHOL FERMENTATION PLANT

ENVIRONMENTAL RESIDUALS (Continued)

	Quantities Released			
	Reference Energy System Annual Levels*		Per 10 ¹² Btu Energy Produced	Remarks
	English Units	Metric Units		
<u>Water Pollutants</u>				
Water runoff from coal storage	Not Quantifiable			
Boiler blowdown	7.92 × 10 ⁶ gal	30.0 × 10 ⁶ l	2.10 × 10 ⁶ gal	
Wastewater effluent to river	363 × 10 ⁶ gal	1374 × 10 ⁶ l	96.0 × 10 ⁶ gal	
Cooling tower blowdown	38 × 10 ⁶ gal	144 × 10 ⁶ l	10.1 × 10 ⁶ gal	
<u>Solid Wastes</u>				
Grain cleaning rejects	54.4 tons	49.4 tonnes	14.4 tons	
Boiler bottom ash	3 × 10 ³ tons	2.72 × 10 ³ tonnes	794 tons	
Boiler fly ash	4.75 × 10 ³ tons	4.31 × 10 ³ tonnes	1.26 × 10 ³ tons	

*A capacity factor of 90% is assumed.

PRODUCTS

	Quantities Produced			Remarks
	Reference Energy System		Per 10 ¹² Btu Energy Produced	
	Annual Production			
	English Units	Metric Units		
Primary				
Ethanol (199 proof)	50 × 10 ⁶ gal	190 × 10 ⁶ l	13 × 10 ⁶ gal	
Byproducts				
Distiller's Dark Grains	177 × 10 ³ tons	161 × 10 ³ tonnes	46.8 × 10 ³ tons	
Dry ammonium sulfate	10.4 × 10 ³ tons	9.47 × 10 ³ tonnes	2.76 × 10 ³ tons	
Fusel oils*	760 tons	690 tonnes	201 tons	

*Fusel oils are usually mixed with the grain ethanol product prior to blending with gasoline.

OCCUPATIONAL SAFETY AND HEALTH

	Reference Energy System Annual	Per 10 ¹² Btu Energy Produced	Remarks
Deaths	8.61 × 10 ⁻³	2.28 × 10 ⁻³	
Injuries	6.84	1.81	

METHANOL FROM WOOD

REFERENCE ENERGY SYSTEM

Wood feedstock is fed into a gasifier where the heated wood releases synthesis gas in the presence of oxygen. Ash and unconverted carbon are waste products of this process. The synthesis gas then passes through an acid gas removal system prior to entering the cryogenic separation unit. The methanol is then synthesized and purified into fuel-grade methanol.

FACILITY OPERATING PARAMETERS

Size:	Will support space heating and hot water needs of about 8100 households
Annual Capacity Factor:	90%
Annual Energy Production:	3.62×10^{12} Btu (net)
Efficiency:	57% (net)
Lifetime:	20 yr

RESOURCES USED

	Quantities Used		Per 10 ¹² Btu Energy Produced	Remarks
	Reference Energy System Annual Usage			
	English Units	Metric Units		
<u>Feed Materials</u>				
Wood (dry)	0.329 × 10 ⁶ tons	0.298 × 10 ⁶ tonnes	90.9 × 10 ³ tons	Assumes dry wood at 9.65 × 10 ³ Btu/lb; quantities used would be twice as much for wet wood at 4.825 × 10 ³ Btu/lb
<u>Energy</u>				
Electricity	59.2 × 10 ⁹ Btu	62.4 × 10 ¹² J	16.4 × 10 ⁹ Btu	
<u>Processing Materials</u>				
Oxygen	0.166 × 10 ⁶ tons	0.150 × 10 ⁶ tonnes	45.9 × 10 ³ tons	
Combustion and dryer air	1.31 × 10 ⁶ tons	1.19 × 10 ⁶ tonnes	0.362 × 10 ⁶ tons	
<u>Water</u>	2.25 × 10 ³ acre-ft	2.78 × 10 ³ l	0.623 × 10 ³ acre-ft	
<u>Total Usage</u>				
<u>Construction Materials</u>				
	Not Determined			
<u>Land</u>				
Feedstock supply	5.36 × 10 ⁶ acres	2.17 × 10 ⁶ ha	1.48 × 10 ⁶ acres	
Plant site	2.0 acres	0.81 ha	0.55 acre	
<u>Personnel</u>				
Construction (1.4 yr)		176 workers	48.6 workers	
Operation and maintenance		61.1 workers	16.9 workers	

COSTS

	Reference Energy System	Per 10 ¹² Btu Energy Produced	Remarks
<u>Facility</u>			
		(1981 \$)	
Construction (1.4 yr)	\$129 × 10 ⁶ total	\$35.8 × 10 ⁶ total	Reference year for costs is 1976. 1976 CCI average (I _R) = 2401. See Explanatory Notes Section.
Operation and maintenance	\$34.3 × 10 ⁶ /yr	\$9.48 × 10 ⁶ /yr	
<u>Environmental Controls</u>			
An acid gas removal system and a sulfur removal system (Stretford) are used to control emissions			

METHANOL FROM WOOD

ENVIRONMENTAL RESIDUALS

	Quantities Released			Remarks
	Reference Energy System Annual Levels		Per 10 ¹² Btu Energy Produced	
	English Units	Metric Units		
<u>Air Pollutants</u>				
Oxides of sulfur		Trace		
Oxides of nitrogen	72.4 tons	65.7 tonnes	20.0 tons	
Particulates		Trace		
<u>Water Pollutants</u>				
Aqueous waste	1.11 × 10 ³ acre-ft	1.37 × 10 ⁹ l	0.307 × 10 ³ acre-ft	
<u>Solid Wastes</u>				
Ash and unconverted carbon	8.33 × 10 ³ tons	7.56 × 10 ³ tonnes	2.30 × 10 ³ tons	
<u>Thermal Discharge</u>				
		Not Determined		
<u>Noise Pollution</u>				
		Not Determined		

PRODUCTS

	Quantities Produced			Remarks
	Reference Energy System Annual Production		Per 10 ¹² Btu Energy Produced	
	English Units	Metric Units		
Primary				
Methanol	3.62 × 10 ¹² Btu	3.82 × 10 ¹⁵ J	1.00 × 10 ¹² Btu	
Byproducts				
Sulfur	395 tons	360 tonnes	109 tons	
Recoverables/Recyclables				
Treated wastewater	0.936 × 10 ³ acre-ft	1.16 × 10 ⁹ l	0.259 × 10 ³ acre-ft	

OCCUPATIONAL SAFETY AND HEALTH

Not Determined

ETHANOL FROM NONWOOD CELLULOSIC WASTES

REFERENCE ENERGY SYSTEM

The Arkansas/Gulf Simultaneous Saccharification and Fermentation process was chosen as the reference system. It employs cellulosic waste material containing about 57 percent cellulose as a feedstock. Typical raw material consists of two-thirds municipal solid waste (MSW) and one-third pumpmill waste (PMW). About 15 percent of the pretreated MSW is sterilized and employed as feedstock in a continuous enzyme production facility, and the remainder is mechanically treated and mixed with incoming PMW to feed the simultaneous saccharification steps. The ethanol is finally recovered to produce either anhydrous-grade (200 proof) or industrial-grade (190 proof) alcohol. Appropriate environmental control technologies are applied to limit residuals within compliance levels.

FACILITY OPERATING PARAMETERS

Size:	50×10^6 gal/yr
Annual Capacity Factor:	90%
Annual Energy Production:	3.60×10^{12} Btu
Efficiency:	51%
Lifetime:	10 yr

RESOURCES USED

	Quantities Used		Per 10 ¹² Btu Energy Produced	Remarks
	Reference Energy System Annual Usage			
	English Units	Metric Units		
<u>Feed Materials</u>				
Municipal solid waste	442 × 10 ³ tons	401 × 10 ³ tonnes	123 × 10 ³ tons	Oven-dry basis ↓
Pulpmill waste	218 × 10 ³ tons	198 × 10 ³ tonnes	60.6 × 10 ³ tons	
<u>Energy</u>				
Power	217 × 10 ⁶ kWh	217 × 10 ⁶ kWh	60.3 × 10 ⁶ kWh	
Fuel oil	392 × 10 ⁹ Btu	414 × 10 ¹² J	109 × 10 ⁹ Btu	
<u>Processing Materials</u>				
Nutrients and water	110 × 10 ³ tons	100 × 10 ³ tonnes	30.6 × 10 ³ tons	
<u>Water</u> (see Processing Materials)				
<hr/> Total Usage <hr/>				
<u>Construction Materials</u>				
		Not Determined		
<u>Land</u>	50 acres	20 ha	14 acres	
<u>Personnel</u>				
Construction (3 yr)		Not Determined		
Operation and maintenance	77 workers		21 workers	

COSTS

	Reference Energy System	Per 10^{12} Btu Energy Produced	Remarks
<u>Facility</u>			
Construction (3 yr)	$\$119 \times 10^6$ total	(1983 \$)* $\$33.1 \times 10^6$ total	
Operation and maintenance	$\$37.2 \times 10^6$ /yr	$\$10.3 \times 10^6$ /yr	
<u>Environmental Controls</u>			
Costs associated with environmental control technology such as flue gas scrubber, wastewater treatment, etc., are included in the above estimates			

*Operating cost estimate for 1983 plant startup.

ETHANOL FROM NONWOOD CELLULOSIC WASTES

ENVIRONMENTAL RESIDUALS

	Quantities Released			Remarks
	Reference Energy System Annual Levels		Per 10 ¹² Btu Energy Produced	
	English Units	Metric Units		
<u>Air Pollutants</u>				
Process carbon dioxide	154 × 10 ³ tons	140 × 10 ³ tonnes	42.7 × 10 ³ tons	
Fly ash (particulates)		Not Determined		
Oxides of sulfur		↓		
Oxides of nitrogen		377-1.51 × 10 ³ tonnes		
Ethanol vapor	415-1.66 × 10 ³ tons	Not Determined	115-461 tons	
Hydrocarbons		↓		
Dust from raw materials handling				
Carbon monoxide				
<u>Water Pollutants</u>				
Biochemical oxygen demand	300-425 tons	272-386 tonnes	83.3-118 tons	
Suspended solids	300-425 tons	272-386 tonnes	83.3-118 tons	
Water flow rate	1.84 × 10 ³ - 8.44 × 10 ³ acre-ft	2.27 × 10 ⁹ - 10.4 × 10 ⁹ l	0.511 × 10 ³ - 2.34 × 10 ³ acre-ft	
<u>Solid Wastes</u>				
Ash	39.6 × 10 ³ tons	36.0 × 10 ³ tonnes	11.0 × 10 ³ tons	
Sludge from wastewater treatment	9.9 × 10 ³ tons	9.0 × 10 ³ tonnes	2.8 × 10 ³ tons	
Noncellulosics from raw material processing	310 × 10 ³ tons	281 × 10 ³ tonnes	86.1 × 10 ³ tons	
<u>Thermal Discharge</u>				
		Not Determined		
<u>Noise Pollution</u>				
		Not Determined		

PRODUCTS

	Quantities Produced			Remarks
	Reference Energy System Annual Production		Per 10 ¹² Btu Energy Produced	
	English Units	Metric Units		
<u>Primary</u>				
Anhydrous ethanol (200 proof)	24.1 × 10 ⁶ gal	91.2 × 10 ⁶ l	6.69 × 10 ⁶ gal	
Industrial ethanol (190 proof)	24.8 × 10 ⁶ gal	93.9 × 10 ⁶ l	6.89 × 10 ⁶ gal	
<u>Byproducts</u>				
Animal feed molasses	176 × 10 ³ tons	160 × 10 ³ tonnes	48.9 × 10 ³ tons	
<u>Recoverables/Recyclables</u>				
Fuel oils	3.96 × 10 ³ tons	3.60 × 10 ³ tonnes	1.10 × 10 ³ tons	

OCCUPATIONAL SAFETY AND HEALTH

	Reference Energy System Annual	Per 10 ¹² Btu Energy Produced	Remarks
<u>Deaths</u>	4.17 × 10 ⁻³	1.16 × 10 ⁻³	
<u>Injuries</u>	3.31	0.919	

LOW-Btu GAS FROM PYROLYSIS (CENTRAL FACILITY)

REFERENCE ENERGY SYSTEM*

The reference system is a simple operation involving storage, shredding, and then pyrolysis. Corn residues are pyrolyzed at low pressures and relatively high temperature (875°C) to produce 64,000 ft³/hr of 150 Btu/ft³ gas. Char and oil are also produced.

*Wheat residues could also be pyrolyzed in essentially the same process to produce a low-Btu (130 Btu/ft³) gas and char. To produce 7.6×10^{10} Btu/yr of gas, 12,510 wet tons/yr of wheat residues would be required. This would also yield 4.1×10^{10} Btu/yr of char for a net system efficiency of 93 percent. Pollutants, costs, and materials would be very similar.

FACILITY OPERATING PARAMETERS

Size:	Scaled for use on a large farm; consumes 11.8×10^3 tons (wet) of corn per year
Annual Capacity Factor:	90%
Annual Energy Production:*	76×10^9 Btu of gas, 41×10^9 Btu of char
Efficiency:	85% total net 42% for gas only
Lifetime:	10 yr

*The production figure does not include the benefits of shredding, as these data were not available. The shredder can be added with only a nominal energy-use penalty (1.5%). The value 76×10^9 Btu of gas is used to convert annual values.

RESOURCES USED

	Quantities Used			Remarks
	Reference Energy System Annual Usage		Per 10 ¹² Btu Energy Produced	
	English Units	Metric Units		
Feed Materials				
Corn residues (dry)	9.3 × 10 ³ tons	8.4 × 10 ³ tonnes	120 × 10 ³ tons	20% moisture content
Corn residues (wet)	11.9 × 10 ³ tons	10.8 × 10 ³ tonnes	157 × 10 ³ tons	
Energy				
Electricity	40.1 × 10 ³ kWh	40.1 × 10 ³ kWh	528 × 10 ³ kWh	
Gasoline	3.30 × 10 ³ gal	12.5 × 10 ³ l	43.4 × 10 ³ gal	
Total Usage				
Construction Materials				
Not Determined				
Land				
Conversion facility	0.25 acre	0.10 ha	3.3 acres	
Corn residue production	2.32 × 10 ³ acres	939 ha	30.5 × 10 ³ acres	
Personnel				
Construction (1 yr)		0.45 worker	6.13 workers	
Operation and maintenance		0.50 worker	6.6 workers	

COSTS

	<u>Reference Energy System</u>	<u>Per 10¹² Btu Energy Produced</u>	<u>Remarks</u>	
<u>Facility</u>				
Construction (1 yr)	\$0.219 × 10 ⁶ total	(1981 \$) \$2.89 × 10 ⁶ total	Reference year for costs is 1977. 1977 CCI average (I _h) = 2577. See Explanatory Notes Section.	
Operation and maintenance	\$0.359 × 10 ⁶ /yr	\$4.73 × 10 ⁶ /yr		
<u>Environmental Controls</u>				
Environmental controls are not required for a plant of this size; particulate control would be necessary for larger plants or for control of cumulative effects of several plants				

LOW-Btu GAS FROM PYROLYSIS (CENTRAL FACILITY)

ENVIRONMENTAL RESIDUALS

	Quantities Released			Remarks
	Reference Energy System		Per 10 ¹² Btu Energy Produced	
	Annual Levels			
	English Units	Metric Units		
<u>Air Pollutants</u>				
Hydrogen sulfide	3.50 tons	3.18 tonnes	46.1 tons	
Oxides of nitrogen	3.96 tons	3.60 tonnes	52.1 tons	
Particulates	2.78 tons	2.53 tonnes	36.6 tons	
<u>Solid Wastes</u>				
None, the char and oil that are produced during pyrolysis are considered to be byproducts because they have a market value				
<u>Thermal Discharge</u>				
		Not Determined		
<u>Noise Pollution</u>				
		Not Determined		

PRODUCTS

	Quantities Produced			Remarks
	Reference Energy System Annual Production		Per 10 ¹² Btu Energy Produced	
	English Units	Metric Units		
<u>Primary</u>				
Product gas	7.6 × 10 ⁹ Btu	80 × 10 ¹² J	1.0 × 10 ¹² Btu	Heating value = 150 Btu/ft ³
<u>Byproducts</u>				
Char	1.4 × 10 ³ tons (41.3 × 10 ⁹ Btu)	1.3 × 10 ³ tonnes (43.6 × 10 ¹² J)	18 × 10 ³ tons (543 × 10 ⁹ Btu)	Heating value = 14.5 × 10 ³ Btu/lb
Pyrolytic oil		Not Determined		Heating value = 18 × 10 ³ Btu/lb

OCCUPATIONAL SAFETY AND HEALTH

Not Determined

MEDIUM-Btu BIOGAS FROM ANAEROBIC DIGESTION (CENTRAL FACILITY)

REFERENCE ENERGY SYSTEM

200 million gal/day of municipal sludge is anaerobically digested in two stages, producing 600 Btu/ft³ gas (primarily methane). The digested sludge is filtered. The resulting filtrate is treated, and the filter cake is disposed of.

FACILITY OPERATING PARAMETERS

Size:	Processes sludge from a city of 2 million people
Annual Capacity Factor:	100%
Annual Energy Production:	0.52×10^{12} Btu (net)
Efficiency:	39%
Lifetime:	20 yr

RESOURCES USED

	Quantities Used		Per 10 ¹² Btu Energy Produced	Remarks
	Reference Energy System Annual Usage			
	English Units	Metric Units		
<u>Feed Materials</u>				
Municipal sludge	73 × 10 ⁹ gal	280 × 10 ⁹ l	140 × 10 ⁹ gal	Input 20.17 × 10 ³ lb/hr solids with 75% volatile
<u>Energy</u>				
Digestors	140 × 10 ⁹ Btu	148 × 10 ¹² J	270 × 10 ⁹ Btu	
Filter operation	10.3 × 10 ⁶ kWh	10.3 × 10 ⁶ kWh	19.8 × 10 ⁹ kWh	
<u>Processing Materials</u>				
Ferric chloride		Not Determined ↓		
Lime				
<u>Water</u> (see PRODUCTS, Recoverables)				
<u>Total Usage</u>				
<u>Construction Materials</u>				
Steel	1.1 × 10 ³ tons	1.0 × 10 ³ tonnes	2.1 × 10 ³ tons	
Concrete	15.8 × 10 ³ tons	16.6 × 10 ³ tonnes	30.4 × 10 ³ tons	
<u>Land</u>	5 acres	2 ha	9.6 acres	
<u>Personnel</u>				
Construction		59.4 workers	114 workers	
Operation and maintenance		Not Determined		

COSTS

	<u>Reference Energy System</u>	<u>Per 10¹² Btu Energy Produced</u>	<u>Remarks</u>
<u>Facility</u>			
		(1981 \$)	Reference year for costs is 1972. 1972 CCI average (<i>I</i> ₁₉₇₂) = 1753. See Explanatory Notes Section.
Construction	\$8.14 × 10 ⁶ total	\$15.7 × 10 ⁶ total	
Operation and maintenance		Not Determined	
<u>Environmental Controls</u>			
Digester gas may need to be scrubbed due to high hydrogen sulfide levels; the digester supernatant and filtrate are returned to wastewater treatment plant where environmental controls are applied			

MEDIUM-Btu BIOGAS FROM ANAEROBIC DIGESTION (CENTRAL FACILITY)

ENVIRONMENTAL RESIDUALS

	Quantities Released			Remarks
	Reference Energy System		Per 10 ¹² Btu Energy Produced	
	Annual Levels			
	English Units	Metric Units		
<u>Air Pollutants</u>				
Carbon dioxide	22.4 × 10 ³ tons	20.4 × 10 ³ tonnes	43.1 × 10 ³ tons	
Hydrogen sulfide	36 × 10 ³ - 72 × 10 ³ tons	33 × 10 ³ - 66 × 10 ³ tonnes	69 × 10 ³ - 140 × 10 ³ tons	
Oxides of sulfur	74.5-149 tons	67.7-135 tonnes	143-287 tons	
Oxides of nitrogen	73 tons	66 tonnes	140 tons	
<u>Water Pollutants</u>				
Suspended solids	625 tons	567 tonnes	1.2 × 10 ³ tons	
Biochemical oxygen demand	575 tons	523 tonnes	1.1 × 10 ³ tons	
<u>Solid Wastes</u>				
Arsenic	3.8 tons	3.5 tonnes	7.3 tons	
Cadmium	2.2 tons	2.0 tonnes	4.2 tons	
Chromium	88.5 tons	80.3 tonnes	170 tons	
Copper	88.5 tons	80.3 tonnes	170 tons	
Lead	88.5 tons	80.3 tonnes	170 tons	
Mercury	0.88 ton	0.80 tonne	1.7 tons	
Nickel	18 tons	16 tonnes	35 tons	
Silver	20 tons	18 tonnes	38 tons	
Selenium	2.3 tons	2.1 tonnes	4.4 tons	
Zinc	221 tons	201 tonnes	425 tons	
<u>Thermal Discharge</u>				
		Not Determined		
<u>Noise Pollution</u>				
		Not Determined		

PRODUCTS

	Quantities Produced			Remarks
	Reference Energy System		Per 10 ¹² Btu Energy Produced	
	Annual Production			
	English Units	Metric Units		
<u>Primary</u>				
Gas (net)	0.52 × 10 ¹² Btu	0.55 × 10 ¹⁵ J	1.0 × 10 ¹² Btu	Heat content of gas = 600 Btu/ft ³
<u>Byproducts</u>				
Filter cake (can be incinerated to drive turbines)	51 × 10 ³ tons	46 × 10 ³ tonnes	98 × 10 ³ tons	
<u>Recoverables/Recyclables</u>				
Water	0.112 × 10 ³ acre-ft	138 × 10 ⁶ l	0.216 × 10 ³ acre-ft	

OCCUPATIONAL SAFETY AND HEALTH

Not Determined

MEDIUM-Btu WOOD GASIFICATION SYSTEM (CENTRAL FACILITY)

REFERENCE ENERGY SYSTEM

Wood is reduced to uniformly sized chips and fed into an oxygen-blown pyrolytic reactor. Product gas (46% carbon monoxide, 27% hydrogen, 13% carbon dioxide, 8% methane, 5% water) leaves the reactor with a heating value of about 260 Btu/ft³. It is then scrubbed and precipitated prior to storage.

FACILITY OPERATING PARAMETERS

Size:	Will support space heating and hot water needs of about 8600 households
Annual Capacity Factor:	Not determined
Annual Energy Production:	3.86×10^{12} Btu (net)
Efficiency:	73.2% (net)
Lifetime:	25 yr

RESOURCES USED

	Quantities Used		Per 10 ¹² Btu Energy Produced	Remarks
	Reference Energy System Annual Usage			
	English Units	Metric Units		
<u>Feed Materials</u>				
Wood chips	310 × 10 ³ tons	280 × 10 ³ tonnes	80 × 10 ³ tons	
Oxygen		Not Determined		
<u>Energy</u>				
Electrical power (estimated)	6.0 × 10 ³ kWh	6.0 × 10 ³ kWh	1.5 × 10 ³ kWh	
<u>Processing Materials</u>				
Gas (for pilot burner in combustor)		Not Determined		
Cleaning solvent (in electrostatic precipitator)		↓		
<u>Water</u>				
Cooling and scrubbing	0.386 × 10 ³ acre-ft	480 × 10 ⁶ l	0.101 × 10 ³ acre-ft	
	Total Usage			
<u>Construction Materials</u>				
		Not Determined		
<u>Land</u>				
Plant site	8.5 acres	3.4 ha	2.2 acres	
For sustainable wood supply	> 60.0 × 10 ³ acres	> 24.3 × 10 ³ ha	> 15.5 × 10 ³ acres	
<u>Personnel</u>				
Construction (2 yr)		382 workers	99 workers	
Operation and maintenance		49 workers	12.7 workers	

COSTS

	Reference Energy System	Per 10 ¹² Btu Energy Produced	Remarks
<u>Facility</u>		(1981 \$)	
Construction (2 yr)	$\$21.6 \times 10^6$ total	$\$5.61 \times 10^6$ total	Reference year for costs is 1976. 1976 CCI average (I_R) = 2401. See Explanatory Notes Section.
Operation and maintenance	$\$10.6 \times 10^6$ /yr	$\$2.75 \times 10^6$ /yr	
<u>Environmental Controls</u>			
The primary impact of a wood gasification system is created by the harvesting of wood rather than the conversion process; the residuals of the conversion process have minimal impact; the slag residue produces no objectionable leachates and is used as a solid fill or roadbed material			

MEDIUM-Btu WOOD GASIFICATION SYSTEM (CENTRAL FACILITY)

ENVIRONMENTAL RESIDUALS

	Quantities Released			Remarks
	Reference Energy System		Per 10 ¹² Btu Energy Produced	
	Annual Levels			
	English Units	Metric Units		
<u>Air Pollutants</u>				
Particulates	1.39 tons	1.26 tonnes	0.360 ton	
Tire wear	0.270 ton	0.250 tonne	0.070 ton	
Sulfur dioxide	4.05 tons	3.68 tonnes	1.05 tons	
Carbon monoxide	41.7 tons	37.9 tonnes	10.8 tons	
HCO	6.56 tons	5.96 tonnes	1.71 tons	
Oxides of nitrogen	30.5 tons	27.7 tonnes	7.90 tons	
Aldehydes	0.42 ton	0.38 tonne	0.11 ton	
Organic acids	0.42 ton	0.38 tonne	0.11 ton	
<u>Water Pollutants</u>				
Suspended solids	3.63 × 10 ³ tons	3.30 × 10 ³ tonnes	940 tons	
Biochemical oxygen demand	42.8 tons	38.9 tonnes	11.1 tons	
Chemical oxygen demand	83.5 tons	75.9 tonnes	21.6 tons	
Carbon solvent	21.7 tons	19.7 tonnes	5.62 tons	
Cadmium	0.040 ton	0.036 tonne	0.01 ton	
Chromium	0.015 ton	0.014 tonne	0.004 ton	
Copper	0.027 ton	0.024 tonne	0.007 ton	
Ferric chloride	5.83 tons	5.30 tonnes	1.51 tons	
Ferric sulphate	2.93 tons	2.66 tonnes	0.76 ton	
Mercury	7.0 × 10 ⁻³ ton	6.3 × 10 ⁻³ tonne	1.8 × 10 ⁻³ ton	
Manganese	6.95 tons	6.31 tonnes	1.80 tons	
Nickel	0.039 ton	0.035 tonne	0.010 ton	
Lead	15.2 tons	13.8 tonnes	3.94 tons	
Zinc	29.6 tons	26.9 tonnes	7.67 tons	
<u>Solid Wastes</u>				
Slag/Ash	3.10 × 10 ³ tons	2.81 × 10 ³ tonnes	803 tons	
Antimony	180 × 10 ⁻⁶ ton	163 × 10 ⁻⁶ tonne	47.0 × 10 ⁻⁶ ton	
Arsenic	630 × 10 ⁻⁶ ton	570 × 10 ⁻⁶ tonne	164 × 10 ⁻⁶ ton	
Barium	43.0 × 10 ⁻³ ton	39.0 × 10 ⁻³ tonne	11.2 × 10 ⁻³ ton	
Beryllium	0.32 × 10 ⁻³ ton	0.29 × 10 ⁻³ tonne	83 × 10 ⁻⁶ ton	
Boron	46 × 10 ⁻³ ton	42 × 10 ⁻³ tonne	12 × 10 ⁻⁶ ton	
Cadmium	1.97 × 10 ⁻³ ton	1.80 × 10 ⁻³ tonne	0.51 × 10 ⁻³ ton	
Chlorine	6.18 tons	5.61 tonnes	1.60 tons	
Chromium	0.71 × 10 ⁻³ ton	0.65 × 10 ⁻³ tonne	0.18 × 10 ⁻³ ton	
Cobalt	1.47 × 10 ⁻³ ton	1.34 × 10 ⁻³ tonne	0.38 × 10 ⁻³ ton	
Copper	43.2 × 10 ⁻³ ton	39.3 × 10 ⁻³ tonne	11.2 × 10 ⁻³ ton	
Fluorine	1.55 × 10 ⁻³ ton	1.41 × 10 ⁻³ tonne	0.40 × 10 ⁻³ ton	
Lead	8.34 × 10 ⁻³ ton	7.57 × 10 ⁻³ tonne	2.16 × 10 ⁻³ ton	
Manganese	1.97 tons	1.79 tonnes	0.51 ton	
Mercury	0.48 × 10 ⁻³ ton	0.44 × 10 ⁻³ tonne	0.12 × 10 ⁻³ ton	
Nickel	8.34 × 10 ⁻³ ton	7.57 × 10 ⁻³ tonne	2.16 × 10 ⁻³ ton	
Selenium	0.63 × 10 ⁻³ ton	0.58 × 10 ⁻³ tonne	0.16 × 10 ⁻³ ton	
Tin	0.92 × 10 ⁻³ ton	0.84 × 10 ⁻³ tonne	0.24 × 10 ⁻³ ton	
Titanium	3.09 × 10 ⁻³ ton	2.80 × 10 ⁻³ tonne	0.80 × 10 ⁻³ ton	
Vanadium	4.98 × 10 ⁻³ ton	4.52 × 10 ⁻³ tonne	1.29 × 10 ⁻³ ton	
Zinc	0.502 ton	0.456 tonne	0.13 ton	

PRODUCTS

	Quantities Produced			Remarks
	Reference Energy System		Per 10 ¹² Btu Energy Produced	
	Annual Production			
	English Units	Metric Units		
Primary				
Pyrolysis gas (net)	13.8 × 10 ⁹ scf	391 × 10 ⁶ m ³	3.58 × 10 ⁹ scf	@ 1 scf = 260 Btu
Heat value of gas (net)	3.86 × 10 ¹² Btu	4.07 × 10 ¹⁵ J	10 ¹² Btu	@ 1 scf = 260 Btu
<u>Recoverables/Recyclables</u>				
Oils and tars collected from the gas by the electrostatic precipitator are returned in the shaft furnace				
Water from the condensor is returned to the gas scrubber				

OCCUPATIONAL SAFETY AND HEALTH

Not Determined

INDUSTRIAL WOOD-FIRED BOILER

ENERGY SYSTEM DESCRIPTION

Wood-Fired Steam Boiler for Industrial Process; Spreader-Stoker, Water Tube Boiler Rated at 150×10^6 Btu/hr Heat Input; Provides 78.4×10^3 lb/hr Process Steam at 250 psig and 406°F With 70 Percent Condensate Return; Wood Fuel at 50 Percent Moisture Content; Mechanical Collectors Followed by Electrostatic Precipitator for Particulate Control; On-Ash Disposal; and Onsite Water Treatment. New Boiler Meets Draft New Source Performance Standards for Non-Fossil, Fuel-Fired Boilers for Particulates and Opacity.

FACILITY OPERATING PARAMETERS

Size:	150×10^6 Btu/hr heat input; 16.5 ton/hr wood feed rate
Annual Capacity Factor:	60%
Annual Energy Production:	0.495×10^{12} Btu
Efficiency:	65%
Lifetime:	30 yr

RESOURCES USED

Resource	Quantities Used			Remarks
	Reference Energy System Annual Usage*		Per 10 ¹² Btu Energy Produced	
	English Units	Metric Units		
<u>Fuel</u>				
Wood to wood storage	86.5 × 10 ³ tons	78.5 × 10 ³ tonnes	175 × 10 ³ tons	
Wood feed to boiler	86.5 × 10 ³ tons	78.5 × 10 ³ tonnes	175 × 10 ³ tons	
<u>Air</u>				
Combustion air to boiler	429 × 10 ³ tons	389 × 10 ³ tons	867 × 10 ³ tons	
<u>Water</u>				
Boiler makeup water	15.8 × 10 ⁶ gal	59.8 × 10 ⁶ litres	31.9 × 10 ⁶ gal	Assumes 70 percent condensate return
Ash disposal water needs	854 × 10 ³ gal	3.23 × 10 ⁶ litres	1.73 × 10 ⁶ gal	
<u>Land</u>				
Boiler plant**	7.4 acres	3.0 ha	15 acres	
Solid waste disposal	0.2 acres	81 × 10 ⁻³ ha	0.40 acres	
<u>Raw Materials</u>				
Sodium chloride	13.9 tons	15.3 tons	28.1 tons	Other raw water treatment chemicals not determined
<hr/> Total Usage <hr/>				
<u>Construction Materials**</u>				
Steel	150 tons	136 tonnes	303 tons	
Refractory	140 tons	127 tonnes	283 tons	
<u>Personnel</u>				
Construction (1.5 yr)	77 workers		156 workers	
Operation and Maintenance	7 workers		14 workers	

*Based on assumed 60% capacity factor.

**One-time acquisition — not an annual requirement.

COSTS

Facility	Reference Energy System (1982 \$)	Per 10^{12} Btu Energy Reduced	Remarks
Capital cost	$\$9.15 \times 10^6$ total	$\$18.5 \times 10^6$ total	
Annualized cost	$\$3.16 \times 10^6$ /yr	$\$6.38 \times 10^6$ /yr	
Air emission controls (capital)*	$\$1.61 \times 10^6$ total	$\$3.25 \times 10^6$ total	

*Included in above estimates for total capital costs.

INDUSTRIAL WOOD-FIRED BOILER

ENVIRONMENTAL RESIDUALS AND PRODUCTS

Reference Energy System				
Annual Levels*				
Residual or Product	English Units	Metric Units	Per 10 ¹² Btu Energy Produced	Remarks
<u>Air Pollutants</u>				
Particulates	39.4 tons	35.7 tonnes	79.6 tons	
Oxides of nitrogen (NO _x)	80.4 tons	72.9 tonnes	162 tons	
Carbon monoxide (CO)	644 tons	584 tonnes	1300 tons	
Hydrocarbons (HC)	161 tons	146 tonnes	325 tons	
Sulfur dioxide (SO ₂)	<34.6 tons	<31.4 tonnes	<70.0 tons	
Polycyclic organic matter (POM)	<0.29 tons	<0.263 tonnes	<0.586 tons	
<u>Water Pollutants</u>				
Wood storage runoff	Not Determined			
Water treatment discharge	1.22 × 10 ⁶ gal	4.62 × 10 ⁶ liters	2.46 × 10 ⁶ gal	
<u>Solid Wastes</u>				
Bottom ash (dry)	585 tons	531 tonnes	1180 tons	
Classifier ash (dry)	848 tons	769 tonnes	1710 tons	
Electrostatic precipitator ash (dry)	344 tons	312 tonnes	695 tons	

*Based on assumed 60% capacity factor.

PRODUCTS

	Quantities Used			Remarks
	Reference Energy System Annual Production		Per 10 ¹² Btu Energy Produced	
	English Units	Metric Units		
Primary				
Steam	206 × 10 ³ tons	187 × 10 ³ tonnes	416 × 10 ³ tons	Steam delivered to industrial process

OCCUPATIONAL SAFETY AND HEALTH

	Annual	Per 10 ¹² Btu Energy Produced	Remarks
Deaths	0.4.7 × 10 ⁻³	0.9.5 × 10 ⁻³	
Injuries	79 × 10 ⁻³ - 94 × 10 ⁻³	0.16 - 0.19	

WOOD-FIRED STEAM ELECTRIC PLANT

REFERENCE ENERGY SYSTEM

Steam is produced through the direct combustion of wood in a spreader stoker furnace. The steam is expanded in a turbo-generator to produce electricity.

FACILITY OPERATING PARAMETERS

Size: 62 MWe or 1.48×10^{12} Btu/yr
 Annual Capacity Factor: 80%
 Annual Energy Production: 1.37×10^{12} Btu (net)
 (0.401×10^9 kWh)
 Efficiency: 19.7% (net)
 Lifetime: 20 yr

RESOURCES USED

	Quantities Used		Per 10 ¹² Btu Energy Produced	Remarks	
	Reference Energy System Annual Usage				
	English Units	Metric Units			
<u>Feed Materials</u>					
Dry wood	365 × 10 ³ tons	330 × 10 ³ tonnes	266 × 10 ³ tons	Dry wood assumed to have an energy content of 9.5 × 10 ³ Btu/lb	
<u>Energy</u>					
Electricity	31.5 × 10 ⁶ kWh	31.5 × 10 ⁶ kWh	23.0 × 10 ⁶ kWh		
<u>Processing Materials</u>					
Combustion air	2.95 × 10 ⁶ ton	2.70 × 10 ⁶ tonnes	2.15 × 10 ⁶ tons		
<u>Water</u>	3.37 × 10 ³ acre-ft	4.16 × 10 ³ l	2.46 × 10 ³ acre-ft		
<u>Total Usage</u>					
<u>Construction Materials</u>					
Concrete	12.3 × 10 ³ tons	11.2 × 10 ³ tonnes	9.0 × 10 ³ tons	Estimated from coal- fired plant statistics	
Carbon steel	4.30 × 10 ³ tons	3.91 × 10 ³ tonnes	3.13 × 10 ³ tons		
Alloy steel	225 tons	204 tonnes	164 tons		
Stainless steel	78 tons	71 tonnes	57 tons		
Copper	110 tons	100 tonnes	80 tons		
Aluminum	36 tons	33 tonnes	26 tons		
Manganese	34 tons	31 tonnes	25 tons		
Chromium	20 tons	18 tonnes	15 tons		
Nickel	3.2 tons	3 tonnes	2.3 tons		
Cast iron	54 tons	50 tonnes	39 tons		
<u>Land</u>					
Storage and plant	102 acres	41.4 ha	74.6 acres		
<u>Personnel</u>					
Construction (2 yr)		357 workers	260 workers		
Operation and maintenance		33.1 workers	24.2 workers		

COSTS

	Reference Energy System	Per 10^{12} Btu Energy Produced	Remarks
Facility			
		(1981 \$)	Reference year for costs is 1977. 1977 CCI average (I_R) = 2577. See Explanatory Notes Section.
Construction (2 yr)	\$79.8 $\times 10^6$ total	\$58.3 $\times 10^6$ total	
Operation and maintenance	\$21.9 $\times 10^6$ /yr	\$16.0 $\times 10^6$ /yr	
Environmental Controls			
Water treatment plant	\$0.507 $\times 10^6$ total	\$0.370 $\times 10^6$ total	Included in facility construction costs
Flue gases can be cleaned with inertial collectors (cyclones), wet scrubbers, dry scrubbers, baghouses, and electrostatic precipitators, but no specific price information was available for these components			Pricing of these items has been done mainly for larger coal-fired plants

WOOD-FIRED STEAM ELECTRIC PLANT

ENVIRONMENTAL RESIDUALS

	Quantities Released			Remarks
	Reference Energy System Annual Levels		Per 10 ¹² Btu Energy Produced	
	English Units	Metric Units		
<u>Air Pollutants</u>				
Sulfur dioxide	740 tons	670 tonnes	540 tons	
Oxides of nitrogen	3.7 × 10 ³ tons	3.4 × 10 ³ tonnes	2.7 × 10 ³ tons	
Particulates (inorganics, unburned hydrocarbons, unburned carbons)		trace		
<u>Water Pollutants</u>				
Aqueous waste	1.78 × 10 ³ acre-ft	2.20 × 10 ⁹ l	1.30 × 10 ³ acre-ft	
<u>Solid Wastes</u>				
Total solid wastes: ash content, 89%; misc. content, 11%	6.71 × 10 ³ tons	6.09 × 10 ³ tonnes	4.90 × 10 ³ tons	Solids are generally inert, composed of silica and alumina oxides with minor fractions of sodium, magnesium, and potas- sium; lead is found in very minor quantities
<u>Thermal Discharge</u>				
Flue gas	3.2 × 10 ⁶ tons	2.9 × 10 ⁶ tonnes	2.3 × 10 ⁶ tons	Heat content of gas not available

PRODUCTS

	Quantities Produced			Remarks
	Reference Energy System Annual Production		Per 10 ¹² Btu Energy Produced	
	English Units	Metric Units		
Primary				
Electricity (net)	401 × 10 ⁶ kWh	401 × 10 ⁶ kWh	293 × 10 ⁶ kWh	

OCCUPATIONAL SAFETY AND HEALTH

	Reference Energy System Annual	Per 10 ¹² Btu Energy Produced	Remarks
<u>Deaths</u>			
Hazards are no different from other fossil fuels except that sander dust is highly combustible and requires the utmost care to prevent explosions			
<u>Injuries</u>			
The logging industry (feed-stock collection) is considered to be a high-risk industry			

WIND ENERGY CONVERSION SYSTEM – ELECTRIC UTILITY APPLICATION

REFERENCE ENERGY SYSTEM

Wind energy turns a horizontal axis rotor to produce shaft horsepower. The machine operates at constant speed by varying the pitch of its rotor blades. Design wind speeds for the high-, medium-, and low-wind machines are 18, 15, and 12 mph, respectively. The shaft horsepower is converted to electrical energy and supplied to the utility grid. Compressed-air energy storage is used as an alternative to battery storage.

FACILITY OPERATING PARAMETERS

Size:	1.5 × 10 ³ kWe rated capacity
	Low wind: 278 ft diameter
	Med. wind: 219 ft diameter
	High wind: 190 ft diameter
Annual Capacity Factor:	Low wind: 0.22
	Med. wind: 0.33
	High wind: 0.39
Annual Energy Production:	Low wind: 10 × 10 ⁹ Btu
	(2.92 × 10 ⁶ kWh)
	Med. wind: 14.8 × 10 ⁹ Btu
	(4.33 × 10 ⁶ kWh)
	High wind: 17 × 10 ⁹ Btu
	(5.01 × 10 ⁶ kWh)
Efficiency:	Varies with wind speed – up to 45%
Lifetime:	30 yr

RESOURCES USED

	Quantities Used		Per 10 ¹² Btu Energy Produced	Remarks
	Reference Energy System Annual Usage			
	English Units	Metric Units		
<u>Feed Materials</u>				
Wind		Not Determined		
<u>Energy</u>				
Ancillary		Not Determined		
<u>Water</u>				
Alternate storage systems, such as pumped hydro, may require significant water usage.				
	Total Usage			
<u>Construction Materials</u>				
Concrete	550 tons	500 tonnes	55.0 × 10 ³ tons	Low wind
	470 tons	420 tonnes	31.5 × 10 ³ tons	Med. wind
	370 tons	340 tonnes	21.4 × 10 ³ tons	High wind
Steel	180 tons	160 tonnes	18.0 × 10 ³ tons	Low wind
	140 tons	130 tonnes	9.4 × 10 ³ tons	Med. wind
	95 tons	90 tonnes	5.5 × 10 ³ tons	High wind
Copper	1.3 tons	1.2 tonnes	130 tons	Same for all sizes
Fiberglass	20 tons	18 tonnes	2.0 × 10 ³ tons	Low wind
	14 tons	13 tonnes	0.94 × 10 ³ tons	Med. wind
	8.5 tons	8 tonnes	490 tons	High wind
<u>Land</u>	0.51 acre	0.2 ha	51 acres	Same for all sizes
<u>Personnel</u>				
Construction (0.3 yr)		1.8 workers	180 workers	Low wind
Operation and maintenance		Not Determined		

WIND ENERGY CONVERSION SYSTEM — ELECTRIC UTILITY APPLICATION

COSTS

	Reference Energy System	Per 10 ¹² Btu Energy Produced	Remarks
<u>Facility</u>		(1981 \$)	
Construction (0.3 yr)	\$30 × 10 ³ total	\$3.0 × 10 ⁶ total*	Low wind
Operation and maintenance		Not Determined	

*Estimated cost of a yet-to-be-commercialized 1.5 × 10³-kW-rated wind machine.

ENVIRONMENTAL RESIDUALS

	Quantities Released		
	Reference Energy System Annual Levels		
	English Units	Metric Units	Per 10 ¹² Btu Energy Produced
<u>Air Pollutants</u>			
Potential for compressed air storage to become contaminated by underground storage exists (for example, residual hydrocarbons from abandoned gas wells or mines)			
<u>Water Pollutants</u>			
Potential for aquifer pollution by compressed air storage			
<u>Solid Wastes</u>			
No annual residuals; however, upon decommissioning, the concrete and fiberglass must be disposed of			
<u>Noise Pollution</u>			
Some problems with low frequency noise have been noted, but they are not considered to be significant			

PRODUCTS

	Quantities Produced		
	Reference Energy System Annual Production		
	English Units	Metric Units	Per 10 ¹² Btu Energy Produced
<u>Primary</u>			
Electricity	2.9 × 10 ⁶ kWh	2.9 × 10 ⁶ kWh	0.29 × 10 ⁹ kWh
<u>Recoverables/Recyclables</u>			
No annual recoverables; however, upon decommissioning, the copper and steel may be economically recoverable			

OCCUPATIONAL SAFETY AND HEALTH

	Reference Energy System Annual	Per 10 ¹² Btu Energy Produced	Remarks
<u>Deaths</u>		Not Determined	
<u>Injuries</u>			
Wind energy conversion systems are characterized by safety hazards associated with mechanical stresses in rotor blades and tower; the stresses may result in catastrophic failure of those members			

SOLAR THERMAL POWER PLANT (CENTRAL FACILITY)

REFERENCE ENERGY SYSTEM

The central receiver (on a tower) is surrounded by or adjacent to a field of tracking heliostats, which are automatically steered to reflect direct solar radiation onto the receiver. The energy is transferred from the absorber to a working fluid, which is a heat source for a thermodynamic cycle. This cycle generates electricity, which is fed into the utility grid. A storage system is employed to provide a more constant generating capacity. The southwestern United States is the location of the reference system.

FACILITY OPERATING PARAMETERS

Size:	100 × 10 ³ kWe plant, 7.45 × 10 ⁶ ft ² heliostats
Annual Capacity Factor:	50%
Annual Energy Production: (location specific)	1.5 × 10 ¹² Btu (0.44 × 10 ⁹ kWh)
Efficiency:	23.4%
Lifetime:	30 yr

RESOURCES USED

	Quantities Used		Per 10 ¹² Btu Energy Produced	Remarks
	Reference Energy System Annual Usage			
	English Units	Metric Units		
Feed Materials				
Incident solar radiation	6.4 × 10 ¹² Btu	6.8 × 10 ¹⁵ J	4.27 × 10 ¹² Btu	
Energy				
Ancillary		Not Determined		
Processing Materials				
Referencing system assumes water as a working fluid and hydrocarbon oil as a storage fluid; other fluids such as liquid sodium, sodium hydroxide, or eutectic salts may be used				
Water				
Process and maintenance	30.3 acre-ft	37.4 × 10 ⁶ l	20.2 acre-ft	Boiler make-up and heliostat washing
Total Usage				
Construction Materials				
Aluminum	2 × 10 ³ – 5 × 10 ³ tons	1.8 × 10 ³ – 4.6 × 10 ³ tonnes	1.3 × 10 ³ – 3.4 × 10 ³ tons	
Concrete	150 × 10 ³ – 250 × 10 ³ tons	140 × 10 ³ – 230 × 10 ³ tonnes	100 × 10 ³ – 170 × 10 ³ tons	
Copper	0.5 × 10 ³ – 1.0 × 10 ³ tons	500 × 10 ³ – 910 × 10 ³ tonnes	340–670 tons	
Exotic metals (chrome and titanium)	110–200 tons	95–180 tonnes	70–130 tons	
Glass	5.0 × 10 ³ – 10 × 10 ³ tons	4.5 × 10 ³ – 9.1 × 10 ³ tonnes	3.3 × 10 ³ – 6.7 × 10 ³ tons	
Insulation	2.0 × 10 ³ – 4 × 10 ³ tons	1.8 × 10 ³ – 3.7 × 10 ³ tonnes	1.3 × 10 ³ – 2.7 × 10 ³ tons	
Plastic	0.5 × 10 ³ – 2 × 10 ³ tons	0.5 × 10 ³ – 1.8 × 10 ³ tonnes	0.3 × 10 ³ – 1.3 × 10 ³ tons	
Silver	1–5.0 tons	0.9–4.5 tonnes	0.7–3.3 tons	
Steel	50 × 10 ³ – 70 × 10 ³ tons	45 × 10 ³ – 64 × 10 ³ tonnes	33 × 10 ³ – 47 × 10 ³ tons	
Land	1 × 10 ³ acres	407 ha	670 acres	
Personnel				
Construction (2-3 yr)	850–1.27 × 10 ³ workers		570–850 workers	
Operation and maintenance	60 workers		40 workers	

SOLAR THERMAL POWER PLANT (CENTRAL FACILITY)

COSTS

	Reference Energy System	Per 10^{12} Btu Energy Produced	Remarks
<u>Facility</u>	(1981 \$)		
Construction (2-3 yr)	$\$192.0 \times 10^6$ total	$\$128.2 \times 10^6$ total	Reference year for costs is 1972. 1972 CCI average (I_R) = 1753. See Explanatory Notes Section.
Operation and maintenance	$\$2.01 \times 10^6 - 3.83 \times 10^6/\text{yr}$	$\$1.41 \times 10^6 - 2.62 \times 10^6/\text{yr}$	
<u>Environmental Controls</u>	Not Determined		

ENVIRONMENTAL RESIDUALS

	Quantities Released		Per 10 ¹² Btu Energy Produced	Remarks
	Reference Energy System Annual Levels			
	English Units	Metric Units		
<u>Air Pollutants</u>				
No normal releases; potential release of pollutants during fire or system rupture (depends on the composition of the working and storage fluids—could include nitrogen oxides, sodium monoxide/peroxide, and sodium hydroxide mists or dusts)				
<u>Water Pollutants</u>				
Boiler blowdown	29 acre-ft	35 × 10 ⁶ l	19 acre-ft	
Accidental or emergency releases and periodic system flushings release pollutants, depending on fluids involved; possible pollutants are hydrocarbon oils, corrosion inhibitors (chromate, borate, nitrate, nitrite, sulfate, sulphite, arsenate, benzoate salts, triazole, silicate, and phosphates), pH controllers, bactericides, and glycols; herbicides and chemical dust suppressors may be released during maintenance				
<u>Solid Wastes</u>				
No annual residuals; however, upon decommissioning, such construction materials as concrete, glass, insulation, and plastic must be disposed of				
<u>Thermal Discharge</u>				
Waste heat	2.3 × 10 ¹² Btu	2.4 × 10 ¹⁵ J	1.5 × 10 ¹² Btu	

PRODUCTS

	Quantities Produced			Remarks
	Reference Energy System Annual Production		Per 10 ¹² Btu Energy Produced	
	English Units	Metric Units		
<u>Primary</u>				
Electrical energy	0.44 × 10 ⁹ kWh	0.44 × 10 ⁹ kWh	0.293 × 10 ⁹ kWh	
<u>Recoverables/Recyclables</u>				
No annual recoverables; however, upon decommissioning, such materials as aluminum, copper, silver, exotic metals, and steel may be economically recoverable				

OCCUPATIONAL SAFETY AND HEALTH

	Reference Energy System Annual	Per 10^{12} Btu Energy Produced	Remarks
<u>Deaths/Injuries</u>			
Reflection from heliostats and fire or system rupture are potential hazards			

SOLAR PHOTOVOLTAIC POWER PLANT (CENTRAL UTILITY)

REFERENCE ENERGY SYSTEM

A field near Phoenix, Arizona, was designated as the reference location for the solar photovoltaic power plant. Ground-mounted arrays of single-crystal silicon photovoltaic cells generated direct electrical current from incident solar radiation. Glass reflectors on the backside of the support structure concentrate the solar radiation in the ratio of 1.23:1. The arrays are connected to a voltage regulator, an a.c./d.c. inverter, and ultimately to a utility grid. The system is designed without a storage device.*

FACILITY OPERATING PARAMETERS

Size: 109 MW_e (peak watts)*
 Annual Capacity Factor: 30%
 Annual Energy Production: 0.79×10^{12} Btu
 (0.23×10^9 kWh)
 Efficiency: 14% net (16% for cells)
 Lifetime: 30 yr

*Photovoltaic power plants in other locations may require different collector areas to attain the same annual energy production. System energy output is highly location dependent. Photovoltaic modules with different semiconductors (i.e., cadmium sulfide, gallium arsenide) glazings, and substrates (i.e., aluminum, plastics) are also possible; they would have different efficiencies, produce different amounts of energy, and have different residuals.

RESOURCES USED

	Quantities Used			Remarks
	Reference Energy System Annual Usage		Per 10 ¹² Btu Energy Produced	
	English Units	Metric Units		
Feed Materials				
Solar energy	5.7 × 10 ¹² Btu	6.0 × 10 ¹⁵ J	7.2 × 10 ¹² Btu	
Water				
Periodic washing of photovoltaic panels and reflector surfaces may be necessary				
	Total Usage			
Construction Materials				
Support structure				
• Concrete	48.8 × 10 ³ tons	44.4 × 10 ³ tonnes	61.5 × 10 ³ tons	
• Steel	4.6 × 10 ³ tons	4.2 × 10 ³ tonnes	5.8 × 10 ³ tons	
Photovoltaic panels*				
• Glazing (Lexan)		Not Determined		
• Silicon	325 tons	296 tonnes	410 tons	
• Silver	11.7 tons	10.7 tonnes	14.8 tons	
• Tantalum pentoxide	1.5 tons	1.4 tonnes	1.9 tons	
• Exotics (boron and phosphorus)	3.0 × 10 ⁻⁶ ton	5.5 × 10 ⁻⁶ tonne	7.6 × 10 ⁻⁶ ton	
• Aluminum	19 tons	17 tonnes	24 tons	
Inverter				
• Steel		Not Determined		
• Copper				
• Zinc				
• Silicon				
Land	230 acres	93 ha	290 acres	
Personnel				
Construction	850 workers		1.08 × 10 ³ workers	
Operation and maintenance		Not Determined		

*Alternate materials available for solar cells include cadmium sulfide and gallium arsenide.

SOLAR PHOTOVOLTAIC POWER PLANT (CENTRAL UTILITY)

COSTS

Facility	Reference Energy System	Per 10 ¹² Btu Energy Produced	Remarks
	(1981 \$)*		
Construction	$\$127 \times 10^6 - 185 \times 10^6$ total	$\$153 \times 10^6 - 218 \times 10^6$ total	Reference year for costs is 1980. 1980 CCI average (I_R) = 3237. See Explanatory Notes Section.
Operation and maintenance	$\$2.1 \times 10^6/\text{yr}$	$\$2.51 \times 10^6/\text{yr}$	

*This represents construction in 1986 (in 1981\$); it assumes Department of Energy goals for central power stations at that time.

ENVIRONMENTAL RESIDUALS

	Quantities Released			Remarks
	Reference Energy System Annual Levels		Per 10 ¹² Btu Energy Produced	
	English Units	Metric Units		
<u>Air Pollutants</u>				
There is a potential for accidental high-voltage arcing, which will generate ozone and fumes from burned plastics				
<u>Water Pollutants</u>				
If the photovoltaic arrays are washed, then the detergents (if any) used may ultimately cause oxygen demand; herbicides, if used, also create oxygen demand				
<u>Solid Wastes</u>				
No annual solid wastes are generated; however, upon decommissioning, such solid wastes as concrete, silicon, and the glazing must be disposed of — depending on the economics and efficiency of the recovery process, it may be possible to recycle the silicon component of the cell				
<u>Thermal Discharge</u>				
Heat loss from inverter	55 × 10 ⁹ Btu	58 × 10 ¹² J	69 × 10 ⁹ Btu	

PRODUCTS

	Quantities Produced			Remarks
	Reference Energy System Annual Production		Per 10 ¹² Btu Energy Produced	
	English Units	Metric Units		
Primary				
Electrical energy	0.23 × 10 ⁹ kWh	0.23 × 10 ⁹ kWh	0.29 × 10 ⁹ kWh	
<u>Recoverables/Recyclables</u>				
No annual recoverables; however, upon decommissioning, such materials as steel, aluminum, silver, and possibly silicon may be economically recoverable				

OCCUPATIONAL SAFETY AND HEALTH

	Reference Energy System Annual	Per 10 ¹² Btu Energy Produced	Remarks
<u>Deaths and Injuries</u>			
Manufacture of photovoltaic cells requires handling, storage, and transportation of potentially hazardous substances; accidents involving such substances may cause injuries; accidental high-voltage arcing or short circuits may result in fires and injuries			

OCEAN THERMAL ENERGY CONVERSION

REFERENCE ENERGY SYSTEM

The reference system uses the ocean temperature differential between the surface and depths of up to 1000 ft to drive a simple Rankine cycle to produce electricity. Ammonia is the working fluid, and titanium shell and tube heat exchangers transmit the thermal energy between the ammonia and seawater. Power is transmitted to shore by either a.c. or d.c. cables, depending on the distance.

FACILITY OPERATING PARAMETERS

Size: 400 MWe at 40° F ΔT
 Annual Capacity Factor: 73 - 90%
 Annual Energy Production:* 8.4×10^{12} - 10.4×10^{12} Btu
 Efficiency: 3%
 Lifetime: 30 yr (plant amortization)

* 8.4×10^{12} Btu used to convert annual values.

RESOURCES USED

	Quantities Used		Per 10 ¹² Btu Energy Produced	Remarks
	Reference Energy System Annual Usage			
	English Units	Metric Units		
<u>Feed Materials</u>				
Seawater				See Water
<u>Energy</u>				
		Not Determined		
<u>Processing Materials</u>				
Ammonia	10 tons	9.1 tonnes	1.2 tons	Make up for losses
<u>Water</u>				
Warm seawater	8.90 × 10 ⁶ acre-ft	11.0 × 10 ¹² l	1.06 × 10 ⁶ acre-ft	
Cold seawater	12 × 10 ⁶ acre-ft	14 × 10 ¹² l	1.4 × 10 ⁶ acre-ft	
<u>Total Usage</u>				
<u>Construction Materials</u>				
Concrete	375 × 10 ³ - 467 × 10 ³ tons	340 × 10 ³ - 424 × 10 ³ tonnes	44.6 × 10 ³ - 55.6 × 10 ³ tons	
Steel	63 × 10 ³ - 77 × 10 ³ tons	57 × 10 ³ - 70 × 10 ³ tonnes	7.5 × 10 ³ - 9.2 × 10 ³ tons	
Titanium	8.2 × 10 ³ - 10 × 10 ³ tons	7.4 × 10 ³ - 9.1 × 10 ³ tonnes	0.98 × 10 ³ - 1.2 × 10 ³ tons	
Copper	4.1 × 10 ³ - 5.0 × 10 ³ tons	3.7 × 10 ³ - 4.5 × 10 ³ tonnes	490-600 tons	
Ammonia	6.4 × 10 ³ - 7.9 × 10 ³ tons	5.8 × 10 ³ - 7.2 × 10 ³ tonnes	760-940 tons	
Lead	1.6 × 10 ³ - 1.9 × 10 ³ tons	1.4 × 10 ³ - 1.7 × 10 ³ tonnes	190-230 tons	
Rubberized nylon	5.0 × 10 ³ - 6.3 × 10 ³ tons	4.5 × 10 ³ - 5.7 × 10 ³ tonnes	600-750 tons	
<u>Land</u>				
Power station	20 acres	8.2 ha	20 acres	Land does not change with plant size
<u>Personnel</u>				
Construction (5 yr)	4.08 × 10 ³ workers		485 workers	
Operation and maintenance		Not Determined		

OCEAN THERMAL ENERGY CONVERSION

COSTS

	Reference Energy System	Per 10^{12} Btu Energy Produced	Remarks
<u>Facility</u>		(1981 \$)	
Construction (5 yr)	$\$1.09 \times 10^9$ total	$\$130 \times 10^6$ total	Reference year for costs is 1972. 1972 CCI average (I_0) = 1753. See Explanatory Notes Section.
Operation and maintenance	$\$74.6 \times 10^6/\text{yr}$	$\$8.87 \times 10^6/\text{yr}$	
<u>Environmental Controls</u>		Not Determined	

ENVIRONMENTAL RESIDUALS

	Quantities Released			Remarks
	Reference Energy System Annual Levels		Per 10 ¹² Btu Energy Produced	
	English Units	Metric Units		
<u>Water Pollutants</u>				
Free chlorine	14 × 10 ³ – 17 × 10 ³ tons	13 × 10 ³ – 15 × 10 ³ tonnes	1.7 × 10 ³ – 2.0 × 10 ³ tons	
Ammonia	10 tons	9.1 tonnes	1.2 tons	
Oil and grease		Negligible		
Nutrients		↓		
Metals				
<u>Solid Wastes</u>				
No annual residuals; however, upon decommissioning, such construction materials as concrete, rubberized nylon, and possibly some portion of the metals must be disposed of				
<u>Thermal Discharge</u>				
Thermal energy change (decrease in surface waters)	290 × 10 ¹² Btu	310 × 10 ¹⁵ J	35 × 10 ¹² Btu	

PRODUCTS

	Quantities Produced		Per 10 ¹² Btu Energy Produced	Remarks
	Reference Energy System Annual Production			
	English Units	Metric Units		
Primary				
Electricity	2.46 × 10 ⁹ kWh	2.46 × 10 ⁹ kWh	0.293 × 10 ⁹ kWh	
Recoverables/Recyclables				
No annual recoverables; however, upon decommissioning, some fractions of the metals and ammonia may be economically recoverable				

OCCUPATIONAL SAFETY AND HEALTH

Not Determined

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GEOTHERMAL TECHNOLOGIES

GEOTHERMAL—VAPOR DOMINATED SYSTEM

REFERENCE ENERGY SYSTEM

Geothermal—vapor dominated (dry steam) system: Unit 16 of Pacific Gas & Electric/Aminoil Company Geysers generating plant in Lake County, California. (This unit is not constructed yet, but represents the latest design.) The unit will produce commercial electricity. Steam from the Geysers field is used to drive turbine-generators and the steam condensate is used for cooling. A Stretford process unit is used to abate hydrogen sulfide, and secondary treatment of the condensate to remove remaining hydrogen sulfide is proposed.

FACILITY OPERATING PARAMETERS

Size:	110 MWe (net)
Annual Capacity Factor:	80%
Annual Energy Production:	2.63×10^{12} Btu
Efficiency:	16%
Lifetime:	30–35 yr

RESOURCES USED

	Quantities Used			Remarks
	Reference Energy System Annual Usage		Per 10 ¹² Btu Energy Produced	
	English Units	Metric Units		
<u>Feed Materials</u>				
Steam (enthalpy of steam)	7.23 × 10 ⁶ tons (17.1 × 10 ¹² Btu)	6.57 × 10 ⁶ tonnes (18.1 × 10 ¹⁵ J)	2.75 × 10 ⁶ tons (6.50 × 10 ¹² Btu)	
<u>Processing Materials</u>				
Hydrogen sulfide abatement				
• Sodium hydroxide	134 tons	122 tonnes	51 tons	
• Sodium ammonium polyvanadate	11 tons	10 tonnes	4.3 tons	
• Anthraquinone disulfonic acid	3 tons	3 tonnes	1.2 tons	
• Hydrogen peroxide	700 tons	640 tonnes	270 tons	
Catalyst				
• Ferrous sulfate and hydroxy acetic acid	200 tons	180 tonnes	75 tons	
<u>Water</u>				
Input from steam wells	5.5 × 10 ³ acre-ft	6.8 × 10 ⁹ l	2.1 × 10 ³ acre-ft	
Discharge to atmosphere	4.4 × 10 ³ acre-ft	5.4 × 10 ⁹ l	1.7 × 10 ³ acre-ft	
Injected via wells	1.0 × 10 ³ acre-ft	1.4 × 10 ⁹ l	400 acre-ft	
	Total Usage			
<u>Construction Materials</u>				
Normal turbine-generator (steam materials)	Not Determined			
<u>Land</u>				
Well field	800 acres	320 ha	300 acres	
Plant site	6.4 acres	2.6 ha	2.4 acres	
<u>Personnel</u>				
Construction (4 yr)	105 workers		40 workers	
Operation and maintenance	18 workers		7 workers	Shared among the plants

COSTS

Facility	Reference Energy System	Per 10^{12} Btu Energy Produced	Remarks
Construction (4 yr)	$\$80.2 \times 10^6$ total	(1981 \$) $\$30.5 \times 10^6$ total	Reference year for costs is 1979 with escalation through 1982. 1979 CCI average (I_h) = 3003. See Explanatory Notes Section.
Operation and maintenance	$\$21.8 \times 10^6$ /yr	$\$8.23 \times 10^6$ /yr	Includes steam costs that are approximately 73% of total operation and maintenance costs
Environmental Controls			
Secondary treatment of hydrogen sulfide	$\$4.94 \times 10^6$ /yr	$\$1.90 \times 10^6$ /yr	Stretford system (hydrogen sulfide abatement) costs are included in operation and maintenance costs above

GEOTHERMAL – VAPOR DOMINATED SYSTEM

ENVIRONMENTAL RESIDUALS

	Quantities Released			Remarks
	Reference Energy System Annual Levels		Per 10 ¹² Btu Energy Produced	
	English Units	Metric Units		
<u>Air Pollutants</u>				
Hydrogen sulfide	25 tons	22 tonnes	9 tons	
Ammonia	214 tons	194 tonnes	81 tons	
Mercury	0.10 ton	0.1 tonne	0.04 ton	
Arsenic	0.03 ton	0.03 tonne	0.01 ton	
Boron	0.2 ton	0.2 tonne	0.07 ton	
Particulates	18 tons	16 tonnes	7 tons	
Methane	19 tons	17 tonnes	7 tons	
Nonmethane hydrocarbons	< 35 tons	< 32 tonnes	< 13 tons	
Carbon dioxide	22 × 10 ³ tons	20 × 10 ³ tonnes	8.3 × 10 ³ tons	
Nitrogen	95 tons	87 tonnes	36 tons	
Radon-222	98 Ci	98 Ci	37 Ci	
<u>Water Pollutants</u>				
None are released except by accidental occurrence				Water not discharged as vapor reinjected into well
<u>Solid Wastes</u>				
Sludges	3.0 × 10 ³ bbl	0.47 × 10 ⁶ l	1.1 × 10 ³ bbl	Assumed 1 bbl U.S. liquid = 0.11924 m ³
<u>Thermal Discharge</u>				
Cooling tower	14.4 × 10 ¹² Btu	15 × 10 ¹⁵ J	5.5 × 10 ¹² Btu	
<u>Noise Pollution*</u>				
Well drilling		65-120 dBA at 50 ft		Environmental Protection Agency community noise criterion for well drilling is 55 dBA
Construction (of plant) operations		70-90 dBA at 50 ft		
Plant operations (20-30 yr)				Other noise standards are promulgated by state and local authorities
• Jet gas ejector (continuous)		84-117 dBA at 5-10 ft		
• Turbine generator building (continuous)		70 dBA outside		

*Noise cannot be expressed in terms of energy produced.

*Noise cannot be expressed in terms of energy produced.

PRODUCTS

	Quantities Produced			Remarks
	Reference Energy System Annual Production		Per 10 ¹² Btu Energy Produced	
	English Units	Metric Units		
<u>Primary</u>				
Electricity	0.771 × 10 ⁹ kWh	0.771 × 10 ⁹ kWh	0.293 × 10 ⁹ kWh	
<u>Byproducts</u>				
Sulfur	400 tons	360 tonnes	150 tons	Recovered as a result of Stretford hydrogen sulfide process

OCCUPATIONAL SAFETY AND HEALTH

	Reference Energy System	Per 10 ¹² Btu Energy Produced	Remarks
<u>Deaths</u>	None Observed		
<u>Injuries/Disease*</u>		0.4 (average)	Range is 0.1-0.7 incidents

*Based on past operating experience with environmental abatement systems that caused dermatoses.

GEOTHERMAL ENERGY PLANT (HYDROTHERMAL FLASHED STEAM)

REFERENCE ENERGY SYSTEM

Hot geothermal fluid is withdrawn from the geothermal reservoir and steam is flashed from the fluid. Steam from this flash is used to power the turbogenerators. Hydrogen sulfide emissions are abated by the Stretford or EIC process. Residual fluid is injected into a subsurface aquifer.

FACILITY OPERATING PARAMETERS

Size:	50 MWe
Annual Capacity Factor:	75%
Annual Energy Production:	1.12×10^{12} Btu
Efficiency:	5-8% overall
Lifetime:	30 yr

RESOURCES USED

	Quantities Used			
	Reference Energy System Annual Usage		Per 10 ¹² Btu Energy Produced	Remarks
	English Units	Metric Units		
<u>Feed Material</u>				
Geothermal fluid (230°C)	26.0 × 10 ⁶ tons	23.6 × 10 ⁶ tonnes	23.2 × 10 ⁶ tons	Assuming 70 kg/kWh
<u>Energy</u>				
Electricity	32.9 × 10 ⁶ kWh	32.9 × 10 ⁶ kWh	29.4 × 10 ⁶ kWh	10% of output
<u>Processing Materials</u>				
Caustic soda process				
• Sodium hydroxide	57.1 tons	51.8 tonnes	51.0 tons	Data adapted from The Geysers
Stretford process				
• Sodium ammonium polyvanadate	4.82 tons	4.37 tonnes	4.30 tons	
• Anthraquinone disulfonic acid (ADA)	1.34 tons	1.22 tonnes	1.20 tons	
Iron catalyst (H ₂ O ₂ supple- mented) process				Chemicals used for secondary H ₂ S abatement processes
• Hydrogen peroxide	302 tons	274 tonnes	270 tons	
Iron catalyst process				
• Ferrous sulfate and hydroxy acetic acid	84.0 tons	76.2 tonnes	75.0 tons	
Copper sulfate	Not Determined			For EIC process
<u>Water</u>				
Cooling tower make-up (10% cycle efficiency)	2.24 × 10 ³ acre-ft	2.75 × 10 ⁹ l	2.00 × 10 ³ acre-ft	Wet, mechanical- draft cooling towers
Total Usage				
<u>Construction Materials</u>				
	Not Determined			
<u>Land</u>				
Wells (18 wells at 5 acres/well)	90.0 acres 5.00-20.0 acres	36.5 ha 2.03-8.10 ha	80.4 acres 4.46-17.9 acres	
<u>Personnel</u>				
Construction (2 yr)	233 workers (maximum)		208 workers	
Operation and maintenance	67 workers		60 workers	

GEOTHERMAL ENERGY PLANT (HYDROTHERMAL FLASHED STEAM)

COSTS

	Reference Energy System	Per 10 ¹² Btu Energy Produced (1981 \$)	Remarks
Facility			Reference year for costs is 1980. 1980 CCI average (I_p) = 3237. See Explanatory Notes Section.
Construction costs	\$19.6-81.8 × 10 ⁶ total	\$17.5-73.1 × 10 ⁶ total	
Operation and maintenance	\$1.09-3.27 × 10 ⁶ /yr	\$0.982-2.95 × 10 ⁶ /yr	
Environmental Controls			
Stretford process (with surface condenser)	\$3.97 × 10 ⁶ total \$45.8-611 × 10 ³ /yr	\$3.55 × 10 ⁶ total \$40.9-546 × 10 ³ /yr	Capital costs Operation and maintenance costs
EIC process	\$5.06 × 10 ⁶ total \$0.317-10.8 × 10 ⁶ /yr	\$4.52 × 10 ⁶ total \$0.283-9.65 × 10 ⁶ /yr	Capital costs Operation and maintenance costs

ENVIRONMENTAL RESIDUALS

	Quantities Released			Remarks
	Reference Energy System Annual Levels		Per 10 ¹² Btu Energy Produced	
	English Units	Metric Units*		
<u>Air Pollutants**</u>				
Hydrogen sulfide	4.41-44.1 tons	4.00-40.0 tonnes	3.94-39.4 tons	
Ammonia	165-17,000 tons	150-15,400 tonnes	147-15,200 tons	
Methane	108-4,520 tons	98.0-4,100 tonnes	96.4-4,040 tons	
Carbon dioxide	6,780-67,800 tons	6,150-61,500 tonnes	6,050-60,500 tons	
Arsenic	0.452-4.52 tons	0.410-4.10 tonnes	0.404-4.04 tons	
Boron	11.4-114 tons	10.3-103 tonnes	10.2-102 tons	
Mercury	0-2.26 tons	0-2.05 tonnes	0-2.02 tons	
Radon	10.5-16.1 Ci	10.5-16.1 Ci	9.38-14.4 Ci	
Benzene	22.0 tons	20.0 tonnes	19.6 tons	
<u>Solid Wastes**</u>				
Drilling mud	181-392 × 10 ³ ft ³	5.13-11.1 × 10 ³ m ³	162-350 × 10 ³ ft ³	
Solid waste (from plant operation)				
• Solids separated from fluid	4300 tons	3900 tonnes	3840 tons	
• Solids from H ₂ S abatement	176 tons	160 tonnes	157 tons	
• Solids from scale removal	231 tons	210 tonnes	206 tons	
<u>Noise Pollution***</u>				
Well drilling	75-85 dB at 50 ft			
Operation of construction machinery	70-95 dB at 50 ft			
Plant operation	70-100 dB at 50 ft			

*Basis of other calculations.

**Quantities indicated for air, water, and solid wastes are based on a total flow of 23.6 × 10⁶ tonnes/yr from 18 wells at 1.31 × 10⁶ tonnes/yr per well. Fluid density is assumed to be 1.15 kg/l.

***Noise cannot be expressed in terms of energy produced.

GEOTHERMAL ENERGY PLANT (HYDROTHERMAL FLASHED STEAM)

PRODUCTS

	Quantities Released		Per 10 ¹² Btu Energy Produced	Remarks
	Reference Energy System Annual Levels			
	English Units	Metric Units		
	<u>Primary</u>			
Electricity (net)	329 × 10 ⁶ kWh	329 × 10 ⁶ kWh	294 × 10 ⁶ kWh	
<u>Recoverables/Recyclables</u>				
Sulfur	378-3780 tons	343-3430 tonnes	338-3380 tons	

OCCUPATIONAL SAFETY AND HEALTH

	Reference Energy System Annual	Per 10 ¹² Btu Energy Produced	Remarks
<u>Injuries/Illnesses</u>			
Based on data from The Geysers (per 50 MW)	0.40 injury/illness	0.36 injury/illness	

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HYDROELECTRIC TECHNOLOGIES

SMALL HYDROELECTRIC PLANT

REFERENCE ENERGY SYSTEM

Small hydroelectric plants are those with less than 15 MWe of capacity and usually fed by a dam with height not more than 65 ft. Impounding is generally less than 500 acres. Components of a typical system (not an exhaustive listing) include the dam, penstock, hydraulic turbine, generator(s) transformer, and other miscellaneous structures and equipment.

FACILITY OPERATING PARAMETERS

Size:	4 MWe
Annual Capacity Factor:	0.35 for new plants, 0.37 for retrofits
Annual Energy Production:	0.04×10^{12} Btu
Efficiency:	90%
Lifetime:	50 yr

RESOURCES USED

	Quantities Used		Per 10 ¹² Btu Energy Produced	Remarks
	Reference Energy System Annual Usage			
	English Units	Metric Units		
<u>Feed Materials</u>				
Water	0.792 × 10 ⁶ acre-ft	0.977 × 10 ¹² l	19.8 × 10 ⁶ acre-ft	Kinetic energy of falling or flowing water
<u>Energy Requirements</u>				
Auxiliary	Not Determined			
	<u>Total Usage</u>			
<u>Construction Materials</u>				
	Not Determined			Typical system components are listed in Reference Energy System description
<u>Land</u>				
	Not Determined			
<u>Personnel</u>				
Construction	Not Determined			
Operation and maintenance	Not Determined			

COSTS

	<u>Reference Energy System</u>	<u>Per 10¹² Btu Energy Produced</u>	<u>Remarks</u>
<u>Facility*</u>	(1981 \$)		Reference years for costs are 1977 for construction and 1972 for operation and maintenance. The corresponding CCI averages (I _p) = 2577 (1977) and 1753 (1972). See Explanatory Notes Section.
Construction	\$10.3 × 10 ⁶ total \$0.109 × 10 ⁶ /yr	\$257 × 10 ⁶ total \$2.72 × 10 ⁶ /yr	
Operation and maintenance	\$0.054 × 10 ⁶ /yr	\$1.35 × 10 ⁶ /yr	
<u>Environmental Controls</u>			
Upstream fish passage facilities can cost between \$27 × 10 ³ to \$134 × 10 ³ /m of elevation			Hydroelectric systems can have water quality and ecological impacts
*Costs are for "installed hydro-power at new dams."			

*Costs are for "installed hydro-power at new dams."

SMALL HYDROELECTRIC PLANT

ENVIRONMENTAL RESIDUALS

	Quantities Released			Remarks
	Reference Energy System		Per 10 ¹² Btu Energy Produced	
	Annual Levels			
	English Units	Metric Units		
<u>Water Pollutants</u>				
Thermal stratification in the reservoir can lead to a lowering of dissolved oxygen levels and elevated concentration of ammonia, hydrogen sulfide, iron, and manganese; shoreline erosion may result in increased turbidity				
<u>Thermal Discharge</u>				
Thermal stratification in the reservoir can result in discharged water being warmer in winter and cooler in summer than ambient river water				

PRODUCTS

	Quantities Produced			Remarks
	Reference Energy System Annual Production		Per 10 ¹² Btu Energy Produced	
	English Units	Metric Units		
Primary Electricity	0.012 × 10 ⁹ kWh	0.012 × 10 ⁹ kWh	0.293 × 10 ⁹ kWh	

OCCUPATIONAL SAFETY AND HEALTH

Not Determined

LARGE HYDROELECTRIC PLANT

REFERENCE ENERGY SYSTEM

A conventional "run-of-river" hydroelectric plant (i.e., no storage capacity) in which an earth-filled dam ($15 \times 10^6 \text{ yd}^3$ of earth) is placed across a river to develop water flow capable of driving three 66.7-MWe turbine/generator sets. The plant, categorized as a large hydroelectric plant (greater than 15 MWe) includes the usual system components of dam, spillway, intakes, and a powerhouse consisting of hydraulic structures, turbines, and electrical equipment.

FACILITY OPERATING PARAMETERS

Size:	200 MWe
Annual Capacity Factor:	56%
Annual Energy Production:	$3.35 \times 10^{12} \text{ Btu}$
Efficiency:	82.6%
Lifetime:	60 yr

RESOURCES USED

	Quantities Used		Per 10 ¹² Btu Energy Produced	Remarks
	Reference Energy System Annual Usage			
	English Units	Metric Units		
<u>Feed Materials</u>				
Fuel (kinetic energy of water flow)	4.01 × 10 ¹² Btu	4.23 × 10 ¹⁵ J	1.20 × 10 ¹² Btu	
<u>Total Usage</u>				
<u>Construction Materials</u>				
Concrete	150 × 10 ³ tons	136 × 10 ³ tonnes	44.8 × 10 ³ tons	
Total steel and castings	14.1 × 10 ³ tons	12.8 × 10 ³ tonnes	4.21 × 10 ³ tons	
Copper, brass, and bronze	287 tons	261 tonnes	86 tons	
Aluminum and castings	151 tons	137 tonnes	45 tons	
Manganese	84 tons	76 tonnes	25 tons	
Chromium	20 tons	18 tonnes	6 tons	
Nickel	3.3 tons	3 tonnes	1 ton	
Cast iron	462 tons	419 tonnes	138 tons	
<u>Land</u>				
Acres occupied	397 acres	161 ha	119 acres	
<u>Personnel</u>				
Construction (4.75 yr)	250 workers		75 workers	
Operation and maintenance	16.8 workers		5.02 workers	

COSTS

	<u>Reference Energy System</u>	<u>Per 10¹² Btu Energy Produced</u>	<u>Remarks</u>
<u>Facility</u>			
		(1981 \$)	
Construction (4.75 yr)*	\$167 × 10 ⁶ total	\$49.8 × 10 ⁶ total	Reference year for costs is 1978. 1978 CCI average (I _h) = 2776. See Explanatory Notes Section.
Operation and maintenance	\$0.891 × 10 ⁶ /yr	\$0.267 × 10 ⁶ /yr	
<u>Environmental Controls</u>			
	Not Determined		Water impoundment may produce minor environmental effects
*Includes cost for estimated land and land rights.			

*Includes cost for estimated land and land rights.

LARGE HYDROELECTRIC PLANT

ENVIRONMENTAL RESIDUALS

	Quantities Released			Remarks
	Reference Energy System		Per 10 ¹² Btu Energy Produced	
	Annual Levels			
	English Units	Metric Units		
<u>Air Pollutants</u>				
No normal releases				
<u>Water Pollutants</u>				
Water quality and quantity may be altered upstream and downstream with potential changes in dissolved gases, tem- perature, and water levels				
<u>Thermal Release</u>				
No normal releases				

PRODUCTS

	Quantities Produced			Remarks
	Reference Energy System		Per 10 ¹² Btu Energy Produced	
	Annual Production			
	English Units	Metric Units		
Primary				
Electricity	0.98 × 10 ⁹ kWh	0.98 × 10 ⁹ kWh	0.293 × 10 ⁹ kWh	

OCCUPATIONAL SAFETY AND HEALTH

Not Determined

PUMPED STORAGE SYSTEM

REFERENCE ENERGY SYSTEM

A pumped-storage (hydroelectric) plant consisting of four 250-MW pumps and drivers that utilize base load power during off-peak demand for pumping water from a lower to a higher reservoir. The pumping units become turbines driving electrical generators when the stored water is released during periods of high demand. By 1985, pumped storage capacity in the United States is expected to approach 37,300 MWe.

FACILITY OPERATING PARAMETERS

Size:	1000 MWe
Annual Capacity Factor:	13%
Annual Energy Production:	3.89×10^{12} Btu
Efficiency:	70%
Lifetime:	60 yr

RESOURCES USED

	Quantities Used		Per 10 ¹² Btu Energy Produced	Remarks
	Reference Energy System Annual Usage			
	English Units	Metric Units		
<u>Feed Materials</u>				
Off-peak base load electricity	5.56 × 10 ¹² Btu	5.87 × 10 ¹⁵ J	1.43 × 10 ¹² Btu	
	Total Usage			
<u>Construction Materials</u>				
Concrete	587 tons	533 tonnes	151 × 10 ³ tons	
Total steel and castings	62.6 × 10 ³ tons	56.8 × 10 ³ tonnes	16.1 × 10 ³ tons	
Copper, brass, and bronze	743 tons	674 tonnes	191 tons	
Aluminum and castings	486 tons	441 tonnes	125 tons	
Manganese	318 tons	290 tonnes	82 tons	
Chromium	54 tons	49 tonnes	14 tons	
Nickel	12 tons	10 tonnes	3 tons	
Cast iron	1.30 × 10 ³ tons	1.18 × 10 ³ tonnes	335 tons	
<u>Land</u>	2.0 × 10 ³ acres	810 ha	514 acres	
<u>Personnel</u>				
Construction (6.5 yr)	494 workers		127 workers	
Operation and maintenance	33 workers		8.49 workers	

COSTS

	<u>Reference Energy System</u>	<u>Per 10¹² Btu Energy Produced</u>	<u>Remarks</u>
<u>Facility</u>			
		(1981 \$)	
Construction (6.5 yr)	\$416 × 10 ⁶ total	\$107 × 10 ⁶ total*	Reference year for costs is 1978. 1978 CCI average (I _p) = 2776. See Explanatory Notes Section.
Operation and maintenance	\$1.83 × 10 ⁶ /yr	\$0.471 × 10 ⁶ /yr	
<u>Environmental Controls</u>			
	Not Determined		

*Includes $\$9.9 \times 10^6$ for estimated land and land rights.

PUMPED STORAGE SYSTEM

ENVIRONMENTAL RESIDUALS

ENVIRONMENTAL RESIDUALS		Quantities Released		Remarks
Reference Energy System		Per 10 ¹² Btu Energy Produced		
Annual Levels				
English Units	Metric Units			
<u>Air Pollutants</u>				
No normal releases				
<u>Water Pollutants</u>				
Water quality and quantity may be altered upstream and downstream with potential changes in dissolved gases, tem- perature, and water levels				
<u>Thermal Discharge</u>				
No normal releases				

PRODUCTS

	Quantities Produced			Remarks
	Reference Energy System		Per 10 ¹² Btu Energy Produced	
	Annual Production			
	English Units	Metric Units		
	Primary			
Electricity	1.14 × 10 ⁹ kWh	1.14 × 10 ⁹ kWh	0.293 × 10 ⁹ kWh	

OCCUPATIONAL SAFETY AND HEALTH

Not Determined

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PART 2. ENVIRONMENTAL CONTROLS

ENVIRONMENTAL CONTROLS FOR COAL-FIRED POWER PLANTS AND INDUSTRIAL BOILERS

Overview

Coal combustion processes in power generation represent a major source of potential environmental pollution unless appropriate control technologies and waste disposal techniques are applied. Although the operation and control of a given plant are highly site specific, suitable control technologies* now are available to allow environmentally acceptable coal-fired power generation in many locations.

All coal-fired power plants and industrial boilers can be assumed to have certain potential sources of environmental pollutants in common. Those sources are shown in broad categories in the block diagram in Figure 1. In most instances, there is more than one method for control or disposal of each of those potential pollutant streams. The choice of control technology or disposal method is influenced by many factors, the most important of which are the operational characteristics, pollution standards, performance, availability, reliability, and

Figure 1. Sources of Environmental Pollutants

* Environmental controls are considered only for those pollutants generated by the combustion process. Fugitive emissions (which result from processes such as coal storage) and coal preparation emissions (e.g., particulates due to pulverizing) are not considered.

costs. The following sections present current summaries of these types of information for contemporary control technologies applied to coal-fired steam electric power plants and industrial boilers.

The electric power industry in the United States generated approximately 2.3 billion MWh of electric power for distribution to its customers in 1980. Of this total, 1.162 billion MWh (or 51 percent) were generated by the combustion of coal. In order to present quantitative information for the control technologies for coal-fired power plants, a generating capacity of 500 MW_e was selected with a 65 percent capacity factor for the boiler and turbine. Where quantitative information showed sensitivity to other plant operating characteristics, such as coal type or plant location, a range of data is presented with appropriate assumptions noted. A large number of new coal-fired industrial boilers will be constructed in the not-too-distant future as a result of plant expansions and replacement of gas- and oil-fired boilers. Projected fuel demand in 1988 will exceed current levels by approximately 800 trillion Btu. Of this quantity, 640 trillion Btu of heat input will be from coal.

Industrial boilers produce nearly the same environmental pollutants as coal-fired power plants (see Figure 1). Capacities of industrial boilers range from less than 0.5 MW to greater than 145 MW. The majority of boilers at the low end of the capacity range are used for space heating, whereas the boilers at the upper end of the capacity range are generally used for process steam and, in some cases, electricity generation. Consequently, the block representing turbine operation in Figure 1 would not, in general, be applicable to industrial boilers.

For industrial boilers, a heat input capacity of 73 MW (250×10^6 Btu/hr) was selected as the appropriate size for presenting environmental control technology information because existing Environmental Protection Agency regulations for federal New Source Performance Standards consider that size facility to be the approximate division point between industrial boilers and utility boilers.

Air Pollution Control

ELECTROSTATIC PRECIPITATORS FOR PARTICULATE CONTROL

Application and Description of Control

When coal is burned in pulverized coal boilers, as much as 80 percent of the ash in the coal leaves the combustion chamber entrained in the combustion gases as fly ash particulate material. The flue gas from a typical utility boiler contains approximately 400 tons/day of particulate matter, and the flue gas from a typical industrial boiler contains approximately 20 tons/day of particulate matter. If no particulate control device were installed, then almost all of this fly ash would be emitted to the atmosphere.

The most popular operational control device for fly ash is the electrostatic precipitator (ESP). This device charges the individual particles in the gas stream using a very high voltage field (20 to 100 kV). Power to operate these high voltage supplies for a contemporary high efficiency ESP can be slightly greater than 1 percent of the plant's maximum power capacity. The particles are attracted to and captured by oppositely charged collector plates. The particles are removed from the plates and collected for disposal by several methods, the most common of which is "rapping."

Rapping is the dislodging of the particulate material from the collector plate by a mechanical impulse or blow delivered to the collector plate by a hammer-like device. The mechanical shock dislodges the material, which falls to the bottom of the ESP housing and is collected in hoppers from where it is pneumatically transported or hydraulically sluiced to storage hoppers or ash disposal ponds. ESPs are constructed in a modular fashion such that the basic operation of sets of collector plates are not dependent on each other and thus a malfunction in one module does not normally directly affect the other modules, collection hoppers, and disposal system. There is, however, some degradation in the overall performance of the total unit.

The ESP can be located at four points in the combustion gas stream. (1) It can be built into the combustor prior to the air preheater heat exchanger where flue gas temperatures range from 550° to 800°F. This is referred to as a hot-side ESP. This approach is generally employed to overcome problems of high resistivity ash from low sulfur coal. (2) The ESP can be located outside the combustor but prior to the stack. (3) The ESP can be located between the combustor and a wet SO₂ control device such as a wet lime scrubber. (4) The ESP can be located after a dry SO₂ control device such as a dry lime scrubber. The last three locations in which the flue gas is typically cooler than 350°F designate the units as cold-side ESPs. When the unit is located downstream of a dry SO₂ device, the ESP is also responsible for collecting the reacted lime from the SO₂ control.¹

Other minor variations on the basic ESP unit include the shape of collection plates, charging wire configurations, and the removal of collected particles by liquid washing.

Standard

The federal standard for the emission of particulate material from large (> 73 MW or >250 million Btu/h heat input) coal-fired steam generators was initially established under the authority of the Clean Air Act—New Source Performance Standards (NSPS) in 1971 at 0.10 lb/million Btu heat input. The NSPS for this class of combustor, revised in 1979, is 0.03 lb/million Btu heat input for new units. No federal NSPS is now in effect for coal-fired boilers smaller than 250 million Btu/h. Boilers with capabilities less than 73 MW are subject to state emission limits for particulate matter. State implementation plans reflect local conditions and needs. As a result, industrial boiler emission limits vary considerably from state to state. In general, the states' emission limits for particulates range from 0.1 to 0.6 lb/10⁶ Btu. The proposed federal standard for particulate matter is 0.05 lb/million Btu heat input for coal-fired industrial boilers that are not equipped with a wet scrubbing flue gas desulfurization (FGD) system. For coal-fired industrial boilers that are supplied with a wet scrubbing FGD system, the proposed particulate matter standard is 0.01 lb/million Btu heat input.²

Control Performance and Efficiency

Control performance and efficiency for both coal-fired power plants and industrial boilers are given in the table below.

Control Type	Efficiency %	Expected Downtime	Availability
Hot-side and cold-side ESP	95-99	Minimal	Full scale

There is little downtime caused by ESP malfunctions.³ ESP units are modular in nature and typical malfunctions are confined to single modules. This degrades but does not generally stop the operation of the ESP unit. Maintenance of the ESP unit is normally accomplished during planned (2 to 4 weeks per year) or necessary shutdown of the boiler/turbine generator.

The primary controlling design factor in the determination of ESP particulate collection efficiency is the area of the collector plates. This can be increased in both types of units to achieve increases in collection efficiency for a fixed set of fuel and combustor conditions. Increases in ash electrical resistivity usually associated with lowering coal sulfur content will decrease the collection efficiency of the ESP. This is offset in the hot-side ESP by collecting the ash at a higher gas temperature at which its resistivity is lower. The resistivity of the ash can also be decreased by injecting small amounts of SO₃/SO₂ into the flue gas upstream of the ESP. This approach is known as flue gas conditioning.

Reliability and State-of-the-Art

The ESP is the main control for about three quarters of the coal-fired boilers in the United States. Because of their modular design, ESPs can be applied over a wide range of boiler sizes. The technology is extraordinarily reliable having been used for particulate control applications for over 40 years. Reliability and related parameters for ESP controls are tabulated below for both coal-fired power plants and industrial boilers.³⁻⁵

Control Type	Status	Ease of Adaptability	Cross-Media Impacts	Estimated Reliability	Negative Factors
Cold-Side ESP	Current full-scale use in U.S.	Can be retrofitted	Disposal of collected particulate as solid waste	Excellent	None
Hot-Side ESP	Current full-scale use in U.S.	Usually installed when boiler is built but can be retrofitted	Disposal of collected particulate as solid waste	Good to excellent	Usually used on new plants; costs slightly more to install and maintain than a cold-side unit
(Hot-side ESPs are currently out of favor based on the less-than-expected performance on some low sulfur, low sodium coals)					

For information concerning a hybrid particulate control mechanism that employs electrostatic phenomenon in combination with granular bed filtration, see the comments on electrostatic granular bed (EGB) filter system experimentation in the subsection on acoustic agglomeration for enhancement of fine particulate control.

Costs: Capital and Operating

The cost of an ESP is directly related to the area of collector plates in the unit. The plate area required for a given particulate collection efficiency in turn is primarily dependent on the flue gas flow rate and the characteristics of the fuel/ash (resistivity). An approximate relationship can be stated between station power level (MW) and flue gas flow rate in actual cubic feet per minute. Based on the $\text{ft}^3/\text{min}(\text{actual})$ flow rates for 28 actual pulverized bituminous coal-fired boilers, the values vary between 300,000 and 350,000 $\text{ft}^3/\text{min}(\text{actual})$ per 100 MW of station power. The exact value will depend on specific plant conditions. Contemporary ESP installations to meet current NSPS are using from 300 to 400 ft^2 of specific collection area/1000 $\text{ft}^3/\text{min}(\text{actual})$ for high sulfur eastern coals and 600 to as high as 900 ft^2 of specific collection area/1000 $\text{ft}^3/\text{min}(\text{actual})$ for some western low sulfur coals.²⁻⁴

Based on costing models developed by Argonne National Laboratory and the Environmental Protection Agency, the following capital and operating costs for

ESP Installation and Operating Costs (\$ 1981)*

Electrostatic Precipitator Type	Capital Cost (\$ million)		Annual Operation and Maintenance** Cost (\$ million)		Unit Cost	
	Power Plant	Industrial Boiler	Power Plant	Industrial Boiler	Power Plant (mills/kWh)	Industrial Boiler (\$1000/10 ⁶ Btu/h)
Low Sulfur Montana Coal						
Cold-Side ESP	23.7		0.29		0.075	
Hot-Side ESP	14.3		0.53		0.145	
Medium Sulfur Illinois No. 6 Coal						
Cold-Side ESP	6.7 [†]		0.25		0.069	
Hot-Side ESP	11.1 [†]		0.69		0.183	
High Sulfur Pennsylvania Coal						
Cold-Side ESP	9.3 [†]	2.4 ^{††}	0.33	0.13 ^{††}	0.088	9.7
Hot-Side ESP	14.4 [†]		0.83		0.20	

*Reference year for cost is 1978; 1978 CCI average (I_p) is 2776. See Explanatory Notes.

**The estimated average yearly maintenance cost for cold-side ESPs has also been estimated at 2 percent of the total purchase price of the unit.⁴

[†]The high ash content of the medium sulfur coal (22 percent) versus the lower ash content of the high sulfur coal (7.2 percent) more than offsets the favorable effects of higher sulfur content.

^{††}Estimated from cost data given in Table 3-1 of Reference 7 using "six-tenths factor" formula given in Reference 8.

ESPs have been developed for three types of coal (Illinois No. 6, medium to high sulfur; Montana Rosebud, low sulfur; and Pennsylvania, high sulfur) for a 500-MW_e plant and a 250 x 10⁶ Btu/h (heat input) industrial boiler.⁶⁻⁹

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FABRIC FILTERS (BAGHOUSES) FOR PARTICULATE CONTROL

Application and Description of Control

Fly ash can be effectively controlled by using fabric filtration systems (baghouses). Fabric filters are currently in wide use by many manufacturing industries; however, their use on coal-fired power plants and industrial boilers is relatively new. Only in the last decade have baghouses been seriously considered as alternatives to electrostatic precipitators (ESPs) for particulate control. Today there are more than 70 installations on over 6700 MW of installed capacity in operation in the United States. They are most popular for western low-sulfur coals when ESPs experience problems due to high ash resistivity.

Filtration is accomplished by passing the ash-laden flue gas through the fabric of a bag or sock-like filter. The flue gas, which in most U.S. systems flows from the inside of the bag to the outside, leaves the ash deposited on the inner surface of the filter. The collected dust is removed by either momentarily reversing the flow in the bag using previously filtered flue gas sent as a gentle pulse to the module compartment being cleaned or by shaking the bag at the top while simultaneously reversing the gas flow to collapse or deflate the bag. A third method, pulse jet cleaning using compressed air inside the bag, has not been used in this country.

When operating at maximum efficiency, the collected particulate layer (and not the fabric fiber) serves as the dominant filtering medium. If too much particulate buildup occurs, however, excessive pressure drop across the filter develops, and bag blinding (plugging) occurs. Fabric material, weave configuration, and fabric coatings must be selected so as to withstand the high flue gas temperatures (250° to 450°F), mechanical stress, and chemical attack while allowing easy removal of the appropriate amount of ash cake during the cleaning cycle. Coated fiberglass has become the most popular bag material with acrylics used in some institutions at temperatures below 280°F.

Baghouses can be located at the flue gas outlet of the boiler or they can be located between the stack and dry SO₂ scrubbing systems such as dry nahcolite injection or spray dry lime injection units.¹⁻³

Standard

The federal standard for the emission of particulate material from large (>250 million Btu/h heat input) coal-fired steam generators was initially established under the authority of the Clean Air Act--New Source Performance Standards (NSPS) in 1971 at 0.10 lb/million Btu heat input. The NSPS for this class of combustor was revised in 1979 to 0.03 lb/million Btu heat input for new units. Promulgation of a standard for fine particulates has been discussed. Such

a standard would create an obvious application for fabric filtration because of its ability to efficiently remove such material from the flue gas stream. No federal NSPS is now in effect for coal-fired boilers smaller than 250 million Btu/h. Boilers with capabilities less than 73 MW thermal input are subject to state emission limits for particulate matter. State implementation plans reflect local conditions and needs. As a result, industrial boiler emission limits vary considerably from state to state. In general, the states' emission limits for particulates range from 0.1 to 0.6 lb/10⁶ Btu.

Control Performance and Efficiency

Control Type	Efficiency %	Expected Downtime	Availability
Fabric filter (baghouse)	> 99.9 possible	Negligible	Full scale

Baghouses are divided into separate compartments that can be isolated and shut down if a failure occurs (usually burst, torn, or plugged bags). This modular construction essentially eliminates the necessity for shutting down the boiler when such failures occur.

The primary controlling design factors in the determination of particulate collection efficiency are the material and weave of the bag and the allowable pressure drop across the filter, which is controlled by bag material design and allowable ash cake buildup on the bag before cleaning is required. In general, the tighter the weave (a low air-to-cloth ratio), the more quickly the ash cake develops and the more effective the filter action.^{1,2}

Reliability and State-of-the-Art

Baghouses currently represent a small fraction of the installed particulate control devices, but this fraction is increasing. Baghouses are most frequently considered in connection with low sulfur western coals and dry SO₂ control systems.⁴ They would represent available technology for the control of fine particulates (<3 μm) should such a standard be promulgated.

Control Type	Status	Ease of Adaptability	Cross-Media Impacts	Estimated Reliability	Negative Factors
Baghouses	Current full-scale use in U.S.	Can be retro-fitted but requires as much or more space as similar ESP	Disposal of collected particulate as solid waste	Good to excellent, little operating experience compared to ESPs	Bag lifetime: hard to predict, sensitive to operating conditions and system upsets. Pressure drop: hard to predict and control, if excessive can increase operating costs

Costs: Capital and Operating

The costs of a baghouse system are directly related to the area of cloth contained in the system.⁵ The capital and operating costs are also sensitive to the design operating pressure drop for the system; this determines the size of the boost fans required to run the unit.⁶ The overall physical size of the unit is a function of the total flue gas flow through the unit and is generally equal or greater than a comparable ESP unit. The costs presented below are for a 500-MW_e boiler and a 250 x 10⁶ Btu/h (heat input) industrial boiler.^{3,6-8} Baghouse costs are relatively insensitive to coal characteristics.

Baghouse Installation and Operating Costs (\$ 1981)*

Type	Capital Cost (\$ million)		Annual Operation and Maintenance Cost (\$ million)		Unit Cost	
	Power Plant	Industrial Boiler	Power Plant	Industrial Boiler	Power Plant (mills/kWh)	Industrial Boiler (\$1000/10 ⁶ Btu/h)
Reverse flow baghouse and collapse and shake baghouse	21.8	1.75**	0.52	0.16**	1.71	0.66

*Reference year for coal-fired industrial boilers control cost is 1978; 1978 CCI average (I_{90}) is 2776. See Explanatory Notes.

**Estimated from cost data given in Table 3-1 of Reference 8 using "six-tenths factor" formula given in Reference 9.

The operating costs are sensitive to bag life and replacement costs as well as to system operating pressure drops. Both of these parameters are difficult to predict based on current operating experience.

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WET SCRUBBERS FOR PARTICULATE CONTROL

Application and Description of Control

Ash resulting from the combustion of coal and exiting the boiler entrained in the flue gas as fly ash can be removed from the gas stream by a wet scrubber.^{1,2} The gas stream containing the particulate materials is brought into contact with a scrubbing liquid that essentially "captures" the particles by one or more of several methods and separates them from the gas stream. The basic scrubber can also remove certain gases and liquid droplets from the gas stream. Relatively few installations are currently in operation for the sole purpose of removing particles. There are several reasons for this including high initial equipment cost, low collection efficiencies unless large pressure drops occur (>10 -in. drop required in venturi units), high pressure liquid spraying required, and high operating power costs associated with the large pressure drops.²

There are many scrubber designs including simple spray towers, wetted-surface, moving-bed, and venturi-injection configurations. The most popular type for power plant and industrial boiler applications is the venturi. The contemporary application of wet scrubber technology involves the utilization of the high alkalinity of certain coals to accomplish both particulate and SO_2 removal in the same system. The scrubbing liquid containing the fly ash captured in a conventional venturi scrubber is circulated to a mixing and holding tank where a combination alkali solution and slurry is prepared. This liquid is sent to an adsorption spray tower where it is contacted with the flue gas to react with and remove SO_2 . High levels of SO_2 removal can be achieved (98 percent, demonstrated) utilizing the natural alkalinity of certain coals. Alkalinity of the coal can be supplemented by addition of materials such as lime to the liquid circulating in the spray tower. This form of SO_2 removal has also been implemented using other forms of particulate removal including both hot and cold electrostatic precipitators (ESPs).¹

Several mechanisms for particle capture and removal are operative in a scrubbing unit. The operative mechanism for a particular particle is influenced by the size of that particle. In a scrubber utilizing droplets, gravitational settling and inertial impaction between droplets and particles account for removal of particles larger than $0.5 \mu\text{m}$.¹ Diffusion of particles to the droplet for particles smaller than $0.1 \mu\text{m}$ accounts for removal of most fine particulates while interception, a modified form of impaction, accounts for particle diameters of the same order of magnitude as the size of the droplet.¹

Ash is removed from the unit in the scrubber liquid and allowed to settle out in an ash pond or settling unit.² The unit can be located immediately after the boiler and just prior to the stack or between the boiler and an SO_2 control device such as a wet lime/limestone scrubber. The particulate scrubber may also be physically integrated with the SO_2 scrubbing system to provide precontrol or simultaneous control of particulate material.

Standard

If the wet particulate scrubber were to be used as the final control device prior to the stack, then it would be required to achieve current federal New Source Performance Standards (NSPS) in new plant installations of over 73-MW or 250-million Btu/h heat input for particulates of 0.03 lb or less per million Btu heat input. When used in the alkaline fly ash SO₂ removal configuration, the venturi scrubber is the primary particulate control device with very little particulate being removed by the spray tower. Mist eliminators may be employed to remove aerosol, which may contain some fine particulate. A scrubber also may be retrofitted in series with an older ESP to improve system particulate control. In some applications, it may be necessary to install a scrubber in series with an ESP to meet NSPS. If a conventional wet SO₂ scrubber is used downstream of the venturi scrubber, then the SO₂ scrubbing system, may remove a sizable fraction of the remaining entrained fly ash. Boilers with capabilities less than 73 MW are subject to state emission limits for particulate matter. State implementation plans reflect local conditions and needs. As a result, industrial boiler emission limits vary considerably from state to state. In general, the states' emission limits for particulates range from 0.1 to 0.6 lb/10⁶ Btu. The proposed Federal standards for particulate matter is 0.05 lb/million Btu heat input for coal-fired industrial boilers that are not equipped with a wet scrubbing flue gas desulfurization (FGD) system. For coal-fired industrial boilers that are supplied with a wet scrubbing FGD system, the proposed particulate matter standard is 0.1 lb/million Btu heat input.³

Control Performance and Efficiency

Control Type	Efficiency %	Expected Downtime
Venturi scrubber	>99 particulate	<5%
Adsorption tower combination	>90 SO ₂	—

The primary factors affecting the performance of scrubbers in the collection of fly ash are power input to the scrubber and particle size distribution of the collected fly ash.^{4,5} Increased power input allows operation with a higher pressure drop across the unit and establishes higher ratios of scrubber liquid-droplet velocity to particle velocity. Theoretical calculations and limited empirical measurements indicate that collection efficiency generally increases for particles below 0.3 μm diameter and increases for particles larger than 0.5 μm diameter. For particles between 0.3 and 0.5 μm diameter, the scrubber has its lowest collection efficiency. The amount of scrubber liquid circulated to the adsorption tower is the primary controlling factor for SO₂ removal efficiency.^{4,5}

Reliability and State-of-the-Art

The wet particulate scrubber has been installed in the last 10 years on power plants primarily as a backup to mechanical collectors or ESPs that were not achieving the required particulate removal efficiency primarily because of low sulfur coal ash with high resistivity. New plants operating under current NSPS would likely integrate the particle scrubber with an SO₂ control system if it were to be chosen as the particle control technology for the plant. A summary of wet scrubber state-of-the-art is presented in the table below.

Control Type	Status	Ease of Adaptability	Cross-Media Impacts	Estimated Reliability	Negative Factors
Venturi scrubber and moving bed scrubber	Current full-scale use in U.S.	Can be retrofitted or integrated with SO ₂ scrubbers for new units	Disposal of wet collected ash as solid waste or mixed with SO ₂ scrubber sludge	—	High pressure drops and associated high power consumption may be necessary to achieve desired particle removal efficiency

Costs: Capital and Operating

The capital cost of wet particulate scrubbers is primarily a function of their size and gas stream capacity and their type. For a given type, larger gas flows require larger physical units and thus cost more. High pressure drops also require larger boost fans, which add to the capital costs. The capital costs presented below are for a typical 500-MW_e plant and a 250 x 10⁶ Btu/h (heat input) industrial boiler.

Operating costs will be primarily determined by scrubber power requirements.^{4,7} Secondary issues will be the cost of any necessary chemical additives to control scaling and pH and the durability of materials of construction of the unit. Excessive scaling and materials susceptible to corrosion will increase operating costs.

Wet Scrubber Installation and Operating Costs (\$ 1981)*

Type	Capital Cost (\$ million)		Annual Operation and Maintenance Cost (\$ million)		Unit Cost	
	Power Plant	Industrial Boiler	Power Plant	Industrial Boiler	Power Plant (mills/kWh)	Industrial Boiler (\$1000/10 ⁶ Btu/h)
Venturi scrubber 15-in. pressure drop	5.5	0.102-0.191	Unknown	0.064-0.088	—	0.38-0.77
Alkali particulate and SO ₂ removal system	51.3	0.25-0.50**	1.9	0.064-0.127**	—	1.02-2.04

*Reference year for coal-fired industrial boilers control cost is 1978; 1978 CCI average (I_R) is 2776. See Explanatory Notes.

**Estimated from cost data given in Table 3-1 of Reference 8 using "six-tenths factor" formula given in Reference 9.

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9. Environmental Protection Agency, A Standard Procedure for Cost Analysis of Pollution Control Operations, Volume II Appendices, EPA-600/8-79-018b, June 1979.

ACOUSTIC AGGLOMERATION FOR ENHANCEMENT OF FINE PARTICULATE CONTROL

Application and Description of Control

Particulate material generated during the combustion of coal and contained in the flue gas leaving the boiler can be controlled by collection and subsequent removal by several basic technologies (e.g., wet scrubbers, electrostatic precipitators, fabric filters). These technologies (discussed elsewhere in this report) generally exhibit poorer performance with respect to collection of smaller particle sizes (3- μ particle diameter). The smaller particles exhibit gas-like properties when applying collection techniques that involve particle mass, inertial impaction, or gravitational separation.

In an effort to improve the fine particle collection efficiency of several basic particle collection devices, the Department of Energy (DOE) has sponsored research in the techniques of acoustic agglomeration. The research concentrates primarily on those techniques as applied to inertial separation by cyclones at elevated pressures, but the technology could also be applied to electrostatic precipitators (ESPs), cyclones, and granular bed filters for conventional pulverized coal-fired power plants. (The technique could also be applied to fabric filters, but it could be expected to improve only marginally the performance of these systems.) The technique is also being investigated for application to pressurized fluidized bed combustors operating with combined cycle gas turbine systems. This technique may be applicable to both coal-fired power plants and industrial boilers.

The technique involves causing the particulate-laden flue gas to flow through a chamber where it is subjected to intense low frequency acoustic energy. This energy sets up local areas of turbulence in the chamber that cause collisions between particles, which in turn result in agglomeration. The resulting larger particles are then easier to separate from the gas stream by conventional methods.^{1,2} Sound energy can be produced in several ways including mechanical moving pistons and high power sirens and whistles. Sound levels applied to accomplish agglomeration are in excess of 150 dB.

Standard

While this technology is not a stand-alone particulate control technology, it can be coupled with other control technology systems to achieve the current New Source Performance Standards (NSPS) for large coal-fired power plants. The federal standard for the emission of particulate material from large (250 million Btu/h heat input) coal-fired steam generators was initially established under the authority of the Clean Air Act—New Source Performance Standards in 1971 at 0.10 lb/million Btu heat input. The NSPS for this class of combustor was revised in 1979 to 0.03 lb/million Btu heat input for new units. Promulgation of a standard for fine particulates has been discussed. Such a standard would create an obvious application for fabric filtration because of its ability to efficiently remove such material from the flue gas stream. The proposed federal standard

for particulate matter is 0.05 lb/million Btu heat input for coal-fired industrial boilers that are not equipped with a wet scrubbing flue gas desulfurization (FGD) system. For coal-fired industrial boilers that are supplied with a wet scrubbing FGD system, the proposed particulate matter standard is 0.01 lb/million Btu heat input.³

Control Performance and Efficiency

The acoustic agglomeration technology has not been implemented in any commercial or pilot-scale installations to date. Some limited laboratory tests have been performed to confirm the feasibility of the technology. These tests have provided a basis for computer simulation and projection of system performance under various conditions. This information is presented below as a guide to the expected performance of this technology.^{1,2}

Control Type	Projected Efficiency %	Comments
With Acoustic Agglomeration		
Two stages of cyclones (4-ft and 10-in. multicyclones)	99.45	Can meet NSPS on conventional coal-fired boilers
Three stages of electrocyclones (12 ft)	99.66	Can meet NSPS on conventional coal-fired boilers
Electrostatic precipitator	99.61	Requires 67% less collector plate area to meet EPA-NSPS
Without Acoustic Agglomeration		
Three stages of electrocyclones (12 ft) for pressurized fluidized bed (PFB)	98.0	Suitable for turbine protection but will not meet EPA-NSPS
Three stages of electrocyclones (12 ft) for PFB	99.92	Will meet EPA-NSPS

The primary design factors in the determination of collection efficiency for electrocyclones coupled with acoustic agglomeration are the level of sound energy achieved, the matching of the sound energy with the treatment chamber (frequency), residence time in the chamber, the gas flow, and the configuration of the cyclone collectors. Higher sound levels, in general, increase the level of agglomeration achieved. Tests to date have shown that a tuned standing wave relationship in the chamber produces the best overall agglomeration results. Longer residence times increase agglomeration levels. Smaller diameter cyclones improve the collection of small particles but increase pressure drop across the unit. The addition of an electrostatic field to the cyclone coupled with acoustic agglomeration allows a 12-ft-diameter unit to accomplish high particulate removal efficiencies without the higher pressure drop associated with smaller diameter units.

Reliability and State-of-the-Art

The techniques of acoustic agglomeration have not yet been applied to commercial-scale coal combustion facilities.^{1,2} Tests to date have been confined to large-scale bench pilot tests. There is, however, considerable industrial test experience with sonic agglomerators on other processes that provides a background for current activities.⁴ As previously noted, tests indicate that while acoustic agglomeration techniques appear to be attractive for application to high pressure, high temperature systems such as pressurized fluidized bed combined-cycle systems, they do not appear economically attractive for conventional coal-fired power plants and industrial boilers.² A summary of acoustic agglomeration state-of-the-art is presented in the table below.

Control Type	Status	Ease of Adaptability	Cross-Media Impacts	Estimated Reliability
ESP with acoustic agglomeration	Laboratory tests of agglomeration only	Could probably be retrofitted to existing ESPs	Collected particulate disposed of as solid waste	Unknown
Electrocyclones with acoustic agglomeration	Laboratory tests of agglomeration and electro-cyclones only	Could probably be retrofitted to existing plants with some difficulty	Collected particulate disposed of as solid waste	Unknown
ESP equivalent	Current full-scale use in U.S.	Can be retro-fitted	Collected particulate disposed of as solid waste	Good
Conventional cyclone equivalent	Current full-scale use in U.S.	Can be retro-fitted	Collected particulate disposed of as solid waste	Good

In addition to research involving the use of acoustic agglomeration for enhancement of fine particulate control, study and experimentation with electrostatic granular bed (EGB) filter systems are also included in the DOE-sponsored work on evaluating novel methods for respirable dust control. Recently (February 1983), the results of a successful pilot test of an EGB system applied for particulate control to a coal-fired utility boiler were reported to DOE. The EGB filter system, incorporating a 10,000-ft³/min pilot electrostatic filter, was pilot tested on a coal-fired power plant with a filter inlet flyash loading of 0.76 grains/ft³/min(standard). The resulting filter outlet loading measured 0.009 lb/10⁶ Btu—nearly an order of magnitude better than the NSPS of 0.03 lb/10⁶ Btu for coal-fired power plants.

The results of the pilot test are encouraging; however, two tasks remain to be completed: scaling up the currently available 10,000-ft³/min commercial filter to a 20,000-ft³/min capacity and testing the unproven larger filter before commercialization occurs. Scale-up of the 10,000-ft³/min commercial filter to 20,000 ft³/min reduces the number of filters (and filter modules) required for a particulate control system suitable for power plants with flue gas flow rates approaching 1.5 x 10⁶ ft³/min(actual) (which would require 80 of the 20,000 ft³/min filters). Reducing the number of filter elements will reduce cost and improve the design reliability. The major risk expected during the scaled-up EGB test is, however, demonstration of the ability to electrostatically precharge the greater quantity of dust.

EGB filter systems are also suitable for high-temperature pressure applications such as pressurized-fluidized bed (PFB) systems for utility power generation. A test program has been formulated for testing the EGB system on a small-scale PFB at atmospheric conditions. The next step would be to test at full temperature and pressure. A final report, "Novel Methods for Respirable Dust Removal," which contains details on acoustic agglomeration and EGB fine particle control enhancement and other data, will be delivered to DOE during the second quarter of CY 1983.

Costs: Capital and Operating

Because acoustic agglomeration is not a complete and independent particulate control technology, its cost must be considered in combination with a basic control technology for purposes of economic comparison. No commercial systems have been installed, so only preliminary cost figures have been developed for the application of acoustic agglomeration to large pulverized coal-fired power plants. These are presented below as a basis for preliminary economic comparison of these techniques with other alternatives.¹

Based on extensive experience as a manufacturer of baghouse filter systems, the DOE subcontractor managing the EGB evaluation effort estimates that an EGB filter system suitable for a flue gas system of 1.5 x 10⁶-ft³/min(actual) capacity would have an installed cost (direct cost) of approximately \$10.1 x 10⁶ (1983\$). The latter amount results in a per unit capital cost of \$6.75/ft³/min(actual), which compares favorably with current baghouse costs of \$9.0 per ft³/min(actual).

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Acoustic Agglomeration System Installation and Operating Costs (\$ 1981)*

Type	Capital Cost** (\$ million)		Annual Operation and Maintenance Cost† (\$ million)		Unit Cost	
	Power Plant	Industrial Boiler	Power Plant	Industrial Boiler	Power Plant (mills/kWh)	Industrial Boiler (\$1000/10 ⁶ Btu/h)
Baghouse (base case)	31.4	2.04††		0.186†		0.8
ESP (base case)	20.0	2.41††		0.132†		9.6
With Agglomerator						
ESP	38.4	Unknown	Agglomerator 2.47	Unknown	0.45	NA [§]
Conventional cyclones	39.3	Unknown		Unknown		NA
Electrocyclones	56.6	Unknown	Electrocyclone 0.65	Unknown	0.11	NA

*Reference year for coal-fired industrial boiler control cost is 1978; 1978 CCI average ($\bar{f}_R$) is 2776. See Explanatory Notes.

**For 500-MWe coal-fired power plant using 3.5 percent sulfur coal, 14 percent ash, and 360 ft²/min(actual) to obtain 0.03 lb/10⁶ Btu.

†Operating costs estimated for a 663-MWe PFB combined cycle system; includes energy costs only.

††Estimated from cost data given in Table 3-1 of Reference 4 using the "six-tenths factor" formula given in Reference 5.

§Not applicable.

- Environmental Protection Agency Proposed Rule and Notice of Public Hearing, 40 CFR Part 60, "Standards of Performance for New Stationary Sources—Industrial Boilers," Draft, April 23, 1982.
- Radian Corporation Report, "Costs of Sulfur Dioxide, Particulate Matter and Nitrogen Oxide Controls on Fossil Fuel Fired Industrial Boilers," EPA Contract No. 68-02-3058, May 20, 1982.
- Environmental Protection Agency, A Standard Procedure for Cost Analysis of Pollution Control Operations, Volume II Appendices, EPA-600/8-79-018b, June 1979.

NITROGEN OXIDE CONTROL

Application and Description of Control

Nitrogen oxides are produced as a result of several natural processes as well as from the combustion of fossil fuels. In all, there are eight oxides of nitrogen, but only nitric oxide (NO) and nitrogen dioxide (NO₂) are considered air pollutants; the term NO_x specifically denotes any combination of these two regulated oxides of nitrogen. In 1976, of the 24.7 million metric tons of anthropogenic NO_x emissions, coal-fired utility boilers accounted for approximately 4.2 million metric tons, and coal-fired industrial boilers accounted for approximately 0.8 million metric tons.¹

NO_x generated by combustion of coal occurs through two mechanisms: one is the oxidation of atmospheric nitrogen (thermal NO_x) and the other involves the conversion of fuel bound nitrogen (fuel NO_x).² The formation mechanism of thermal NO_x is well established and is known to be highly temperature-dependent with virtually no formation occurring below 1500°C. The formation mechanism of fuel NO_x is not as well understood. Fuel NO_x, which accounts for 50 to 80 percent of total NO_x formed during coal combustion, is generated during the combustion of coal particles as either the volatiles released from the particle or as char burnout of the remaining solid material.¹ The primary parameter affecting the conversion to NO_x is oxygen availability; the formation appears to be relatively insensitive to temperature.

In general, NO_x control is achieved by either trying to inhibit its formation by minimizing temperature and oxygen availability via combustion modification (CM) techniques or by trying to either capture or reduce the NO_x after it forms via flue gas treatment (FGT) techniques.¹⁻⁶

CM techniques used to control NO_x include changing the design and operation of furnaces and burners and adjusting fuel-air ratios, mixing rates, and flame geometry. Systems using low excess air (LEA) and staged combustion have been shown to be effective techniques in reducing NO_x emission. LEA firing involves reducing the combustion air to the minimum amount required to ensure complete combustion, to control furnace slagging, to reduce carbon carryover, and to maintain steam temperature. With less oxygen available in the flame zone, thermal and fuel NO_x formation is reduced. In addition, the reduced airflow reduces sensible heat stack losses, resulting in an improvement in overall boiler efficiency. NO_x emissions are significantly influenced by excess O₂ decreasing by 50 to 150 ppm for each 1 percent decrease in excess O₂ level.¹ Possible reductions in minimum operating excess O₂ levels from those currently employed are difficult to assess. Generally, units are operated with a margin above an "absolute" minimum excess O₂ to allow for load variations.

Staged combustion, also referred to as "biased" or "off-stoichiometric" firing, involves stratifying the air/fuel mixture in the boiler (i.e., combustion is carried out initially in a primary, fuel-rich combustion zone and is then

completed at lower temperatures in a second, fuel-lean zone). Various techniques are available to divert part of the combustion air supply to points outside of the initial fuel and air mixing zone, thus reducing the availability of oxygen in the primary combustion zone and reducing peak combustion temperature. A convenient technique that can be implemented on units with multiple burner systems is burner-out-of-service (BOOS) operation. In this technique, the fuel flow is terminated to individual burners (while maintaining the air flow) and redistributed to the remaining in-service burners. Thus, fuel-rich conditions are created at the in-service burners, and the remaining air required for complete combustion is introduced through the BOOS. Generally, removing burners from service in the upper portion of the furnace is the most effective procedure. An alternative technique involves the use of overfire air (OFA) ports: a portion of the combustion air supply is introduced through air ports arranged above the burner elevations to generate the fuel-rich burner conditions described previously. Unlike BOOS operation, OFA operation requires that the unit be fitted with the OFA ports. In practice, LEA and staged combustion are effectively combined to achieve minimum NO_x emissions.^{3,5,6}

FGT systems offer the advantage of being add-on systems near the end of the gas flow stream causing little interference with the combustion process. Selective catalytic reduction (SCR) processes are the only ones that have achieved notable success in treating combustion flue gas for removal of NO_x and have progressed to the point of being commercially applied.⁴ SCR processes are based on the preferential reaction of ammonia with NO_x rather than other flue gas constituents (i.e., ammonia selectively reduces NO_x to N_2). Anhydrous ammonia is usually injected into the flue gas after the boiler economizer, and the resulting mixture is passed over a catalyst. A homogeneous gas phase reaction of NO is completed with very little interference from oxygen or other substances. Therefore, large reducing agent quantities are not required, and injection rates of the same magnitude as NO levels are possible at a temperature of about 375°C .^{1,4}

Standard

The Clean Air Act of 1970 required the Environmental Protection Agency (EPA) Administrator to set standards for new sources. The only NO_x source category for which federal New Source Performance Standards are in effect is steam generators with a thermal input greater than 73 MW (250×10^6 Btu/h). The standard, revised in 1979, is $0.6 \text{ lb } \text{NO}_x / 10^6 \text{ Btu}$ for bituminous coal, and $0.5 \text{ lb } \text{NO}_x / 10^6 \text{ Btu}$ for subbituminous coal. The basis of these regulations is CM to reduce NO_x formation, and compliance is achieved with LEA and staged combustion.^{3,5} Boilers with capabilities less than 73-MW thermal input are subject to state emission limits for particulate matter. State implementation plans reflect local conditions and needs. As a result, industrial boiler emission limits vary considerably from state to state. In general, the states' emission limits for NO_x range from 0.3 to $0.8 \text{ lb} / 10^6 \text{ Btu}$. The proposed federal standard for NO_x is $0.7 \text{ lb} / \text{million Btu heat input}$ for pulverized coal-fired industrial boilers. For all other types of coal-fired industrial boilers, the proposed federal NO_x standard is $0.6 \text{ lb} / \text{million Btu heat input}$.

Control Performance and Removal Efficiency

Control Method	NO _x Reduction Potential (%)	Limiting Factors in Effectiveness	Retrofit Limitations	Energy Penalties	Secondary Pollutants	Operation and Maintenance Considerations	Reliability
Low excess air	20	Carbon carryover	Combustion controls and instrumentation	May increase slightly	No effect	Additional combustion controls, increased maintenance	Excellent
Burners out of service	40	Carbon carryover, flame stability, smoke	Pulverizer and fan capacity, flexibility of coal feed system	None	No effect	Additional combustion controls, increased maintenance	Excellent
Overfire air	35	Carbon carryover, flame stability, smoke	Furnace configuration, fan capacity	None	No effect	Additional combustion controls, increased maintenance	Excellent
Selective catalytic reduction	> 90	Particulate plugging of catalyst bed, lack of proven NH ₃ controls	None	May increase slightly	NH ₃ and NH ₃ compounds, SO ₃	Additional costs, increased maintenance	Good to excellent

Due to differences in furnace design and fuel composition, uncontrolled NO_x emissions for coal-fired utility boilers range from 0.6 to 1.4 lb/10⁶ Btu and from 0.3 to 1.0 lb/10⁶ Btu for coal-fired industrial boilers.^{1,7,8} Field test studies have shown that a combination of LEA and staged combustion is an effective means of controlling NO_x from coal-fired utility boilers. NO_x reductions averaging 40 percent have been obtained without significant adverse side effects. Retrofit limitations and the impact on auxiliary equipment are dependent on the unit characteristics and the condition of existing equipment. Currently, only CM controls are in use in the United States; FGT controls are used extensively in Japan.⁴ However, because the California Air Resources Board has required existing utility boilers in the South Coast Air Quality Management District to achieve 90 percent NO_x control by 1990, and EPA is considering the development of a New Source Performance Standard for industrial boilers with FGT, FGT controls will probably be used in this country in the near future.

Reliability and State-of-the-Art

Most of the current research is being directed toward the development of FGT controls (because of the greater potential for reducing NO_x emissions), but a considerable effort is underway to develop innovative burner designs that will inhibit NO_x formation. These diffusion flame burners avoid mixing between primary and secondary streams, thereby minimizing oxygen availability and

reducing combustion temperature. To date, these low NO_x burners have achieved emission reductions in the 50 to 65 percent range during field tests.⁶ Some FGT techniques currently being studied are simultaneous NO_x and SO₂ removal schemes. Dry adsorption of both pollutants (with 50 to 60 percent NO_x removal) is possible using activated carbon.² Regeneration of the adsorbent by high temperature releases N₂ and SO₂. Another removal technique uses electron beam radiation to convert NO_x and SO₂ to particulates that are then removed (80 percent NO_x removal) by an electrostatic precipitator.² High energy electron bombardment produces ions that oxidize SO₂ and NO_x to higher reactive levels. These highly reactive species then combine with other compounds (e.g., ammonia that has been injected into the flue) to form particulates.

Costs: Capital and Operating

Capital and operating costs for CM (either new units or retrofit) are relatively low because the equipment is inherent to the boiler, i.e., burners and boilers have to be designed and manufactured in any case.^{1,6,8-11} This, unfortunately, is not the case for FGT controls; these controls are an add-on to the basic boiler structure. As such, the cost for SCR technologies is about two orders-of-magnitude greater than for CM controls for utility boilers. (Due to these high costs, FGT controls are not currently economically viable for use on industrial boilers.) FGT costs are estimated on the basis of their usage in Japan.^{1,4,6}

Combustion Modification Installation and Operating Costs (\$ 1981)*

NO _x Control	Capital Cost (\$ million)				Unit Cost	
	Retrofit		New		Power Plant (mills/kWh)	Industrial Boiler** (\$1000/10 ⁶ Btu/h)
	Power Plant	Industrial Boiler	Power Plant	Industrial Boiler**		
Low excess air (LEA)	0.52	Unknown	0	0	0	0
Staged combustion	0.60	Unknown	0.19	0.04	0.026	0.27
LEA and staged combustion	1.12	Unknown	0.19	0.04	0.026	0.27
Selective catalytic reduction	Unknown	Unknown	17.8-53.5†	Unknown	2.9-5.8**	Unknown

*Reference year for coal-fired industrial boilers control cost is 1977; 1977 CCI average (I_A) is 2577. See Explanatory Notes.

**Estimated from cost data given in Table 3-1 of Reference 10 using "six-tenths factor" formula given in Reference 11.

†1979 dollars.

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WET LIME AND LIMESTONE SCRUBBING FOR SULFUR DIOXIDE CONTROL

Application and Description of Control

All coal burned in large coal-fired utility boilers and industrial boilers contains some sulfur. When coal is burned, this sulfur is converted primarily into SO_2 with small amounts of SO_3 also being formed. The SO_2 exits the boiler in the flue gas stream and is discharged to the atmosphere as an air pollutant unless some form of SO_x control is applied. A 500-MW_e pulverized coal boiler firing 12,000 Btu/lb of coal with a sulfur content of 3 percent would produce 294 tons of SO_2 per day, about 90 percent of which would be discharged to the atmosphere in the absence of some form of control technology. An industrial boiler with a 73-MW (250×10^6 Btu/h) heat input without controls produces 16 tons of SO_2 per day.^{1,2}

The most popular operational control device for SO_2 control is the wet lime/limestone scrubber. In this device, the SO_2 -laden flue gas is brought into contact with a solution or slurry of lime or limestone and water. The SO_2 reacts with the lime and limestone (CaCO_3) slurry to form CaSO_3 and CaSO_4 , which remain in the scrubbing liquid and are eventually removed from the system in a thickener as a waste sludge. Contact between the liquid and the gas is achieved by turbulent mixing in a venturi configuration, spraying in a counterflow tower arrangement or in a packed bed contactor. While regeneration of the sorbent material is not practical, the waste products can be force oxidized and marketed as gypsum. The waste material in this form is also easier to dispose of in landfills.

Modular scrubber units may be used on coal-fired power plants and industrial boilers. Standby modular units can then be used to replace malfunctioned units or units undergoing routine maintenance.¹ The scrubber or complement of modules connected in parallel can be located immediately after a particulate control device such as an electrostatic precipitator (ESP). Also, the scrubber modules can control the particulate and SO_2 emissions.

The choice of lime versus limestone is controlled by the physical characteristics of the scrubber and depends on a nearby source of limestone. When limestone is used, additional sorbent preparation steps may be required at the site such as crushing and grinding to obtain a slurry. Because of the nonreactive material included and less reactive nature of limestone, a larger amount by weight is required to accomplish the same level of scrubbing than is necessary when using lime.

Standard

The federal standard for emission of SO_2 from large (>250 million Btu/h heat input) coal-fired steam generators was initially established under the authority of the Clean Air Act--New Source Performance Standards (NSPS) in

1971 at 1.2 lb of SO₂ per 10⁶ Btu heat input. The NSPS for this class of combustor was changed on June 11, 1979. The revised NSPS for SO₂ emissions is a function of the uncontrolled SO₂ emissions. Allowable emissions range from 1.2 lb SO₂/10⁶ Btu to less than 0.6 lb SO₂/10⁶ Btu. The reason that the NSPS is variable is that the standard is defined in terms of percentage reductions: if uncontrolled emissions exceed 12 lb SO₂/10⁶ Btu, then (variable) greater than 90 percent reduction in SO₂ emissions is required; if uncontrolled emissions range from 12 to 6 lb SO₂/10⁶ Btu, then a (constant) 90 percent reduction in SO₂ emissions is required; if uncontrolled emissions range from 6 to 2 lb SO₂/10⁶ Btu, then a (variable) 90 to 70 percent reduction in SO₂ emissions is required; and if uncontrolled emissions are less than 2 lb SO₂/10⁶ Btu, then a (constant) 70 percent reduction in SO₂ emissions is required. At the present time, there are no federal SO₂ standards for industrial boilers. The Environmental Protection Agency has deferred consideration of SO₂ emissions until Congress revises the Clean Air Act.³ However, industrial boilers with capacities less than 73 MW (250 x 10⁶ Btu/h) heat input are subject to state emission limits for SO₂. State implementation plans reflect local conditions and needs. As a result, industrial boiler emission limits vary considerably (0.3 to 6.0 lb/10⁶ Btu) from state to state.

Control Performance and Efficiency

The major controlling factors for the efficiency of SO₂ removal in a scrubber are the degree and duration of contact between the scrubbing slurry and the flue gas and the reactivity of the scrubbing slurry. Increases in removal efficiency can also be accomplished through increases in the stoichiometric ratio of sorbent to sulfur at the expense of higher operating costs. A summary of lime/limestone scrubber control performance and efficiency is presented below.

Control Type	Efficiency %	Expected Downtime %	Availability
Limestone scrubber	80	< 10	Full scale
Lime scrubber	85	< 10	Full scale

Reliability and State-of-the-Art

The lime/limestone wet scrubber is the SO₂ control system most widely used today. As of January 1, 1981, 133 systems were operational covering an installed electrical capacity of over 60,000 MW. While many units have demonstrated extended periods of operation with high availability and reliability (>90 percent), reliability continues to be an issue for the general class of technology. State-of-the-art technology requires considerable redundancy of critical components such as absorbers and slurry pumps. Units also require extensive regular maintenance to ensure acceptable reliability. Lime/limestone wet scrubber reliability for industrial boilers is difficult to assess because only a few have been in operation for a short period of time. However, those in operation have demonstrated high reliability (maintained operation more than 95 percent of the time).¹ A summary of lime/limestone wet scrubber state-of-the-art is presented in the table below.

Control Type	Status	Ease of Adaptability	Cross-Media Impacts	Estimated Reliability	Negative Factors
Limestone scrubber	Current full-scale use in U.S.	Can be retrofitted, may require additional space for limestone preparation	Disposal of waste sludge as solid waste	Good	Waste disposal
Lime scrubber	Current full-scale use in U.S.	Can be retrofitted	Disposal of waste sludge as solid waste	Good	Waste disposal

Costs: Capital and Operating

The capital cost of lime/limestone SO₂ control systems is determined by the volume of flue gas passing through the system, the sulfur content of that flue gas, the degree of sulfur removal required, and the type of sorbent and preparation and handling facilities required for it. If a large boiler is to be controlled (i.e., 500 MW_e), the system may be built in modules with extra unit capacity to act as a spare should a malfunction occur. This capability will increase the capital cost per kilowatt of capacity. Operating costs are sensitive to the quality of materials of construction and the maintenance philosophy practiced for the installation. A high degree of system reliability generally requires an intensive preventive maintenance activity which in turn will increase operating costs. Capital and operating costs for a 500-MW_e electrical power plant and an industrial boiler with a 73-MW (250 x 10⁶ Btu/h) heat input are presented below.⁴⁻⁷

FGD Scrubber Installation and Operating Costs (\$ 1981)*

Type	Capital Cost (\$ million)		Annual Operation and Maintenance Cost (\$ million)		Unit Cost	
	Power Plant**	Industrial Boiler	Power Plant†	Industrial Boiler	Power Plant (mills/kWh)**	Industrial Boiler (\$1000/10 ⁶ Btu/h)
Lime slurry ⁴						
Low sulfur (0.4%)	65.4		7.4		9.6	
High sulfur (4%)	87.8		15.2		15.5	
Limestone slurry ⁴						
Low sulfur (0.4%)	69.5		7.6		9.5	
High sulfur (4%)	98.4		13.3		15.0	
Lime scrubber (small units) ^{5,6}	2.9-31.1 [†]		0.75-0.93 [†]		14.9 [†]	
Lime slurry ⁷	61.9		8.1		9.19	
Limestone slurry ⁷	55.1		4.8		6.6	

*Reference year for coal-fired power plants and industrial boilers control cost is 1979; 1979 CCI average I_P is 3003. See Explanatory Notes.

**Levelized annual revenue requirement.

†Estimated from cost data given in Tables 3-1 and 3-3 of Reference 5 using "six-tenths factor" formula given in Reference 6. Cost data in Reference 4 are based on a 13.5 capital recovery factor, a 15-year equipment life, and a 10 percent interest rate.

Examination of the data reported in both references for individual units showed a wide range of variability for comparable systems. This variation indicates a high degree of cost sensitivity to site-specific factors or to cost-reporting methods or to both.

References

1. Environmental Protection Agency, Fossil Fuel Fired Industrial Boilers--Draft EIS -- Background Information, Volume I: Chapters 1-9, March 1982.
2. _____, "Electric Utility Steam Generating Units--Background Information for Proposed SO₂ Emission Standards," EPA-450/2-78-007a, EPA-OAQPS, Research Triangle Park, North Carolina, July 1978.
3. Catalano, L., "SO₂ Standard Not Included in EPA's Proposed NSPS for Industrial Boilers," in "Washington Update," Power, June 1982.
4. Electric Power Research Institute, "Economic and Design Factors for Flue Gas Desulfurization Technology," CS-1428, April 1980.
5. Radian Corporation Report, "Costs of Sulfur Dioxide, Particulate Matter and Nitrogen Oxide Controls on Fossil Fuel Fired Industrial Boilers," EPA Contract No. 68-02-3058, May 20, 1982.
6. Environmental Protection Agency, A Standard Procedure for Cost Analysis of Pollution Control Operations, Volume II Appendices, EPA-600/8-79-018b, June 1979.
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LIME SPRAY-DRY SCRUBBERS FOR SULFUR DIOXIDE CONTROL

Application and Description of Control

The removal of SO_2 from flue gas using wet lime/limestone scrubbing has been practiced for many years at electrical power plants and are currently being considered for industrial boilers. A more recent adaptation of this basic scrubbing technique is designated as spray-dry or dry scrubbing. Dry scrubbers are being applied to low sulfur (less than 2 percent) coal-fired units; however, it remains to be seen whether spray dryer systems will be able to achieve high SO_2 removal efficiencies from industrial boilers firing a range of coal types.^{1,2}

This approach involves the same basic reactions between sorbent (only lime is in current commercial use) and SO_2 as does conventional wet scrubbing. In spray-dry scrubbing, however, only enough water is added to the dry sorbent to allow spraying as a slurry. This slurry when sprayed into the flue gas stream in a spray tower reacts with the flue gas to form CaSO_3 and CaSO_4 . During this reaction and contact with the hot flue gas, the majority of the water (except some which is chemically bound) is evaporated leaving a dry fly-ash-like residue in the gas stream. The material carrying the captured SO_2 can be removed from the flue gas stream using particulate control technology such as a baghouse or electrostatic precipitator (ESP).

There are several apparent advantages to this SO_2 control approach: many of the problems associated with scrubbers, such as scaling and plugging, are substantially reduced if not eliminated; the creation of wet sludge is eliminated reducing handling and disposal problems; and the overall system can be simpler and involve less capital cost than a similar wet scrubbing system. Operating costs are also lower for spray-dry scrubbing than for wet scrubbing because of decreased power requirements, reduced maintenance requirements, and increased system potential life.

A variation of spray-dry scrubbing involves the injection of a dry sorbent material into the flue gas stream with subsequent collection of the reacted material by a particulate control device. The point of injection can vary from directly into the fire box to a point just prior to the particulate control device. Recent pilot-scale tests of this technique have used nahcolite (a naturally occurring form of sodium bicarbonate), but lime and limestone have also been considered as candidate dry-injection materials. One advantage lime/limestone would have as an injection material is that it would yield a more stable end waste product. The sodium-based solids are water soluble leading to potential disposal problems while the calcium-based material is far more stable. The cost and supply of nahcolite is also in question.

Standard

The federal standard for emission of SO_2 from large (>250 million Btu/h heat input) coal-fired steam generators was initially established under the

authority of the Environmental Protection Agency's (EPA) Clean Air Act--New Source Performance Standards (NSPS) in 1971 at 1.2 lb of SO₂ per 10⁶ Btu heat input. The NSPS for this class of combustor was changed on June 11, 1979. The revised NSPS for SO₂ emissions is a function of the uncontrolled SO₂ emissions. Allowable emissions range from 1.2 lb SO₂/10⁶ Btu to less than 0.6 lb SO₂/10⁶ Btu. The reason that the NSPS is variable is that the standard is defined in terms of percentage reductions: if uncontrolled emissions exceed 12 lb SO₂/10⁶ Btu, then (variable) greater than 90 percent reduction in SO₂ emissions is required; if uncontrolled emissions range from 12 to 6 lb SO₂/10⁶ Btu, then a (constant) 90 percent reduction in SO₂ emissions is required; if uncontrolled emissions range from 6 to 2 lb SO₂/10⁶ Btu, then a (variable) 90 to 70 percent reduction in SO₂ emissions is required; and if uncontrolled emissions are less than 2 lb SO₂/10⁶ Btu, then a (constant) 70 percent reduction in SO₂ emissions is required. At the present time, there are no federal SO₂ standards for industrial boilers. EPA has deferred consideration of SO₂ emissions until Congress revises the Clean Air Act.³ However, industrial boilers with capacities less than 73-MW (250 x 10⁶ Btu/h) heat input are subject to state emission limits for SO₂. State implementation plans reflect local conditions and needs. As a result, industrial boiler emission limits vary considerably (0.3 to 6.0 lb/10⁶ Btu) from state to state.

Control Performance and Efficiency

The primary controlling design and operational factors in the determination of scrubber removal efficiency are the relative reactivity of the sorbent selected, the contact between gas and sorbent achieved, and the chemical (stoichiometric) ratio of sorbent to sulfur in the coal. Improvements in sorbent utilization can be achieved by recycling part of the combined collected fly ash-sorbent. Tests to date have shown lime to be more reactive and capable of higher removal efficiencies at lower stoichiometric ratios than limestone. A summary of control efficiency is presented in the table below.

Control Type	Efficiency %	Expected Downtime	Availability
Spray-dry lime scrubber	85	Unknown	Pilot-scale and full-scale now operational
Spray-dry limestone scrubber	60	Unknown	Pilot-scale tests
Dry injection (nahcolite)	90	Unknown	Pilot-scale tests

Reliability and State-of-the-Art

Spray-dry and dry SO₂ scrubbing are in current use on only a few utility boilers but are being installed or considered for installation on several new plants now under construction. While these new plants are located primarily in the west and burn low sulfur coals, recent tests on a boiler at Argonne National Laboratory using high sulfur midwestern coal show 85 to 90 percent removal of SO₂. Because dry scrubbing is a relatively recent innovation in industrial boiler flue gas desulfurization, very few data are available on long-term reliability or operability of these systems.¹ State-of-the-art and reliability information are tabulated in the following table.

Control Type	Status	Ease of Adaptability	Cross-Media Impacts	Estimated Reliability	Negative Factors
Spray-dry lime scrubber	Current full-scale use in U.S.	Can be retrofitted	Disposal of collected dry spent sorbent as solid waste	Little operating experience, expected to be more reliable than wet scrubbers
Spray-dry limestone scrubber	Pilot-scale testing in U.S.	Can be retrofitted	Disposal of collected dry spent sorbent as solid waste	Little operating experience, expected to be more reliable than wet scrubbers	
Dry injection (nahcolite)	Pilot-scale testing in U.S.		Disposal of collected dry spent sorbent as solid waste	Little operating experience, expected to be more reliable than wet scrubbers	Dry waste material highly soluble in water

Costs: Capital and Operating

The capital cost of a spray-dry or dry-injection scrubbing unit is primarily dependent on the relative complexity of the system and on the volume of flue gas to be handled. Equipment for sorbent-fly-ash recycle or addition of sorbent reactivity enhancing agents will also add to the basic capital cost of the unit. Dry injection units will generally cost less than spray-dry slurry units because of the elimination of mixing and slurry handling equipment. The cost information presented in the following table are based on a few actual installed plants or plants under construction.

DRY SO₂ Scrubber Installation and Operating Costs (\$ 1981)*

Type	Capital Cost (\$ million)		Annual Operation and Maintenance Cost (\$ million)		Unit Cost	
	Power Plant**	Industrial Boiler	Power Plant†	Industrial Boiler	Power Plant (mills/kWh)	Industrial Boiler (\$1000/10 ⁶ Btu/h)
Lime spray dryer ⁶ Low sulfur coal (0.7%)	71.2		3.4		6.8	
Lime spray drying (small units) ^{6, 7}		2.8††		0.54		13.2††
Lime spray dryer ⁵ High sulfur coal (4%)	66.3		10.9		11.3	
Low sulfur coal (0.4%)	25.8		3.7		4.1	
Limestone spray dry			Only small R&D units; costs not available			
Dry injection			Only small R&D units; costs not available			

*Reference year for coal-fired industrial boiler control cost is 1978; 1978 CCI average is 2776. See Explanatory Notes.

**Includes cost of associated baghouse and waste handling and disposal facilities.

†Assumes 90 percent annual capacity factor.

††Estimated from cost data given in Tables 3-1 and 3-3 of Reference 6 using the "six-tenths factor" formula given in Reference 7. Cost data in Reference 5 are based on a 13.5 percent capital recovery factor, a 15-yr equipment life, and a 10 percent interest rate.

References

1. Janssen, Kent E., and Robert L. Eriksen, "Basin Electric's Involvement With Dry Flue Gas Desulfurization," paper presented at EPA Symposium on Flue Gas Desulfurization, Las Vegas, Nevada, March 5-8, 1979.
2. Environmental Protection Agency, Fossil Fuel Fired Industrial Boilers--Draft EIS -- Background Information, Volume 1: Chapters 1-9, March 1982.
3. Catalano, L., "SO₂ Standard Not Included in EPA's Proposed NSPS for Industrial Boilers," in "Washington Update," Power, June 1982.
4. Environmental Protection Agency, "Preliminary Economic Analysis of a Lime Spray Dryer FGD System," EPA-600/7-80-050, EPA-IERL, Research Triangle Park, North Carolina, March 1980.
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6. Radian Corporation Report, "Costs of Sulfur Dioxide, Particulate Matter and Nitrogen Oxide Controls on Fossil Fuel Fired Industrial Boilers," EPA Contract No. 68-02-3058, May 20, 1982.
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SODIUM CARBONATE AND DUAL ALKALI WET SCRUBBING FOR SULFUR DIOXIDE CONTROL

Application and Description of Control

Sulfur dioxide contained in the flue gas of coal-fired power plants and industrial boilers can be removed by reaction with and capture by wet scrubbing mediums other than lime/limestone slurries. The most popular of these scrubbing materials are solutions of sodium-based chemicals such as soda ash (Na_2CO_3). Two processes utilizing this material are sodium carbonate scrubbing and double alkali (soda-lime) scrubbing.

Sodium carbonate scrubbing involves contacting the SO_2 -laden flue gas with a clear solution of water and Na_2CO_3 in an absorption tower. If good particulate removal is accomplished prior to the entrance of the flue gas into the absorption tower, the absorber can be a simple packed bed or tray tower which will have high SO_2 removal efficiency with low pressure drops. If little or no particulate removal takes place before entrance into the absorber, a venturi scrubber can be used with a lower SO_2 removal efficiency and a higher unit pressure drop. Because the sodium solution is highly reactive with SO_2 , smaller liquid-to-gas ratios are required to achieve a given level of SO_2 scrubbing than with lime/limestone slurry. The level of reactivity of the scrubbing solution must be maintained by purging a stream of the reactant containing the captured SO_2 in the form of sodium sulfate (Na_2SO_4) and sodium sulfite (Na_2SO_3).^{1,2} This liquid is the waste product of the system and must be disposed of by evaporative ponding, chemical fixation, or by-product recovery (sodium sulfate). Because of the high solubility of the material in the liquid, care must be taken to protect groundwater when ponding is used.

A second system, the double alkali scrubber, combines features of the sodium carbonate system with the limestone process to allow regeneration of the sodium carbonate scrubber medium and produce an insoluble calcium salt as the waste product. The sodium carbonate scrubbing solution is brought in contact with the flue gas in essentially the same manner as in sodium carbonate scrubbing. The liquid purge stream containing the captured sulfur in the form of sodium bisulfate is sent to a mixing tank where it is mixed and reacted with a slurry of lime or limestone. This reaction produces an insoluble calcium salt containing the captured sulfur. The salt can be removed from the liquid by conventional thickener units and disposed of as a sludge in the same manner as wastes from a lime/limestone system. The liquid portion of the material can be returned to the scrubbing system where it is mixed with fresh sodium carbonate and water and recirculated in the absorber unit.^{1,2}

The advantages of both the systems described above over conventional lime/limestone scrubbing are system simplicity, very high SO_2 removal efficiency, low capital cost, and good system operability and reliability. Some problems related to working with lime/limestone slurries are encountered in the regeneration processes of the double alkali system, but the process produces a more desirable waste product.

Standard

The federal standard for emission of SO_2 from large (>250 million Btu/h heat input) coal-fired steam generators was initially established under the authority of the Clean Air Act--New Source Performance Standards (NSPS) in 1971 at 1.2 lb of SO_2 per 10^6 Btu heat input. The NSPS for this class of combustor was changed on June 11, 1979. The revised NSPS for SO_2 emissions is a function of the uncontrolled SO_2 emissions. Allowable emissions range from 1.2 lb $\text{SO}_2/10^6$ Btu to less than 0.6 lb $\text{SO}_2/10^6$ Btu. The reason that the NSPS is variable is that the standard is defined in terms of percentage reductions: if uncontrolled emissions exceed 12 lb $\text{SO}_2/10^6$ Btu, then (variable) greater than 90 percent reduction in SO_2 emissions is required; if uncontrolled emissions range from 12 to 6 lb $\text{SO}_2/10^6$ Btu, then a (constant) 90 percent reduction in SO_2 emissions is required; if uncontrolled emissions range from 6 to 2 lb $\text{SO}_2/10^6$ Btu, then a (variable) 90 to 70 percent reduction in SO_2 emissions is required; and if uncontrolled emissions are less than 2 lb $\text{SO}_2/10^6$ Btu, then a (constant) 70 percent reduction in SO_2 emissions is required. At the present time, there are no federal SO_2 standards for industrial boilers. The Environmental Protection Agency (EPA) has deferred consideration of SO_2 emissions until Congress revises the Clean Air Act.³ However, industrial boilers with capacities less than 73-MW (250×10^6 Btu/h) heat input are subject to state emission limits for SO_2 . State implementation plans reflect local conditions and needs. As a result, industrial boiler emission limits vary considerably (0.3 to 6.0 lb/ 10^6 Btu) from state to state.

Control Performance and Efficiency

The primary design factors in the determination of system SO_2 removal efficiency are the degree of liquid to gas contact achieved in the absorber unit and the reactivity of the scrubbing solution which is circulated in the absorption unit. The latter is controlled by the rate at which fresh Na_2CO_3 solution is added to the system and the pH established in the circulating scrubbing liquid. One demonstration showed that raising the pH from 5.2 to 6 resulted in an increase in SO_2 removal efficiency from 95 to 98 percent. A summary of control performance and efficiency is presented in the table below.

Control Type	Efficiency %	Expected Downtime %	Availability
Sodium carbonate	>90 demonstrated	10	Full-scale 1000 MW _e in operation
Double alkali	>90 demonstrated	10*	Full-scale 1300 MW _e in operation

*Based on limited operating experience at utility scale.

Reliability and State-of-the-Art

Sodium carbonate-based systems have good reliability and SO_2 removal efficiencies; but they also are used more extensively on smaller industrial boilers; they have not been widely accepted as an SO_2 control option on large utility

boilers. The probable cause of lack of acceptance is the cost of sodium carbonate and to some degree the disposal problems associated with the soluble sodium-based waste products. Data from an EPA industrial boiler flue gas desulfurization survey indicate that dual alkali system reliability averages slightly higher than 90 percent.²

Control Type	Status	Ease of Adaptability	Cross-Media Impacts	Estimated Reliability	Negative Factors
Sodium carbonate	Current full-scale use in U.S.	Can be retrofitted, simple system	Liquid waste product with dry salts highly soluble in water	Very good	High cost of raw materials (sodium carbonate); liquid waste may pose disposal problems
Double alkali	Current full-scale use in U.S.	Can be retrofitted	Sludge which must be disposed of as solid waste	Good (>90%)	High cost of raw materials (sodium carbonate)

Costs: Capital and Operating

The capital costs of sodium-based scrubbing systems are determined primarily by the volume of flue gas to be handled by the system. The addition of the sorbent regeneration process in the double alkali system obviously increases the capital cost of the system substantially but potentially decreases the operating costs through the reduction of sodium carbonate required to operate the system with reduced potential waste disposal problems.

Sodium-Based SO₂ Scrubber Installation and Operating Costs (\$ 1981)*

Type	Capital Cost (\$ million)		Annual Operation and Maintenance Cost (\$ million)		Unit Cost	
	Power Plant	Industrial Boiler	Power Plant	Industrial Boiler	Power Plant (mills/kWh)	Industrial Boiler (\$1000/10 ⁶ Btu/h)
Sodium carbonate ⁴	50.8		4.1		5.9	
Dual alkali ⁴	67.3		5.4		7.8	
Dual alkali (small units) ^{5,6}		3.1**		0.92**		15.9**
Double alkali ⁷						
Low sulfur coal (0.4%)	77.7		6.2		8.2†	
High sulfur coal (4%)	96.0		12.6		13.5†	

*Reference year for coal-fired industrial boiler control cost is 1978; 1978 CC1 average (I_{PI}) is 2776. See Explanatory Notes.

**Estimated from cost data given in Tables 3-1 and 3-3 of Reference 5 using the "six-tenths factor" formula given in Reference 6. Cost data in Reference 5 are based on a 13.5 percent capital recovery factor, a 15-yr equipment life, and a 10 percent interest rate.

†Levelized annual revenue requirements.

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1. Environmental Protection Agency, "Electric Utility Steam Generating Units--Background Information for Proposed SO₂ Emission Standards," EPA-450/2-78-007a, EPA-OAQPS, Research Triangle Park, North Carolina, July 1978.
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SCRUBBING TO PRODUCE SULFUR BY-PRODUCTS FOR SULFUR DIOXIDE CONTROL

Application and Description of Control

The SO_2 produced when coal is burned has been controlled primarily through the use of wet limestone scrubbers that produce a throwaway sludge containing the captured sulfur. While acceptable methods are available for the disposal of this waste sludge, it is generally deemed desirable to develop a practical and economical scrubbing process that will produce a useful by-product utilizing the sulfur removed from the flue gas. Examples of such by-products are elemental sulfur and sulfuric acid. Several processes have been proposed to accomplish this objective. Two of these systems in current operation are the Wellman-Lord process and the magnesium oxide (Mag Ox) process. Both processes allow the recovery of sulfur in its elemental form or as sulfuric acid.

Both the Wellman-Lord and Mag Ox systems use a wet scrubbing unit contacted and reacting with the SO_2 -laden flue gas. The Mag Ox unit utilizes a slurry of magnesium oxide (MgO) and water (~10 percent solids), and the Wellman-Lord uses a clear liquid sodium alkali solution (sodium sulfite in water) as the scrubbing liquid. Both systems use thermal processes to separate an SO_2 -rich gas stream and recover the sorbent material for reuse. The SO_2 -rich gas stream can then be converted to either elemental sulfur or sulfuric acid in separate standard chemical processes. The Wellman-Lord regeneration process involves evaporation to release the SO_2 from the scrubbing medium, and Mag Ox utilizes calcining of the dried solid material that has been separated from the scrubbing liquid by centrifuge. The dry material can be transported offsite for regeneration to minimize the complexity of the overall power plant installation.

Both systems have been operated at full scale on coal-fired power plants in the United States. There have been three full-scale prototype/test installations of the Mag Ox system, all of which have suspended operation. There are currently three Mag Ox units under construction totaling 724 MW_e of electrical capacity. One Wellman-Lord unit has ceased operation and seven other installed units with an installed capacity of 1540 MW_e are in current operation. One other unit with a capacity of 534 MW_e is under construction. The Wellman-Lord and Mag Ox systems are applicable to coal-fired industrial boilers; however, none are known to be applied this way at this time.^{1,2}

Both systems require some form of effective particulate control prior to the scrubber entrance to prevent significant mixing of fly ash with the scrubber liquid. Other than this requirement, the scrubbing units can be located in the same position as conventional lime/limestone scrubber units.

Standard

The federal standard for emission of SO_2 from large (>250 million Btu/h heat input) coal-fired steam generators was initially established under the authority of the Clean Air Act--New Source Performance Standards (NSPS) in

1971 at 1.2 lb of SO₂ per 10⁶ Btu heat input. The NSPS for this class of combustor was changed on June 11, 1979. The revised NSPS for SO₂ emissions is a function of the uncontrolled SO₂ emissions. Allowable emissions range from 1.2 lb SO₂/10⁶ Btu to less than 0.6 lb SO₂/10⁶ Btu. The reason that the NSPS is variable is that the standard is defined in terms of percentage reductions: if uncontrolled emissions exceed 12 lb SO₂/10⁶ Btu, then (variable) greater than 90 percent reduction in SO₂ emissions is required; if uncontrolled emissions range from 12 to 6 lb SO₂/10⁶ Btu, then a (constant) 90 percent reduction in SO₂ emissions is required; if uncontrolled emissions range from 6 to 2 lb SO₂/10⁶ Btu, then a (variable) 90 to 70 percent reduction in SO₂ emissions is required; and if uncontrolled emissions are less than 2 lb SO₂/10⁶ Btu, then a (constant) 70 percent reduction in SO₂ emissions is required. At the present time, there are no federal SO₂ standards for industrial boilers. The Environmental Protection Agency (EPA) has deferred consideration of SO₂ emissions until Congress revises the Clean Air Act.³ However, industrial boilers with capacities less than 73-MW (250 x 10⁶ Btu/h) heat input are subject to state emission limits for SO₂. State implementation plans reflect local conditions and needs. As a result, industrial boiler emission limits vary considerably (0.3 to 6.0 lb/10⁶ Btu) from state to state.

Control Performance and Efficiency

Limited operating experience with the Wellman-Lord and Mag Ox units makes it difficult to forecast the expected downtime; however, they should exhibit performance characteristics similar to or better than comparable wet lime/limestone scrubber units. The primary controlling design factors in the determination of system SO₂ removal efficiency are liquid-to-gas contact, liquid-to-gas ratio, and scrubber liquid reactivity. Questions remain as to how well the regenerated scrubber material will retain its activity. Control performance and efficiency is given in the table below.

Control Type	Efficiency %	Expected Downtime	Availability
Wellman-Lord and magnesium oxide (Mag Ox)	> 90 demonstrated	Unknown	Full scale

Reliability and State-of-the-Art

The nonthrowaway, regenerative SO₂ wet scrubber has not been widely accepted by either coal-fired power plants or industrial boilers even though full-scale operation of such systems dates back to 1972. There has been enough recorded operating experience and there are enough systems now in operation to classify these processes as commercially available; however, regulatory and economic conditions have not been generally conducive to their selection over more conventional and proven lime/limestone-based systems.

Control Type	Status	Ease of Adaptability	Cross-Media Impacts	Estimated Reliability	Negative Factors
Wellman-Lord and magnesium oxide scrubber (Mag Ox)	Wellman-Lord: current full-scale use in U.S. Mag Ox: Previous full-scale use suspended; new full-scale units under construction	Can be retrofitted	Eventually spent dry sorbent must be disposed of as solid waste	Good: Little operating experience has been recorded for these units but both systems have demonstrated extended periods of operation with essentially 100 percent availability.	Process including regeneration and sulfur recovery more complex than conventional lime/limestone control system; power plant personnel not generally familiar with associated processes; larger capital investment is required

Costs: Capital and Operating

The capital costs of regenerative scrubber units are determined by the volume of flue gas to be treated and the degree of SO₂ removal desired. These systems are somewhat more complex than equivalent lime/limestone scrubber units and a separate system for regeneration of sorbent must also be provided. These factors account for the significantly higher capital costs of these units. Reported operating costs are also high in comparison to lime/limestone throwaway systems, but many operating and waste disposal problems are eliminated through sorbent regeneration.

Regenerative SO₂ Scrubber Installation and Operating Costs (\$ 1981)

Type	Capital Cost (\$ million)		Annual Operation and Maintenance Cost (\$ million)		Unit Cost	
	Power Plant	Industrial Boiler*	Power Plant*	Industrial Boiler*	Power Plant (mills/kWh)*	Industrial Boiler (\$1000/10 ⁶ Btu/h)*
Wellman-Lord ³	119.8	20.4	5.7	0.97	16.4	85.7
Wellman-Lord ⁴						
High sulfur coal (4%)	82.0	15.3	5.3	0.86	15.0	64.9
Low sulfur (0.4%)	73.3	11.3	5.7	0.54	9.1	45.4
Magnesia Slurry (Mag Ox) ⁴						
High sulfur (4%)	101.5	15.0	4.5	0.77	12.7	63.0
Low sulfur coal (0.4%)	74.5	11.0	3.0	0.51	8.6	42.6

*Estimated from cost data for a 500-MW plant given in References 4 and 5 using the "six-tenths factor" formula given in Reference 2.

**Levelized annual revenue requirement.

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PHYSICAL COAL CLEANING FOR SULFUR DIOXIDE CONTROL

Application and Description of Control

All coal, when it is removed from the ground, contains varying amounts of sulfur in two forms, organic and pyritic. Organic sulfur for the most part is contained in the chemical coal matrix while pyritic sulfur is found as finely divided particles among the coal and ash fractions of the coal. Much of this unwanted sulfur can be separated from the coal by techniques of physical coal cleaning prior to combustion.

The objective of physical coal cleaning is to separate the coal particles from the pyrite-containing sulfur and ash by the use of differences in their individual physical properties such as specific gravity, surface characteristics, size, or shape. In order to accomplish this separation, the coal must be reduced to particles which contain a predominance of either coal or the unwanted impurities. This involves crushing or grinding the coal to sizes less than 3/8 in. in diameter. In general, the smaller the coal is ground (some systems operate on 28-mesh or 0.650-mm material), the higher the level of impurity removal possible.

Coal cleaning, aside from lowering the sulfur-to-heat-content ratio of a coal, can reduce ash content, moisture content, provide greater uniformity of fuel composition, and reduce fouling and corrosion of steam generator surfaces caused by sulfur. However, because of the wide ranges of coal characteristics, the ability of existing separation processes to remove the sulfur and ash varies widely from coal to coal. The measure of ability to perform this separation on a specific coal is known as its "washability."

Physical coal cleaning systems are generally made up of a group of unit operations selected from the large number of techniques available. They are selected to match the physical characteristics of the coal to be processed and the level of cleaning desired. Process complexity ranges from rough crushing and screening of run-of-mine coal to wet processing of finely ground coal to produce a fine cleaned fraction and a second stream less finely divided and containing a higher level of impurities. Physical coal cleaning plants can be located either near the coal mine, at the power plant, or at some intermediate site to prepare coal for industrial boiler use. Provisions must be made for the disposal of the solid waste removed from the coal and control of liquid effluents from the process if wet processing techniques are used.

Physical coal cleaning is essentially limited to the removal of pyritic sulfur. While relatively high levels of pyritic sulfur removal can be achieved for coals with high washability, the increases come at the expense of increased losses of coal (carbon or heat content) to the waste stream. Because the sulfur content of many coals is roughly half pyritic and half organic forms, coal cleaning is essentially limited to removal of about half of the total sulfur in the coal.¹⁻³

Standard

To meet new regulations under the New Source Performance Standards, removal of sulfur from coal prior to combustion must be augmented by some additional form of SO₂ control. This is because only about 10 to 40 percent of total sulfur can be removed by current techniques.³

The federal standard for emission of SO₂ from large (>250 million Btu/h heat input) coal-fired steam generators was initially established under the authority of the Clean Air Act--New Source Performance Standards (NSPS) in 1971 at 1.2 lb of SO₂ per 10⁶ Btu heat input. The NSPS for this class of combustor was changed on June 11, 1979. The revised NSPS for SO₂ emissions is a function of the uncontrolled SO₂ emissions. Allowable emissions range from 1.2 lb SO₂/10⁶ Btu to less than 0.6 lb SO₂/10⁶ Btu. The reason that the NSPS is variable is that the standard is defined in terms of percentage reductions: if uncontrolled emissions exceed 12 lb SO₂/10⁶ Btu, then (variable) greater than 90 percent reduction in SO₂ emissions is required; if uncontrolled emissions range from 12 to 6 lb SO₂/10⁶ Btu, then a (constant) 90 percent reduction in SO₂ emissions is required; if uncontrolled emissions range from 6 to 2 lb SO₂/10⁶ Btu, then a (variable) 90 to 70 percent reduction in SO₂ emissions is required; and if uncontrolled emissions are less than 2 lb SO₂/10⁶ Btu, then a (constant) 70 percent reduction in SO₂ emissions is required. At the present time, there are no federal SO₂ standards for industrial boilers. The Environmental Protection Agency has deferred consideration of SO₂ emissions until Congress revises the Clean Air Act.⁴ However, industrial boilers with capacities less than 73-MW (250 x 10⁶ Btu/h) heat input are subject to state emission limits for SO₂. State implementation plans reflect local conditions and needs. As a result, industrial boiler SO₂ emission limits vary considerably (0.3 to 6.0 lb/10⁶ Btu) from state to state.

Equipment for all cleaning levels is now in commercial operation or available at proven commercial scale. Level 1 is included to show the base case of sizing preparation only with no cleaning attempted. Plants have been assumed to produce 1000 tons/h for 13 production hours per day for 5 days per week. Normal maintenance and repair can be accomplished in the downtime periods.

The performance of a particular coal cleaning system is dependent on the characteristics of the input coal, primarily its washability characteristics. If the cleaning system is matched to the input coal, then increases in the level of sulfur removal are achieved by grinding and processing the coal at smaller sizes. This approach leads to higher losses of coal (carbon) in the refuse stream and more complex systems with higher associated costs.⁴

Reliability and State-of-the-Art

The basic techniques of physical coal cleaning have been known and practiced for many years. The primary objective in the past has been to remove rock, ash, and other mine-related dilutions as a means of obtaining a more salable product. Recently (within the last 10 years) more consideration has been

given to coal cleaning as a potential way to solve environmental problems such as the emission of SO₂. While most current steam coal cleaning activities are still restricted to coarse coal (>3/8 in.) cleaning to remove mine dilutions, some metallurgical coal and some steam coal are being processed at commercial scale in coal cleaning plants at sizes around 28 mesh or 0.650 mm.

Control Performance and Efficiency^{1,2}

The performance and efficiency of the physical coal cleaning process is summarized in the table below.

Cleaning Level	Coal Type Examined	% Sulfur in Coal	% of Total Sulfur Removed	% of Ash Removed	% of Btu Loss
Crushing and classification only	MT (Rosebud)	0.7	0	0	0
	IL (No. 6)	2.69	0	0	0
Crushing and screening with coarse coal cleaning	WV (Cedar Grove)	0.81	7.4	25	2.6
Level 2 plus cleaning fines and thermal drying of fines	CO (Montrose County)	0.80	8.8	46	5.7
Level 3 plus separate cleaning of three size ranges down to 28 mesh or 0.650 mm, thermal drying of 1/4 in. fraction	PA (Lower Kittanning)	2.77	71.1	64	3.8
Crushing and screening to two size fractions (2 × 3/8 in. and < 3/8 in.), fractions cleaned separately to produce two levels of cleaned coal	PA (Upper Freeport)	3.4	(Fines)	75.6	85
			(Middlings)	36.2	25
					38.8
					69.9

Costs: Capital and Operating

The capital costs of physical coal cleaning systems are primarily dependent on the level of processing and cleaning desired. In general, the cleaner the desired product, the more processing and associated processing units are required. Of equal importance in determining the process complexity are the washability and associated processing characteristics of the raw coal input. For coals with good washability characteristics, simple processing systems can achieve a high level of coal cleaning while poor washability characteristics generally require complex systems to achieve even a moderate level of sulfur and ash removal. The data presented below are for a coal cleaning plant operating at the coal mine.

Physical Coal Cleaning Plant Installation and Operating Costs^{3,5,6} (\$ 1981)*

Cleaning Level	Coal Type	Capital Cost (\$ million)		Annual Operation and Maintenance Cost (\$ million)		Unit Cost ^{†,††}	
		Power Plant ^{**}	Industrial Boiler [§]	Power Plant	Industrial Boiler [§]	Power Plant (mills/kWh)	Industrial Boiler (\$1000/10 ⁶ Btu/h) [§]
Crushing and classification only	MT (Rosebud) IL (No. 6)	7.4 6.4	1.28 1.1	0.62 0.57	0.106 0.10\$	0.88 0.78	5.5 4.7
Crushing and screening with coarse coal cleaning	WV (Cedar Grove)	12.6	2.16	0.90	0.15\$	0.67	9.2
Level 2 plus cleaning fines and thermal drying of fines	CO (Montrose County)	21.8	3.7	1.24	0.22\$	2.2	15.7
Level 3 plus sepa- rate cleaning of three size ranges down to 0.650-mm, thermal drying of ¼-in. fraction	PA (Lower Kittanning)	26.6	4.5	1.78	0.31\$	2.85	19.4
Crushing and screening to two size fractions (2 × 3/8 in. and <3/8 in.), fractions cleaned separately to produce two levels of cleaned coal	PA (Upper Freeport)	41.1	7.0	2.68	0.46\$	4.35	29.7

*Reference year for coal-fired industrial boilers control cost is 1977; 1977 CCI average (t_{R1}) is 2577. See Explanatory Notes.

**Scaled to 500 ton/h plant capacity (approximately enough to supply a 500-MWe plant).

†Assumes a 38 percent efficiency for overall electric generation process.

††Levelized annual revenue requirements.

[§]Estimated from cost data for a 500-MWe plant given in References 3 and 5 using the "six-tenth factor" formula given in Reference 6.

Cleaning Level	Status	Ease of Adaptability	Cross-Media Impacts	Estimated Reliability	Negative Factors
Crushing and classification only	In common commercial use	May require only existing equipment	Solid waste for disposal plus potential for liquid discharges	Mechanical reliability good to excellent	Removes little or no sulfur
Crushing and screening with coarse coal cleaning	In common commercial use, especially for eastern coals	Necessary equipment could be retrofitted but complete new plant more likely	Solid waste for disposal plus potential for liquid discharges	Mechanical reliability good to excellent; removal efficiency highly dependent on <i>uniformity of raw coal feed</i>	Requires some additional form of SO ₂ emission control to meet current NSPS
Level 2 plus cleaning fines and thermal drying of fines	In common use, however used chiefly on metallurgical coals	Complete new cleaning plant likely	Solid waste for disposal plus potential for liquid discharges	Mechanical reliability good to excellent; removal efficiency highly dependent on <i>uniformity of raw coal feed</i>	Requires some additional form of SO ₂ emission control to meet current NSPS
Level 3 plus separate cleaning of three size ranges down to 0.650 mm, thermal drying of 1/4-in. fraction	Several systems operating primarily on metallurgical and special use coals	Complete new cleaning plant likely	Solid waste for disposal plus potential for liquid discharges	Mechanical reliability good to excellent; removal efficiency highly dependent on <i>uniformity of raw coal feed</i>	Requires some additional form of SO ₂ emission control to meet current NSPS
Crushing and screening to two size fractions (2 × 3/8 in. and < 3/8 in.), fractions cleaned separately to produce two levels of cleaned coal	A few commercial-scale demonstrations in operation; at least one is producing steam coal	Complete new plant required	Solid waste for disposal plus potential for liquid discharges	Mechanical reliability good to excellent; removal efficiency highly dependent on <i>uniformity of raw coal feed</i>	Requires some additional form of SO ₂ emission control to meet current NSPS; has high loss of coal heat content associated with current technology

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Water Pollution Control

WASTEWATER CONTROL

Application and Description of Control

Boiler-associated wastewater originates from two major sources: feedwater preparation and boiler blowdown. Coal pile runoff and ash handling device systems also contribute but at less frequent intervals. The pollutants of concern present in these wastewater streams are suspended and dissolved solids, organics, temperature, and pH, all of which are amenable to commercially available treatment methods. When comparing industrial and power plant boiler wastewaters and their treatment, consideration must be made to account for the significantly less volume discharged by the former and consequently the availability of more treatment alternatives. In general, facilities today that do treat their boiler-associated wastewater separately use evaporation ponds effecting virtually zero discharge.¹

The control technology for wastewater streams is composed of water system designs that (1) minimize wastes; (2) reuse wastewater in the plant; (3) dispose wastewater onsite by ponding and evaporation; or (4) treat wastewater to allow discharge to surface waters or publicly owned treatment works. These designs are all available and currently being employed to varying degrees at both power plants and industrial facilities. However, zero-discharge water systems are the preferred configuration whenever feasible.

If any facility desires to treat these waste streams, the technologies usually employed are (1) filtration, (2) ion exchange, (3) reverse osmosis, (4) electrodialysis, (5) coagulation/sedimentation, (6) biological processes, and (7) neutralization. Others do exist, but their capital and operation and maintenance costs must be carefully studied to determine their attractiveness.

- Ion exchange is used to selectively remove ionic species from feedwater that may interfere in facility operations. The interchange of ions occurs between the wastewater and an insoluble, solid salt (the ion exchanger), with no change in the physical structure of the solid. When the ion exchanger is exhausted, it is regenerated using either an acid or base depending on the ions removed.
- Reverse osmosis selectively traps the interfering substances from feedwater on a semipermeable membrane allowing high purity water to pass through.
- Electrodialysis uses an electric field to direct charged substances through alternating cation and anion membranes.
- Coagulation/sedimentation uses various additives to convert soluble substances to insoluble precipitates and cause the aggregation of small suspended materials into larger, more settleable sizes.

- Biological treatment processes use microorganisms to remove or reduce the soluble organic contaminants and operate either aerobically or anaerobically. (The former is the most prevalent.)
- Neutralization uses either acid or base addition to produce wastewater conditions between pH6 and pH9.

Ion exchange, reverse osmosis, and electrodialysis are only now becoming attractive as wastewater treatment methods due to rising energy costs. Unless a facility plans to recycle its wastewater, the costs of such systems need careful analysis. Additionally, each system produces a secondary wastewater stream that must also be treated prior to a discharge. Coagulation/sedimentation and biological processes generate a sludge that must be managed, and filtration requires periodic backwashing to maintain effective operation. The backwash stream must also be managed (e.g., evaporation pond).

The design of the wastewater treatment facility may use several of the above options in series in order to maximize the effectiveness of each. For example, because suspended solids dramatically reduce the effectiveness and life of ion exchange materials and reverse osmosis membranes, coagulation and sedimentation technologies with or without filtration may precede these units. These design considerations are accounted for during preliminary engineering analyses.

The degree of treatment depends on whether the facility intends to discharge directly to a receiving water body or to a publicly owned treatment works (POTW). The former case has stricter requirements and necessitates compliance with a National Pollutant Discharge Elimination System permit. The latter case will require some degree of pretreatment prescribed by the POTW. Generally, coal-fired power plants discharge directly while industrial facilities use either option.

Standard

Assuming that reuse or evaporative disposal of waste streams within plants is accomplished, no government standards apply to the quality of the waste stream. If discharge outside the plant boundary to a surface water body is used, then federal and state limitations for National Pollution Discharge Elimination System permits apply. New Source Performance Standards² applicable to the specific industries and regulations for the control of hazardous substances will also apply. For new electric utility plants, the regulations address total suspended solids (< 100 mg/l), oil and grease (< 20 mg/l), pH (between 6.0 and 9.0), polychlorinated biphenyls (none), copper (< 1.0 mg/l), iron (< 1.0 mg/l), free available chlorine (< 0.5 mg/l), zinc, chromium, phosphorous, and other corrosion inhibitors. The Environmental Protection Agency (EPA) expects to publish draft regulations for industrial boilers in 1983. Individual states may have more stringent regulations for these pollutants or may have additional regulations for other pollutants such as specific inorganic ions. Pond discharges

into surface water or groundwater require monitoring to meet the National Pollution Discharge Elimination System requirements. Although few states are currently enforcing groundwater monitoring, some plants are voluntarily monitoring groundwater.

Control Performance and Efficiency

Total reuse of the water in the plant constitutes a 100-percent effective control. If onsite disposal through evaporation is selected, 100-percent effective control of the waste stream is accomplished. This assumes effective containment of the liquid waste in the pond during the evaporation process and can be accomplished by using a low permeability soil material such as clay or by installing a pond liner such as bentonite clay or plastic. If treatment for discharge is selected, several conventional water treatment technologies are available. The following list presents achievable pollutant removal efficiencies for various alternatives.^{3,4}

Alternative	Removal Efficiency (%) [*]
Filtration	75-95
Ion exchange ^{**}	80-95
Reverse osmosis ^{**}	75-95
Electrodialysis ^{**}	80-95
Coagulation/sedimentation	95
Biological treatment	50-95
Neutralization	pH between 6 and 9

^{*}For those pollutants identified in the description.

^{**}Assumes pretreatment to remove suspended solids.

Reliability and State-of-the-Art

Because the treatment methods generally applicable to boiler-associated wastewaters have extensive use, their reliability is generally very good. Important system considerations are described in the following table.

System	Status	Cross-Media Impacts	Reliability	Negative Factors
Ion exchange	Current full-scale use	None	Very good	Produces an acid or base side stream requiring additional treatment
Reverse osmosis	Current full-scale use	None	Very good	Produces a concentrate stream requiring treatment
Electrodialysis	Just starting in full-scale use	None	Good	Produces a concentrate stream requiring treatment
Coagulation/sedimentation	Current full-scale use	Produces sludge requiring disposal	Very good	May require land for sludge disposal
Biological processes	Current full-scale use	Produces sludge requiring disposal	Very good	May require land for sludge disposal
Neutralization	Current full-scale use	None	Very good	Must store caustic materials onsite
Evaporation ponds	Current full-scale use	Potential soil contamination	Very good	Temporary land loss; potential groundwater contamination

Costs: Capital and Operating

The following table represents values for capital investment costs and operation and maintenance cost for the applicable wastewater treatment technologies.⁴⁻⁷

Wastewater Treatment Installation and Operating Costs (\$ 1981)*

Treatment Alternative	Capital Cost (\$ million)		Annual Operation and Maintenance Cost (\$ million)		Unit Cost	
	Power Plant	Industrial Boiler	Power Plant	Industrial Boiler	Power Plant (mills/kWh)	Industrial Boiler (\$1000/10 ⁶ Btu/h)
Evaporation ponds	5.2	0.8**	Unknown	Unknown	Unknown	3.6
Ion exchange†	0.5-1.6	0.5-1.6	0.26	0.26	0.18-0.026	2.1
Reverse osmosis	1.3	1.3	0.13	0.13	0.16	2.0
Electrodialysis†	0.23	0.23	0.18	0.18	0.13	1.58
Coagulation/sedimentation†	0.013-	0.013-	0.013-	0.026-	0.009-0.060	Unknown
Biological process†	0.4	0.4	0.053	0.079		
Neutralization†	0.4-0.79	0.4-0.79	0.026-0.079		0.041-0.06	0.47-1.12
	1.3	1.3	1.3	1.3	0.93	10.5

*Reference year for coal-fired power plants and industrial boilers control cost is 1978; 1978 CCI average (I_H) is 2776. See Explanatory Notes.

**Estimated from cost data given in Table 3-1 of Reference 6 using "six-tenth factor" formula given in Reference 7.

†Costs are \$ million per million gal./day.

References

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ONCE-THROUGH COOLING SYSTEMS FOR THERMAL DISCHARGE CONTROL

Application and Description of Control

A considerable amount of waste heat is rejected from power plants and to a lesser extent from industrial boilers. With once-through cooling systems, water is drawn from a source (groundwater, aquatic, estuarine, or marine), pumped through the condenser to absorb heat, and returned directly to the source at an elevated temperature.^{1,2} For efficient cooling, intake sites are located such that withdrawing warm water from prior use (either by the facility itself or a nearby industrial facility) is minimized.

Once-through discharge cooling is designed to use either large cooling water flow rates with small temperature rise or low flow rates with large temperature increases to accommodate waste heat loads with relatively little water consumption. Large volume, high velocity discharges produce more rapid mixing and thus impact a smaller area than do small volume, low velocity discharges, which tend to remain and disperse over the surface with little mixing. A 500-MW_e plant has withdrawal requirements between 112,000 and 448,000 gal./min.³ An industrial boiler with a heat input of 250×10^6 Btu/h has water requirements of between 5600 and 22,400 gal./min.

Once-through cooling systems normally are the least expensive cooling alternatives to construct, operate, and maintain.^{2,4} However, water availability is a priority issue governing the once-through cooling option. In arid regions, this option may not be available. Final design considerations are site specific and must address meteorological, environmental, economic, and institutional factors prevalent in the region where the plant is or will be located.

Standard

Cooling water discharges are regulated by the Clean Water Act, PL 95-217, Sections 301, 306, and 316. The statute requires that a discharge permit that specifies effluent characteristics be obtained. Any state granted primacy by the Environmental Protection Agency (EPA) to conduct a discharge-permitting program has the authority to establish these limits. The federal thermal discharge standards recommended by EPA are summarized below.^{1,3}

Recommended Standards (above ambient)

Water Body	$\Delta T_{\max}$ (°F)	$\Delta T_{\max}$ (°C)
Streams and rivers	5.0	2.8
Lakes	3.0	1.7
Estuaries and marine coastal waters		
Winter (Sept.-May)	4.0	2.2
Summer (June-Aug.)	1.5	0.8

Section 316 provides conditions that may exempt a discharger from these limits provided the owners can demonstrate that the imposed limits are too stringent, in which case new limits will be proposed. EPA has promulgated guidelines on what conditions must be surveyed before applying for an exemption. In general, three environmental impact categories must be assessed: (1) potential organism entrainment and impingement during withdrawal, (2) potential organism entrainment in discharge heat plume and the associated fatality rate, and (3) the average receiving water body ΔT effected at the discharge point and within the mixing zone.

Control Performance and Efficiency

Overall performance is measured in terms of energy conversion efficiency as well as water temperature elevation and cooling water flow rate (Q). Newer power plants are experiencing a ΔT of about 10°C (18°F) when Q is about $16.5 \text{ m}^3/\text{s}$. Thus, ΔT must be reduced to the existing standard within the mixing zone of the receiving water body (as defined by each permitting authority). Industrial boilers, because of their smaller size, have much smaller temperature differences and flow rates to contend with. However, the ΔT must still be reduced to meet the existing standard for the receiving water body.

Reliability and State-of-the-Art

The following features summarize implementation of once-through cooling systems with direct discharge.

Status	Ease of Adaptability	Cross-Media Impacts	Estimated Reliability*	Negative Factors
Current full-scale use in U.S.	Readily adaptable	None	Good	Large water requirement

*Pumps require routine maintenance to minimize downtime. Reserve pumps should be available for emergency situations.

Costs: Capital and Operating

Once-through cooling system costs include intake structure, pipelines, pumps, condenser, and discharge structure. The following costs were derived for a 500-MW_e plant and a $250 \times 10^6 \text{ Btu/h}$ (heat input) industrial boiler.²⁻⁶

Once-Through Cooling Installation and Operating Costs (\$ 1981)

Capital Cost (\$ million)		Annual Operation and Maintenance Cost** (\$ million)		Unit Cost	
Power Plant	Industrial Boiler	Power Plant	Industrial Boiler	Power Plant (mills/kWh)	Industrial Boiler (\$1000/10 ³ Btu/h)
6.3	1.06 [†]	0.07	0.01 [†]	0.40 ^{††}	4.23

*Reference year for coal-fired power plants and industrial boilers control cost is 1977; 1977 CCI average (I_R) is 2577. See Explanatory Notes.

**Operation and maintenance costs are assumed to approximate 1 percent of cooling system capital costs.

[†]Estimated from cost data given in Table 3-1 of Reference 5 using "six-tenths factor" formula given in Reference 6.

^{††}Levelized annual revenue requirements.

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4. Environmental Protection Agency, "Water Quality Criteria for Water," Office of Water and Hazardous Materials, Washington, D.C., 1976.
5. Radian Corporation Report, "Costs of Sulfur Dioxide, Particulate Matter and Nitrogen Oxide Controls on Fossil Fuel Fired Industrial Boilers," EPA Contract No. 68-02-3058, May 20, 1982.
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COOLING POND SYSTEMS FOR THERMAL DISCHARGE CONTROL

Application and Description of Control

Cooling ponds generally are large (hundreds to thousands of acres) man-made bodies of water that dissipate waste heat through evaporation, radiation, and conduction.^{1,2} Further cooling improvement is available by installing water spray modules in the pond. The pond detains water sufficiently to provide adequate condenser cooling.

As of 1976, power plants employing cooling ponds represented about 7.3 percent of the available cooling options in use. In general, the amount of waste heat from coal-fired industrial boilers is significantly less than that from coal-fired power plants; consequently, a cooling pond is an economically attractive method for thermal discharge control. Factors influencing decisions to construct cooling ponds include land and water availability and applicable federal or state regulations. The Environmental Protection Agency (EPA) currently identifies cooling towers as the "best available technology" and specifies conditions that may preclude the cooling pond option in certain cases (40 CFR 423.11(m,n)).

Cooling ponds are extremely water-consumptive due primarily to evaporation and seepage.^{3,4} For example, in the semiarid western regions evaporation can account for about 1 gal./min/acre, thus requiring a considerable amount of makeup water. Because cooling ponds operate most efficiently with greater surface areas, ponds are generally shallow with large acreage requirements. Land needs range from 0.5 to 4 surface acres/MW.^{4,5} If either the water or land variables become too costly (either monetarily, environmentally, socially, or politically), other options such as cooling towers should be considered. Auxiliary spray units might also be considered. Land requirements could be reduced by a factor of 10, but this must be evaluated relative to water consumption, capital, operation, and maintenance expenses for spray units.¹

Standard

Cooling water discharges are regulated by the Clean Water Act, PL 95-217, Sections 301, 306, and 316. The statute requires that if the pond has an effluent that is discharged to public waters, a discharge permit that specifies effluent characteristics must be obtained. Any state-granted primacy by EPA to conduct a discharge permitting program has the authority to establish those limits. The federal standards recommended by EPA for enclosed water bodies are summarized in the following table.^{2,4}

Recommended Standards (above ambient)

Water Body	$\Delta T_{\max}$ (°F)	$\Delta T_{\max}$ (°C)
Streams and rivers	5.0	2.8
Lakes	3.0	1.7
Estuaries and marine coastal waters		
Winter (Sept.-May)	4.0	2.2
Summer (June-Aug.)	1.5	0.8

Section 316 of the Clean Water Act provides conditions that may exempt a discharger from established limits provided the owners can demonstrate that the imposed limits are stringent, in which case new limits will be proposed. EPA has stipulated guidelines on what conditions must be surveyed before applying for an exemption. Temperature limitations are site specific (e.g., dependent on the nature of the receiving water body and sensitive, endemic species residing in the area impacted by the thermal plume).

Control Performance and Efficiency

Cooling pond performance is site specific and affected by regional meteorological and hydrodynamic system design conditions. Ponds generally evaporate more water than do cooling towers⁴ and operate at higher intake temperatures because the water recirculates continuously and cannot be cooled (as in once-through cooling) by direct discharge. The addition of spray modules will, however, allow the pond to be cooled to a lower temperature than otherwise possible.

Maximum cooling is achieved with fixed-depth ponds constructed with dikes and baffles to induce a one-dimensional vertically mixed flow with a large surface area. If designed properly, cooling ponds can have an inlet temperature within 5°F of the natural equilibrium temperature for that site.

Reliability and State-of-the-Art

Cooling ponds can serve as adequate heat sink mechanisms to receive waste heat. Although certain areas of the country use cooling ponds, generally they are not used because of the conditions required for their efficient operation. Reliability and related parameters for cooling ponds are summarized in the following table.

Status	Ease of Adaptability	Cross-Media Impacts	Estimated Reliability	Negative Factors
Current full-scale use in U.S.	Can be retrofitted	Potential groundwater mixing; potential fogging and icing	Fair	Considerable water consumption; large land requirement

Costs: Capital and Operating

For illustrative purposes, Federal Energy Regulatory Commission (FERC) data for the year ending December 31, 1976, give cooling pond installation and operating costs as follows:⁶⁻⁸

Cooling Pond Installation and Operating Costs (\$ 1981)

Capital Cost** (\$ million)		Annual Operation and Maintenance Cost† (\$ million)		Unit Cost	
Power Plant	Industrial Boiler	Power Plant	Industrial Boiler	Power Plant (mills/kWh)	Industrial Boiler (\$1000/10 ⁶ Btu/h)
3.7	0.63††	0.37	0.054††	0.47§	0.08

*Reference year for coal-fired power plants and industrial boilers control cost is 1976; 1976 CCI average (I_R) is 2401.

See Explanatory Notes.

**Includes land at about \$3000 per acre, pumps, site preparation, and baffles.

†Includes chemicals to keep cooling system free of fouling agents.

††Estimated from cost data given in Table 3-1 of Reference 7 using "six-tenths factor" formula given in Reference 8.

§Levelized annual revenue requirements.

Multiple cooling pond uses can dramatically alter construction costs. They may be designed for large-scale recreational use and include land costs not directly attributable to efficient facility operation.

Capital investment is affected differently by existing real estate costs and may be prohibitively great when land costs approach \$10,200/acre; other cooling alternatives should then be considered.

References

1. Department of Energy, "An Environmental and Economic Comparison of Cooling System Designs for Steam Electric Power Plants," COO-4114-8, 1979.
2. Atomic Energy Commission, "Heat Sink Design and Cost Study for Fossil and Nuclear Power Plants," WASH-1360, 1974.
3. Oak Ridge National Laboratory, "Water Law Constraints to Siting and Operating Coal-Fired Electric Generation Plants in Kentucky," ORNL/TM-7263, 1980.
4. Environmental Protection Agency, "Comparison of Model Predictions and Consumptive Water Use of Closed Cycle Cooling Systems," EPA-600/7-78-206, 1978.
5. _____, "An Engineering-Economic Study of Cooling Pond Performance," Report 16130-DFX05/70, 1970.
6. Federal Energy Regulatory Commission, "Steam-Electric Plant Air and Water Quality Control Data," Summary Report, DOE/FERC-0036, 1979.

7. Radian Corporation Report, "Costs of Sulfur Dioxide, Particulate Matter and Nitrogen Oxide Controls on Fossil Fuel Fired Industrial Boilers," EPA Contract No. 68-02-3058, May 20, 1982.
8. Environmental Protection Agency, A Standard Procedure for Cost Analysis of Pollution Control Operations, Volume II Appendices, EPA-600/8-79-018b, June 1979.

WET COOLING TOWERS FOR THERMAL DISCHARGE CONTROL

Application and Description of Control

Wet (evaporative) cooling towers achieve condenser water cooling by distributing water in fine droplets over circulating air. Air circulation occurs in either natural or mechanical draft towers and in either counterflow or crossflow directions relative to water flow. Where water and land availability and cost constrain or prohibit once-through or cooling pond applications, wet (or dry) towers (see Dry Towers also) become increasingly appropriate.

Natural draft hyperbolic towers are hollow structures (shells) supported above a water collection basin. The support columns provide an open area through which air enters. In counterflow towers, the fill (material over which the water falls, generally designed as splash or film arrangements) is located above the columns inside the shell; in crossflow towers, the fill is external to the shell and forms a ring about the base. A canopy seals the ring to the shell. For either tower type, hot water is pumped from the condenser to the top of the fill and passes down through the fill to the basin while air sweeps either up or across the fill area. The air flow is produced due to the density difference between the ambient air and the warmer, humid air in the tower.¹

Mechanical draft towers are significantly smaller than natural draft towers because the mechanically induced air flow eliminates the need for a chimney section (as tall as 300 ft for hyperbolics). They can be designed to accommodate a broad range of water flows by altering cell size and number of cells. (A cell is a tower subdivision that can function independently.) Counterflow types (induced-draft) draw air upward through the fill packing; crossflow types (forced-draft) move air normal to water flow. While less efficient thermally, crossflow towers have less resistance to air flow and can operate at higher velocities than counterflow towers.²

Because evaporation increases the dissolved solids concentration in the recirculating cooling water, periodic or continual tower blowdown is necessary to minimize scaling and/or corrosion. For either tower type, tower blowdown ranges from 0.5 to 3 percent of the average condenser flow rate.^{2,3} Makeup water must be continuously supplied to compensate for water lost to blowdown, evaporation, and drift. This amount depends on intake water quality and may range from approximately 3 to 5 percent of the average condenser flow rate in natural draft towers and about 1.5 to 4.5 percent for mechanical draft towers.²

Standard

Cooling tower discharges to U.S. waterways are regulated by the Clean Water Act, PL 95-217, Sections 301, 306, and 316. The statute requires that a discharge permit that specifies effluent characteristics be obtained. Any state granted primacy by the Environmental Protection Agency (EPA) to conduct a

discharge permitting program has the authority to establish these limits. The federal thermal discharge guidelines recommended by EPA are summarized below.^{4,5}

Recommended Standards (above ambient)

Water Body	$\Delta T_{\max}$ (°F)	$\Delta T_{\max}$ (°C)
Streams and rivers	5.0	2.8
Lakes	3.0	1.7
Estuaries and marine coastal waters		
Winter (Sept.-May)	4.0	2.2
Summer (June-Aug.)	1.5	0.8

Section 316 provides conditions that may exempt a discharger from those limits provided the owners can demonstrate that the imposed limits are unnecessarily stringent, in which case more appropriate limits will be proposed. EPA has stipulated guidelines on what conditions must be surveyed before applying for an exemption. In any case, temperature limitations are site specific (e.g., dependent on the nature of the receiving water body and sensitive species residing in the area impacted by the thermal plume).

Control Performance and Efficiency

Wet cooling towers can successfully reduce cooling water temperatures. Three basic factors influence the cooling performance of towers. First, the total area of the air/water interface must be maximized and depends on the fill type and its configuration. Second, the ratio of air flow to water flow within the tower must be properly determined. This creates an effective heat sink and ensures replacing heated air with ambient air to maximize evaporation. Third, selection of a counterflow or crossflow system must be made. In counterflow systems, circulating air becomes warmer as it approaches the top but contacts progressively warmer water thereby maintaining a fairly constant enthalpy differential between the two flow paths. Crossflow systems do not have the thermodynamic advantage of maintaining a constant enthalpy differential but also do not have the disadvantage of larger head loss through the fill, which reduces the air flow through the tower.

Evaluation of the environmental effects from wet towers is difficult due to the site-specific nature of the impacts. Fogging, icing, and visibility effects are generally associated with the condensate plume and may be significant enough to preclude facility siting in certain areas. Both tower types also have blowdown, the constituents of which may be potentially damaging to the environment. Mechanical towers have two additional problems: noise and land requirements. The former is due to fans, and the latter is due to the need to separate the towers to minimize fogging, icing, and visibility possibilities.

Reliability and State-of-the-Art

EPA has identified cooling towers as the best available technology to mitigate adverse environmental impacts due to the discharge of waste heat from power plants (40 CFR 423.11(d), 423.13(1)). Reliable cooling (evaporation) models exist and the design characteristics are known to properly design an efficient cooling operation. The following factors summarize various features of the two wet tower types.

Wet Tower Type	Status	Ease of Adaptability	Cross-Media Impacts	Estimated Reliability	Negative Factors
Natural draft	Current full scale	Can be retro-fitted but costly to do so; no mechanical or electrical components	Potential visibility effects; blowdown can contaminate surface water or groundwater	Fair	Considerably water consumptive; great tower height to produce draft; blowdown disposal
Mechanical draft	Current full scale	Can be retro-fitted but costly to do so; low pumping head	Potential fogging, icing, and visibility effects; blowdown can contaminate surface water or groundwater	Good	Considerably water consumptive; subject to mechanical breakdown; blowdown disposal

Costs: Capital and Operating

Wet cooling tower construction costs are extremely variable due to inconsistent meteorological conditions, labor, and materials costs throughout the nation. Because mechanical towers do not require a chimney section (which accounts for about 1/3 to 1/2 of hyperbolic tower costs), their construction costs are less than natural draft towers due to using fewer materials and less expensive materials. This lower investment consequently carries smaller interest and depreciation charges.

Regarding availability and land costs, mechanical towers may require four to five times more land than natural draft towers due to the fogging potential of the former, which necessitates adequate spacing.² Installation and operating costs per tower for a 500-MW_e facility^{1,3,6,7} follows:

* In general, the temperature and pressure of steam required by industrial boilers are significantly less than that required by utility boilers, and cooling towers (owing to their large economic costs) are not used. For those boilers, either once-through cooling systems or cooling pond systems are used, or the steam is just vented to the ambient atmosphere.

Wet Cooling Tower Installation and Operating Costs (\$ 1981)*

Wet Tower Type	Capital Cost** (\$ million)		Annual Operation and Maintenance Cost (\$ million)		Unit Cost	
	Power Plant	Industrial Boiler	Power Plant	Industrial Boiler	Power Plant (mills/kWh)	Industrial Boiler (\$1000/10 ⁶ Btu/h)
Natural draft	15.8	NA†	Unknown	NA	1.00	NA
Mechanical draft	14.3	NA	Unknown	NA	0.90	NA

*Reference year for coal-fired power plants and industrial boilers control cost is 1977; 1977 CCI average (I_{19}) is 2577. See Explanatory Notes.

**Estimated from cost data given in Table 3-1 of Reference 8 using "six-tenths factor" formula given in Reference 7.

†Not applicable.

References

1. Atomic Energy Commission, "Heat Sink Design and Cost Study for Fossil and Nuclear Power Plants," WASH-1360, 1974.
2. Power, Cooling Towers: Special Report, Power Reprint Dept., 1221 Avenue of the Americas, New York, New York 10020, 1973.
3. Department of Energy, "An Environmental and Economic Comparison of Cooling System Designs for Steam Electric Power Plants," COO-4114-8, 1979.
4. Paddock, R. A., and J. D. Ditmars, "An Assessment of the Once-Through Cooling Alternative for Central Steam-Electric Generating Stations," ANL/WR-78-5, Argonne National Laboratory, 1978.
5. Environmental Protection Agency, "Water Quality Criteria for Water, Criteria and Standards Division," Washington, D.C., 1976.
6. Radian Corporation Report, "Costs of Sulfur Dioxide, Particulate Matter and Nitrogen Oxide Controls on Fossil Fuel Fired Industrial Boilers," EPA Contract No. 68-02-3058, May 20, 1982.
7. Environmental Protection Agency, A Standard Procedure for Cost Analysis of Pollution Control Operations, Volume II Appendices, EPA-600/8-79-018b, June 1979.

DRY COOLING TOWERS FOR THERMAL DISCHARGE CONTROL

Application and Description of Control

For power plants and those industrial boilers generating electricity, the steam that passes through the turbine must be condensed.¹ This can be accomplished by cooling a condenser with a recirculating stream of water, which has itself been cooled by some means such as a cooling tower.

In a dry cooling tower, the condenser water passes through a heat exchanger where the heat is transferred to the ambient air by conduction. Thus, because the cooling is not by evaporation, dry towers are attractive for water-scarce geographic areas. In addition, the problems of icing, fogging, and visible vapor plumes associated with wet cooling towers are eliminated. There is no routine blowdown and no water effluent to be treated and discharged. The penalties for these advantages of dry towers are higher capital and operating costs, poor performance in extreme meteorological conditions, and reduced net electrical output from the plant.^{2,3}

The dry tower closed-cycle system described above is an indirect cooling method. For a direct method, the steam is condensed in the cooling tower coils without the use of a condenser. The direct method is currently used only for power plants of very low power (less than 0.3 MW_e).² As with wet cooling towers, the dry towers may be either mechanical or natural draft.

Standard

The regulations governing cooling tower use deal only with the temperature of liquid effluents. Because dry cooling towers have no liquid effluents, they are not affected by regulations governing thermal discharges. Dry towers are viewed as the most environmentally attractive method of thermal discharge control.

Control Performance and Efficiency

The performance of a dry cooling tower is measured by the temperature difference between the condensing steam of the turbine exhaust and the ambient air entering the cooling tower. The ambient air entering the tower can be no cooler than the dry-bulb temperature of the air; in a wet tower, the performance is determined by the cooler wet-bulb temperature. The lower temperature difference for a dry tower means that less cooling is accomplished for a given amount of energy to run the tower. Because dry towers are less efficient in this respect, there is an increase in capital and operating costs—a dry tower must be proportionately larger than a wet tower and must consume more energy.

There is an additional problem for dry towers. For either wet or dry towers, a positive pressure of a few pounds per square inch is usually imposed inside the cooling loop to prevent the drawing in of air in the event of leaks.

The capability of most turbines in use today is reduced for back-pressures above 3.5 in. Hg. Unfortunately, this loss of turbine capability is more significant for a dry tower than for a wet tower. For example, in a typical eastern U.S. location, the dry-bulb and wet-bulb temperatures exceeded for 1 percent of the summer hours are 90°F and 76°F, respectively. Under these conditions, the condensing temperature is 150°F for the dry tower and 124°F for the wet tower, which results in turbine back-pressures of 7.6 in. Hg and 3.8 in. Hg, respectively. This means that for 1 percent of the summer, the dry tower would suffer a 47-MW_e loss of capability, whereas the wet tower would lose only 3 MW_e.²

Reliability and State-of-the-Art

Although there is little operating experience with dry cooling towers, they should be considered to be comparable in reliability to wet towers. The towers can be expected to operate effectively with routine maintenance.

As water becomes more scarce, there will be stronger motivation for improvements in dry cooling technology. Several years ago, major turbine manufacturers began studying high back-pressure designs, which could eliminate some of the disadvantages of dry cooling.³ Such designs have been primarily used for low powered plants, and their use appears to result in compromises.

Perhaps more promising is the concept of wet-dry towers. For plant sites that have some water available for cooling, but not enough for wet towers, the wet-dry towers can be attractive. The tower has separate wet and dry sections that can be used together, individually, or in a varying ratio. The dry section is designed to dissipate the total heat load at some specified low ambient dry-bulb temperature. Thus, the problem of excess capacity at low temperatures is not as extensive as with a totally dry tower. The annual water consumption may be as low as 15 percent of that for a conventional wet tower.²

Costs: Capital and Operating

Estimating the cost of cooling towers in general, and especially dry towers, is a complex process for several reasons: (1) towers in operation are designed to meet specific needs, thus the costs vary widely for a given size of power plant; (2) few comprehensive studies of cooling system costs have been made; and (3) wide variation exists in economic assumptions made by different analysts (e.g., fuel costs), significantly affecting the end result.^{1,4,5*} Installation and operating costs per tower for a 500-MW_e facility follows:

* In general, the temperature and pressure of steam required by industrial boilers are significantly less than that required by utility boilers, and cooling towers (owing to their large economic costs) are not used. For those boilers either once-through cooling systems or cooling pond systems are used, or the steam is just vented to the ambient atmosphere.

Dry Cooling Tower Installation and Operating Costs (\$ 1981)*

Type	Capital Cost** (\$ million)		Annual Operation and Maintenance Cost (\$ million)		Unit Cost	
	Power Plant	Industrial Boiler	Power Plant	Industrial Boiler	Power Plant (mills/kWh)	Industrial Boiler (\$1000/10 ⁶ Btu/h)
Mechanical draft wet-dry tower	24.6	NA†	Unknown	NA	1.55	NA
Mechanical draft dry tower	25.3	NA	Unknown	NA	1.59	NA

*Reference year for coal-fired power plants and industrial boilers control cost is 1977; 1977 CCI average is 2577. See Explanatory Notes.

**Estimated from cost data given in Table 3-1 of Reference 4 using "six-tenths factors" formula given in Reference 5.

†Not applicable.

Although it is not possible to determine separately the operating costs for the cooling schemes shown in the table, the levelized costs (mills/kWh) should be comparable to those that would be calculated using the economic assumptions used here. The table assumes a 35-year plant life versus the 30-year lifetime used for the calculations. The effect of the difference in plant lifetimes should be less than 10 percent.

References

1. Najjar, K. F., et al., "An Environmental and Economic Comparison of Cooling System Designs for Steam-Electric Power Plants," Massachusetts Institute of Technology, Energy Laboratory Report No. MIT-EL 79-037, January 1979.
2. American Institute of Chemical Engineers, "Cooling Towers," Chemical Engineering Progress Technical Manual, 1972.
3. American Society of Mechanical Engineers, "Dry and Wet-Dry Cooling Towers for Power Plants," HTD-Vol. 6, 1973.
4. Radian Corporation Report, "Costs of Sulfur Dioxide, Particulate Matter and Nitrogen Oxide Controls on Fossil Fuel Fired Industrial Boilers," EPA Contract No. 68-02-3058, May 20, 1982.
5. Environmental Protection Agency, A Standard Procedure for Cost Analysis of Pollution Control Operations, Volume II Appendices, EPA-600/8-79-018b, June 1979.

Solid Waste Pollution Control

ASH DISPOSAL

Application and Description of Control

Two basic ash disposal schemes, generally referred to as wet and dry handling systems, are used to handle ash from electric power plants and industrial boilers. Ash disposal essentially entails the transport of ash from the collection points to disposal areas for placement. Wet systems commonly use pipelines to move ash from its source to a pond area. The ash is contained in ponds that function as large-scale sedimentation basins. Upon entering the pond, the ash settles, leaving a supernatant. The supernatant can be treated and discharged, recycled, evaporated, or impounded. Local climate, receiving water quality, and regulations influence supernatant disposal. The ponds may be operated as permanent sites or filled, drained, dredged, and transported to a dry site for final disposal. Site construction for wet systems requires building an embankment and excavating a pond. Increasing concern with groundwater contamination by ash leachate may lead to regulations requiring ash basins to be in impermeable soils or lined. Closure usually involves capping with soil over the pond surface and directing surface water from the site. Due to slurry transport costs and other constraints, wet sites are most often colocated in the vicinity of the ash source.

Dry systems commonly use trucks to transport ash, although rail, barge, or conveyor systems may be feasible in some cases. Disposal areas usually can be landfill sites or sites needing reclamation, such as mines or quarries. Dry systems use landfills for the ash; water aids placement, dust control, and compaction. Bottom ash is relatively inert and porous and is used to construct drainage filters in the landfill. Fly ash can be spread and compacted with conventional earth-moving equipment. If compacted and reclaimed, a closed site can be used for housing developments, parks, and agricultural or industrial uses because compacted ash is capable of supporting moderate foundation loads. Dry systems are constructed to minimize leachate and erosion. A liner or drainage blanket can be used to control and to collect leachate. Surface water is usually directed around the site. Dry sites can be constructed as conventional landfills or in valleys. Erosion and runoff are controlled by low slope grades; as a section is filled, it is capped and revegetated.

Considerable amount of ash is generated annually by coal-fired power plants and industrial boilers, and the disposal of the ash involves considerable expense and land use. Ash surveys¹ of 131 utilities (accounting for 90 percent of coal burned) showed that in 1978 approximately 68 million tons of ash were generated. Most of this ash is generated from coal-fired power plants. Although most of this ash was considered refuse for disposal, about 24 percent of 16 million tons were sold for pavement aggregate (bottom ash) or concrete filler (fly ash). The remainder of 52 million tons were sluiced to ash ponds (51 percent) and dry handled to landfills (49 percent). Although most of the ash is generated by electric power plants, in general, coal-fired industrial boilers generate as much as 200 lb or more of ash for every ton of coal burned.²

Most ash is currently handled in wet systems; however, the national trend is away from wet toward dry handling systems because of costs and regulatory requirements.

Standard

Federally mandated state water and solid waste laws regulate the disposal of power plant ashes. Discharge of ash transport water is controlled by the Clean Water Act, specifically the National Pollution Discharge Elimination System (NPDES) Permit Program and 40 CFR 423.12³ and the ash solid wastes under the Resource Conservation and Recovery Act (RCRA). Congress currently has declared that ash and flue gas desulfurization scrubber wastes generated by coal-fired utilities are not hazardous under 40 CFR 261.4(b)4. This exemption also applies to industrial boiler sludges. Nonhazardous waste disposal management techniques are governed by section 4004 of RCRA. Although regulations vary among states, they essentially require state solid-waste permits for landfills and surface impoundments and NPDES permits for discharge of ash transport water.

Some state permits protect against groundwater contamination from ponds and landfills and require groundwater monitoring to verify control effectiveness. Although few states are currently enforcing groundwater monitoring activities at coal-fired power plants, there are indications that state legislation is being enacted to require closer scrutiny of the groundwater environment. Some power plants, although not required by a state regulatory agency, are monitoring groundwater voluntarily as a means of recognizing improper disposal systems and for taking appropriate remedial action.

Control Performance and Efficiency

Control performance of ash disposal methods is best expressed qualitatively. The landfill and wet ponding disposal methods appear to be trouble-free. Concern with leachate escape into groundwaters and surface discharge remains a general problem with older sites. Newer sites are practicing best practicable control technology by using natural, clay, or manmade liners, some water for dust control, and compaction techniques during operations, accepted closure covering and revegetation practices after the landfill is full, and post-closure monitoring and maintenance to prevent erosion and surface runoff as well as groundwater monitoring. Landfills of ash are considered very efficient and environmentally acceptable—they allow the land to be reused.

Although a popular disposal method, wet pond systems are facing strict effluent regulations for ash transport water, and there are increased environmental concerns with operating wet systems. Ponding requires more land than dry disposal.

Reliability and State-of-the-Art

All coal-fired power plants and industrial boilers generate ash as a result of burning coal. The ash is disposed of by either wet ponding or dry landfill methods with some ash (about 15 percent) sold for reuse purposes. Ongoing R&D

includes the environmental concerns associated with the impacts of ash leachate on groundwater and ash wastewater discharge to surface waters. The leachate may contain hazardous materials that will need additional control under RCRA. Reliability and related parameters of ash disposal alternatives are listed below.

Control Type	Status (1978)	Cross-Media Impacts	Reliability	Negative Factors
Wet ponding	26.4 million tons*	Potential for ash water contaminating surface water and ground-water	Good	Temporary loss of land use for a decade or so while filling
Dry landfill	25.3 million tons*	Potential for leachate contaminating ground-water	Very good	Temporary loss of land use for a decade or so while filling

*0.04 million tons are attributed to industrial boiler ash.

Costs: Capital and Operating

The costs for ash disposal alternatives are a function of land costs; distance from plant; plant size; and operating hours, disposal site lifetime, regulations, capital depreciation, and inflation.

Alternative Disposal Costs (\$ 1981)*

Ash Disposal Method	Capital Cost (\$ million)		Annual Operation and Maintenance Cost (\$ million)		Unit Cost	
	Power Plant***	Industrial Boiler†	Power Plant	Industrial Boiler††	Power Plant (mills/kWh)††	Industrial Boiler (\$1000/10 ⁶ Btu/h)†
Wet ponding	8.62	1.46	0.484	0.43	0.81	7.5
Dry landfill	0.57	0.096	0.480	0.082	0.33	0.71

*Reference year for coal-fired power plants and industrial boilers control cost is 1980; 1980 CCI average (I_{PI}) is 3237. See Explanatory Notes.

**New 500-MWe coal-fired plant, midwest location, 30-year lifetime, 168,000 dry tons of ash per year, 1 mile to disposal site.

†Estimated from cost data for a 500-MW plant given in Reference 1 using the "six-tenths factor" formula given in Reference 5.

††Levelized annual revenue requirement.

An environmental concern is the amount of radon gas emanation from ash piles, which has been studied by the Department of Energy.⁴ The release of radon-222 from ash piles does not appear to be a problem because measurements show low emanation (< 0.1 pCi/m²/s compared to normal soil background values of 0.5 pCi/m²/s). Evidence indicates that all radionuclide releases associated with coal ashes pose only a minimal threat to the environment. Further research evidence is needed to back this conclusion.

References

1. Electric Power Research Institute, Coal Ash Disposal Manual, Final Report, EPRI FP-1257, December 1979.

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3. Environmental Protection Agency, Code of Federal Regulations (40 CFR Parts 423 and 261).
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NONREGENERABLE FLUE GAS DESULFURIZATION SLUDGE DISPOSAL

Application and Description of Control

Flue gas desulfurization (FGD) throwaway processes employed by coal-fired power plants and industrial boilers use lime or limestone as the major absorbent to scrub the flue gas for SO_2 . These processes generate large quantities of waste sludge, primarily calcium sulfite (CaSO_3) and calcium sulfate (CaSO_4) for disposal. The problems associated with the disposal of the sludge are: space--large quantities of sludge must be permanently stored (~ 400 (dry) ton/ MW_e annually for a coal-fired boiler using 3.3 percent sulfur coal and a 30-year plant lifetime requires approximately 0.6 acre of land/ MW_e for sludge disposal); storage--must be environmentally acceptable (leachate, runoff, and fugitive dust must be controlled); physical handling and stability--must be considered (wet untreated sludge tends to be thixotropic and low load bearing); and future land use--possibilities must be considered.

Control methods available for pretreating and disposing of wet calcium sulfate-sulfite sludge are (1) ponding untreated waste, (2) chemical treatment (fixation) and landfill, (3) mine disposal, and (4) ocean disposal of treated waste. The first two methods are the most commonly used, the third method has limited use, and the fourth option is currently in the R&D feasibility stage. Emerging is a dry FGD scrubbing process where the waste is essentially a dry powder similar to fly ash. The sludge leaves the FGD process as a wet (20 percent) solid slurry; it is typically filtered, clarified, or centrifuged to dewater the sludge to a solids content ranging from 35 to 50 percent prior to treatment. Further dewatering by use of thickeners and vacuum filters or centrifuges achieves up to 50 to 70 weight percent of solid sludge called filter cake. This sludge can also be blended with fly ash to achieve up to 80 weight percent solid sludge.

Selection of a control method depends on costs in addition to waste characteristics, climate, hydrology, disposal site availability, and proximity. Main control options for sludge handling and final disposal are described in the following paragraphs.

Pond Disposal--Disposal in excavated ponds is one of the least costly methods of disposal. Wet ponding can be with or without dewatering or blending dry fly ash with the sludge. If the pond does not have an impermeable base, a liner (clay or elastomeric) is added to prevent seepage. Ponding appears to be trouble free, but land reuse could be a problem, because untreated sludges are thixotropic in nature and low load bearing. Some ponds, after evaporation occurs, can be covered with clay and soil and be vegetated. Others in low evaporation areas remain as ponds. Underdrainage can be used to increase dewatering (and control leachate) and allow for earlier capping after disposal site closure.

Landfill--Nearly all landfill sludge is chemically treated (fixation) to a stabilized clay-like solid. Fixation is the stabilization of sludge by use of additives other than fly ash to improve physical and chemical properties. Commercial processes include Dravo Lime and IU Conversion Systems. Dravo uses an additive called Calcilox[®], and IU adds lime and fly ash. Both processes greatly improve the physical stabilization of the sludge, reduce water pollution, and permit land reclamation. The majority of coal-fired units with FGD chemically treat their sludge and use landfills for the waste product.

Forced oxidation to gypsum is a fixation alternative where the calcium sulfite portion of the sludge is converted to calcium sulfate using air. An advantage is a more stabilized, nonhixotropic material that may have some commercial resale value (plasterboard) if a nearby market exists, otherwise a landfill is used for the gypsum sludge.

Mine Disposal--Sludge, usually untreated, is typically thickened, centrifuged, and mixed with dry fly ash, to a resulting 80 weight percent solid. It is then transported to a nearby surface-area coal mine. Disposal consists of spreading the sludge onto a mined-out strip, recovering with overburden, and returning the terrain to its near original elevation. Two utilities are using this method. There are no known deep mine disposal applications, although it has been considered.

Ocean Disposal--An R&D project¹ to evaluate the feasibility and environmental effects of ocean disposal of scrubber sludge, fly ash, and bottom ash from power plants has constructed an artificial reef in the Atlantic Ocean, off Long Island, from about 15,000 stabilized concrete blocks (about 500 tons) of these waste materials. Preliminary data show the blocks compatible with the marine environment. No utility currently uses this R&D method.

Standard

State solid-waste regulations² control the disposal of FGD scrubber sludges following federal guidelines³ for nonhazardous waste regulations. Although regulations vary among states, they essentially require state permits for landfills, surface impoundments, or treatment facilities. The permit is required for either new or retrofit coal-fired utilities operating FGD scrubbers and faced with long-term sludge disposal. Congress currently, under the Resource Conservation and Recovery Act (RCRA), has declared that scrubber sludges and ash wastes generated by coal-fired utilities are not hazardous under 40 CFR 261.4(b)4. This exemption also applies to industrial boiler sludges. Nonhazardous waste disposal management techniques are governed by section 4004 of RCRA. Some state permits protect against groundwater contamination and require groundwater monitoring to verify control effectiveness. Although few states are currently enforcing groundwater monitoring activities at coal-fired utility plants, there are indications that state legislation is being enacted to require closer scrutiny of the groundwater environment. Some facilities, although not required by a state regulatory agency, are monitoring groundwater voluntarily as a means of recognizing improper disposal systems and of taking appropriate remedial action.

Control Performance and Efficiency

Control performance of sludge disposal methods is best expressed qualitatively. Ponds, when lined to reduce leachate and control runoff, appear to be trouble-free. Sludge disposal requires much land and limits its future use. Landfills of stabilized sludge are considered very efficient, environmentally acceptable, and allow the land to be reused. Surface minefill, although of limited use, works well and is cost efficient if the transport distance is not excessive. If ocean disposal were found feasible, it would free up land required for landfill and be useful to seaboard power plants near cities where land is scarce.

Wet sludge handling equipment is usually troublesome and has a record of high maintenance. Dry powder sludge, from dry scrubbers, is handled by conventional dry handling systems used for fly ash and should have few problems when conventionally landfilled.

Reliability and State-of-the-Art

The majority of the power plant capacity operating with FGD units in 1980 are of the wet lime or limestone throwaway process. Sludge generated by coal-fired power plants and industrial boilers are primarily disposed of in ponds or landfills.⁷ The sludge is disposed of in either nearby ponds or landfills, with a few power plants using minefill disposal. Ongoing R&D in ocean disposal of sludge is determining its feasibility and environmental effects. Reliability and related parameters of sludge disposal alternatives are listed in the following table.

Control Type	Status (1980) ⁴	Cross-Media Impacts	Estimated Reliability*	Negative Factors
Ponding (untreated)	16 units producing 3700 MW _e now operating	Potential for leachate and runoff affecting groundwater	Good	Could limit land reuse, degrades large areas of land ³
Landfill				
Chemically treated	46 units producing 21,500 MW _e now operating	Less concern of leachate migration	Very good	Treating improves physical stability and allows for land reuse
Forced oxidation to gypsum	R&D in U.S., operational in Japan	Less concern of leachate migration	Very good	Salable by-product if market available
Dry powder sludge	Two units beginning operation; limited field test experience	Less concern of leachate migration	Very good (expected)	None apparent
Minefill (untreated)	Two units producing 600 MW _e now operating	Potential for leachate effect on ground-water	Very good	Low costs for mine-mouth plants
Ocean disposal (for seaboard plants)	R&D project evaluating method	No biological effects observed (preliminary)	Very good (expected)	R&D results promising; appears expensive

*Sludge disposal type has not been a controlling factor in FGD operating reliability.

Costs: Capital and Operating

The costs for FGD waste sludge disposal alternatives are a function of many variables including location; plant size, fuel, and annual operating hours; disposal site lifetime; scrubber efficiency; capital depreciation; cost of land; and distance from plant to disposal site. Installation and operating costs for the various sludge disposal alternatives for a 500-MW_e plant and a 250 x 10⁶-Btu/h (heat input) industrial boiler follow:^{1,5,6}

Cost Comparison of Disposal Alternatives (\$ 1981)

Sludge Disposal Method	Total Capital Cost (\$ million)		Annual Operation and Maintenance Cost (\$ million)*		Unit Cost	
	Power Plant	Industrial Boiler **	Power Plant	Industrial Boiler **	Power Plant (mills/kWh)	Industrial Boiler (\$1000/10 ⁶ Btu/h) **
Ponding (untreated sludge)						
Pond with indigenous liner	7.71	1.3	0.22	Unknown	0.71	0.005
Pond with hypalon liner	17.84	3.0	0.22	Unknown	1.53	0.112
Pond with underdrainage	13.0	2.2	0.23	Unknown	1.14	0.009
Landfill (treated sludge)						
Chemically treated sludge	8.9	1.5	Unknown	Unknown	1.34	0.007
Forced oxidation to gypsum, indigenous liner	12.5	2.1	0.59	Unknown	1.27	0.007
Forced oxidation to gypsum, hypalon liner	19.9	3.4	0.59	Unknown	1.88	0.014
Dry powder	Unknown	Unknown	Unknown	Unknown	Unknown	Unknown
Mine disposal (untreated sludge)	1.6	0.27	Unknown	Unknown	0.49	0.001
Ocean disposal (treated sludge)	17.8	3.0	2.7	Unknown	2.59	0.012

*Reference year for coal-fired power plants and industrial boilers control cost is 1980; 1980 CCI average I_g is 3237. See Explanatory Notes.

**Estimated from cost data for a 500-MW plant given in Reference 1 using the "six-tenths factor" formula given in Reference 8.

Variables for the cost comparison listed above (except for ocean disposal and mine disposal) are:

Coal:	3.5 percent sulfur, 12,000 Btu/lb, and 14 percent ash
Annual Operating Hours:	4250 h (48 percent capacity factor for 30 years)
Disposal Site Lifetime:	30 yr
SO ₂ Removal:	90 percent
Sludge Generated:	4.8 x 10 ³ tons/yr (dry)
Limestone Use:	80 percent
Annual Capital Charges (30-yr average):	17 percent of total capital investment
Land Costs for Disposal:	\$5000/acre
Disposal Site:	Within 1 mile of plant

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**ENVIRONMENTAL CONTROLS FOR SYNTHETIC
FUEL PRODUCTION FROM COAL AND OIL SHALE**

Overview and Background

Synthetic fuels (synfuel) production is a potential source of environmental pollution. There are several technologies being proposed to produce synfuels including coal gasification, direct and indirect coal liquefaction, and oil shale retorting. Schematic diagrams of these synfuel technologies are shown in Figure 2. This document addresses controls for indirect coal liquefaction (which includes coal gasification) and oil shale retorting because they are two major synfuel production technologies that were considered seriously for commercial operation. Both synfuel technologies can be assumed to have many potential sources of environmental pollutants in common. These sources and the types of pollutants generated from both technologies are shown in Figure 3. In some instances, the method of control or disposal of particular pollutants is similar for both synfuel technologies. For example, both oil shale and indirect coal liquefaction technologies may employ the Stretford process for H_2S removal, Phosam-W or Chemie Linz/Lurgi process for ammonia recovery, and the phenolsolvan process for phenol recovery. Descriptions of these and other pollutant controls* that can be used during the production of synfuels are presented in this section of the handbook along with other important factors, such as standards, control performance, reliability, and costs.

Indirect Coal Liquefaction

Indirect coal liquefaction is a technology in which coal is gasified by steam and pure oxygen or air to form a synthesis gas. This gas is composed of carbon monoxide and hydrogen and is converted to synthetic fuel by catalytic reaction.**

The process as shown in Figure 4 has four steps: (1) coal gasification, (2) shift conversion and gas cleaning, (3) acid gas removal, and (4) catalytic synthesis and fractionation. In the gasification step, coal is reacted at high temperature and pressure with steam and oxygen. The principal gaseous emissions from the gasifier are fugitive emissions from coal and ash lockhopper vents. The lockhopper vent gases are controlled by a venturi scrubber.

The hot gas coming from the gasifier is quenched and scrubbed with recycled water in the gas cleaning and shift conversion step. A portion of the quenched gas is sent to a shift converter to adjust the ratio of hydrogen to carbon monoxide for producing the desired mix of liquid and gaseous products.

The entire gas stream then passes to an acid gas removal step (e.g., Lurgi-rectisol process). The carbon dioxide and most of the hydrogen sulfide are

* Most synfuel plants will probably use onsite boilers that burn waste residuals as feedstock to meet power requirements. Pollutant controls associated with boilers have been discussed in the section entitled "Environmental Controls for Coal-Fired Power Plants and Industrial Boilers" and will not be repeated here.

** Department of Energy, Energy Technologies and the Environment, Environmental Information Handbook, June 1981.

Figure 2. Schematic Diagrams of Various Syntfuel Technologies

Figure 3. Uncontrolled Synfuel Pollutants

Figure 4. Indirect Coal Liquefaction Technology

scrubbed out, and the resultant concentrated acid gases are sent to a sulfur recovery unit such as the Stretford or ADIP/Claus process. (ADIP is an abbreviation for diisopropanolamine, the solvent used in the process.) The wastewater from the rectisol unit and the gas liquor are recycled after treatment. Phenols, oil, and tars removed by a wastewater treatment plant are generally incinerated in a boiler along with residual gases and liquids from other process units.

In the catalytic synthesis unit, the cleaned and shifted synthesis gas is preheated to the synthesis reactor-inlet temperature. The hot synthesis gas then enters a series of catalytic reactors where it is converted to gasoline, methanol, or a complex mixture of hydrocarbons, depending on the catalytic synthesis option used.

Oil Shale

Oil shale is a fine-grained sedimentary rock containing varying amounts of organic material called kerogen. When heated to about 900°F at atmospheric pressure, a minimal residence time is required for the kerogen to fully decompose into hydrocarbons and a carbonaceous residue. Upon cooling, these hydrocarbons condense into a heavy liquid called shale oil which, after upgrading, can be refined into fuel products such as gasoline, jet fuel, and diesel fuel.

The process (as considered in this handbook) is shown in Figure 5 and consists of three primary steps: retorting* the shale, shale oil recovery, and upgrading the shale oil. Retorting occurs in an aboveground metal vessel where process flows and operating parameters can be easily controlled.

The product gas from the retort consists of a mixture of shale oil vapors; particulate matter; light hydrocarbon gases; water; and noncondensable gases such as nitrogen, hydrogen, carbon dioxide, ammonia, and hydrogen sulfide. If the gases leave the retort at a low enough temperature, aqueous condensation will occur; therefore, the oil can be separated from the retort gas relatively free of water. The oil aerosol can be removed from the retort gases by passing through electrostatic separators.

After the shale oil and water are removed from the retort gas, approximately 67 percent of the retort gas is recycled to the retort and used to generate process heat; the remaining 33 percent is cooled and treated to remove ammonia (NH₃) and hydrogen sulfide (H₂S). Once NH₃ and H₂S have been removed from the product gas, it can be used as boiler fuel to meet in-plant power requirements.

* Although there are several different techniques for retorting oil shale, surface retorting is, technologically, the technique closest to commercialization and is therefore used here for the representative model.

The shale oil has to be upgraded by hydrogenation before it is sent to a conventional refinery because the shale oil is highly unsaturated and much of the hydrocarbon component is in heterocompounds containing reactive fragments of nitrogen and sulfur. In addition, there is a relatively large arsenic concentration in shale oil (approximately 40 ppm). It is highly desirable to remove these elements for several reasons: nitrogen and sulfur must be removed for pollution control, sulfur compounds promote corrosion and result in poor lead susceptibility, nitrogen and arsenic poison the hydrocracking processing and reforming catalysts used in refining, and large concentrations of nitrogen adversely affect the thermal and storage stability of diesel and turbine fuels.

Figure 5. Surface Retorting Oil Shale Technology

Air Pollution Control

RECTISOL PROCESS FOR ACID GAS CONTROL

Application and Description of Control

The removal of acid gas is unique to the coal liquefaction technology and is not necessary for the conversion of oil shale to synfuel. Acid gas containing as much as 6.1×10^6 tons/yr of H_2S is produced in a 50,000-bbl/d coal liquefaction plant.¹ There are several processes available for the removal of acid gas (primarily hydrogen sulfide and carbon dioxide) from the raw product gas produced in the coal gasifier as shown below.

Processes for Removing H_2S and CO_2 from Low- and Intermediate-Btu Gases*

Process	Sorbent	Removes
Amine	Monethanolamine, 15% in water	CO_2 , H_2S
Econamine	Diglycolamine, 50%-70% in water	CO_2 , H_2S
Alkacid	Solution M or DIK (potassium salt of dimethylamine acetic acid), 25% in water	H_2S , small amount of CO_2
Benfield, Catacarb	Hot potassium carbonate, 20%-30% in water (also contains catalyst)	CO_2 , H_2S ; selective to H_2S
Purisol (Lurgi)	η -methyl-2-pyrrolidone	H_2S , CO_2
Fluor	Propylene carbonate	H_2S , CO_2
Selexol (Allied)	Dimethylether polyethylene glycol	H_2S , CO_2
Rectisol (Lurgi)	Methanol	H_2S , CO_2
Sulfinol (Shell)	Tetrahydrothiophene dioxide (sulfolane) plus diisopropanol amine	H_2S , CO_2 ; selective to H_2S
Giammarco-Vetrocoke	K_3AsO_3 activated with arsenic	H_2S
Stretford	Water solution of Na_2CO_3 and anthraquinone disulfonic acid with activator of sodium-metavanadate	H_2S
Activated carbon	Carbon	H_2S
Iron sponge	Iron oxide	H_2S
ADIP	Alkanolamine solution	H_2S , some COS , CO_2 , and mercaptans
SNPA-DEA	Diethanolamine solution	H_2S , CO_2
Takahax	Sodium, 1, 4-naphthaquinone, 2-sulfonate	H_2S

*Adapted from Panel on Coal Gasification Technology 1974, Table I-C, p. 62 as cited in Reference 2.

Because the rectisol process is currently in successful commercial operation, it was selected as the representative process for discussion in this handbook.¹ The rectisol process uses cold methyl alcohol (-45°F) as the solvent for the removal of H₂S and CO₂ from acid gas.^{1,2} The solubilities of the gases that are impurities (H₂S, COS, and CO₂) increase with decreasing temperature of methanol while the solubilities of the desired product gases (CH₄, CO, and H₂) are not affected by low temperature. It is for this reason that the raw gas feed for the rectisol process is precooled, and refrigerated methanol is used as the solvent. After absorption of the sulfur compounds, the methanol temperature is increased to release the soluble gases for treatment in a sulfur recovery unit. More than 95 percent of the sulfur in the raw product gas can be removed by the rectisol process.¹

Standard

Federal air pollution standards for coal conversion technologies have not been established. However, federal performance standards for related industries (petroleum refineries, coal carbonization industries, and fossil-fueled power plants) are relevant. New Mexico has coal gasification plant air standards that directly relate to the requirements necessary for coal liquefaction standards. Federal air standards for petroleum- and fossil-fueled power plant emissions are compared with New Mexico gasification plant air standards in the following table.^{2,3}

Existing State (New Mexico) and Federal Emission Standards for Future Coal Conversion Technologies*

Pollutant	Federal		New Mexico	
	Petroleum Refineries	Fossil-Fueled Steam Generators	Gas-Fired Power Plant Associated with Coal Gasification Plants	Gasification Plants
Sulfur dioxide	0.10 grain H ₂ S/std. ft ³ (dry) in fuel gas (plant gas fuel combustion)**	1.2 lb/10 ⁶ Btu (solid) 0.8 lb/10 ⁶ Btu (liquid)	0.16 lb/10 ⁶ Btu	NA†
Sulfur (total)	NA	NA	NA	0.008 lb/10 ⁶ Btu
Reduced sulfur (sum of H ₂ S, CS ₂ , and COS)	NA	NA	NA	100 ppm
Hydrogen sulfide	NA	NA	NA	10 ppm

*Adapted from Rubin and McMichael 1975, Table 5, p. 115 as reprinted in Reference 1.

**Equivalent to 0.1lb/10⁶ Btu for gas with 250 Btu/ft³.

†Not Applicable.

Control Performance and Efficiency

The performance of the rectisol process can be considered very good based on previous operating experience at various coal conversion plants. The rectisol process used by El Paso Burnham I Coal Gasification (Lurgi) facility removes

sulfur (to 0.2 ppmv) as well as hydrogen cyanide.² The offgas from the rectisol solvent regeneration section for the El Paso facility, which is sent to a sulfur recovery unit, is shown in the following table.

**Rectisol Unit Offgas from
El Paso Burnham I Coal Gasification Plant**

Component	Mole %
CO ₂	97.63
H ₂ S	0.75
C ₂ H ₄	0.24
CO	0.07
H ₂	0.43
CH ₄	0.56
C ₂ H ₆	0.32
N ₂ + A	
Total	100.0

The vented rectisol carbon dioxide stream (284 million std. ft³/d) for one coal gasification (Lurgi) plant is composed of carbon dioxide (98.3%), hydrocarbons (CH₄, C₂H₆, C₂H₄), and 35 ppm carbonyl sulfide. A rectisol unit at South African Coal, Oil and Gas Corporation (SASOL) has achieved sulfur recovery removal to 0.007 ppmv.²

Reliability and State-of-the-Art

The rectisol process is considered very reliable based on operations at several gasification plants including those located at Sasolburg and Modderfontein, South Africa; Westfield, Scotland; and Kosovo, Yugoslavia. The rectisol process state-of-the-art is summarized as important advantages and major disadvantages:

- Advantages

- Sulfur levels of less than 0.1 ppmv can be obtained in treated gas.
- Complete removal of organic sulfur compounds such as mercaptans, thiophene, COS, and CS₂.
- Removal of higher molecular weight organics that tend to form coke. Sorbed organics do not degrade the solvent and are recovered as naphtha by-product.
- Removes HCN.
- Dehydrates gas that allows smaller size downstream units.

- Disadvantages

- More hydrocarbons and other higher heating value compounds (mainly H_2 and CO) are absorbed than in other absorption type systems.
- High solvent loss and carryover in concentrated acid gas streams.
- High refrigeration load required.

Costs: Capital and Operating

The capital cost of a rectisol process unit depends on the volume of raw gas to be processed and the amount of acid gas to be removed for a given plant size. The operating costs strongly depend on the amount of solvent loss during processing and labor requirements. Capital and operating costs for a rectisol unit operating at a 50,000-bbl/d fuel oil equivalent (FOE) coal liquefaction plant are given in the table below.

Acid Gas Removal Installation and Operating Costs (\$ 1981)*

Process	Capital Cost (\$ million)		Annual Operation and Maintenance Cost (\$ million)		Unit Cost (\$/bbl FOE)	
	Coal Liquefaction Plant	Oil Shale Conversion	Coal Liquefaction Plant	Oil Shale Conversion	Coal Liquefaction Plant	Oil Shale Conversion
Rectisol [†]	78.4	NA**	10.9	NA	2.12 [†]	NA

*Reference year for coal liquefaction plant environmental control cost is 1977; 1977 CCI average (I_{CI}) is 2577. See Explanatory Notes.

**Not applicable.

[†]Levelized annual revenue requirement (assuming a 90 percent annual plant capacity factor).

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SULFUR CONTROL AND RECOVERY

Application and Description of Control

If not properly controlled, approximately 100 to 200 tons of SO_2 will be emitted each day to the atmosphere from a 50,000-bbl/d oil shale facility with an onsite power generating plant.^{1,2} Sulfur emissions can be controlled by either removing H_2S prior to burning the retort gases or by scrubbing SO_2 from the post-combustion flue gas. Flue gas desulfurization processes are basically of two types: throwaway systems that produce a waste sludge by-product and regenerable systems that produce a usable by-product and regenerate the sorbent. Wet lime and limestone scrubbers, lime spray dry scrubbers, sodium carbonate and dual alkali wet scrubbers, and regenerable systems such as Wellman-Lord and magnesium oxide scrubbers are commercially available and will be applicable to the synfuels industry. These controls have been discussed previously in this document in the section on coal-fired power plants and industrial boilers and will not be considered further. Summaries of several methods for removing H_2S from a gas stream generated in both oil shale conversion and coal liquefaction technologies are provided in the following paragraphs.

The Stretford process is a liquid-phase oxidation process using an aqueous solution of sodium vanadate and anthraquinone disulfonic acid (ADA) in which H_2S is both absorbed and converted to sulfur.^{1,2} The H_2S is absorbed in either a packed tower or contacted in a venturi scrubber then oxidized to sulfur by the sodium vanadate. Reduced vanadium is then oxidized by the ADA solution. ADA is regenerated by air in the oxidizer tanks where elemental sulfur is removed as a froth. The Stretford process is most applicable to streams containing 1 to 3 percent H_2S and can use a concentration of up to 10 percent H_2S .

The Claus process is a dry, high temperature process in which H_2S is catalytically reacted with SO_2 to form elemental sulfur.¹ Input acid gas is split into two streams and one-third of the input acid gas is combusted in a reaction furnace to form SO_2 . Heat is recovered from the gas before it is recombined with the other two-thirds of the feed. The combined stream then enters a series of converter stages where elemental sulfur is produced. The Claus process is applicable to streams containing 5 to 99 percent H_2S .

The tail gas from a Claus plant usually contains sizable concentrations of H_2S and SO_2 . Processes developed specifically for Claus plant tail gas treatment (and their removal effectiveness) that may find some application in the oil shale industry are Shell Claus offgas treating (SCOT) (300 ppmv before incineration), Beavon (300 ppmv, no incineration), and the Institute Francais du Petrok (IFP) (2500 ppmv before incineration).¹

The SCOT process was designed specifically to clean up the offgas from a Claus plant. The offgas is heated with a reducing gas or hydrogen, and the mixture is passed through a bed of cobalt molybdate catalyst where, within

equilibrium considerations, all the compounds containing sulfur are reduced to H_2S . The H_2S is routed to an absorber where the gas is dissolved and concentrated. Heat is applied to the absorbing solution, and the concentrated H_2S that is liberated from the absorbing medium is returned to the Claus plant.

In the Beavon process, the tail gas from the Claus plant is heated by mixing it with hot combustion products of fuel gas and air. The mixture is passed through a catalyst where all the sulfur compounds are converted to H_2S . The H_2S -rich gas is cooled by a slightly alkaline buffer solution and then treated by a Stretford unit.

The basic reaction used in the IFP process is the same as that used for the Claus process, except that it occurs in a liquid phase rather than a gaseous phase. The liquid phase is composed of a polyalkylene glycol and a 5-percent-by-weight catalyst, orthophthalic acid monopolyethylene glycol ester.

Standard

Federal environmental pollution standards for the synthetic fuels industry have not yet been established. The environmentally problematic effluents from synfuels operations have not been thoroughly characterized; in some cases, adequate sampling and analysis methods have not been developed, validated, and standardized.³ As such, the proposed pollution control equipment in a synfuels plant must represent best available control technology (BACT), and controlled residuals must not violate ambient standards.

The concept of BACT for air emissions control is defined as the maximum degree of reduction determined case by case, taking into account energy, environmental, and economic impacts. If applicable prevention of significant deterioration increments are predicted to be violated, better control than that prescribed by BACT must be employed (possibly by reevaluating the economic and energy costs associated with BACT).

For oil shale operations, it is highly probable that there will be an onsite boiler utilizing retort offgas as feedstock for generating electrical power and thermal energy requirements. For the coal liquefaction, there will probably be an onsite boiler for generating electrical power for the plant as well as steam for the coal gasifiers. Current new source performance standards (NSPS) for these boiler pollutant emissions are in effect and have to be satisfied. The current NSPS for SO_2 emissions are listed in the following table.⁴

Uncontrolled Emissions (lb SO_2 /10 ⁶ Btu)	Percent Reduction Needed	Controlled Emissions (lb SO_2 /10 ⁶ Btu)
>8	>90	0.8 (maximum)
8 to 2	90	0.8 - 0.2
2 to 0.2	90 - zero	0.2 (constant)

Basically, for gaseous fuels burned in a boiler with uncontrolled emissions exceeding 8 lb SO₂/10⁶ Btu, SO₂ reductions exceeding 90 percent would be required to limit emissions to a maximum of 0.8 lb SO₂/10⁶ Btu. For gaseous fuels whose uncontrolled emissions range from 8 to 2 lb/10⁶ Btu, a constant 90-percent removal is required, resulting in controlled emissions ranging from 0.8 lb SO₂/10⁶ Btu to 0.2 lb/10⁶ Btu. For gaseous fuels with sulfur contents that would emit 2 to 0.2 lb SO₂/10⁶ Btu, a variable removal rate between 90 and 0 percent is required to achieve a constant 0.2 lb SO₂/10⁶ Btu. For example, at 2 lb SO₂/10⁶ Btu, 90-percent removal is required; at 0.2 lb SO₂/10⁶ Btu, 0 percent is required; and at 1 lb SO₂/10⁶ Btu, 80 percent is required. In all cases, it should be noted that the controlled emissions are 0.2 lb/10⁶ Btu.

Control Performance and Removal Efficiency

The Stretford and Claus processes, along with various Claus plant tail gas cleanup processes are compared in the following table.

Key Features of Sulfur Removal Technologies

Process	Process Principle	Components Removed	Efficiency	Feed Stream Requirements and Restrictions	By-Products	Effects of High CO ₂ in Feed	General Comments
Stretford	Liquid phase oxidation of H ₂ S to elemental sulfur in an alkaline solution of meta-vanadate and anthraquinone disulfonic acid	H ₂ S HCN CH ₃ SH NH ₃	As low as 1 ppmv 100% 90% 0%	High HCN loading should be reduced prior to processing to prevent excessive solution purge	Elemental sulfur	High CO ₂ concentrations will decrease absorption efficiency by lowering solution alkalinity; increasing absorber tower height and base addition are required	1 ppmv H ₂ S in tail gas is possible; however, higher limits would probably be employed when 200 to 500 ppm of other reduced sulfur species are present in tail gas
Claus	Catalytic oxidation of H ₂ S and SO ₂ to elemental sulfur	Sulfur compounds H ₂ S H ₂ CO NH ₃ H ₂ CO CO	95% 33% 33% 33% 33%	H ₂ S levels much below 10% require enrichment prior to processing	Elemental sulfur	Can adversely affect sulfur removal ability of the process	Direct application to H ₂ S-rich acid gases may only be possible in high sulfur coal cases; low sulfur coal cases require enrichment (e.g., ADIP)
SCOT	Sulfur species are catalytically reduced to H ₂ S; H ₂ S is scrubbed in a regenerable amine system	H ₂ S SO ₂ COS CS ₂	Can remove up to 97% of sulfur species (will vary depending on CO ₂ and H ₂ S concentration in specific applications)		Concentrated H ₂ S	Reduces conversion efficiency by catalyst; high CO ₂ levels reduce efficiency of alkanamine system	Offgas from amine scrubber is not as low in total sulfur as Beavon process offgas
Beavon	Catalytic reduction of sulfur compounds to H ₂ S, followed by integral Stretford process	H ₂ S COS CS ₂ SO ₂	99.8% removal for Claus tail gas containing 4% equivalent H ₂ S or can attain equivalent of 50 ppm total sulfur in tail gas (not including reducing gases)		Elemental sulfur	Reduces conversion efficiency of catalyst; decreases H ₂ S absorption in Stretford solution	Exact ppm limit achievable in coal gasification application not well known; 100 ppmv is believed by vendor to be attainable
IFP-2	Incineration of tail gas followed by ammonia scrubbing; solution is evaporated to produce a concentrated SO ₂ stream that is returned to the Claus plant	COS CS ₂ H ₂ S	Capable of reducing sulfur species in Claus tail gas to less than 500 ppm	H ₂ S:SO ₂ ratio maintained in the range of 2.0 to 2.4	Elemental sulfur	No effect	Cannot attain as low of residual sulfur in tail gas as Beavon process

Reliability and State-of-the-Art

The Stretford process and the Claus process (plus Claus plant tail gas cleanup) have a history of proven commercial reliability and operation. Many in the oil shale industry believe, therefore, that the hydrogen sulfide technology could be transferable from other petroleum applications, and there are no plans to conduct significant research and development studies. The Environmental Protection Agency does not totally dispute this claim, but would like to see the sulfur control technologies successfully demonstrated before agreeing with the premise.¹ The reliability of the Stretford and Claus processes are given in the following table.

**Reliability of
Sulfur Removal Technologies**

Process	Process Principle	Reliability and Limitations
Stretford	Liquid phase oxidation of H_2S to elemental sulfur in an alkaline solution of metavanadate and anthraquinone disulfonic acid	Process does not remove $COS + CS_2$; HCN and SO_2 degrade solution
Claus	Catalytic oxidation of H_2S and SO_2 to elemental sulfur	NH_3 and HCs may cause catalyst plugging and variable sulfur recovery

Costs: Capital and Operating

For oil shale and coal liquefaction facilities, H_2S concentrations will be relatively low (i.e., about 5 percent). Due to this low concentration, if the Claus process is used, there will have to be additional equipment upstream of it for enriching the H_2S . Thus, the Stretford process will be most appropriate for H_2S removal in these industries.^{1,2} The costs of the Stretford and Claus processes as they relate to the synfuels industry are unknown. However, based on experience, capital and operating and maintenance costs for a 50×10^3 bbl/d synerude equivalent synfuels plant can be estimated. These estimates are given in the following table.^{1,5,6}

Stretford Process Installation and Operating Costs (\$ 1981)*

Process	Capital Cost (\$ million)		Annual Operation and Maintenance Cost (\$ million)		Unit Cost** (\$/bbl FOE)	
	Coal Lique- faction Plant	Oil Shale Conversion	Coal Lique- faction Plant	Oil Shale Conversion	Coal Lique- faction Plant	Oil Shale Conversion
Stretford	38.2-54.6	38.2-54.6	1.6-3.3	1.6-3.3	0.7-1.0	0.7-1.0
Claus 100 kg-mol/h sulfur removed	4.4 [†] -6.0 [†]	4.0 [†] -6.0 ^{††}	NA	NA	NA	NA
1000 kg-mol/h sulfur removed	22.0-33.0 [†]	22.0 [†] -33.0 ^{††}	NA	NA	NA	NA

*Reference year for the environmental control cost is 1980; 1980 CCI average (I_p) is 3237. See Explanatory Notes.

**Levelized annual revenue requirement (assuming a 90 percent annual plant capacity factor)

[†]Forty percent sulfur in feed.

^{††}Fifteen percent sulfur in feed.

References

1. Environmental Protection Agency, "Environmental Perspective on the Emerging Oil Shale Industry," EPA-600/2-80-205a, 1980.
2. Department of Energy, "Environmental Control Costs for Oil Shale Processes," DOE/EV-0055, October 1979.
3. Environmental Protection Agency, "Environmental Assessment, Perspective on the Emerging Oil Shale Industry," EPA-625/9-81-005, January 1981.
4. "New Source Performance Standards: Electric Utility Steam Generating Units," Federal Register, 44, No. 113, 40 CFR Part 60, June 11, 1979.
5. Environmental Protection Agency, "Control of Emissions from Lurgi Coal Gasification Plants," EPA-450/2-78-012, March 1978.
6. Catalytic, Inc., The Stretford Process, December 1976.

GASIFIER LOCKHOPPER VENT GAS CONTROL

Application and Description of Control

The control of lockhopper vent gas is a problem associated only with indirect coal liquefaction plants—not oil shale conversion plants. Uncontrolled vent gas from the lockhopper of an indirect coal liquefaction gasifier can be as much as 0.1 percent of the raw synthesis gas produced in the gasifier. A 50,000 fuel oil equivalent (FOE) barrels-per-day indirect coal liquefaction plant generates about 4.290 million lb/h of raw gas and therefore releases about 102,960 lb/d of lockhopper vent gas.¹ The vent gas has the same composition as the raw synthesis gas and consists of organic compounds, fatty acids, and many of the trace elements found in coal. The outlet gases also have high particulate loading with part of the particulates consisting of tarry material, which may contain polycyclic organic compounds.

Several types of controls are available for removing particulates. Cyclones are generally employed for the removal of bulk particulates. The capital and operating costs for cyclones are relatively low. Baghouses have very high particulate removal efficiency and can lend themselves to applications involving small or intermittent gas flows. Baghouses, however, have high pressure drops and normally cannot handle wet gases, gases containing oily materials, or gases having temperatures in excess of 300°C. Therefore, venturi scrubbers are generally selected to control lockhopper vent gas because they can handle gases having high temperatures, can operate at high pressure, can tolerate wet and tarry gases, and can be very efficient for the removal of submicrometer particulates.¹ Venturi scrubbers remove particulates from a gas stream by intimate contact with multiple jet streams of scrubbing water and droplets. Agglomerated particles are subsequently removed by centrifugal force or by a mist eliminator.²

Standard

Because federal air pollution standards for coal conversion technologies have not been established, federal performance standards for related industries (petroleum refineries, coal carbonization industries, and fossil-fueled power plants) become relevant. New Mexico has coal gasification plant air standards that directly relate to what would be necessary for coal liquefaction standards.³ Federal air standards for petroleum- and fossil-fueled power plant emissions are compared with New Mexico gasification plant air standards in the following table.

**Existing State (New Mexico) and Federal Emission Standards for
Future Coal Conversion Technologies***

Pollutant	Federal		New Mexico	
	Petroleum Refineries	Fossil-Fueled Steam Generators	Gas-Fired Power Plant Associated with Coal Gasification Plants	Gasification Plants
Particulate matter	0.27 grain/std. ft ³ + 0.10 lb/10 ⁶ Btu aux. fuel; 30% opacity, except for 3 min/h (catalytic cracking unit catalyst regenerator)	0.1 lb/10 ⁶ Btu 20% opacity	0.03 lb/10 ⁶ Btu	0.03 grain/std. ft ³
Hydrocarbons	Specified vapor pressure limits and required control devices (petroleum storage vessels)	NA**	NA	NA
Nitrogen oxides	NA	0.7 lb/10 ⁶ Btu (solid) 0.3 lb/10 ⁶ Btu (liquid) 0.2 lb/10 ⁶ Btu (gas)	0.20 lb/10 ⁶ Btu	NA
Sulfur (total)	NA	NA	NA	0.008 lb/10 ⁶ Btu
Reduced sulfur (sum of H ₂ S, CS ₂ , and COS)	NA	NA	NA	100 ppm
Hydrogen sulfide	NA	NA	NA	10 ppm
Hydrogen cyanide	NA	NA	NA	10 ppm
Hydrogen chloride and hydrochloric acid	NA	NA	NA	5 ppm
Ammonia	NA	NA	NA	25 ppm

*Adapted from Rubin and McMichael 1975, Table 5, p. 115 as reprinted in Reference 3.

**Not Applicable.

Control Performance and Efficiency

Particulate removal efficiency by the venturi scrubber is in the range of 95 to 99.9 percent, depending on particle size distribution and venturi pressure drop.² A mid-range pressure drop of 25 cm (H₂O gauge) is usually assumed to be sufficient for 99 percent particulate removal. Scrubber liquor can be routed to a small settling basin for removal of bulk particulates and subsequently combined with Lurgi raw gas liquor for further treatment. The removal efficiencies for a venturi scrubber are given in the following table.

Venturi Scrubber Efficiency Range*

Particle Diameter (μm)	Efficiency (wt. %)
0.25	50 - 92.5
0.50	60 - 98
0.75	70 - 99
> 3	90 - 99.6

*Inlet loading limitation > 0.5 g/m³ (normal).

Normal pressure drop range = 13 to 250 cm H₂O.

Reliability and State-of-the-Art

Although there is very little operating experience with venturi scrubbers at full-scale synfuel plants, there are many operating years of experience cleaning flue gas from coal-fired power plants and industrial boilers. Based on what is known from boiler operations, some believe the reliability of venturi scrubbers when cleaning lockhopper vent gas may be limited by sealing, fouling, or corrosion.

Nevertheless, the current state-of-the-art for venturi scrubbers is high particulate removal efficiency and the capability of treating streams with wide ranges in temperature, pressure, and gas composition.

Costs: Capital and Operating

The cost of scrubbers varies greatly as a function of the type of metal used for fabrication, metal thickness, pressure drop, and flow rate.^{2,4} Cost data for a 100,000 ft³/min(actual) flow rate venturi scrubber are given in reference 4 and are presented in the following table.

**Lockhopper Vent Gas Control Installation
and Operating Costs (\$ 1981)***

Type	Capital Cost (\$ million)		Annual Operation and Maintenance Cost (\$ million)		Unit Cost (\$/bbl FOE)	
	Coal Lique- faction Plant	Oil Shale Conversion	Coal Lique- faction Plant	Oil Shale Conversion	Coal Lique- faction Plant	Oil Shale Conversion
Venturi scrubber ⁴	0.207	NA**	0.065	NA	0.010	NA

*Reference year for environmental control cost is 1977; 1977 CCI average II_R is 2577. See Explanatory Notes.

**Not applicable.

References

1. Shreiner, M., "Research Guidance Studies to Assess Gasoline from Coal by Methanol-to-Gasoline and SASOL-Type Fischer-Tropsch Technologies," FE-2447-13, prepared for U.S. Department of Energy by Mobil Research and Development Corporation, August 1978.
2. Cheremisnoff, P.N., and R.A. Young, Pollution Engineering Practice Handbook, Ann Arbor Science Publishers, Inc., 1976.
3. Oak Ridge National Laboratory, Environmental, Health, and Control Aspects of Coal Conversion: An Information Overview, Volume 1, April 1977.
4. Bostwick, L.E., M.R. Smith, D.O. Moore, and D.K. Webber, Coal Conversion Control Technology, Volume II. Gaseous Emissions: Solid Wastes, EPA-600/7-79-228b, prepared for the U.S. Environmental Protection Agency by Pullman Kellogg, Houston, Texas, October 1979.

NO_x CONTROL

Application and Description of Control

The initial processing of raw shale and coal for the production of synthetic fuels occurs in a reducing environment. Thus, rather than forming NO_x, nitrogen combines with hydrogen to form ammonia, NH₃, gas.¹ Ammonia has a relatively low boiling point and will not condense during the recovery of the liberated fuel oil, but remains as a gas with the light hydrocarbons. These noncondensable hydrocarbons are usually used as boiler feedstocks for onsite power generation. If the NH₃ (source of fuel-bound nitrogen) is not removed prior to combustion, then NO_x concentration will be increased by up to about 5 to 10 x 10³ ppm in the flue gas.* NO_x formation from thermal fixation of atmospheric nitrogen will be inhibited by using combustion modification controls as discussed previously in this document in the section on coal-fired power plants and industrial boilers. Thus, NO_x control plans must include effective NH₃ removal from the retort offgases.

Ammonia in fuel gas process streams can be removed by water scrubbing.^{1,4} Removal processes include the Chevron and Phosam methods. These two physical separation processes are proprietary; they both are based on the principle that the solubility of NH₃ in water decreases with increasing temperature, thereby allowing the absorbed NH₃ to be stripped from the water and recovered as a by-product.

In the Chevron unit, the NH₃ stripper is a highly efficient reboiler-stripper column in which the NH₃ is stripped from the water and taken overhead, while the clean water collects at the bottom of the column.^{2,3} The overhead stream is partially condensed using cooling water and is taken to an accumulator. The vapor stream from the accumulator is taken through two scrubbers, compressed, and condensed to yield anhydrous liquid ammonia.²

In a Phosam unit, NH₃ is scrubbed by using a phosphoric acid solution and the liquid is stripped by using low-pressure steam. The basis of the fundamental process is that H₃PO₄ has three hydrogen atoms that can be replaced by ammonium ions in water solution.² Thus, a range of mole ratios of NH₃ to H₃PO₄ exists in which the NH₃ is bound tightly enough (by chemical reaction) to permit good absorption of NH₃ from water yet is bound loosely enough to permit the desorption of the NH₃ from the solution in a downstream processing stage.

Standard

Federal environmental pollution standards for the synthetic fuels industry have not yet been established. The environmentally problematic effluents from synfuels operations have not been thoroughly characterized; in some cases, adequate sampling and analysis methods have not been developed, validated, and standardized.⁵ As such, the proposed pollution control equipment in a synfuels plant must represent best available control technology (BACT), and controlled residuals must not violate ambient standards.

* This statement is based on the suppositions that raw shale and coal contain approximately 0.5 percent nitrogen and 1 percent nitrogen, respectively, and that all of the nitrogen in NH₃ is converted to NO_x.

The concepts of BACT for air emissions control is defined as the maximum degree of reduction determined case by case, taking into account energy, environmental, and economic impacts. If applicable prevention-of-significant-deterioration increments are predicted to be violated, better control than that prescribed by BACT must be employed (possibly by reevaluating the economic and energy costs associated with BACT).

For synthetic fuels operations, it is highly probable that there will be an onsite boiler utilizing retort offgas as feedstock for generating electrical power and thermal energy requirements. Current new source performance standards for these boiler pollutant emissions are in effect and have to be satisfied.

The Clean Air Act of 1970 required the Environmental Protection Agency Administrator to set standards for new sources. The only NO_x source category for which federal new source performance standards are in effect is steam generators with a thermal input greater than 73 MW (250×10^6 Btu/h). The standard is 0.2 lb $\text{NO}_x/10^6$ Btu for gas-fired boilers.⁶ The basis of these regulations is combustion modification to reduce NO_x formation; compliance is achieved with low excess air and staged combustion. Boilers with capabilities less than 73-MW_t input are subject to state emission limits for particulate matter. State implementation plans reflect local conditions and needs. Florida, New Mexico, and Oklahoma have the federal standard in effect for steam generators with a thermal input greater than 15 MW (50×10^6 Btu/h), and California and Wyoming have the federal standard in effect for all steam generators.⁷ All other states follow the federal standard as written.

Control Performance and Removal Efficiency

The Chevron and Phosam processes are compared in the following table. When reading this table, realize that even though both processes are commercial, both are still proprietary. As such, only limited data on the processes are available in the open literature.

Key Features of Ammonia Removal Technologies

Process	Process Principle	Components Removed	Removal Efficiency	Feed Stream Requirements/ Restrictions	By-Products	Operating Conditions
Chevron	Insolubility of contaminants in water at elevated temperatures	NH_3 H_2S	99.9% 99.99%	In general, phenol concentrations have to be removed from wastewater prior to initiating Chevron process Wastewater concentrations: 3-5.5 wt% NH_3 4-5.5 wt% H_2S	Anhydrous ammonia and sulfur	P ~ 50 psig T ~ 250°F
Phosam	Phosphate salts are used to remove contaminants from wastestream	NH_3 H_2S	99% 99%	Wastestream concentrations of NH_3 and H_2S for technical and economical feasibility not available	Anhydrous ammonia and sulfur	P ~ 200 psig T (not available)

Reliability and State-of-the-Art

The Chevron and Phosam processes have a history of proven commercial reliability and operation. The reliability factor for onstream commercial-size plants is approximately 95 percent for both processes. These processes are expected to be the most practical NO_x control systems (along with inherent combustion modification controls) for the synthetic fuels industry.^{1,2}

Costs: Capital and Operating

The economics of the Chevron and Phosam processes as they relate to the synfuels industry is unknown. However, based on experience, capital and operating and maintenance costs for a 50 x 10³ bbl/d syncrude equivalent synfuels plant can be estimated. These estimates are given in the following table.^{1,2}

Chevron and Phosam Processes Installation and Operating Costs (\$ 1981)*

Process Output (gal./min)	Capital Cost (\$ million)		Annual Operation and Maintenance Cost (\$ million)		Unit Cost** (\$/bbl FOE)	
	Coal Lique- faction Plant	Oil Shale Conversion	Coal Lique- faction Plant	Oil Shale Conversion	Coal Lique- faction Plant	Oil Shale Conversion
Chevron						
100 gal./min	4.4	4.4	1.2	1.2	0.13	0.13
200 gal./min	5.5	5.5	2.1	2.1	0.29	0.29
500 gal./min	7.6	7.6	4.7	4.7	0.62	0.62
Phosam						
100 gal./min	3.2	3.2	0.55	0.55	0.11	0.11
200 gal./min	4.7	4.7	0.98	0.98	0.16	0.16
500 gal./min	8.2	8.2	2.2	2.2	0.34	0.14

*Reference year for environmental control cost is 1980; 1980 CCI average (I₉) is 3237. See Explanatory Notes.

**Levelized annual revenue requirement (assuming a 90 percent plant capacity factor).

References

1. Department of Energy, "Environmental Control Costs for Oil Shale Processes," DOE/EV-0055, October 1979.
2. Singh, S.P.N., et al., "Costs and Technical Characteristics of Environmental Control Processes for Low-BTU Coal Gasification Plants," ORNL-5425, Oak Ridge National Laboratory, June 1980.
3. Environmental Protection Agency, "Coal Conversion Control Technology, Volume 1, Environmental Regulations, Liquid Effluents," EPA-600/7-79-228a, October 1979.
4. Schreiner, M., "Research Guidance Studies to Assess Gasoline from Coal by Methanol-to-Gasoline and SASOL-Type Fischer-Tropsch Technologies," FE-2447-13, prepared for Department of Energy by Mobile Research and Development Corporation, August 1978.

5. Environmental Protection Agency, "Environmental Assessment, Perspective on the Emerging Oil Shale Industry," EPA-625/9-81-005, January 1981.
6. "New Source Performance Standards: Electric Utility Steam Generating Units," Federal Register 44, 113, 40 CFR Part 60, June 11, 1979.
7. Environmental Protection Agency, Fossil Fuel Fired Industrial Boilers—Background Information, Volume 1: Chapters 1-9, EPA-450/3-82-006a, 1982.

FLARING FOR WASTE GAS CONTROL

Application and Description of Control

In the petroleum and other industries,¹ flares of various kinds are commonly used to combust and disperse waste gases. Because waste gas from an indirect coal liquefaction plant can amount to 1 to 3 percent of the raw synthesis gas flow rate on an average yearly basis, flaring is often employed.^{2,3} The amount of waste gas generated during oil shale conversion usually is too small, has too low a heat content to flare, and is disposed of by combustion in an onsite power plant or released to the atmosphere.⁴

In an indirect coal liquefaction plant during gasifier startup, shutdown, and upset situations, a significant amount of gasifier gas is sent to a flare stack where it is burned. The greatest amount of flaring occurs during plant startup rather than during the later normal plant operation. The components of the waste gas sent to the flare stack are the same as the raw synthesis gas.^{2,3} A 50,000-bbl/d-fuel oil equivalent (FOE), indirect coal liquefaction plant can generate as much as 4.7×10^5 tons/yr of flare gas.⁵ Flaring waste gas results in the oxidation of reduced sulfur compounds, reactive hydrocarbons, CO, HCN, and NH₃.

Standard

Because federal air pollution standards for coal conversion technologies have not been established, federal performance standards for related industries (petroleum refineries, coal carbonization industries, and fossil-fueled power plants) become relevant. New Mexico has coal gasification plant air standards that are directly related to what would be necessary for coal liquefaction standards.⁶ Federal air standards for petroleum- and fossil-fueled power plant emissions are compared with New Mexico gasification plant air standards in the following table.

Existing State (New Mexico) and Federal Emission Standards for Future Coal Conversion Technologies

Pollutant	Federal		New Mexico	
	Petroleum Refineries	Fossil-Fueled Steam Generators	Gas-Fired Power Plant Associated with Coal Gasification Plants	Gasification Plants
Sulfur dioxide	0.10 grain H ₂ S/std. ft ³ (dry) in fuel gas (plant gas fuel combustion)**	1.2 lb/10 ⁶ Btu (solid) 0.8 lb/10 ⁶ Btu (liquid)	0.16 lb/10 ⁶ Btu	NA†
Particulate matter	0.27 grain/std. ft ³ + 0.10 lb/10 ⁶ Btu aux. fuel; 30% opacity, except for 3 min/h (catalytic cracking unit catalyst regenerator)	0.1 lb/10 ⁶ Btu 20% opacity	0.03 lb/10 ⁶ Btu	0.03 grain/std. ft ³

*Adapted from Rubin and McMichael 1975, Table 5, p. 115 as reprinted in Reference 6.

**Equivalent to 0.1 lb/10⁶ Btu for gas with 250 Btu/ft³

†Not Applicable.

**Existing State (New Mexico) and Federal Emission Standards for
Future Coal Conversion Technologies* (continued)**

Pollutant	Federal		New Mexico	
	Petroleum Refineries	Fossil-Fueled Steam Generators	Gas-Fired Power Plant Associated with Coal Gasification Plants	Gasification Plants
Hydrocarbons	Specified vapor pressure limits and required control devices (petroleum storage vessels)	NA	NA	NA
Nitrogen oxides	NA	0.7 lb/10 ⁶ Btu (solid) 0.3 lb/10 ⁶ Btu (liquid) 0.2 lb/10 ⁶ Btu (gas)	0.20 lb/10 ⁶ Btu	NA
Sulfur (total)	NA	NA	NA	0.008 lb/10 ⁶ Btu
Reduced sulfur (sum of H ₂ S, CS ₂ , and COS)	NA	NA	NA	100 ppm
Hydrogen sulfide	NA	NA	NA	10 ppm
Hydrogen cyanide	NA	NA	NA	10 ppm
Hydrogen chloride and hydrochloric acid	NA	NA	NA	5 ppm
Ammonia	NA	NA	NA	25 ppm

* Adapted from Rubin and McMichael 1975, Table 5, p. 115 as reprinted in Reference 6.

** Equivalent to 0.1 lb/10⁶ Btu for gas with 250 Btu/lb³

† Not Applicable.

Control Performance and Efficiency

Various methods for incineration of waste gases (other than flaring) have been investigated. These methods include plant boiler, thermal, and catalytic incineration. The expected concentrations for waste gas components incinerated by these methods as compared to flaring is given in the following table.

Incinerated Waste Gas Emissions

Constituent	Boiler (ppm)	Incinerator (ppm)	Flare (ppm)
Reduced sulfur species	5	5	10
Reactive hydrocarbons	100	100	300
CO	100	300	1000
HCN	1	1	5
NH ₃	0.5	0.5	10

Reliability and State-of-the-Art

Flares have been known to be very reliable for the combustion of waste gases generated in the petroleum refining industries. Very little work has been done to predict flare contributions to ambient air quality; most research

has been limited to large stack sources. Flare emissions, because they are released nearer to the ground than stack gases, might be expected to be important on a local level. A well-known air pollution relationship, the Pasquill-Gifford dispersion equation, seems to approximate the behavior of flare plumes reasonably well. This relationship depicts expected concentrations of pollutants at ground level beneath the plume centerline. Normally, an optimum flare height is calculated from the dispersion equations, such that the allowable ambient concentration is not exceeded anywhere downwind.¹

In some applications, supplemental fuel is required for reliable flaring. For example, a low H₂S gas mixture would require addition of hydrocarbons to promote good combustion, while a high sulfur gas may require no fuel at all.¹

There is a lower practical heating value below which combustion cannot be supported. This limit will vary with composition of flare gas and fuel, particularly as a function of CO₂ concentration.

Costs: Capital and Operating

The capital cost of a flare stack is primarily dependent upon the flow rate and composition of the waste gas to be incinerated. Flare operating costs depend on the amount of supplemental fuel needed to maintain proper combustion. A comparison of flare costs with boiler and thermal incinerator costs are given in the following table.

Comparison of Waste Gas Combustion Techniques Installation and Operating Costs (\$ 1981)*

Type	Capital Cost (\$ million)		Annual Operation and Maintenance Cost (\$ million)		Unit Cost (\$/bbl FOE)	
	Coal Liquefaction Plant	Oil Shale Conversion	Coal Liquefaction Plant	Oil Shale Conversion	Coal Liquefaction Plant	Oil Shale Conversion
Flare	0.68	0.68	0.13	0.13	0.022**	0.022**
Boiler, ESP, FGD	10.0-13.1	10.0-13.1	3.1-4.4	2.6-4.4	0.46-0.64**	0.46-0.64**
Thermal incinerator, ESP	2.4	2.4	0.44	0.44	0.08**	0.08**

*Reference year for environmental control cost is 1980; 1980 CCI average (I_R) is 3237. See Explanatory Notes.

**Levelized annual revenue requirement (assuming a 90 percent plant capacity factor) for a 50,000-FOE bbl/day facility.

References

1. Cheremisinoff, P.N., and R.A. Young, Pollution Engineering Practice Handbook, Ann Arbor Science Publishers, Inc., 1976.
2. Ghassemi, M.K., K. Crawford, and S. Quinlivan, "Environmental Assessment Report: Lurgi Coal Gasification Systems for SNG," EPA-600/7-79-120, prepared for U.S. Environmental Protection Agency by TRW, Inc., May 1979.
3. Cleland, J.G., et al., "Pollutants From Synthetic Fuels Production: Coal Gasification Screening Test Results," EPA-600/7-79-200, prepared for U.S. Environmental Protection Agency by Research Triangle Institute, Research Triangle Park, North Carolina, August 1979.

4. Department of Energy, "Oil Shale Surface Retorting Environmental Characterization Information Report," Edition 1, January 1981.
5. Shreiner, M., "Research Guidance Studies to Assess Gasoline from Coal by Methanol-to-Gasoline and SASOL-Type Fischer-Tropsch Technologies," FE-2447-13, prepared for U.S. Department of Energy by Mobil Research and Development Corporation, August 1978.
6. Oak Ridge National Laboratory, Environmental, Health, and Control Aspects of Coal Conversion: An Information Overview, Volume I, April 1977.

Water Pollution Control

WASTEWATER TREATMENT

Application and Description of Control

Significant quantities of wastewater are generated during the production of synthetic fuels from coal and oil shale. Specifically addressed here are wastewaters associated with indirect coal liquefaction and the surface retorting of oil shale.

Oil shale surface retorting activities and indirect coal liquefaction processes produce wastewater from mining, dust control, runoff, by-product recovery, boiler blowdown, air pollution stack control, and raw water (source supply) treatment operations.^{1,2} Wastewater volumes vary due to different operating conditions from site to site and to differences in the chemical composition of the feedstock.

Wastewater contaminants are similar for both conversion technologies; however, their concentrations will vary according to the processing applications employed and to the resource processed. (That is, one processing application preparing two different types of coal will generate the same pollutants but in different concentrations as will two processing applications using a common feedstock.) In general, the pollutants of most concern are organics (e.g., phenols), ammonia, suspended and dissolved solids, thiocyanate/cyanide, pH, and metals. Oil and grease can be a potential problem especially if refining is performed onsite.^{3,4}

The state-of-the-art of wastewater treatment is sufficiently advanced to satisfactorily remove or reduce pollutants to levels required for any disposal or reuse option. Most oil shale and coal conversion facilities are expected to employ total reuse thereby eliminating offsite discharges and the need to obtain discharge permits.

Of the many alternatives commercially available, the following list presents the most appropriate wastewater treatment candidates.^{5,6}

- Biological oxidation
- Carbon adsorption
- Chemical precipitation and clarification
- Distillation
- Evaporation
- Ion exchange
- Oil separation
- Reverse osmosis
- Ultrafiltration
- Wet-air oxidation

Because no single alternative can treat all the pollutants to the appropriate level, several alternatives must be arranged in series (treatment train) to maximize the effectiveness of each. Additionally, the high ammonia and phenol concentrations may interfere with proper biological treatment. These contaminants are usually removed prior to the biological treatment unit by the methods discussed elsewhere in the handbook (e.g., see phenolsolvan process for

phenol recovery). Consequently, these methods are not discussed here but are components of an overall wastewater treatment strategy.

Standard

Currently no federal effluent guidelines exist regulating the discharge of wastewater from either coal or oil shale conversion operations. Although discharges are not expected, effluent guideline estimates can be made by comparing existing regulations for industries with similar wastewaters such as iron and steel (coking) and petroleum refining. Nonetheless, any point source discharge to a receiving water body will require a National Pollution Discharge Elimination System (NPDES) permit issued either by the Environmental Protection Agency (EPA) or a state with an EPA-approved NPDES permit program. The following table presents current effluent regulations for the major pollutants common to similar industrial activities.⁶

Wastewater Effluent Regulations

Pollutant Parameter	Petroleum Refining		Steel/Coke		Anticipated regulations		
	(lb/10 ³ bbl)	(lb/10 ⁶ lb)	(lb/10 ³ lb)	(lb/10 ⁶ lb)	Low (lb/10 ⁶ lb)	High (lb/10 ⁶ lb)	ppm (lb/10 ⁶ lb)
TSS	1.20-15.4	1.80-23.1	0.0104	7.18	1	7	3-15
Phenols	0.010-0.125	0.015-0.188	0.0002	0.138	0.01	0.15	0.03-0.3
Oil and grease	0.44-5.8	0.66-8.72	0.0042	2.90	0.5	3	1-16
CH			0.0001	0.069	0.01	0.05	0.02-0.1
NH ₃	0.28-11.0	0.42-16.5	0.0042	2.9	0.4	2.5	0.8-5
S ²	0.008-0.10	0.012-0.15	0.0001	0.069	0.01	0.1	0.02-0.2
BOD	1.4-18.9	2.1-28.3			2	15	4-30
COD	7.1-131	10.6-196			10	150	20-350
pH	6-9	6-9	6-9	6-9		6-9	6-9

Reliability and State-of-the-Art

Treatability studies conducted on synthetic and actual wastewaters from coal conversion and oil shale facilities indicate that existing wastewater treatment methods will satisfactorily reduce or remove all contaminants of concern. Newer applications, such as distillation and wet-air oxidation, are becoming more attractive, but their use is quite limited at this time. For the treatment alternatives listed in the following table, all are considered to have very good reliability, and except for wet-air oxidation and distillation, which are experimental processes, all are commercially available.

Alternative	Cross Media Impacts	Negative Factors
Available		
Biological processes	Produces sludge requiring disposal	May require land for sludge disposal
Carbon adsorption	None	Must regenerate or replace used carbon
Coagulation/sedimentation	Produces sludge requiring disposal	May require land for sludge disposal

Alternative	Cross Media Impacts	Negative Factors
Available		
Evaporation pond	Potential soil contamination	Temporary land loss; potential groundwater contamination
Oil separator	None	None
Ion exchange	None	Produces an acid or base side stream requiring additional treatment
Reverse osmosis	None	Produces a concentrate requiring treatment
Experimental		
Distillation	May exhaust steam	High capital and operating and maintenance costs; potential scaling
Wet-air oxidation	None	High capital and operating and maintenance costs

Control Performance and Efficiency

Characterization studies on wastewater from both oil shale retorting and coal liquefaction processes indicate that no unmanageable pollutants are generated. Given proper engineering design, wastewater facilities will meet the necessary effluent reuse requirements. The following list presents general removal efficiencies that can be expected, given a properly operating facility.

<u>Technology</u>	<u>Removal Efficiency %</u>
Dissolved air flotation	90 (oil and grease)
Clarification	80 (suspended solids)
Multimedia filtration	95 (suspended solids)
Distillation	99 (dissolved solids)
Reverse osmosis	60-95 (dissolved solids, organics)
Ion exchange	High (dissolved solids, metals)
Activated sludge	95 (BOD)/40 (COD)
Rotating biological contactor	90 (BOD)/20-50 (COD)
Chemical oxidation	90 (BOD)/90 (COD)
Wet-air oxidation	64 (BOD)/74 (COD)
Carbon adsorption	99 (BOD)

Costs: Capital and Operating

Among the wastewater treatment alternatives described, several can be selected for a treatment system for a particular site. Costs presented in the following table represent an exemplary treatment system with the following components: equalization basin, oil-water separator, a mixed media filter, an activated sludge unit, and a carbon adsorption unit. Phenol and ammonia removal

units are also integral elements of wastewater treatment plants, but they are not included here. (They are listed in the sections on phenol and ammonia recovery.) Any sludge generated must also be managed in an acceptable manner such as by landfilling, anaerobic digestion, or aerobic digestion.

**Wastewater Treatment Capital and Operating Costs
for a 50,000-bbl/d Synfuel Plant⁸ (\$ 1981)***

Treatment Alternative	Capital Cost (\$ million)		Annual Operation and Maintenance Cost (\$ million)		Unit Cost (\$/bbl FOE)	
	Coal Liquefaction Plant**	Oil Shale [†]	Coal Liquefaction Plant**	Oil Shale [†]	Coal Liquefaction Plant**	Oil Shale [†]
Equalization basin	0.8	0.65	—	—	0.011	0.011
Carbon adsorption	1.5	1.2	0.17	0.13	0.055	0.044
Activated sludge	0.44	0.12	0.22	0.76	0.044	0.12
Mixed media filter	0.55	0.44	0.011	0.011	0.011	0.011
Oil/water separator	1.1	0.8	0.22	0.12	0.055	0.033
Coagulation/sedimentation	1.2	0.44	0.12	0.066	0.033	0.022

*Reference year for environmental control cost is 1980; 1980 CCI average (I_{PI}) is 3237. See Explanatory Notes.

**Assumes wastewater flow rate of 1.59 million gal./day.⁷

[†]Assumes wastewater flow rate of 0.77 million gal./day.

References

1. Environmental Protection Agency, "Environmental Perspective on the Emerging Oil Shale Industry," EPA 600/2-80-205a, 1980.
2. Department of Energy, "Reuse and Disposal Options for Wastewaters in Coal Conversion," DOE/EV/10367-12, April 1981.
3. Luthy, R.g., "Treatment of Coal Coking and Coal Gasification, J. Water Pollution Control Fed. 53, (3), 1981.
4. Hampton, N.F., and B.Y. Ryan, Jr., "Water Related Constraints on Energy Production," ATR-78(9409)-1, The Aerospace Corporation, June 1978.
5. Environmental Protection Agency, "Environmental Aspects of Fuel Conversion Technology-VI," Denver, Colorado, October 1981.
6. Klein, J.A., and R.E. Barker, "Assessment of Environmental Control Technology for Coal Conversion Aqueous Wastes," ORNL/TM-6263, Oak Ridge National Laboratory, 1978.
7. Shreiner, M., "Research Guidance Studies to Assess Gasoline From Coal by Methanol-to-Gasoline and SASOL-Type Fischer-Tropsch Technologies," FE-2447-13, prepared for U.S. Department of Energy by Mobil Research and Development Corporation, August 1978.
8. Environmental Protection Agency, "Treatability Manual, Volume IV, Cost Estimating," EPA-600/8-80-042d, 1980.

PHENOLSOLVAN PROCESS FOR PHENOL RECOVERY

Application and Description of Control

During indirect coal liquefaction, raw gas produced in the gasifier is cooled forming a gas liquor that contains a high concentration of phenol and other contaminants such as ammonia, tar, and oil. Recovery of phenol can be an important environmental control step because phenol has a significant heat content (7800 Btu/lb) and consequently may be used as a supplemental fuel to improve the economic operation of an onsite coal-fired power plant.

The phenolsolvan process is employed at the SASOL indirect coal liquefaction plant to recover phenol.¹ The removal of phenol from wastewater is necessary for coal liquefaction plants, but not for oil shale conversion plants. As much as 60,000 tons/yr of phenol can be extracted from a 50,000-bbl/d fuel oil equivalent (FOE), indirect coal liquefaction plant.²

The phenolsolvan process is a proprietary process marketed in the United States by the American Lurgi Corporation. The process was developed by the Lurgi Company in Germany to remove phenols from coke-oven liquors, and the first commercial plant was built about 1940. The process extracts phenols from wastewater using isopropyl ether as the solvent; however, a newer version of the process uses a proprietary solvent called Phenisol to extract the phenols.³

The basic unit operation in the phenolsolvan process is solvent extraction. In this process, the phenolic wastewater is first passed through a gravel-bed filter to remove any suspended solids. The wastewater is then taken to a mixer-settler vessel where it is intimately contacted with a solvent (e.g., isopropyl ether) in a counter-current flow condition. The mixer-settler is ordinarily a horizontal vessel containing several mixing and settling stages arranged in series. The phenolic wastewater enters the vessel at one end, and the lean solvent enters at the opposite end. As the solvent traverses the vessel, it contacts wastewater containing increasing concentrations of phenols. The solvent is relatively immiscible with the water; however, it removes the phenols present in the wastewater by solvent extraction.

The raffinate stream is taken from the mixer-settler and stripped of any carryover solvent in a raffinate stripper column using nitrogen. The dephenolized water is taken from the bottom of the column for further downstream processing such as acid-gas stripping or biological treatment.

The extract stream is taken from the mixer-settler vessel to the solvent distillation column where the lean solvent is recovered as an overhead stream from the extract. The crude phenols flow to the bottom of the column for subsequent removal.

Standard

Federal water pollution standards for coal conversion processes have not yet been established. However, federal wastewater performance standards for related industries (petroleum refineries, coal carbonization industries, and fossil-fueled power plants) are relevant. The following table presents federal wastewater standards for oils, phenolics, sulfide, and ammonia in petroleum and coking industries.¹ The table also compares the standards on an equivalent process feedstock energy input.

Adjusted New Source Performance Standards for By-Product Coke Making and Petroleum Refining (30-Day Maximum)*

Pollutant	Petroleum Refineries	By-Product Coke Making
	(pounds of pollutant/10 ¹² Btu feedstock)**	
Phenolics	1.5 - 19	12
Ammonia (as N)	40 - 1700	240
Sulfide	1.1 - 16	5.8
Total chromium	3.5 - 47	NA†
Hexavalent chromium	0.06 - 0.80	NA
Cyanides amenable to chlorination	NA	5.8
5-day biochemical oxygen demand	210 - 2900	NA
Total suspended solids	140 - 1920	600
Chemical oxygen demand	1050 - 20,000	NA
Oil and grease	70 - 890	240

*Adapted from Rubin and McMichael 1975, Table 6, p. 115 as reprinted and cited in Reference 1.

**Assumes heating values of 6.5 million Btu/bbl for crude oil and 12,000 Btu/lb for coal, with a coke yield of 0.69 lb coke/lb coal.

†Not applicable.

Control Performance and Efficiency

Because the phenolsolvan process is proprietary, very little performance data are available. However, it has been reported that the phenolsolvan process has the following removal efficiencies: (1) 99.5 percent for the monohydric phenols, (2) 60.0 percent for the polyhydric phenols, and (3) 15 percent for other organic compounds.^{3,4} The phenolsolvan process is claimed to be capable of producing an effluent water stream that contains only 5 to 20 ppm of phenols and a crude phenol stream containing 85 to 95 percent phenols.^{3,5}

Reliability and State-of-the-Art

Because there is no commercial-size coal liquefaction plant operating in the United States at this time, no measure of the reliability of the phenolsolvan process can be determined. Although the process was initially developed to recover phenols from coke-oven liquors, it appears that the current state-of-the-art can be applied to treating phenolic wastewaters generated in coal liquefaction plants. No specific limits of operability have been reported for

the phenolsolvan process; however, a lower limit probably exists for phenol concentration in wastewater below which the operation of the process (though technically feasible) may not be economically viable.

Costs: Capital and Operating

Capital and operating costs for phenolsolvan process units treating phenolic wastewater (containing 15,000 ppm mixed phenols) at various flow rates are given in the following table. Costs for the process were estimated in Reference 3 according to information given in Reference 5.

Phenolsolvan Process Installation and Operating Costs (\$ 1981)*

Wastewater Flow Rate** (gal./min)	Capital Cost (\$ million)		Annual Operation and Maintenance Cost (\$ million)		Unit Cost (\$/bbl FOE)	
	Coal Liquefaction Plant	Oil Shale Conversion	Coal Liquefaction Plant	Oil Shale Conversion	Coal Liquefaction Plant††	Oil Shale Conversion
50	1.52	NA†	0.27	NA	0.05	NA
100	2.13	NA	0.33	NA	0.06	NA
200	2.96	NA	0.44	NA	0.08	NA
500	4.60	NA	0.70	NA	0.13	NA

*Reference year for environmental control cost is 1978; 1978 CCI average (I_R) is 2776. See Explanatory Notes.

**Wastewater containing approximately 1.5 wt. % mixed phenols.

†Not applicable.

††Levelized annual revenue requirement (assuming a 90 percent plant capacity factor).

References

1. Oak Ridge National Laboratory, Environmental, Health, and Control Aspects of Coal Conversion: An Information Overview, Volume 1, April 1977.
2. Shreiner, M., "Research Guidance Studies to Assess Gasoline From Coal by Methanol-to-Gasoline and SASOL-Type Fischer-Tropsch Technologies," FE-2447-13, prepared for U.S. Department of Energy by Mobil Research and Development Corporation, August 1978.
3. Singh, S.P.N., et al., "Costs and Technical Characteristics of Environmental Control Processes for Low-BTU Coal Gasification Plants," ORNL-5425, Oak Ridge National Laboratory, June 1980.
4. Beychok, M.R., "Coal Gasification and the Phenolsolvan Process," Am. Chem. Soc. Div. Fuel Chem. Prepr. 19(5), 85, 1974.
5. American Lurgi Corporation, "Dephenolization of Effluents by the Phenolsolvan Process," brochure, April 1969.

Solid Waste Pollution Control

SPENT CATALYST AND GASIFIER ASH DISPOSAL

Application and Description of Control

The control and disposal of spent catalyst and gasifier ash is unique only to the coal conversion technology and is not appropriate for oil shale. A variety of catalysts are used in coal conversion. Catalysts deactivate with use and require regeneration or disposal. Regeneration frequently involves return to the supplier; disposal frequently involves return to the mine with ash.¹ Spent catalysts are discharged periodically in quantities that are small in comparison to the ash stream.² Production (from coal) of liquid or gaseous fuels containing 250 billion Btu/d will produce on the order of 10.4 to 25 million ft³/yr of mixed solids consisting of ash with small amounts of inorganic salts, sludges, and catalysts.² The selection of a control or controls to manage each type of solid waste is dependent upon a number of factors including (1) classification (as hazardous or nonhazardous) of the waste in accordance with the Resource Conservation and Recovery Act, (2) the quantity of waste, (3) the expected hydrogeological conditions, and (4) potential markets for solid waste. The disposal methods applicable to solid waste streams from a Lurgi-indirect coal liquefaction plant are given in the following table. As can be seen, most of the solid waste is disposed of in landfills. Therefore, this discussion focuses on landfilling as a viable method of control of coal conversion solid waste.

**Disposal Options for Solid Wastes
for Indirect Coal Liquefaction**

Solid Waste Stream	Resource Recovery	Incineration	Land Treatment	Surface Impoundment	Landfill	Co-Disposal with Ash
Gasifier ash	X			X	X	X
Spent shift catalyst	X				X	
Spent sulfur guard					X	
Spent methanation catalyst	X				X	
Spent methanol catalyst	X				X	
Spent Fischer-Tropsch catalyst					X	
Spent Mobil M-gasoline catalyst					X	
Boiler bottom ash	X			X	X	X
Boiler fly ash	X			X	X	X
FGD sludge				X	X	X
Raw water treatment sludge				X	X	X
Spent Claus catalyst					X	
Biosludge		X	X	X	X	X
Chemical precipitation sludge				X		X
Stretford sulfur	X				X	
Dust from particulate control	X	X			X	

Prior to landfilling, certain wastes may need to be treated (fixation). The fixation process is based on mixing the waste with a material to induce chemical reactions similar to those involved in the cement industry. Fixation generally combines solidification and stabilization steps. Solidification alters the waste to attain desired structural characteristics. Stabilization immobilizes toxic substances by chemical reactions to form insoluble compounds or by entrapping the toxic substances in watertight inert polymer or stable crystal lattice.

A number of fixation techniques exist or are under development. The various types of techniques are

- Cement-based
- Lime-based
- Thermoplastic (including bitumen, paraffin, and polyethylene)
- Organic polymer
- Self-cementing
- Glassification

The selection of a fixation method depends on (1) the type of waste, (2) the degree of containment required, (3) the increase in bulk of the waste, and (4) the changes in the handling characteristics. The design and location of the landfill that will receive the fixed wastes is a major consideration in deciding on the required degree of containment and physical properties.

Landfills have been widely used for the disposal of municipal refuse and a range of industrial wastes and would be suitable for disposal of gasifier ash, raw water treatment sludges, biosludge, and unrecyclable spent catalysts from an indirect liquefaction facility. Landfilling methods include area, trench, and depression. In the area method, wastes are spread on the surface of the land in long, narrow strips that vary in depth from 16 to 30 inches. Each layer is compacted until the thickness of the compacted wastes reaches 6 to 10 feet. A layer of soil 6 to 12 inches deep is placed over the waste. In the trench method, wastes are placed in trenches varying from 100 to 400 feet in length, 3 to 6 feet in depth, and 15 to 25 feet in width. The wastes are compacted and added until the desired height is reached, then are covered with soil. The depression method is similar to the trench method, except that natural or artificial depressions are used to contain the waste.

Standard

Although no coal gasification wastes currently are listed as hazardous wastes, some may fail the toxicity or corrosivity test and thus be classified as hazardous. All solids and liquids not discharged into the air or surface water are subject to regulation under the Resource Conservation and Recovery Act. Regulations for the control of both hazardous and nonhazardous wastes are listed below:

<u>Regulation</u>	<u>Description</u>
40 CFR 241 Landfill disposal of solid waste	Guidelines recommending management practices that meet criteria for nonhazardous waste disposal facilities.
40 CFR 257 Criteria for classification of solid waste disposal facilities and practices	Determines which nonhazardous solid waste land disposal facilities and practices pose adverse environmental effects.

<u>Regulation</u>	<u>Description</u>
40 CFR 260-267 Hazardous waste regulations	Hazardous waste management system.
40 CFR 260	Defines terms common to all hazardous waste regulations.
40 CFR 266	Standards for management of specific hazardous wastes and specific types of hazardous waste management facilities.
40 CFR 267	Standards for owners and operators of new hazardous waste land disposal facilities.
40 CFR 265	Standards for owners and operators of hazardous waste treatment, storage, and disposal facilities.
40 CFR 262	Standards for generators of hazardous waste.
40 CFR 263	Standards for transporters of hazardous waste.
40 CFR 264	Standards for owners and operators of hazardous waste treatment, storage, and disposal facilities.

Control Performance and Efficiency

One of the performance problems involved in solid waste disposal is preventing leachates from contaminating the soil areas surrounding the disposal site and the surface waters and groundwaters.² Interposing an impervious membrane between the wastes and the environment offers an attractive means of avoiding environmental damage. Liners often used as impervious membranes can be selected to resist leachate of low or high pH and to prevent failure, loss of strength, or increases in permeability. In clay-lined areas, permeability is very low, on the order of 1×10^{-9} to 1×10^{-10} cm/s for water.²

Reliability and State-of-the-Art

The following factors are important when considering liner reliability:

- Some clay soils, including bentonites, can lose their impermeability when impounding strong acids, strong bases, or brines. Careful evaluation may be required for selection of a clay that remains impermeable.

- Plastic liners have been known to degrade from long exposure to sunlight. Some polymers, such as polyvinyl chloride, may become brittle and crack, either by loss of plasticizer or evaporation or by degradation by ultraviolet light. Special plasticizers or inhibitors may be required in polymer formulations. Butyl rubber is susceptible to cracking from ozone attack.
- Liners exposed to severe weather may be damaged by drying or by freeze/thaw of exposed areas.
- There is variability in the strength and chemical resistance of field splices of the polymeric liners.

In addition to disposal of solid waste, there are also current state-of-the-art methods for converting the material to a salable product. High-temperature gasification processes (Koppers-Totzek) produce a slag that may be suitable for fill material, road aggregate, or cinder block material.¹ Tests have shown that gasifier coal ashes having significant iron content are suitable sorbents for desulfurization of low-calorific-value fuel gas from coal.¹

Costs: Capital and Operating

A comparison of the estimated costs of impoundment areas of various dimensions and types of liners for solid waste amounting to 10.4 to 25 million ft³ is given in the following table.

**Solid Waste (Spent Catalyst and Gasifier Ash)
Landfill Installation and Operating Costs (\$ 1981)**

Impoundment Size*	Capital Cost (\$ million)		Annual Operation and Maintenance Cost (\$ million)		Unit Cost (\$/bbl FOE)	
	Coal Lique- faction Plant**	Oil Shale Conversion	Coal Lique- faction Plant	Oil Shale Conversion	Coal Lique- faction Plant	Oil Shale Conversion
1000 ft ²						
High cost liner†	1.11 -1.55	NA††	NA	NA	0.081-0.112	NA
Medium cost liner§	0.918-1.33				0.068-0.097	
Low cost liner§§	0.736-1.12				0.053-0.083	
750 ft ²						
High cost liner†	0.756-1.34	NA	NA	NA	0.055-0.10	NA
Medium cost liner§	0.63 -1.20				0.047-0.09	
Low cost liner§§	0.516-1.06				0.04 -0.08	

*For 10.4 to 24 million ft³ of solid waste.

**Reference year for coal liquefaction environmental control cost is 1977; 1977 CCI average (H₂) is 2577. See Explanatory Notes.

†Paving asphalt plus sealer, 4-in. thickness, \$3.33 to \$4.60/yd², medium \$4.00 for calculation.

††Not applicable.

§Average cost of \$2.84/yd².

§§Soil cement plus sealer, 8-in. thick, \$1.77/yd².

1. Oak Ridge National Laboratory, Environmental, Health, and Control Aspects of Coal Conversion: An Information Overview, Volume 1, April 1977.

2. Bostwick, L.E., M.R. Smith, D.O. Moore, and D.K. Webber, Coal Conversion Control Technology, Volume II. Gaseous Emissions: Solid Wastes, EPA-600/7-79-228b, prepared for U.S. Environmental Protection Agency by Pullman Kellogg, Houston, Texas, October 1979.

RETORTED SHALE DISPOSAL

Application and Description of Control

The control and disposal of retorted shale are processes unique to the oil shale conversion technology. Spent oil shale can be disposed of on the surface in piles or as canyon fills.

A 50,000-bbl/d syncrude equivalent oil shale production plant retorts approximately 88,000 tons/d of oil shale. After retorting, approximately 81 percent, by weight, or 23×10^6 tons/yr of this retorted shale must be disposed of in an environmentally acceptable manner.^{1,2} The disposal of retorted shale must be controlled to avoid pollution from surface erosion (wind and water) and subsurface leaching of soluble salts.^{1,3} Retorted shale contains about 20 lb/ton of readily leachable salts, roughly five times that leachable from raw oil shale.^{1,4} In addition, the carbonaceous component of retorted shale contains organic substances that can be extracted by water.^{1,5}

One control method for retorted shale is to construct a leachate-impervious lining of compacted retorted shale in a valley disposal area and a cross-valley earthen dam, also of retorted shale, built at the mouth of a valley.^{1,6} Such a disposal site would be capable of handling the retorted shale generated by a 50,000-bbl/d plant over the 25-yr life of the plant. For example, the retorted shale bed depth would be 530 ft; retention dam height, 364 ft; and site-surface area, 1080 acres. The retorted shale used for the construction of the dam would be compacted to a density of 90 lb/ft³ and have a permeability of 9.7×10^{-8} cm/sec.^{1,2} The dam outer face will be covered with a 1-ft-thick water-stabilized retorted shale mixture, which further protects against leaching and erosion. The entire disposal area surface behind the dam would also be covered to a depth of 1 ft with the same mixture, after removal of the native soil cover. This type dam is built up slowly as the retorted shale disposal pile height increases, avoiding creation of an area behind the dam that would retain runoff water. A catchment basin with a capacity of about 300 acre-ft would contain any runoff water.

After being dumped and compacted in the shale-lined void behind a shale dam, the retorted shale would be vegetated.^{1,2} The vegetation process will consist of leaching salts from the top layer of the shale pile; applying a soil layer for plants with such additives as soil conditioners, native microorganisms, topsoil, and fertilizers; selecting a mixture of native and imported plants compatible with local climate and soil conditions; protecting surfaces with mulches; installing fences to ward off grazing animals during the early period of growth; and irrigating the planted area for 2 years or more to establish a viable root system.^{1,3,7}

Standard

Processed shale will probably be treated as a solid waste in accordance with Resource Conservation and Recovery Act (RCRA) regulations.⁸ Under this

classification, processed shale shall not be disposed of in environmentally sensitive areas such as wetlands, flood plains (100-yr flood), critical habitats, and the recharge zone of a sole-source aquifer.

The RCRA requires that solid and hazardous waste generators and transporters receive permits and that wastes are disposed of only by safe practices. Regulations have been promulgated in 40 CFR 261 for (1) the criteria to identify solid and hazardous wastes (Section 3001), (2) disposal standards (Section 3004), and (3) permit programs (Section 3005). If a waste is not defined as hazardous (i.e., it is defined only as a solid waste), disposal will be governed by the Section 4004 regulations as promulgated in 40 CFR 257 on September 13, 1979. The promulgated regulations define a waste as hazardous if it is ignitable (flash point of 60°C or 140°F), corrosive (extract pH of 2 or of 12.5), reactive (explosive or oxidizing), or toxic (extract concentration 10 times greater than drinking water standards). Overburden mine wastes that are returned to the mine are exempt from these regulations. Also, materials ready for further processing are exempt.

Control Performance and Efficiency

Spent oil shale weighs about 80 to 85 percent the weight of raw mined oil shale. Even with maximum compaction, it occupies a volume approximately 12 percent greater than the volume of the original in-place shale. Performance factors that should be considered in surface disposal of spent shale include:

- Location of disposal sites large enough to accommodate the large amounts of spent shale and yet permit the disposal site to blend into the natural topography,
- Generation of fugitive dust until the disposal site has been revegetated,
- Proper cooling to avoid retorted shale temperatures that could be a serious impediment to revegetation,
- Deterioration of surface water and possibly groundwater quality by runoff from disposal piles,
- Deterioration of groundwater and possibly surface water quality by leachates permeating the disposal pile, and
- Difficulty in revegetating some spent shale piles without soil cover (some spent shales are highly alkaline and contain few nutrients).

Results of EPA-sponsored field studies, listed in the following table, indicate that permeability of retorted shale take on a wide range of values.

**Range of Reported Permeability Values of
Various Compacted Spent Oil Shales**

Type of Shale	Permeability Value (cm/yr)	Comment
Paraho, direct mode	2.2×10^3 to 4.7×10^3	Environmental Protection Agency field study
USBM	1.6×10^1 to 3.2×10^1	Lab-weathered shale
Paraho pilot plant	3.4×10^1 to 6.4×10^4	Lab study, various particle sizings and compactive efforts
Paraho	3×10^2 to 4.6×10^2	
Paraho, direct mode	3×10^1 to 4.6×10^2	Standard tests
TOSCO II	8.8×10^2 to 1.3×10^3	Rainfall permeability
TOSCO II	3.0×10^1	Colony study

Any proposed spent shale disposal plan using compaction to make the shale impervious should first prove that the particular spent shale and compactive effort can indeed make spent shale impervious.

Reliability and State-of-the-Art

Information on the reliability of spent shale disposal is nearly nonexistent. However, it is known that instability of spent shale piles, resulting from improper pile design, may produce erosion, soil creep, and possibly landslides.⁸ Fine-textured spent shales may be prone to slippage. Because of the very large areas required for surface disposal of spent oil shale, the quality of surface runoff water is of great concern.

Use of underground disposal of spent oil shales in conventional underground oil shale mines could avoid many of the potential environmental impacts of surface disposal. However, since the volume of spent shale exceeds the in-place volume of the original mined shale, not all spent shale can be disposed of underground. Underground disposal could possibly increase the potential for groundwater contamination unless great care is taken to prevent contact with groundwater.

Those solid wastes disposed of on the surface will be subject to leaching by water from several sources, including normal precipitation, water applied to cool the spent shale pile, water applied to leach the spent shale for revegetation, and irrigation water needed to establish vegetative cover. The condition of large quantities of solid waste exposed to water from varied sources may create a risk of generating leachate that could affect surface water and groundwater quality.

Little work has been done to date to determine whether vegetation grown on spent shale disposal areas contains increased levels of trace elements, especially metals.

Costs: Capital and Operating

Capital and operating costs for solid waste management from a 50,000-bbl/d oil shale plant are given in the following table.

**Solid Waste (Retorted Shale Disposal)
Installation and Operating Costs (\$ 1981)***

Type	Capital Cost (\$ million)		Annual Operation and Maintenance Cost (\$ million)		Unit Cost (\$/bbl FOE)	
	Coal Lique- faction Plant	Oil Shale Conversion ²	Coal Lique- faction Plant	Oil Shale Conversion ²	Coal Lique- faction Plant	Oil Shale Conversion ²
Spent shale (Paraho)**	NA†	1.5	NA	2.8-3.7	NA	0.34-0.45††

*Reference year for costs is 1977; 1977 CCI average (I_R) is 2577. See Explanatory Notes.

**Aboveground disposal using a landfill design.

†Not applicable.

††Levelized annual revenue requirement (assuming a 90 percent annual plant capacity factor).

References

1. Department of Energy, "Oil Shale Surface Retorting Environmental Characterization Information Report," Edition 1, January 1981.
2. Department of Energy, "Environmental Control Costs for Oil Shale Processes," DOE/EV-0055, Assistant Secretary for Environment, Office of Technology Impacts, October 1979, pp. 41, 338, and 357.
3. Environmental Protection Agency, "Lysimeter Study on the Disposal of Paraho Retorted Oil Shale," EPA-600/7-79-188, Office of Research and Development, Industrial Research Laboratory, Cincinnati, August 1979, pp. 1-5, 28, 29.
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6. Department of Energy, "Draft Environmental Impact Statement: The Paraho Research Project at the Anvil Points Oil Shale Facility," Assistant Secretary for Fossil Energy, June 9, 1980, pp. 2.12-2.16.

7. National Research Council, National Academy of Sciences, "Surface Mining of Non-coal Minerals, Appendix II: Mining and Processing of Oil Shale and Tar Sands," ISBN 0-309-03037-4, 1980, pp. 122-125.
8. Environmental Protection Agency, "Environmental Perspective on the Emerging Oil Shale Industry," EPA-600/2-80-205a, 1980.

COSTING PROCEDURE

COSTING PROCEDURE

In order to examine the costs of an environmental control technology, it is necessary to use a standard technique that considers capital costs, operating and maintenance (O&M) costs, and financial considerations such as the costs of interests, inflation, taxes, depreciation, etc. The technique most widely used is the levelized annual revenue requirement (LARR) method, which is described below.

There are several advantages to using LARR in cost analysis for plants: (1) it is becoming the standard technique used by utilities, (2) it uses tabulated levelizing factors which free the user from detailed financial calculations, and (3) the results can be modified easily if the user wants to make alternative economic assumptions.

The LARR method basis is that over the lifetime of a plant, there must be enough revenue (from selling electricity or steam) to cover all costs associated with building and operating the plant, including the cost of borrowing money. Although operating and maintenance costs will vary from year to year because of both inflation and real cost differences, it is convenient to levelize the costs so that total costs over the plant lifetime are divided into equal annual amounts; hence, the term "levelized annual revenue requirement."

The procedure for arriving at a value for LARR is straightforward:

$$\text{LARR} = (\text{capital requirement}) (\text{fixed charge rate}) + (\text{first year O\&M cost}) (\text{O\&M levelizing factor})$$

Capital requirement: All the items normally considered part of the capital cost of the plant, e.g., equipment, engineering, construction, land, contingency, and allowance for funds used during construction.

First year O&M cost: The cost of operating and maintaining the plant for a year. It includes items such as labor and fuel to operate the equipment. Although the annual maintenance costs might be expected to increase as the plant ages (over and above inflation), this increase is assumed to be offset by the normal decrease in the percentage of time the plant will operate late in plant life.

Fixed charge rate: The factor used to levelize the capital cost of the plant.

O&M levelizing factor: The factor used to levelize O&M costs.

The following assumptions have been made in this handbook:

Plant life	30 years
Long-term inflation rate	6 percent
Cost of borrowing money (above inflation)	4 percent
Plant capacity factor*	65 percent

Using these assumptions, plus typical depreciation and tax considerations, the fixed-charge rate is 0.18 and the operations and maintenance levelizing factor is 1.886. These have been used for the calculations in this handbook. (The capacity factor has no bearing on these levelizing factors.) For example, if for an electric power plant the capital requirement for an environmental control were \$10 million and first year O&M costs were \$600,000, the levelized annual revenue requirement becomes:

$$\text{LARR} = (\$10,000,000) (0.18) + (\$600,000) (1.886) = \$2,932,000$$

In a year, the number of kilowatt hours generated by a 500-MW electric power plant will be:

$$(500 \text{ MW}) (10^3 \text{ kW/MW}) (8760 \text{ h/yr}) (0.65 \text{ capacity factor}^*) = 2.85 \times 10^9 \text{ kWh/yr}$$

Thus, the unit cost of the control technology is:

$$\text{LARR}/(\text{kWh/yr}) = (\$2.932 \times 10^6) (10^3 \text{ mills}/\$) / (2.85 \times 10^9 \text{ kWh/yr}) = 1.03 \text{ mills/kWh}$$

If the unit cost is also needed in terms of some other parameter such as dollars per ton of sludge handled, the LARR is divided by the appropriate measure. For example, if the control technology discussed above handled 100,000 tons of sludge per year, the unit cost would be:

$$(\$2.932 \times 10^6 / \text{yr}) / (10^5 \text{ tons/yr}) = \$29.32 / \text{ton}$$

The cost calculations in this handbook are based on a 30-yr plant life. For other plant lifetimes, the levelizing factors would be:**

* The capacity factor is the percentage of time the plant actually operates out of 24 hours a day, 365 days a year.

** Electric Power Research Institute, Technical Assessment Guide, Chapter 3, EPRI PS-1201-SR, July 1979.

Life (yr)	Fixed Charge Rate	O&M Levelizing Factor
5	0.34	1.182
10	0.23	1.335
15	0.20	1.484
20	0.19	1.629
25	0.18	1.763
30	0.18	1.886
35	0.18	1.996
40	0.18	2.094

Notice that unit cost calculations are highly sensitive to the percentage of time the plant operates, i.e., the capacity factor. In this handbook, a 65 percent capacity factor has been assumed. This amount represents the actual capacity factor that can be expected of modern plants and is based on a careful review of reported plant statistics. However, the reader should be warned that the capacity factors used in published cost calculations for power plants range from 50 to 85 percent.

To convert cost data using one capacity factor to another capacity factor requires only a simple ratio calculation. In the example above, the 1.03 mills/kWh (at 65 percent capacity factor) would become the following if the capacity factor were 50 percent:

$$(1.03 \text{ mills/kWh}) (65/50) = 1.34 \text{ mills/kWh}$$

Annual plant capacities can be used to adjust available cost data from one size plant to another. Examples of annual capacity include kWh of electricity, tons of product, Btu/h of steam production, and quantities of manufactured items. If cost figures for one size plant are available, an approximation of the cost for another size plant can be found from the following equation*:

$$E_b = E_a \left(\frac{r_b}{r_a} \right)^n$$

where

E_b = Cost of plant b

E_a = Cost of plant a

r_b = Capacity of plant b

r_a = Capacity of plant a

* Environmental Protection Agency, A Standard Procedure for Cost Analysis of Pollution Control Operations, Volume II Appendices, EPA-600/8-79-018b, June 1979.

The exponent n varies from 0.4 to 0.9 but a good average is 0.6; this is why these scaling costs are termed: use of "the six-tenths factor."

In this handbook, it was assumed that environmental control costs for a plant are directly proportional to its annual capacity expressed as Btu/h of input. The costs for an environmental control unit for a small plant can be calculated if the costs for the same type of unit operating for a large plant are known. For example, given that a Wellman-Lord wet scrubbing unit for a 500-MW_e power plant costs \$120 million, then the cost for the same type of unit for an industrial boiler is estimated to be \$20.4 million as follows:

A 500-MW_e coal-fired power plant has a heat input of 4.88×10^9 Btu/h (assuming 35 percent efficiency for conversion to electrical power)

$$r_a = 4880 \times 10^6 \text{ Btu/h.}$$

An industrial boiler has a heat input of 250×10^6 Btu/h

$$r_b = 250 \times 10^6 \text{ Btu/h.}$$

$$E_b = E_a \left(\frac{r_b}{r_a} \right)^n$$

$$E_b = (\$120 \times 10^6) \left(\frac{250 \times 10^6 \text{ Btu/h}}{4880 \times 10^6 \text{ Btu/h}} \right)^{0.6}$$

$$E_b = (\$120 \times 10^6) (0.17)$$

$$E_b = (\$20.4 \times 10^6)$$

GLOSSARY

Anaerobic digestion. The decomposition of organic waste by bacteria that function in the absence of oxygen. Properly controlled, anaerobic digestion will produce a mixture of methane and carbon dioxide and substantially reduce the volume of the waste.

Baghouse. A system for removing particles from a gas stream by means of simple fabric filters shaped like bags. Large sizes and numbers of bags necessitate a separate building (baghouse). Most of the filtering effect is provided by a layer of particles on top of the fabric.

Biochemical oxygen demand (BOD). A measure of the amount of oxygen consumed in the biological processes that break down organic matter in water. The greater the degree of pollution, the greater the BOD.

Blowdown. Portion of fluid in a system (e.g., cooling tower, boiler) removed at regular intervals to prevent accumulation of dissolved and suspended material.

Bottom ash. Noncombustible residues of coal combustion that are collected and removed from the boiler.

Bottoms. Leftovers from distillation consisting of residue that did not evaporate.

Capacity factor. The actual plant output in a year divided by the output that would be achieved if the plant were to operate at 100-percent power for 365 days/year.

Char. Carbonaceous material left over after heating coal or other organic matter.

Chemical oxygen demand (COD). A measure of the amount of oxygen required to oxidize contaminants of water. The COD test is used to determine the degree of pollution in an effluent.

Clarifiers. A system used to remove total suspended solids in river makeup water.

Cogeneration. The near-simultaneous production of electricity and process heat (usually steam) by utilizing the waste heat generated in electricity production.

Cooling tower drift loss. Aerosol of water that is lost to the atmosphere from the cooling towers.

Cooling tower evaporation loss. Circulating water that is evaporated as a result of heat transferred from the circulating water system and lost in the atmosphere via the cooling towers.

Curie (Ci). An amount of radioactive material that decays at a rate of 3.7×10^{10} disintegrations per second.

Cyclone. A mechanical separator that uses swirling air flow to sort particles in a gas stream according to size and density.

Decommissioning. The process of deactivating a facility (e.g., a nuclear power plant) that will not be used again.

Ecosystem. A biological community together with its physical environment.

Electrostatic precipitator (ESP). A device used to remove fine particles (e.g., fly ash) from a gaseous stream. Particles are imparted in an electric charge so that they are attracted to an oppositely charged electrode where they accumulate and are then periodically removed.

Elutriator System. A system that allows dust, etc., to be separated from solid material by washing with a gas (e.g., flue gas).

Fermentation. Originally used to describe the conversion of sugar to alcohol by yeast. The term is now used to describe the enzymatic transformation of organic substances, especially carbohydrates, by the action of microbes.

Flash. Rapid transportation of a heated fluid from liquid to gaseous phase, generally accomplished by sudden reduction in pressure. Superheated geothermal fluid can be partly flashed to yield a steam that is clean enough for use in a turbine.

Flue gas. Gaseous products of combustion. Consists mainly of nitrogen, carbon dioxide, carbon monoxide, oxygen, nitrogen oxides, sulfur dioxide, and fly ash.

Flue gas desulfurization. Removal of sulfur dioxide from flue gas, usually by lime/limestone scrubbing.

Fluidized bed. Freely circulating solid particles in a vessel supported by a flow of gas. In fluidized bed combustion, lime or dolomite can be added as part of the bed material, which reacts with and retains the sulfur compounds released in the combustion process.

Fly ash. Noncombustible residues of coal combustion that are carried out of the boiler in the flue gas, consisting mainly of silica and alumina. Fly ash is removed from flue gas by baghouse filters or electrostatic precipitators.

Fugitive emissions. Unintentional emissions, such as dust blowing from a shale pile.

Fume. Tiny solid particles formed by the condensation of vapors of solid matter.

HEPA filters. Filters used in gaseous waste streams to remove particulate matter.

Kerogen. Organic material contained in oil shale. When heated to about 900°F, kerogen decomposes into hydrocarbons and a carbonaceous residual.

Leaching. Washing out. The natural flow of water through the soil, ore piles, refuse piles, or landfill slowly dissolves and removes soluble substances into groundwater, streams, and rivers. Substances may be removed and transported by percolating water.

Makeup. Water or other fluid regularly added to a system to compensate for losses through process use, evaporation, and blowdown.

Man-rem. A unit for considering the collective radiation dose received by a group of people. One man-rem is equivalent to the amount of radiation dose received by one person exposed to one rem, two persons exposed to one-half rem, etc.

Offgas. Gas produced during a process step, usually as a by-product or waste.

Overburden. Soil and rock between the surface and a coal seam. The thickness and nature of the overburden is a determinant of the economic feasibility of mining the coal.

Particulates. Finely divided solid material carried an appreciable distance in a gas stream or in the ambient atmosphere. Definitions and size range vary widely.

Plant efficiency. Electrical energy out of the plant to the transmission network divided by total heat energy used to produce the electric energy.

Pyrolysis. The process of chemically decomposing a substance by heating it in an oxygen-deficient atmosphere.

Raw shale. Oil shale that has not been retorted.

Recycle water. Water that is collected after process use, treated, and reused at the facility.

Regeneration. Chemical process that permits the reuse of an efficient absorbent or catalyst without discarding it when used up. Chemicals used are called regenerants.

Reinjection. A method to dispose of geothermal fluids that have given up their heat and cannot be easily disposed of on the surface. Reinjection is also used to prevent ground subsidence.

Rem. A unit of radiation dose.

Retort. A closed refractory chamber in which shale is heated and gives off its oil content.

Retorted shale. Shale that has had the oil values extracted and still contains carbon.

Retort gas. High- or low-Btu quality gas that is one of the products of the retorting of oil shale.

Rubblize. The process of breaking up the oil shale deposits, usually with the help of explosives, into rough, angular fragments.

Run-of-mine. Used to describe coal or shale as it comes from the mine before sizing or other preparation.

Scrubber. A device for removing some constituent from a gas stream by spraying the stream with a liquid (usually water) or forcing it through a series of baths.

Shale oil. Oil that results from retorting oil shale. It is a liquid multicomponent hydrocarbon mixture resulting from the molecular rearrangement of the kerogen.

Sludge. A general term for wet, semisolid material. Common examples include sewage sludge produced at sewage plants and flue-gas desulfurization (FGD) sludge, which consists of calcium sulfate, calcium sulfite, and water.

Slurry. Solid particles suspended in liquid, such as finely powdered coal suspended in a liquid such as oil or water. Slurries can be pumped and sent through pipelines, greatly easing the difficulties of overload transportation.

Storage battery. Also known as secondary or rechargeable battery. The battery can be recharged after partial or complete discharge by the flow of direct current in a direction opposite to that of the discharge.

Surface retorting. Extracting oil from oil shale in an aboveground retort.

Syncrude. Shale oil that has been upgraded to remove nitrogen, sulfur, and metals and that has little to no bottoms remaining.

Tailings. Leftover material from extraction of ore. They usually contain some unextracted material (e.g., approximately 2 percent of original uranium in uranium tailings).

Trace elements. Chemical elements occurring at low but significant concentrations, either because of their high toxicity or because of uncertainties in the effects of chronic exposure to such elements. Among the most important are certain "heavy metals," e.g., lead, mercury, beryllium, cadmium.

ACRONYMS AND ABBREVIATIONS

a.c.	alternating current
bbl	barrel
Btu	British thermal unit
C _c	current year costs (where current year is 1981)
CCI	Cost Construction Index
C _R	reference year costs (year initial cost estimates were made)
CFR	Code of Federal Regulations
Ci	curie
dBA	decibel, adjusted
dia.	diameter
dscf	dry cubic feet at standard conditions
ECIR	Environmental Characterization Information Report
ENR	Engineering News Record
fbm	board feet
FOE	fuel oil equivalent
FT	Fischer-Tropsch
ft	foot
gal.	gallon
gr	grains
ha	hectare
HEPA	high-efficiency particulate aerosol (filter)
hp	horsepower
I _c	annual average of monthly CCIs for the year 1981
in.	inch
I _R	annual average of monthly CCIs for a given reference year
J	joule
kg	kilogram
km	kilometer
kV	kilovolt
kWh	kilowatthour
l	liter
lb	pound
m	meter
m ³	cubic meter
max.	maximum
mg	milligram (10 ⁻³ grams)
mi	mile
MJ	megajoule
mph	miles per hour
MTHM	metric tons (tonnes) of heavy metal
MW	megawatt
MWe	megawatt-electric (10 ⁶ watts)
psi	pounds per square inch
ppm	parts per million
ROW	right-of-way
V	volt
W	watt
wk	week
yr	year

APPENDIX. ENVIRONMENTAL CHARACTERIZATION INFORMATION REPORTS

Introduction

Under the sponsorship and direction of the Department of Energy (DOE) Office of Environmental Analysis, Office of Assistant Secretary for Environmental Protection, Safety, and Emergency Preparedness, the following Environmental Characterization Information Reports (ECIRs) have been developed as of the publication date of this Handbook.

<u>ECIR Title</u>	<u>Report Number/Status</u>	<u>Date</u>
NUCLEAR TECHNOLOGIES:		
Pressurized Water Reactor Nuclear Power Plant	DOE/EP-0012	January 1981
Boiling Water Reactor Nuclear Power Plant	Draft	February 1982
Commercial High-Level Nuclear Waste Repository	Draft	February 1982
SYNTHETIC FUEL TECHNOLOGIES:		
Oil Shale Surface Retorting Paraho Process (Direct Mode)	DOE/EP-0015	January 1981
Indirect Coal Liquefaction Plant (Lurgi Fischer-Tropsch Process)	Draft	October 1981
Colony TOSCO II Oil Shale Process	Draft	January 1982
Solvent Refined Coal II (SRC-II) Plant	Draft	February 1982
Lurgi High-Btu Coal Gasification	Draft	October 1982

<u>ECIR Title</u>	<u>Report Number/Status</u>	<u>Date</u>
COAL TECHNOLOGIES:		
Coal-Fired Power Plant (Eastern Coal)	DOE/EP-0013	January 1981
Coal-Fired Power Plant (Western Coal)	DOE/EP-0019	January 1981
Eastern Underground Coal Mining	Draft	January 1982
Eastern Surface Coal Mining	Draft	January 1982
Western Surface Coal Mining	Draft	January 1982
SOLAR TECHNOLOGIES:		
Alcohol Fermentation Plant	Draft	September 1981
Residential Wood Stove	Draft	September 1982
Industrial Wood-Fired	Draft	September 1982
GEO THERMAL TECHNOLOGIES:		
Geothermal Energy Plant (Hydrothermal Flashed Steam)	Draft	September 1981

As indicated above by the DOE report numbers, 4 of the 17 ECIRs developed to date have been published in final report form and are available from

National Technical Information Service (NTIS)
U.S. Department of Commerce
5285 Port Royal Road
Springfield, Virginia 22161

Price: Printed copy \$8.00
Microfiche \$3.50

The four published ECIRs (DOE/EP-0012, DOE/EP-0013, DOE/EP-0015, and DOE/EP-0019) were included in the Appendix to the Second Edition of this Handbook published in June 1981. The Second Edition (DOE/EP-0028) is also available in printed copy and microfiche from NTIS. The previously unpublished 13 ECIRs are contained in this Appendix.

As supplementary documents, ECIRs augment the information summaries provided in Part 1 of the Technology Characterizations Handbook. The purpose of ECIRs is to present a more explicit treatment of the origin and derivation of the information by providing the reader with an expanded discussion of the data elements of the information summaries (environmental residuals, energy resources used, costs, energy products, and occupational health and safety statistics associated with each reference energy system). Sufficient detail is provided to enable the reader to determine similar or analogous quantitative information for other energy systems, energy process configurations, or varying operational assumptions.

The information contained in an ECIR represents the synthesis of data from a broad range of sources to characterize a "generalized" system configuration for a given reference energy system. The reference energy system or facility is of a particular size and design, with operational data presented on the basis of annual quantities or total system lifetime quantities, as appropriate. In addition, the data are normalized to 10^{12} Btu of energy output to facilitate cross-technology comparison and use of the data in computerized data bases and analysis algorithms. The information presented provides a sound basis for general environmental analysis/assessment activities, although the actual site-specific design may vary somewhat from the reference energy system described.

Responsibility for the contents and development of an ECIR is assigned to individual technology specialists in the DOE Environmental Assessments Division. In this endeavor, DOE also draws upon the technical support and assistance of qualified external experts familiar with the energy systems. Technical comments regarding this ECIR should be directed to the Division.

Boiling Water Reactor Nuclear Plant

Environmental Characterization Information Report

February 1982

U.S. Department of Energy
Assistant Secretary for Environmental
Protection, Safety, and
Emergency Preparedness
Office of Environmental Analysis

CONTENTS

	<u>Page</u>
I. INTRODUCTION	A.2-3
II. SUMMARY.	A.2-7
III. PLANT AND PROCESS DESCRIPTION AND ENVIRONMENTAL POINTS OF INTEREST.	A.2-9
1. Uranium Requirements and Spent Fuel Disposition.	A.2-11
2. Gaseous Radioactive Effluents.	A.2-13
3. Liquid Radioactive Effluents	A.2-17
4. Low-Level Solid Radioactive Wastes	A.2-19
5. Evaporative Losses from Wet Cooling Towers	A.2-20
6. Cooling Tower Blowdown	A.2-23
7,8. Service Water System Evaporative Losses and Blowdown	A.2-24
9. Total Plant Water Usage.	A.2-25
10. Chemical Usage	A.2-27
11. Chemical and Biocide Waste Discharge	A.2-28
12. Miscellaneous Fossil Fuel Combustion Products.	A.2-30
IV. PHYSICAL REQUIREMENTS.	A.2-31
V. PERSONNEL REQUIREMENTS	A.2-33
VI. OCCUPATIONAL SAFETY AND HEALTH	A.2-34
VII. DECOMMISSIONING.	A.2-37
APPENDIX: COST INFORMATION	A.2-39
GLOSSARY.	A.2-40
ACRONYMS AND ABBREVIATIONS.	A.2-44

I. INTRODUCTION

There are currently two types of light water reactors (LWR) being manufactured in the United States: the boiling water reactor (BWR) manufactured by General Electric and the pressurized water reactor (PWR) being manufactured by Westinghouse, Combustion Engineering, and Babcock and Wilcox. About 33 percent of the LWRs built, under construction or considered in the U. S., as of 1981, are BWRs. In the BWR, the nuclear reactor is used to boil water and produce steam which directly drives the main turbine. In the PWR, the water in the reactor is maintained at high pressure to prevent boiling. Steam to drive the main turbine is generated in a secondary loop by a steam generator. The PWR design is sufficiently different from the BWR design that it is treated in a separate Environmental Characterization Information Report (ECIR).

The "model plant" selected for the BWR ECIR is General Electric's standardized BWR/6 reactor with the Mark III containment design. This reactor was first introduced in 1973 and has been the standard BWR ordered since then. Although no BWR/6 is yet operational in the United States, eight are under construction. Unless otherwise stated, the information in this ECIR will be based on the BWR-6/Mark III power plant described in the second General Electric Standard Safety Analysis Report (GESSAR-II).² For the purposes of this ECIR, the differences between the reactor described in GESSAR-II and that described in the original GESSAR^{3,4} in 1973 and its many amendments are minor.

The rated thermal power output of the BWR-6/Mark III described in GESSAR-II is 3579 Mwt with a net electrical output of 1220 MWe. The data presented in this ECIR have been scaled to 1000 MWe for ease of comparison with other technologies. In the few cases where scaling by electrical power output is not strictly correct, the error is no greater than about 20 percent (unless otherwise noted). All BWRs ordered in the U. S. since 1971 have been in the 950 to 1300 MWe range. Earlier BWR designs used in the U. S. and elsewhere were typically in the 500 to 1100 MWe range.

The model BWR is assumed to have natural draft cooling towers for removal of waste heat. Cooling systems using other types of cooling towers, cooling lakes and spray canals, and once-through cooling from a river or large body of water have sometimes been used at BWRs, but natural draft cooling towers are more common at recent sites. BWRs with cooling lakes would require considerably more land, and those with once-through cooling systems would require much more cooling water.

This report assumes that the model plant will store its spent reactor fuel waste indefinitely (i.e., no interim spent fuel storage sites or reprocessing plants are available). Radioactive wastes are assumed to be processed and recycled to the maximum extent required in keeping with the as-low-as-reasonably-achievable (ALARA) principle established in Nuclear Regulatory Commission (NRC) regulations.

Only the resources used and environmental residuals due to the power plant portion of the nuclear power energy systems employing BWRs are covered in this ECIR. Other portions of the nuclear fuel cycle such as uranium mining and milling, uranium enrichment and fuel fabrication, spent fuel reprocessing and recycling, and low and high level radioactive waste disposal will be covered in separate ECIRs.

References

1. U. S. Department of Energy, Pressurized Water Reactor Nuclear Power Plant -- Environmental Characterization Information Report, DOE/EP-0012, January 1981.
2. General Electric Company, GESSAR-II, 238 Nuclear Island, Vol. 1-18, submitted to U. S. Nuclear Regulatory Commission March 31, 1980, 8775 pages and Amendment 1 to GESSAR-II, December 1, 1980, 825 pages.
3. General Electric Company, BWR/6 Standard Safety Analysis Report, Vol. 1-6, submitted to U. S. Nuclear Regulatory Commission June 30, 1973, and Amendments 1-39 (various dates).
4. U. S. Nuclear Regulatory Commission, Safety Evaluation Report in the Matter of General Electric Standard Safety Analysis Report (GESSAR-238 NUREG 75/110 and 0124, December 1975 and Safety Evaluation Report related to the preliminary design of the GESSAR-238 Nuclear Steam Supply System Standard Design, NUREG-0151, March 1977.

II. SUMMARY

This Environmental Characterization Information Report (ECIR) for a Boiling Water Reactor Nuclear Power Plant has been prepared from the latest available environmental and technical information collected from a number of sources. The typical plant chosen for characterization has a 1000-MWe nameplate rating with wet-natural-draft cooling towers and modern radioactive waste control and processing equipment.

The process, plant operating parameters, resources needed, and the environmental residuals and products associated with the power plant are presented in this section in the summary table (Table 1). Annual resource usage and pollutant discharges are shown in English and metric units, assuming an annual plant capacity factor of 70 percent, which was selected as representative of the average experience of all nuclear power plants during 1978-1979.

In addition to annual quantities, the summary table gives quantities in terms of 10^{12} Btu (about 293 million kWh) of electrical energy produced. These figures are provided to allow comparison among energy processes and to facilitate application of the information in computer models.

The supporting information and calculational procedures for the data are given in Section III. Twelve environmental points of interest are discussed individually, giving a brief description of the pollutants or resources involved, standards to be met, example calculations showing the derivation of quantities, scaling laws and extrapolation methods to adjust to other conditions, and a bibliography of cited references.

Cost information is discussed in the Appendix. A glossary and list of acronyms and abbreviations are provided at the end of this report.

Reference

1. U. S. Nuclear Regulatory Commission, "Operating Status Report, Licensed Operating Reactors," NUREG-0020, Vol. 4, No. 2, February 1980, pp. 1-3.

TABLE 1. SUMMARY SHEET

BOILING WATER REACTOR NUCLEAR POWER PLANT

REFERENCE ENERGY SYSTEM

The General Electric Company Standardized BWR/6 Reactor With the Mark III Containment Design. Natural Draft Cooling Towers. Fuel is 3% Enriched Uranium-235; Onsite Storage of Liquid Radioactive Wastes; Filtration of Building Exhausts; Onsite Water Treatment of River Supply Water; Natural Draft Wet Cooling Towers.

FACILITY OPERATING PARAMETERS

Size:	1×10^3 MWe
Annual Capacity Factor:	70%
Annual Energy Production:	21×10^{12} Btu
Efficiency:	33%
Lifetime:	30-40 yr

PROCESS FLOW

RESOURCES USED

RESOURCES USED		Quantities Used			
		Reference Energy System Annual Usage			
Code No.	Resource	English Units	Metric Units	Per 10 ¹² Btu Energy Produced	Remarks
①	<u>Feed Materials</u>				
	Uranium fuel (3.0% enriched Uranium-235)	34 tons	31 tonnes	1.6 tons	One-fourth of capacity annually
⑨	<u>Processing Materials</u>				
	<u>Water</u>				
	Make-up water for cooling towers and miscellaneous plant services	5.5 × 10 ⁹ gal	21 × 10 ⁹ litre	0.26 × 10 ⁹ gal	
		Total Usage			
	<u>Construction Materials</u>				
	Concrete	4.5 × 10 ⁶ ft ³	130 × 10 ³ m ³	210 × 10 ³ ft ³	

TABLE 1. (Continued)

BOILING WATER REACTOR NUCLEAR POWER PLANT

RESOURCES USED (Continued)		Quantities Used		
		Reference Energy System Annual Usage		
Code No.	Resource	English Units	Metric Units	Per 10 ¹² Btu Energy Produced
	Reinforcing steel	17 × 10 ³ tons	15 × 10 ³ tonnes	810 tons
	Structural steel	8.7 × 10 ³ tons	7.9 × 10 ³ tonnes	420 tons
	<u>Land</u>			
	Site land requirements	1100 acres	450 ha	21 acres
	Transmission route	1800 acres	730 ha	34 acres
	Disrupted land surface (site)	350 acres	140 ha	6.7 acres
	Committed land	130 acres	53 ha	2.5 acres
	<u>Personnel</u>			
	Construction (9 yr)	2.3 × 10 ³ workers		110 workers
	Operation and maintenance	230 workers		

COSTS		Reference Energy System	Per 10 ¹² Btu Energy Produced	Remarks
		(1976 \$)		
<u>Facility</u>				
Construction (9 yr) (with interest during construction)				Total life cycle costs = 74 mills/kWh
Operation and Maintenance				
<u>Environmental Controls</u>				Included in facility costs

ENVIRONMENTAL RESIDUALS

Quantities Released

Code No.	Resource	Reference Energy System Annual Levels		Per 10 ¹² Btu Energy Produced	Remarks
		English Units	Metric Units		
2	<u>Air Pollutants</u>				
	Gaseous radioactive effluents				10 CFR 50 and 40 CFR 190 specify individual concentration limits
	• Noble gases	11 × 10 ³ Ci	11 × 10 ³ Ci	540 Ci	
	• Tritium	110 Ci	110 Ci	5.2 Ci	
	• Carbon-14	6.8 Ci	6.8 Ci	0.32 Ci	
	• Iodine-131 (elemental)	64 × 10 ⁻³ Ci	64 × 10 ⁻³ Ci	3.0 × 10 ⁻³ Ci	
	• Iodine-131 (nonelemental)	140 × 10 ⁻³ Ci	140 × 10 ⁻³ Ci	6.6 × 10 ⁻³ Ci	
	Fossil fuel air emissions	210 tons			
	Airborne water from cooling tower evaporation losses	3.8 × 10 ⁹ gal	14.4 × 10 ⁹ litre	0.18 × 10 ⁹ gal	
	<u>Water Pollutants</u>				
	Liquid radioactive effluents				10 CFR 50 and 40 CFR 190 specify individual concentration limits
	• Tritium	35 Ci	35 Ci	1.7 Ci	
	• Activation and fission products	0.1 Ci	0.1 Ci	5 × 10 ³ Ci	
	Dissolved solids				40 CFR 423 specifies allowable increases in river concentrations
	• Sulfates	23 tons	21 tonnes	1.1 tons	
	• Chlorine	0.9 ton	0.8 tonne	0.04 ton	
	• Sodium	11 tons	10 tonnes	0.53 ton	
	• Other	5.8 tons	5.3 tonnes	0.28 ton	
	<u>Solid Wastes</u>				
	Low-level solid radioactive wastes				

TABLE 1. (Continued)

BOILING WATER REACTOR NUCLEAR POWER PLANT

ENVIRONMENTAL RESIDUALS (Continued)

		Quantities Released			
		Reference Energy System Annual Levels			
Code No.	Resource	English Units	Metric Units	Per 10 ¹² Btu Energy Produced	Remarks
	• Wet material embedded in concrete	19 × 10 ³ ft ³	530 m ³	900 ft ³	
	• Dry material in drums	3.3 × 10 ³ ft ³	94 m ³	160 ft ³	
	Water filtration waste products				
	• Aluminum hydroxide	10 tons	9.1 tonnes	0.48 ton	
	• Settled solids	8 tons	7.3 tonnes	0.38 ton	
	<u>Thermal Discharge</u>				
	Heat dissipated	61 × 10 ¹² Btu	64 × 10 ¹⁵ J	2.9 × 10 ¹² Btu	
	<u>Noise Pollution</u>		Negligible		

PRODUCTS

	Quantities Used			
	Reference Energy System Annual Production			
	English Units	Metric Units	Per 10 ¹² Btu Energy Produced	Remarks
<u>Primary</u>				
Electric power	6.13 × 10 ⁹ kWh	6.13 × 10 ⁹ kWh	2.93 × 10 ⁸ kWh	
<u>Byproducts</u>			Not Determined	
<u>Recoverables/Recyclables</u>				
<u>Spent nuclear fuel containing</u>				
• Uranium-235 nuclear fuel				
— Mass	616 lb	280 kg	29.3 lb	
— Energy equivalent	4.3 × 10 ⁹ kWh (14.7 × 10 ²¹ Btu)	4.3 × 10 ⁹ kWh (15.5 × 10 ²⁴ J)	0.21 × 10 ⁹ kWh (0.7 × 10 ²¹ Btu)	
• Fissile plutonium nuclear fuel				
— Mass	396 lb	780 kg	18.8 lb	
— Energy equivalent	3.4 × 10 ⁹ kWh (10.5 × 10 ²¹ Btu)	3.4 × 10 ⁹ kWh (11.1 × 10 ²⁴ J)	1.6 × 10 ⁹ kWh (0.5 × 10 ²¹ Btu)	
• Isotopes for medical and industrial applications			Not Determined	

OCCUPATIONAL SAFETY AND HEALTH

	Reference Energy System Annual Average	Per 10 ¹² Btu Energy Produced	Remarks
<u>Deaths</u>	0.0	0.0	
<u>Injuries</u>			
Number	0.51-3.0	0.02-0.14	
Total lost days	14-91	0.67-4.33	
Occupational Radiation Exposure	1.1 × 10 ³ man-rems	53 man-rems	Average collective dose

III. PLANT AND PROCESS DESCRIPTION AND ENVIRONMENTAL POINTS OF INTEREST

For the convenience of the reader, the data presented in this report are scaled to 1000 MWe with an overall plant efficiency of 33 percent. Uranium dioxide (UO_2) fuel with approximately 3.0 percent uranium-235 enrichment is assumed. Resource utilization and environmental residual generation are based on a 70-percent annual capacity factor.

A block diagram of the major elements in the model BWR power plant is shown in Figure 1. The reactor containment building houses the reactor, main steamlines and recirculation system. The auxiliary building houses the engineered safety features and auxiliary systems. The fuel building houses the new and spent fuel storage and shipping areas and the standby gas treatment system. Diesel generators providing emergency power are located in the diesel generator building.

The control building houses the control room and computer facilities. Solid and liquid radioactive waste treatment facilities are located in the radwaste building. Gaseous radioactive waste treatment facilities are located in the radwaste building and the turbine building, which contains the turbines and electrical generators. The makeup water treatment building contains water purification equipment. Main condenser cooling is by natural-draft, hyperbolic cooling towers with makeup water supplied from local water sources.

Environmental points of interest have been identified in Figure 1 and are characterized and discussed in the following sections. These points of interest identify the principal sources of radioactive and nonradioactive releases from the typical plant and major uses of water, fuel and land resources.

Cost information for the plant is given in the Appendix.

A.2-10

FIGURE 1. PROCESS FLOWCHART WITH ENVIRONMENTAL POINTS OF INTEREST

1

Uranium Requirements and Spent Fuel Disposition

The amount of uranium dioxide (UO_2) fuel required to load the core of the model 1000 MWe BWR is about 135 tons. About one-fourth of the core, 33.7 tons, will be replaced annually beginning in the second year.

In the model 1000 BWR operating at 70 percent capacity factor, the first or initial core would be loaded with about 135 tons of uranium in the form of UO_2 . Subsequently, about one-quarter of the fuel assemblies in the core, or about 33.7 tons of fuel would be replaced annually. The average uranium enrichment of the initial core would be 1.9 percent U-235 and subsequent replacement fuel would average 3.0 percent U-235. Over the life of the BWR, about 204 tons of purified U_3O_8 from a uranium mill and 138 tons of separative work units (SWUs) from a uranium enrichment plant would be required annually to supply the replacement fuel necessary to produce the annual 700 MW-year (20.9×10^{12} Btus) output of the model BWR. Table 2 presents the uranium resource and enrichment requirements for the model 1000 MWe BWR.

Table 2. Uranium and Enrichment Requirements for
a Model 1000 MWe BWR (70% capacity factor)

	Initial Core (tons)	Average Annual Reload (tons)	30-Year Cumulative (tons)
UO_2 Enriched Fuel (tons heavy metal)	135	33.7	1,110
U_3O_8 to produce UO_2 fuel (0.2 wt % U-235 tails)	505	204	6,420
Separative work to produce UO_2 fuel (0.2 wt % U-235 tails)	245	138	4,250

The 1220 MWe BWR-6/Mark III uses sintered uranium dioxide (UO_2) fuel in which the U-235 content has been enriched slightly from the 0.71 percent level found naturally. The GESSAR reactor core consists of 748 fuel bundles, each containing 62 fuel rods containing UO_2 . Each bundle may contain fuel rods of several different U-235 enrichments.

In the 1220 MWe BWR, one-fourth of the core, or about 187 fuel bundles, will be removed annually from the reactor core and placed in a water-filled spent fuel storage pool in the fuel building adjacent to the reactor. In the discharged fuel, the U-235 enrichment will have decreased to about 0.8 to 1.0 percent, due to fissioning of the U-235 in the reactor. The total plutonium concentration in the discharged fuel will have increased from its initial zero value to about 0.8 to 1.0 weight percent. Near the end of a fuel bundle's initial life in the core, the U-235 and plutonium contribute about equally to power production. The fuel assemblies will be highly radioactive and will generate substantial heat. Both the radioactivity and decay heat will decrease in time as the fission products decay. Table 3 presents total activity and decay heat after 150 days, 1 year and 10 years for BWR fuel with 30 GWd/THM burnup.³

Table 3. Radiation and Heat from Discharged BWR Fuel

	Decay Period		
	150 days	1 year	10 years
Total Activity (Ci/ton)	3.4×10^6	1.7×10^6	1.6×10^5
Decay Heat (Btu/hr-ton)	5.8×10^4	2.5×10^4	6.8×10^3

The discharged fuel bundles are assumed to be stored onsite in the spent fuel cooling pond until commercial fuel reprocessing plants, away-from-reactor (AFR) storage sites or high-level waste repositories for power reactor fuel become available.

References

1. U. S. Department of Energy, Nuclear Proliferation and Civilian Nuclear Power, Report of the Nonproliferation Alternative Systems Assessment Program, Vol. IX: Reactor and Fuel Cycle Description, DOE/NE-0001/9, June 1980.
2. General Electric Company, GESSAR-II, 238 Nuclear Island, Vol. 1-18, submitted to U. S. Nuclear Regulatory Commission March 31, 1980, 8775 pages and Amendment 1 to GESSAR-II, December 2, 1980, Section 4.3.
3. International Atomic Energy Agency, International Nuclear Fuel Cycle Evaluation: Spent Fuel Management, Report of INFCE Working Group, International Atomic Energy Agency, Vienna, Austria, STI/PUB/534, May 1980.

2

Gaseous Radioactive Effluents

Gaseous radioactive effluents from a model 1000 MWe BWR will average 11,000 Ci/yr for noble gases, 64 mCi/yr for elemental iodine-131, 140 mCi/yr for nonelemental iodine-131, 110 Ci/yr for tritium, and 6.8 Ci/yr for carbon-14. The variation in annual releases between plants may be large.¹

Sources of Radioactive Gases

In a BWR, a portion of the reactor coolant water is converted into steam by heat from the fuel elements in the reactor. The steam containing some radioactive gases expands through a turbine, is condensed and returned to the reactor. This reactor coolant is the main source of radioactive gases and materials in a BWR. The principal mechanisms that affect the concentrations of radioactive materials in the coolant are the amounts of: 1) fission product leakage to the coolant from defects in the fuel cladding, 2) corrosion products activated in the core, and 3) radioactivity removed by leakage of various reactor coolant cleanup systems.

The principal source of radioactive gaseous wastes will be off-gas from the main condenser air ejector, which continuously removes dissolved gases from the reactor coolant. Additional sources of gaseous wastes include gases purged from the main condenser by the mechanical vacuum pumps during plant shutdown, gases purged periodically from the reactor drywell, and ventilation air from building housing systems which contain radioactive materials. The turbine gland seals in the newer BWRs are supplied with "clean" steam and no longer contribute to gaseous radioactive releases. The quantities of radioactive effluents released to the environment are reduced by use of a low temperature charcoal delay system for treating the off-gas from the main condenser air ejector, and iodine and particulate control systems for certain building ventilation systems.

Estimated Effluents

Effluent evaluations were made based on the Nuclear Regulatory Commission (NRC) BWR-GALE (Boiling Water Reactor Gaseous and Liquid Effluents) Code.² This code is a computerized mathematical model used by NRC's reactor licensing staff for calculating gaseous and liquid effluents from BWRs. The calculations are based on operating reactor data, field and laboratory tests, and plant specific design considerations.

A detailed isotopic breakdown by source of the calculated releases from the 1000 MWe GESSAR-II plant using the BWR-GALE code is provided in Table 4. The following assumptions¹ are built into the calculation:

- 1) A calendar year consisting of 300 days of power operations (80 percent capacity factor) and one refueling/maintenance shutdown period;
- 2) A concentration of I-131 in the reactor water of 2.13 Ci/kg;
- 3) A carry over of I-131 from reactor water to steam of 1.5 per-
- 4) Forward-pumped heater drains; and
- 5) Use of "clean" steam from an auxiliary boiler for the turbine gland seals.

Table 4. Annual Gaseous Radioactive Effluents (Ci)

Nuclide	Half-Life Days	Containment Building	Auxiliary Building	Turbine Building	Radwaste Building	Mechanical Vacuum Pump	Air Ejector Offgas	Drywell Purge	Plant Total
<u>Tritium</u>									
H-3	4.8 + 3 ^a	27		27				99	150
<u>Carbon 14</u>									
C-14	2.09 + 6			9.5			0.02		9.5
15								0.02	0.02
N-13								0.05	0.05
16								1.1	1.1
17								0.0002	0.0002
F-18								0.07	0.07
O-19								0.03	0.03
<u>Iodine</u>									
I-131	8.05 + 0	0.013	0.025	0.13	0.013	0.098		0.004	0.28
132	9.58 - 2	0.22	0.43	2.34	0.22	1.70		0.007	4.9
133	8.75 - 1	0.17	0.34	1.84	0.18	1.3		0.005	3.8
134	3.61 - 2	0.38	0.75	4.1	0.39	3.0		0.005	8.5
135	2.78 - 1	0.18	0.34	1.9	0.18	1.4		0.002	3.9
Total Iodine: 22									
<u>Noble Gases</u>									
Ar-41	7.62 - 2			38				3.8	42
Kr-83m	7.75 - 2							0.03	0.03
85m	1.83 - 1	2	6	50			120	0.04	180
85	3.93 + 3						280-560	0.02	280-560
87	5.42 - 2		4	120				0.03	130
88	1.17 - 2	2	6	180			6	0.08	200
89	2.20 - 3		4	1160	58			0.009	1200
90	3.40 - 4							0.003	0.003
Xe-131m	1.19 + 1						37	0.02	37
133m	2.30 + 0						0.02	0.05	0.07
133	5.2 - 0	54	170	300	440	2600	940	2.6	4500
135m	7.1 - 3	30	90	800	1060			0.07	2000

Table 4. Annual Gaseous Radioactive Effluents (Ci) (continued)

Nuclide	Half-Life Days	Containment Building	Auxiliary Building	Turbine Building	Radwaste Building	Mechanical Vacuum Pump	Air Ejector Offgas	Drywell Purge	Plant Total
<u>Noble Gases (continued)</u>									
Xe-135	1.53 - 1	66	190	660	560	1000		0.61	2500
137	2.60 - 3	90	270	2000	166			0.01	2500
138	9.72 - 3	4	12	2000	4			0.03	2000
139	4.98 - 4							0.004	0.004
Total Noble Gases: 16,000									
<u>Particulates</u>									
Cr-51	2.27 + 1	0.0004	0.0018	0.0018	0.0014			0.005	0.0104
Mn-54	3.30 + 2	0.0008	0.002	0.0012	0.008			0.0001	0.012
Fe-59	4.50 + 1	0.00018	0.0006	0.0002	0.0006			0.00003	0.0016
Co-58	7.13 + 1	0.0002	0.0004	0.001	0.0004			0.0002	0.0022
60	1.92 + 3	0.002	0.008	0.001	0.014			0.0007	0.026
Zn-65	2.45 + 2	0.002	0.008	0.012	0.0006			0.0003	0.023
Sr-89	5.20 + 1	0.00006	0.00004	0.012	---			0.0001	0.012
90	1.02 + 5	0.000006	0.000014	0.000040	---			0.00001	0.00007
Zr-95	6.50 + 1	0.0006	0.0014	0.00008	0.0016			0.00001	0.0037
Nb-95	3.50 + 0	0.002	0.018	0.000012	0.000008			0.00001	0.020
Mo-99	2.78 + 0	0.012	0.12	0.004	0.000006			0.0005	0.14
Ru-103	3.95 + 1	0.0004	0.0080	0.00010	0.000002			0.00002	0.0085
Ag-110	2.84 - 4	0.0000008	0.000004	---	---			0.00002	0.00007
Sb-124	6.04 + 1	0.00004	0.00006	0.00020	0.00014			---	0.0004
Cs-134	7.49 + 2	0.0014	0.008	0.0004	0.0048			0.0001	0.0147
136	1.35 + 1	0.0002	0.0008	0.0002	---			0.00002	0.0012
137	1.10 + 4	0.002	0.010	0.002	0.008			0.003	0.022
Ba-140	1.28 + 1	0.004	0.04	0.020	0.000008			0.0002	0.06
Ce-141	3.52 + 1	0.0004	0.0014	0.020	0.000014			0.00003	0.022
Total Particulates: 0.38									

a. This notation represents 4.48×10^3 , etc.

For this 1220 MWe GESSAR-II reactor, approximately 16,000 Ci/plant/yr of noble radioactive gases are released; one-half of this total from the turbine building. The total particulate release rate is approximately 0.4 Ci/yr. Approximately 89 mCi/yr of nonelemental iodine-131 and 190 mCi/yr of elemental iodine-131 will be released. About 150 Ci of tritium and 9.5 Ci of carbon-14 are also released annually from the 1220 MWe GESSAR-II plant.

The effluents from the model 1000 MWe-70 percent capacity factor BWR have been estimated by scaling the results calculated for the 1220 MWe GESSAR-II plant. The model plants emissions would then be about 28 percent less than those calculated for the GESSAR-II plant -- due to a lower power and fewer full power days. Such scaling would imply that for each 1000 MWe of installed BWRs (with a 70 percent capacity factor), annual releases of the key radionuclides would be approximately 11,000 Ci of noble gases, 64 mCi of elemental iodine, 140 mCi of nonelemental iodine, 110 Ci of tritium, and 68 Ci of carbon-14.

In reality, released quantities of some of the radionuclides have been nearly independent of reactor power level, and more dependent on control technologies and number of fuel failures. Releases from operating BWRs have averaged somewhat higher than the releases expected from the model BWR and the BWR/6's under construction. These new plants employ more advanced emission control technologies than some of the existing BWRs and also use a more advanced fuel type which is experiencing far fewer fuel cladding defects than experienced with earlier fuel types.

In 1977, among the 21 operating large (>500 MWe) BWRs in the U. S., the reported noble gas releases averaged 99,000 Ci but ranged from 1,270 to 620,000 Ci. The reported emissions for I-131 and particulates with half-lives equal to or greater than 8 days averaged 1.2 Ci but ranged from 0.006 to 9.0 Ci. Gaseous tritium emissions averaged 48 Ci but ranged from 0.6 to 250 Ci.

In all cases, the effluents are monitored to ensure that the plant's technical specifications (based on the NRC design basis objectives given in 10 CFR 50, Appendix I) are not exceeded.

References

1. General Electric Company, GESSAR-II, 238 Nuclear Island, Vol. 1-18, Section 12.2, submitted to U. S. Nuclear Regulatory Commission March 31, 1980.
2. Cardile, F. P., et al., Calculation of Releases of Radioactive Materials in Gaseous and Liquid Effluents from Boiling Water Reactors (BWR-GALE Code), U. S. Nuclear Regulatory Commission, NUREG-0016, Rev. 1, January 1979.
3. Decker, T. R., Radioactive Materials Released from Nuclear Power Plants, Annual Report 1977, U. S. Nuclear Regulatory Commission, NUREG-0521, January 1979.

3

Liquid Radioactive Effluents

The liquid radioactive effluents from the model plant will contain about 35 Ci/yr of tritium¹ and less than 0.1 Ci/yr of activation and fission products.²

BWRs use a liquid radioactive waste treatment system consisting of equipment and instrumentation necessary to collect, process, monitor, recycle and dispose of potentially radioactive liquid wastes. Wastes are generally divided into three categories: high purity wastes, low purity wastes from floor drains, and detergent-laundry wastes. The liquid radioactive waste systems at typical plants are designed such that most of the radioactive materials except tritium are removed from the water as solids. Therefore, no radioactive liquid wastes (excluding tritium) need to be discharged under a wide variety of anticipated operational occurrences.² If allowance is made for unusual operating conditions, the General Electric Company has calculated² (using the BWR-GALE code discussed earlier) that it is reasonable to expect an annual discharge of fission and activation products of 0.1 Ci (excluding tritium). The isotopic distribution of these liquid effluents is given in Table 5.² These effluent concentrations are generally several orders of magnitude less than the federal limits established in 10 CFR 20.

Actual releases of mixed fission and activation products in liquid effluents in twenty large operating BWRs averaged 0.88 Ci and ranged from 0 to 3.4 Ci.³

Tritium is produced by activation of deuterium in the coolant water, fast neutron reactions in the boron carbide in the control blades, and fissioning in the fuel. The generation rate is somewhat proportional to the power output. NRC has estimated that based on historical data, the total tritium released through liquid and gaseous pathways is approximately 0.03 Ci/yr per Mwt assuming 0.8 capacity factor. This corresponds to about 107 Ci/yr for the GESSAR plant or about 71 Ci/yr for the model 1000 MWe plant. NRC also assumes that about 50 percent of the tritium is released in the liquid pathway or, for the model BWR, about 35 Ci/yr. The reported tritium release in liquid effluents in 1976 and 1977 averaged 11.2 Ci/reactor with a range of 0 to 47 Ci/reactor (based on NRC's estimation techniques, the expected average would have been about 24 Ci/reactor).

Liquid wastes from a typical plant are processed on a batch basis which provides optimum control of releases. Discharges are sampled and monitored for radioactivity. Discharges are automatically terminated if radioactivity levels exceed predetermined levels in the discharge line.

Table 5. Annual Discharge of Fission and Activation Products in Liquid Effluents.

Nuclide	Ci/Yr	Nuclide	Ci/Yr
Sodium-24 (Na-24)	4.2-06 ^a	Zirconium-97 (Zr-97)	7.9-06
Phosphorus-32 (P-32)	5.2-07	Niobium-95 (Nb-95)	3.4-04
Chromium-51 (Cr-51)	1.5-03	Molybdenum-99 (Mo-99)	1.8-03
Manganese-54 (Mn-54)	1.4-04	Technetium-099m (Tc-099m)	4.1-05
Manganese-56 (Mn-56)	5.0-04	Technetium-101 (Tc-101)	4.4-08
Cobalt-58 (Co-58)	1.7-02	Ruthenium-103 (Ru-103)	5.2-05
Cobalt-60 (Co-60)	1.8-03	Ruthenium-106 (Ru-106)	8.2-06
Iron-59 (Fe-59)	2.6-04	Rhodium-103m (Rh-103m)	5.2-05
Nickel-65 (Ni-65)	2.0-06	Rhodium-106 (Rh-106)	8.2-06
Zinc-65 (Zn-65)	7.9-08	Tellurium-129m (Te-129m)	8.3-04
Zinc-69m (Zn-69m)	5.6-08	Tellurium-132 (Te-132)	1.3-02
Silver-110m (Ag-110m)	2.2-04	Cesium-134 (Cs-134)	5.7-06
Tungsten-187 (W-187)	1.1-03	Cesium-136 (Cs-136)	2.3-06
Bromine-83 (Br-83)	1.4-05	Cesium-137 (Cs-137)	8.3-06
Bromine-84 (Br-84)	2.7-07	Cesium-138 (Cs-138)	5.7-07
Iodine-131 (I-131)	3.6-02	Barium-137m (Ba-137m)	8.3-06
Iodine-132 (I-132)	1.3-02	Barium-139 (Ba-139)	4.6-06
Iodine-133 (I-133)	1.2-02	Barium-140 (Ba-140)	1.9-04
Iodine-134 (I-134)	1.2-05	Barium-141 (Ba-141)	1.1-07
Iodine-135 (I-135)	1.7-03	Barium-142 (Ba-142)	2.1-08
Strontium-89 (Sr-89)	9.2-05	Lanthanum-140 (La-140)	2.1-04
Strontium-90 (Sr-90)	8.2-06	Cerium-141 (Ce-141)	1.0-04
Strontium-91 (Sr-91)	7.6-05	Cerium-143 (Ce-143)	1.5-05
Strontium-92 (Sr-92)	1.3-05	Cerium-144 (Ce-144)	1.1-04
Yttrium-90 (Y-90)	8.2-06	Praseodymium-143 (Pr-143)	8.2-05
Yttrium-91m (Y-91m)	5.0-05	Neodymium-147 (Nd-147)	2.8-05
Zirconium-95 (Zr-95)	1.2-04	Neptunium-239 (Np-239)	1.7-03
Total		1.0-01	

a. This notation represents 4.2×10^{-6} , etc.

References

1. Cardile, F. P., et al., Calculations of Releases of Radioactive Materials in Gaseous and Liquid Effluents from Boiling Water Reactors (BWR-GALE Code), U. S. Nuclear Regulatory Commission, NUREG-0016, Rev. 1, January 1979.
2. General Electric Company, GESSAR-II, 238 Nuclear Island, Vol. 1-18, Sections 11.1 and 11.2, submitted to U. S. Nuclear Regulatory Commission, march 31, 1980.
3. Decker, T. R., Radioactive Material Released from Nuclear Power Plants, Annual Report 1977, U. S. Nuclear Regulatory Commission, NUREG-0521, January 1979.

Low-Level Solid Radioactive Wastes

The annual discharge of low-level solid radioactive waste from a model plant will average about 110 containers (170 ft³ each) containing about 2400 Ci of wet radioactive material embedded in concrete and about 450 55-gallon drums containing about 5 Ci of compacted dry radioactive wastes.

Solid waste from the typical reactor is generally categorized as either wet or dry based on the process necessary to put the waste in an acceptable form for packaging and shipment offsite for burial. Wet solid waste consists largely of spent demineralizer resins, filter slugs, and evaporator bottoms. The wet waste is mixed with cement and solidified into 150 to 170 ft³ shipping containers. Dry solid waste consists largely of ventilation air filters, contaminated clothing and paper, and miscellaneous contaminated items. They are hydraulically compressed into 55-gallon steel drums for shipment.

NRC has estimated² that about 110 containers (170 ft³ each) containing approximately 2400 curies would be generated annually from the GESSAR plant. Furthermore, about 450 55-gallon drums of compressed dry wastes containing a total of less than 5 Ci of radioactive materials would also be generated annually. The quantities of wastes generated will not vary significantly with plant size, therefore, the same quantities are assumed for the model plant. Large variations may occur, however, with plant operating procedures.

Based on data reported to the NRC in 1977 for 22 large BWRs,³ shipments of low-level solid radioactive waste averaged 40.4 ft³ per MWe produced, with a range of 9.1 to 166 ft³/MWe produced. For the model BWR, this corresponds to about 28,300 ft³ of solid waste per year (about 3850 55-gallon drums). The activity of the shipped solid waste averaged 14.1 Ci/MWe produced, and ranged from 0.4 to 70 Ci/MWe produced. This corresponds to about 9870 Ci/yr for the model BWR.

References

1. General Electric Company, GESSAR-II, 238 Nuclear Island, Vol. 1-18, Section 11.4, submitted to U. S. Nuclear Regulatory Commission March 31, 1980.
2. U. S. Nuclear Regulatory Commission, Safety Evaluation Report in the Matter of General Electric Standard Safety Analysis Report (GESSAR-238 NI), NUREG 75/110, December 1975.
3. Decker, T. R., Radioactive Materials Released from Nuclear Power Plants, Annual Report, 1977, U. S. Nuclear Regulatory Commission, NUREG-0521, January 1979.

5

Evaporative Losses from Wet Cooling Towers

Evaporative losses from the cooling towers into the atmosphere will be approximately 3.8×10^9 gal/yr.

Water necessary for the operation of a nuclear power plant is supplied by three distinct systems. These systems are the condenser cooling, service water, and sanitary (potable) water systems. Each system must take in an amount of water to make up for losses and discharges. This makeup water for the condenser cooling and service water systems is obtained from a river, lake or ocean, while the sanitary water system obtains water from local water utilities or wells. Figure 2 illustrates a typical water use for a two-unit plant.

Residual heat from condensed steam is transferred to the condenser circulating water system. This heat is removed from the condenser cooling system through evaporative (81.2 percent) and sensible (18.8 percent) heat transfer in a cooling tower. The evaporation loss in the cooling tower is a fraction of the percentage of the net heat released to the circulating water system and the heat of vaporization of the water (which is a function of relative humidity and wet bulb temperature). In general,²

$$W_{EVAP}, \text{ gal/day} = \frac{2880 (\text{percent gross heat rejected to tower})(\dot{Q}_a)(P)}{(\text{water heat of vaporization, Btu/lb})}$$

Where

$$\begin{aligned}\dot{Q} &= \text{Net station heat rate} &= 10,342 \text{ Btu/kWh at 33\% efficiency} \\ P &= \text{Net electrical power} &= 1000 \text{ MWe}\end{aligned}$$

If 65 percent of the gross heat released from the plant is rejected to the circulating water (2 percent is lost elsewhere in the plant) and the water heat of vaporization is assumed to be 1300 Btu/lb,* then for the typical plant the water requirements are as follows:

$$\begin{aligned}W_{EVAP} &= \frac{2,800 (0.65)(10,342 \text{ Btu/kWh})(1000 \text{ MWe})}{(1300 \text{ Btu/lb})} \\ &= 14.9 \times 10^6 \text{ gal/day}\end{aligned}$$

* This figure is based on actual operating data from Reference 2 and is greater than the typical textbook value of 1050 Btu/lb.

Figure 2. Plant Water Use Diagram for a Typical Two Unit BWR Plant.

On an annual basis,

$$\begin{aligned} W_{\text{EVAP}} &= (14.9 \times 10^6 \text{ gal/day})(365 \text{ days/yr})(0.7 \text{ capacity factor}) \\ &= 3.8 \times 10^9 \text{ gal yr} \end{aligned}$$

On an annual basis,

$$\begin{aligned} W_{\text{tower evap}} (\text{gal/yr}) \\ &= (14.9 \times 10^6 \text{ gal/day})(365 \text{ days/yr})(0.7 \text{ capacity factor}) \\ &= 3.8 \times 10^9 \text{ gal/yr} \end{aligned}$$

The cooling tower evaporation rate is closely proportional to the power output of the plant. The proportionality factor will vary only slightly for different power levels and cooling tower designs.

References

1. Nuclear Regulatory Commission, Final Environmental Statement Related to the Construction of Hartsville Nuclear Plants of the Tennessee Valley Authority, NUREG-75/039, June 1975.
2. Probstein, R. F., and H. Gold, Water in Synthetic Fuel Production: The Technology and Alternatives, The MIT Press, pp. 47-81, 1978.

6

Cooling Tower Blowdown

Cooling tower blowdown is equivalent to 20 to 30 percent of the evaporation losses. For a typical plant, blowdown will be 1.2×10^9 gal/yr and will be discharged to the river.

The condenser circulating water system contains dissolved or suspended solids which are concentrated by the cooling tower evaporation process. In order to limit this buildup, a fraction of the circulating water (termed blowdown) is discharged to the river and replaced by makeup water of a lower dissolved solids concentration. The rate of blowdown is determined by the concentration of solids in the makeup water, and the maximum permissible concentration of solids in both the condenser cooling system and the blowdown discharge to the river. The rate of blowdown as a fraction of evaporation varies from site to site and has values of between 10 percent and 100 percent of evaporative losses. For the typical plant, blowdown will be equivalent to 20 to 30 percent of the evaporative losses, or about

$W_{\text{tower blowdown}}$

$$= 4.7 \times 10^6 \text{ gal/day}$$

$W_{\text{tower blowdown}}$

$$= (4.7 \times 10^6 \text{ gal/day}) \times (365 \text{ day/yr}) \times 0.7 \text{ capacity factor}$$

$$= 1.2 \times 10^9 \text{ gal/yr}$$

7 & 8 Service Water System Evaporative Losses and Blowdown

The service water system of the model plant discharges approximately 1.3×10^8 gal/yr to the atmosphere due to evaporation and from spray ponds or cooling tower. 3.2×10^8 gal/yr to the river due to blowdown and miscellaneous services.

The service water system provides water for the essential service water, for nonnuclear or safety related equipment, for treated water for bearing lubrication and sealing, and for further purification in the demineralizing system. The essential service water (ESW) system is used to cool nuclear and safety related equipment. The essential service water is cooled by either a cooling tower or by a spray pond (as shown in Figure 2). Both ESW cooling systems are subject to comparable evaporative losses. These losses are compensated by the essential service water makeup. The essential service water makeup is 500 gpm to offset a blowdown at 250 gpm and for an evaporation and drift rate of 250 gpm. Nonnuclear or safety related equipment is cooled by a once-through system using 300 gpm which is discharged to the river. Pump bearing lubrication accounts for 20 gpm and flows into the condenser cooling water system. The remaining 40 gpm is demineralized and used for reactor water makeup and miscellaneous high purity water. These figures are independent of the reactor power level and will vary slightly from plant to plant.

$W_{\text{service water use}}$

= 860 gal/min

= 1.2×10^6 gal/day

= 4.5×10^8 gal/yr

$W_{\text{service water discharge}}$

= 610 gal/min

= 8.8×10^5 gal/day

= 3.2×10^8 gal/yr

$W_{\text{service water evaporation}}$

= 250 gal/min

= 3.6×10^5 gal/day

= 1.3×10^8 gal/yr

Reference

1. Nuclear Regulatory Commission, Final Environmental Statement Related to the Construction of Hartsville Nuclear Plants of the Tennessee Valley Authority, NUREG-75/039, June 1975.

9 Total Plant Water Usage

A total of 5.5×10^9 gal/yr is necessary to provide makeup water for the cooling towers and miscellaneous plant services. A total of 1.5×10^9 gal/yr of waste water is discharged to the river and 3.9×10^9 gal/yr is lost by the cooling towers and spray ponds by evaporation and drift.

To replenish the water in the condenser cooling system which is lost to evaporation and blowdown, makeup water is added to the system.

$$\begin{aligned} W_{\text{tower makeup}} &= W_{\text{tower blowdown}} + W_{\text{tower evap.}} \\ &= 4.7 \times 10^6 \text{ gal/day} + 14.9 \times 10^6 \text{ gal/day} \\ &= 20 \times 10^6 \text{ gal/day} \end{aligned}$$

or on an annual basis, with an 0.7 capacity factor,

$$W_{\text{tower makeup}} = 5.1 \times 10^9 \text{ gal/yr}$$

The sanitary water system provides potable water for drinking, showers, laundry, and sewage. The water is purchased from public utilities at a rate of approximately 4 gpm. After its use, the water is treated and discharged. This water usage rate does not depend on reactor power level and is independent of plant size.

$$\begin{aligned} W_{\text{sanitary water usage}} &= 4 \text{ gpm} \times 1440 \text{ min/day} \\ &= 5.8 \times 10^3 \text{ gal/day} \\ &= 2.1 \times 10^6 \text{ gal/yr} \end{aligned}$$

Total plant water demands and discharges are summarized in Tables 6 and 7, respectively.

Table 6. Total Plant Water Demands

<u>Use</u>	<u>Source</u>	<u>Quantity (gal/yr)</u>
Condenser cooling system makeup water	river	5.1×10^9
Service water makeup	river	4.5×10^8
Sanitary water system	public utility	2.1×10^6
Total	river	5.5×10^9
	public utility	2.1×10^6

Table 7. Total Plant Water Discharges

<u>Source</u>	<u>Discharge Location</u>	<u>Quantity (gal/yr)</u>
Cooling tower evaporation	atmosphere	3.8×10^9
Cooling tower blowdown	river	1.2×10^9
Spray pond evaporation and drift	atmosphere	1.3×10^8
Service water blowdown and misc.	river	3.2×10^8
Sanitary waste	river	2.1×10^6
Total	atmosphere	3.9×10^9
	river	1.5×10^9

10 Chemical Usage

Large amounts of chemicals are required to treat raw river water prior to make-up for regeneration of the demineralizers. Lesser amounts are used as biocides and corrosion inhibitors for piping surfaces.

The annual usage of chemicals is highly variable among plants due to varying river water quality, circulation rates, and water treatment schemes. Raw intake river water is treated in the filtration plant with coagulants and settling agents to remove suspended solids. Annual usage of these chemicals at the model BWR amounts to 21,000 pounds per year aluminum sulfate and 7,600 pounds per year soda ash.¹

High purity water for use in the steam cycle and for other minor plant use is provided by additional demineralizers. Large amounts of chemicals are required to regenerate the demineralizers. Annual usage amounts to 49,000 pounds of sulfuric acid and 37,000 pounds of sodium hydroxide.¹

Lesser amounts of hydrazine (5 to 10 ppm),¹ or similar agents for corrosion control, are added to the component cooling water system as well as biocides, such as hypochlorite, to prevent fouling of the condenser surfaces.

Reference

Nuclear Regulatory Commission, Final Environmental Statement Related to the Construction of Hartsville Nuclear Plants of the Tennessee Valley Authority, NUREG-75/039, June 1975.

⑪ Chemical and Biocide Waste Discharge

Various chemical and biocide waste will be generated by the model BWR and either discharged to the river or disposed of in a landfill.

The chemical composition of waste discharges for a BWR are not easily typified due to such plant-specific factors as intake water quality, pre-operational cleaning requirements, and facility design. However, the discharges typically consist of liquid and solid wastes which contain residues from chemical additives introduced into the water treatment systems or from biocides and other agents used to control slime, scaling, or corrosion of the condenser surfaces. Other miscellaneous wastes are oily wastewater effluent from yard and building drains, and sanitary wastes.

The major source of liquid effluents is the cooling tower blowdown system which discharges to the river, often via a holding pond. The discharge is comprised not only of the direct cooling tower blowdown water from the condenser cooling system, but discharges from the service water and sanitary systems and the make-up demineralizers. The greatest contributors of chemicals to this common discharge are the regenerate wastes and waste water from the high-purity water demineralizers, where approximately 49,000 pounds of sulfuric acid and 37,000 pounds of sodium hydroxide are used annually to regenerate the demineralizers for a typical unit.

The concentration of total solids in the cooling tower blowdown system during normal operation is maintained at approximately twice that of the intake river water by adjustment of the cooling tower blowdown flow such that about half of the river intake water is lost to evaporation and half is returned to the river in the cooling tower blowdown. This concentration factor of 2 is maintained by the appropriate discharge flowrate, but may exceed this up to a factor of 6.6 in cases of blowdown cut-off or hold-up, i.e., in periods of low river flow. From plant to plant, the concentrations of chemical constituents may vary, being dependent on the discharge rate and the chemical treatment needs of the local water. In any case, the effluent must conform to EPA and State guidelines and standards for ambient water quality.

Table 8 describes the major constituents, their concentrations and annual additions to existing water parameters for the model 1000 MWe BWR.

Table 8. Demineralizer Regenerant Discharges and Cooling Tower Blowdown System Effluent Data¹

Constituent	Annual Discharge (lbs)	Conc. in Effluent (mg/l)	Conc. in River (mg/l)*	Maximum Daily Avg. Increase in Conc. in River due to Demineralization (mg/l)**
SO ₄ ⁴	47,000	41.8	38.0	0.48
Na ⁺	22,300	7.5	5.4	0.21
Cl ⁻	1,840	6.0	6.0	-
Other	11,600			
Total Dissolved Solids	83,000	228	220	0.80

* Intake water parameters at a concentration factor of 2.

** After a 10-fold dilution and mixing.

Biocidal treatment of the various circulating water systems to prevent fouling will result in the release of chlorine and acrolein residues to the river. In normal operation, hold-up procedures allow ample dilution before blowdown discharge to reduce their concentration to meet Federal effluent guidelines. Other minor miscellaneous waste sources include yard drainage systems, oil and grease collection systems, and sanitary wastes.

The water filtration system provides water to the demineralizers, using aluminum sulfate and soda as coagulation agents. The solid dewatered waste product amounts to 9,000 pounds of aluminum hydroxide and 30,000 pounds of settled solids annually. They are disposed of in a state-approved landfill.

References

1. Nuclear Regulatory Commission, Final Environmental Statement Related to the Construction of Hartsville Nuclear Plants of the Tennessee Valley Authority, NUREG-75/039, June 1975.
2. Code of Federal Regulations, Title 40, Part 423, "Effluent Standards and Guidelines for Steam Electric Generating Plants."

12 Miscellaneous Fossil Fuel Combustion Products

Small amounts of combustion products are generated through the periodic operation of the auxiliary boiler and the standby diesel generators.

An auxiliary steam generator is used to provide a source of clean steam for start-up and in-plant heating needs. The model BWR has one oil-fired unit rated at 100,000 pounds per hour. Annual usage depends on weather conditions and start-up schedules.

Diesel generator units are the most common source of on-site electric power and are intended to provide prompt power to engineered safety features in case of an accident or to maintain the plant during loss of off-site power. These units function independently and are subject to stringent NRC regulations regarding their reliability. The model BWR has three generator units, rated at 3700 kW each and are tested at least one hour per month.²

Estimated annual emissions of combustion products for a typical BWR are presented in Table 9 below.

Table 9. Estimated Emissions from Combustion of Diesel Fuel

Pollutant	3700 kW Diesel Generator ^a (lbs/hr)	Annual Emission ^b (tons/yr)	100,000 lb/hr Boiler ^c (lbs/hr)	Annual Emission ^d (tons/yr)	Total Emission (tons/yr)
Particulates	4.4	0.1	13.5	23	23
Sulfur Oxides	10.2	0.2	65.0	109	109
Nitrogen Oxides	160.8	2.9	35.0	59	62
Carbon Monoxide	33.4	0.6	3.7	6	7
Hydrocarbons	13.2	0.2	2.8	5	5
Total		4.0		202	206

- Data from reference 2 which assumes use of No. 2 fuel with 0.3% sulfur.
- Total for three generators, tested for 1 hour/month at rated capacity.
- Data from reference 1 which assumes use of No. 2 fuel with 0.5% sulfur.
- Total for boiler, assuming operation at maximum capacity for 140 days/yr.

References

- Nuclear Regulatory Commission, Final Environmental Statement Related to the Construction of Hartsville Nuclear Plants of the Tennessee Valley Authority, NUREG-75/039, June 1975.
- Nuclear Regulatory Commission, Final Environmental Statement Related to Construction of Skagit Nuclear Power Project, Units 1 and 2, NUREG-75/055, May 1975.

IV. PHYSICAL REQUIREMENTS

The major natural resource materials consumed in operation of the facility are uranium and water, which are discussed in items ① and ⑨, respectively. The chemical usage requirements are discussed in item ⑩. Land and construction materials requirements are discussed below.

The land-use requirements for the BWR/6 facility are dictated largely by the requirements of 10 CFR 100 which defines the minimum exclusion boundary in terms of a specified dose limit to the public under normal and accident conditions. Local meteorology and population characteristics, therefore, affect the required exclusion area around the reactor containment building. In some cases the exclusion boundary coincides with the actual site boundary. Large variations in site area are due to the utility's future expansion plans, land costs, recreational development and other area-related factors. An analysis¹ of over 60 sites found the average nuclear power plant site to be about 1160 acres, with a range of 84 acres² to over 30,000 acres. Typical land-use requirements for a two-reactor site² are presented in Table 10 below. These are averages and ranges in site sizes for more than 50 actual light-water reactor sites.²

Table 10. Land Use for Two-Unit Reactor Sites

<u>Land Use</u>	<u>Area* (acres)</u>
Total Site	1,100 + 900
Transmission Route	1,800 + 2,200
Disrupted Land Surface (Site)	350 + 610
Committed Land	130 + 100

-
- For two 1250 MWe units with natural draft cooling.²

Land use is expected to be nearly independent of reactor power. The committed land area will increase with additional reactor units on the site, but the total land use may not.

Concrete and steel constitute the bulk of construction materials for the BWR facility. Estimated amounts of the materials for the model 1000 MWe BWR are presented in Table 11.³

Table 11. Major Construction Materials for
a Model 1000 MWe BWR*

<u>Material</u>	<u>Quantity</u>
Concrete, ft ³	4.5×10^6
Reinforcing steel, tons	17×10^3
Structural steel, tons	8.7×10^3

* Based on single 1190 MWe unit with mechanical draft wet cooling towers data (Ref. 3).

References

1. U. S. Atomic Energy Commission, Final Environmental Statement Concerning Proposed Rule Making Action; Numerical Guides for Design Objectives and Limiting Conditions for Operation to Meet the Criterion "As Low As Practicable," for Radioactive Material in Light-Water-Cooled Nuclear Power Reactor Effluents, Vol. 1, WASH-1258, July 1973.
2. U. S. Department of Energy, Preliminary Safety and Environmental Information Document, Vol. 1, Light Water Reactors, DOE/NE-0003/1, January 1980.
3. United Engineers and Constructors, Inc., Capital Cost: Boiling Water Reactor Plant, Vol. 1, Number two in the series "Commercial Electric Power Cost Studies," NUREG-0242, C00-2477-6, June 1977.

V. PERSONNEL REQUIREMENTS

Total construction craft labor for a 1190 MWe BWR has been estimated to be about 11.3×10^6 man-hours.¹ A recent study of the actual peak construction work force requirements at 33 power plants indicates an average peak labor force of 3000 was required for single unit plants.²

The number of personnel used for operation and maintenance of BWRs has increased substantially in recent years. Estimates of staff requirements for 701-1400 MWe single unit plants in 1975 were 145 people.³ The permanent staff at an operational BWR is typically equivalent to around 230 full-time people. In 1979, the average number of workers (including plant staff, utility and contractor personnel) monitored⁴ for radiation purposes at 10 single unit BWRs was 1850 ± 830 (in 1976, the same plants⁵ averaged 1340 ± 380 workers). The increase in number of workers is due in part to increased security requirements, the use of contractor personnel to perform maintenance functions, and the desire to reduce the average occupational radiation dose per worker by using part-time workers.

References

1. United Engineers and Constructors, Inc., Capital Cost: Boiling Water Reactor Plant, Vol. 1, Number 2 in the Series "Commercial Electric Power Cost Studies," NUREG-0242, C00-2477-6, June 1977.
2. Braid, Robert, Jr., "Better Work Force Projections Needed for Nuclear Plant Construction," in Power Engineering, April 1981, pp. 91-95.
3. U. S. Energy Research and Development Administration, A Procedure for Estimating Non-Fuel Operating and Maintenance Costs for Large Steam-Electric Power Plants, ERDA-76-37, October 1975.
4. Brooks, B. G., Occupational Radiation Exposure at Commercial Nuclear Power Reactors -- 1977 Annual Report, U. S. Nuclear Regulatory Commission, NUREG-0713, Vol. 1, March 1981.
5. U. S. Nuclear Regulatory Commission, Occupational Radiation Exposure at Commercial Nuclear Power Reactors, 1976, NUREG-0323, March 1978.

VI. OCCUPATIONAL SAFETY AND HEALTH

Workers at BWRs are exposed to two types of occupational risks: the day-to-day risks of industrial accidents and the latent risks of still uncertain effects from exposure to certain chemical compounds and low-level radiation. A third risk, the danger of radiation exposure during a major nuclear reactor accident, is considered of sufficiently low probability not to be discussed here.

Industrial Accidents

Detailed statistics on occupational injuries and illnesses during construction, testing, operation and maintenance of BWRs owned by the Tennessee Valley Authority (TVA) have been compiled for 1975 to 1979. These data indicate TVA's personnel averaged 0.77 ± 0.54 serious injuries and 23 ± 17 lost days per 100 man years of work. If it is assumed that this accident rate also carries over to strictly reactor operation and maintenance (no new construction) and 230 full time plant workers per reactor, then workers at the model 1000 MWe (70 percent capacity factor) BWR would average about 1.8 serious injuries and 53 lost days annually (or 0.086 serious injuries and 2.5 lost days per 10^{12} Btus of electrical energy produced).

Exposure to Low-Level Radiation

Occupational radiation exposure is caused by the presence of personnel in radiation fields. Workers necessarily enter these radiation fields as part of normal plant operations, maintenance, inspection, and refueling, as well as other possible non-routine functions. Administrative programs and procedures, in conjunction with facility design ensure that occupational radiation exposure is kept as low as reasonably achievable (ALARA) and within the limits set forth in 10 CFR 20. Table 12 summarizes the exposure data reported to NRC for 25 BWRs for the 1979 calendar year.

Table 12. Summary of Occupational Exposure Data During 1979
at BWR Nuclear Power Plants

<u>Number of Reactors Included</u>	<u>Average Dose Per Worker (Rems)</u>	<u>Average Collective Dose Per Reactor (Man-Rems)</u>	<u>Average No. Personnel With Measurable Doses</u>	<u>Average Man-Rems Per MWe</u>	<u>Average Rated Capacity (MWe)</u>
25	0.73	733	1010*	1.6	669

Area of Exposure

<u>Reactor Operations</u>	<u>Routine Maintenance</u>	<u>Inservice Inspection</u>	<u>Special Maintenance</u>	<u>Radwaste Processing</u>	<u>Refueling</u>
13.4%	39.3%	7.3%	31.2%	4.3%	4.4%

* Includes temporary personnel.

For BWRs, the average yearly total exposure from the years 1969 to 1979 inclusive was 1.6 man-rems/MW-yr.² This number was calculated by dividing the total annual collective doses from all commercial BWRs in the U. S. by the total gross megawatt-years (electric) generated by these plants. For the model 1000 MWe plant with a 0.7 capacity factor, the annual collective dose is

$$(1.6 \text{ man-rems/MW-yr}) \times (1000 \text{ MW})(0.7) = 1.1 \times 10^3 \text{ man-rems/year}$$

Sources of Occupational Radiation

In BWRs, the primary contributor to radiation fields in areas to which personnel exposure is greatest are activated corrosion products deposited onto pipes, pumps, valves, and other components which contain reactor coolant. This accumulation of radioactive materials on these surfaces is the predominant source of exposure for maintenance and operational tasks on these components. Of the sources of these radiation fields, the activated corrosion product Co-60 accounts for between 80 and 90 percent of the dose rate.

The source of the cobalt which activates and eventually deposits itself is originally stable stainless steel alloys containing cobalt in the reactor coolant and feedwater systems. This stable cobalt corrodes and is transported to the core where it absorbs neutrons, activates and, at some point, may deposit itself on out-of-core piping and other components.

References

1. O'Donnel, F. R., and H. C. Hoy, Occupational Safety Data for Energy Technology Characterization -- Vol. I -- Uranium Technologies, Draft, Oak Ridge National Laboratory, Appendix I, May 1980.
2. Brooks, B. G., Occupational Radiation Exposure at Commercial Nuclear Power Reactors 1979, Annual Report, U. S. Nuclear Regulatory Commission, NUREG-0713, Vol. 1, March 1981.

VII. DECOMMISSIONING

Decommissioning of a nuclear facility at the end of the useful life of the plant is necessary to ensure the protection of the public from any residual radioactivity or other hazards associated with the facility. This section presents information on available technology, safety considerations and costs for decommissioning a BWR power station.

The major bases for the study¹ incorporate the following: the decommissioning must be conducted within the existing NRC regulations; the evaluation is based on an existing single 1155 MWe BWR; thirty full-power years of plant operation; estimated radiation dose rates are based on measured data from operating plants, current proven decommissioning technology and techniques are used; a nuclear waste disposal facility is in operation; all radioactive materials exceeding unrestricted release levels are removed from the site before the site is released for unrestricted use; ALARA occupational philosophy is used; the costs are in 1978 dollars.

Three alternatives for the decommissioning of a nuclear facility have been studied and evaluated. These alternatives are: the immediate dismantlement; safe storage with deferred dismantlement; and entombment.

Dismantlement is the removal from the site of all materials having radioactivity levels greater than permitted for the unrestricted use of the property. It is the only alternative that allows termination of the nuclear operating license within a finite period of time.

Safe storage with deferred dismantlement requires that the radioactive materials and contaminated areas be decontaminated or secured and the structures and equipment be maintained as necessary to ensure protection of the public from residual radioactivity. During this period of passive safe storage, the use of the property is limited by the nuclear license. Eventual dismantlement is necessary if unrestricted use and license termination are required.

Entombment is the encasement of nonreleasable radioactive materials in a monolithic structure of concrete or other structural material. The entombment period can range from 100 years to thousands of years. Security and surveillance are required for entombment and safe storage. The use of the property is restricted by the nuclear license.

The operating license for a nuclear plant is regulated by 10 CFR 50. The requirements to terminate operation are specified by sections 50.51 and 50.82 of Title 10 of the Code of Federal Regulations. After final plant shutdown, the operating license may be terminated if the immediate dismantlement course of action is chosen. If either of the other two alternatives is employed, a possession-only license is required which is governed by 10 CFR, Parts 30, 40, and 70.

The manpower requirements for decommissioning a BWR depends on the alternative chosen. To the extent that the work is so-called "hands-on" work, the radiation dose level is a determining factor. The whole body dose permitted for a "hands-on" worker is regulated by 10 CFR 20.

A summary of the costs, manpower requirements and occupational exposure for the three decommissioning options from ref. 1 is given in Table 13.

Table 13. Summary of Decommissioning Cost, Manpower and Occupational Exposure

Decommissioning Option	Costs (x 10 ⁶ 1978 \$)	Manpower (man-years)	Occupational Dose (man-rem)
Immediate dismantlement	43.6	600	1845
Passive safe storage	58.8	385	375-495
Entombment	35.0-40.6	590-630	1573-1684

The occupational doses are based on the Co-60 decay rate. Injuries and fatalities can also result due to industrial accidents. About seven lost-time injuries could result during immediate dismantlement, about three during preparations for safe storage and about six lost-time injuries for entombment. Less than one lost-time injury and must less than one fatality result from the maintenance and surveillance tasks.

Estimated¹ volume and activity of radioactive waste generated by dismantlement are given in Table 14.

Table 14. Volume and Activity of Radioactive Waste from Reactor Dismantlement

Waste Type	Volume (ft ³)	Activity* (Ci)
Neutron Activated Materials	8.0 x 10 ³	6.6 x 10 ⁶
Contaminated Materials	6.1 x 10 ⁵	8.6 x 10 ³
Wet Solid Radwastes	1.9 x 10 ⁴	NA
Dry Solid Radwastes	2.4 x 10 ⁴	NA

* NA = not available.

Reference

1. Oak, H. D., et al., Technology, Safety and Costs of Decommissioning a Reference Boiling Water Reactor Power Station, Battelle Pacific Northwest Laboratories, Richland, Washington, NUREG/CR-0672, June 1980.

APPENDIX COST INFORMATION

Sufficient information is available to approximate the costs for the typical plant from historical data. An extensive effort by the Department of Energy (DOE) and the Nuclear Regulatory Commission (NRC) examined the total costs (capital, fuel, and operating and maintenance) for various plant types and sizes under a range of economic assumptions. The plant most similar to the model plant in this Environmental Characterization Information Report (ECIR) is a 1190-MWe single unit BWR/6 system. The actual costs for a particular plant may vary significantly from the figures presented in this appendix. Variations in utility preferences, environmental and licensing considerations, site location (in particular, earthquake and tornado design criteria), labor availability, escalation and interest costs, and construction schedules all have major impacts on the actual cost of a given plant.

The DOE/NRC study found the plant capital cost for the 1190 MWe plant to be \$670 million (1976 dollars). Assuming an 8 percent escalation rate and a 1985 date for first operations, the total (integrated) capital cost in June 1981 dollars for the 1190-MWe plant is \$1240/kWe, or \$1450 million. If the escalation rate were only 5 percent, the capital cost would be \$1041/kWe, or \$1240 million.

The cost for power generation at other smaller sized BWRs does not scale linearly due to substantial economies of scale. Capital investment costs where substantial economies of scale exist are generally scaled by a power law, such as:

$$\text{Cost}/\$/\text{kWe} = (\text{reference cost}, \$/\text{kWe})[(\text{size}, \text{MWe})/\text{reference size MWe}]^n$$

where the exponent $n = -0.55$ is used for nuclear plants.

Based on this relationship, the total capital costs for the model 1000 MWe BWR would be \$1360 million or \$1360/kWe.

The DOE/NRC study also calculated the total life-cycle costs* for the 1985 plant in mills/kWh (including capital, fuel, and operating and maintenance), assuming various escalation and discount rates. The total costs for the 1190-MWe plant (70 percent capacity factor) are as follows:

*Costs for ultimate decommissioning and decontamination are not included; they will vary from plant to plant, depending on factors such as the utility operating philosophy.

Total Generation Costs for a Model 1190 MWe BWR
Beginning Operation in 1985 with a 70 Percent Capacity Factor

Cost Component (1976 dollars)	5% Escalation Rate	8% Escalation Rate
	10% Discount Rate (mills/kWh)	12% Discount Rate (mills/kWh)
Capital Cost	30.6	36.4
Fuel Costs	19.0	32.8
Operating and Maintenance Costs	2.8	4.8
Total Generating Costs	52.4	74.0

References

1. United Engineers and Constructors, Inc., "Total Generating Cost: Coal and Nuclear Plants," Vol. 8 in a series of 8 Commercial Electric Power Cost Studies, NUREG-0248, C00-2477-12, February 1979.
2. U. S. Department of Energy, Nuclear Proliferation and Civilian Nuclear Power, Volume IX: Reactor and Fuel Cycle Descriptions, DOE/NE-0001, June 1980.

GLOSSARY

As low as reasonably achievable (ALARA)

Requirement by the Nuclear Regulatory Commission in 10 CFR 50 limiting occupational and public exposure to radiation taking into account the state of technology and cost of improvements in relation to the benefits to the public health and safety.

Blowdown

Water that is periodically removed from cooling towers or the fossil-fuel boiler to prevent excessive buildup of total dissolved solids.

Capacity factor

The actual electrical output produced by a power plant over a period of time divided by the design output of the plant over the same period of time.

Circulating water

Water supplied to the generating plant's main condenser that is cooled by the cooling towers or other heat sinks.

Clarifiers

System used to remove the majority of total suspended solids in the river makeup water.

Cooling tower drift

Aerosols of water (mist) that are discharged to the atmosphere from the cooling towers.

Cooling tower evaporation loss

Circulating water that is evaporated as a result of heat transferred from the circulating water system and lost in the atmosphere through the cooling towers.

Curie

Term used to define the amount of a given radioactive material; equivalent to the amount of material that decays at a rate of 3.7×10^{10} disintegrations per second.

Decontamination factor (DF)

The ratio of the initial amount of a nuclide in a stream (specified in terms of concentration or activity of radioactive materials) to the final amount of that nuclide in the stream following treatment by a given process.

Discount rate

A factor in cost accounting formulas used for analyzing the time value of money. Its magnitude depends on the cost of capital, financing schemes, etc.

Escalation

Increases in cost of equipment, materials, labor, etc., as a result of inflation.

GLOSSARY

Fi ssile material	Forms of uranium or plutonium (e.g., U-235) that undergo fission in a light-water reactor.
Fission product	A nuclide (usually radioactive) produced either by fission or by subsequent radioactive decay.
GALE code	Computer model used by the Nuclear Regulatory Commission to calculate the quantity of radioactive effluents released to the air and water.
Gaseous effluent	Processed gaseous wastes containing radioactive stream materials resulting from the operation of a nuclear power reactor.
HEPA filters	Filters used in gaseous waste streams to remove particulate matter.
Liquid effluent stream	Liquid wastes containing radioactive materials resulting from the operation of a nuclear power reactor (may be processed before release).
Liquid radwaste evaporators	Devices used to concentrate liquid radwaste prior to solidification.
Man-rem	A unit for considering the collective radiation dose received by a group of people. One man-rem is equivalent to the amount of radiation dose received by one person exposed to one rem, two persons exposed to one-half rem, etc.
Net station heat rate (Q)	Amount of fuel input (in Btu) necessary to generate 1 kWh of electricity.
Plant efficiency	Electrical energy out of the plant to the transmission network divided by total heat energy used to produce the electric energy.
Radioactive halogens	The isotopes of fluorine, chlorine, bromine, and iodine. The radioactive isotopes of iodine are the key isotopes considered in dose calculations for reactor effluents.
Radioactive noble gases	The radioactive isotopes of helium, neon, argon, krypton, xenon, and radon, which are characterized by their chemical inactivity. The radioactive isotopes of krypton and xenon are the key elements considered in dose calculations.

GLOSSARY

Radwaste	Waste that is known or suspected to be contaminated with radioactive material.
Reactor water clean-up system	Removes a small portion of reactor water flow for continuous purification and return to reactor water.
Reactivity	A measurement of the fissioning activity inside the reactor core.
Reactor core	The portion of the reactor where the fissioning of uranium takes place.
Rem	A unit of radiation dose.
Source term	The calculated average quantity of radioactive material released to the environment from a nuclear power reactor during normal operation, including anticipated operational occurrences. The source term is the isotopic distribution of radioactive materials used in evaluating the impact of radioactive releases on the environment.
Spent reactor fuel	Nuclear fuel that has reached its end of useful life in the reactor core.

ACRONYMS AND ABBREVIATIONS

AFR	away from reactor
ANS	American Nuclear Society
ANSI	American National Standards Institute
ALARA	as low as reasonably achievable
Btu	British thermal unit
BWR	Boiling Water Reactor
CCW	Condenser circulating water
CFR	Code of Federal Regulations
Ci	curie
cm	centimeter
DOE	Department of Energy
ECIR	Environmental Characterization Information Report
EPA	Environmental Protection Agency
ESW	Essential service water
ft ³	cubic foot
gal	gallon
GESSAR	General Electric Standard Safety Analysis Report
GESSAR-II	General Electric Standard Safety Analysis Report (1980)
gpm	gallons per minute
GWd/tHM	Gigawatt-days/metric ton heavy metal
ha	hectare
HEPA	high efficiency particulate aerosol (filter)
kWh	kilowatt hour
l	liter
lb	pounds

ACRONYMS AND ABBREVIATIONS

mCi	millicurie (10^{-3} Ci)
mg	milligram (10^{-3} grams)
min	minute
millirem (10^{-3} rem)
MWt	megawatt-electricity (10^6 watts)
	megawatt-thermal (10^6 watts)
NPDES	National Pollutant Discharge Elimination System
NRC	Nuclear Regulatory Commission
OSHA	Occupational Safety and Health Administration
P	net power delivered to the transmission grid
ppm	parts per million
PWR	Pressurized Water Reactor
RCW	Raw water system
TVA	Tennessee Valley Authority
U-235	uranium-235
UO ₂	uranium dioxide
^W BLOWDOWN	cooling tower blowdown
^W EVAP	cooling tower evaporation loss
^W TOW	cooling tower makeup water
yr	year

Commercial High-Level Nuclear Waste Repository

Environmental Characterization Information Report

February 1982

U.S. Department of Energy
Assistant Secretary for Environmental
Protection, Safety, and
Emergency Preparedness
Office of Environmental Analysis

CONTENTS

	<u>Page</u>
I. INTRODUCTION AND SUMMARY.	A.3-3
II. PROCESS DESCRIPTION AND ENVIRONMENTAL POINTS OF INTEREST. . . .	A.3-7
1. Radiological Releases	A.3-11
2. Nonradioactive Gaseous Emissions.	A.3-11
3. Dust Emissions.	A.3-15
4. Solid Waste	A.3-16
5. Liquid Effluents.	A.3-17
6. Thermal Releases.	A.3-18
III. PHYSICAL REQUIREMENTS	A.3-19
IV. PERSONNEL REQUIREMENTS.	A.3-22
V. OCCUPATIONAL SAFETY AND HEALTH.	A.3-23
VI. DECOMMISSIONING	A.3-25
VII. LONG-TERM ENVIRONMENTAL RESIDUALS	A.3-26
APPENDIX A: COST INFORMATION	A.3-30
APPENDIX B: CHARACTERIZATION OF THE LONG-TERM ENVIRONMENTAL RESIDUALS FROM A GEOLOGICAL REPOSITORY	A.3-33
APPENDIX C: SUMMARY TABLE FOR A GEOLOGICAL REPOSITORY FOR SPENT FUEL	A.3-53
GLOSSARY	A.3-56
ACRONYMS AND ABBREVIATIONS	A.3-59

I. INTRODUCTION AND SUMMARY

This environmental characterization information report describes the process parameters, resource requirements and environmental residuals for a model mined geologic repository for highly radioactive waste, capable of receiving spent fuel from commercial nuclear power plants or, alternately, high-level wastes (HLW) and transuranic wastes (TRU) from the reprocessing of spent fuel. Data are presented here for the repository for reprocessing wastes, in two widely differing geologic media, salt and basalt. Corresponding data for a repository for spent fuel are summarized in Appendix C. Environmental residuals are presented for two time frames -- near-term, during construction and operation of the repository; and long-term, for hundreds to millions of years after closure.

The U. S. Department of Energy, in its efforts to develop technologies for the management and long-term disposal of high-level wastes from the commercial uranium fuel cycle, has prepared a generic environmental analysis of deep geologic disposal for comparison with alternative disposal concepts.¹ It is from this environmental analysis and its various technical support documents^{2,3} that the model repository for this ECIR was chosen.

It is assumed that the model repository occupies the same subsurface repository area (800 ha) for either waste type and media. The mining phase of construction, lasting seven years, is begun after three years of surface construction and is completed during the first five years of operation. Since construction activities are closely integrated with the operational phase, this ECIR will address the environmental points of interest associated with all activities of the repository with the following distinction made between "construction" and "operation":

Repository construction includes the construction of surface facilities and the mining of the entire repository, whereas the operational phase includes the receiving, handling and placement of the wastes into storage areas, with subsequent backfilling as capacity is reached.

The process, operating parameters, resources needed, and the environmental residuals and products associated with the construction and operation of a repository for reprocessing wastes constructed in salt or basalt are summarized in Table 1. Similar information for a repository for spent fuel is presented in Appendix C. Annual resource usage and pollutant discharges are given in English and metric units, based on the construction period and/or operating lifetime (which varies from 16 to 25 years).

The summary tables also give the quantities of resources and environmental residuals used or released per 10^{12} Btu (about 293 million kWh) of electrical energy produced by the nuclear fuel. The capacity of the repository for replaced waste is expressed in terms of the heavy metal content, chiefly uranium, of the original fuel (MTHM). The electrical energy output represented by the contents of the repository is based on the typical light-water reactor fuel requirement of approximately 1.3 MTHM per 10^{12} Btu produced.

Detailed descriptions of HLW and spent fuel repositories and the environmental points of interest associated with them are presented in Section II. Resource and personnel requirements are given in Sections III and IV. Occupational Safety and Health aspects are presented in Section V and Decommissioning in Section VI. The long-term environmental residuals from spent fuel and HLW repositories are discussed briefly in Section VII and in detail in Appendix B. Cost information is provided in the Appendix A.

References

1. Final Environmental Impact Statement -- Management of Commercially Generated Radioactive Wastes, DOE/EIS-0046F, Volume 1-3, October 1980.
2. Technology for Commercial Waste Management, DOE/ET-0028, Volume 1-5, May 1979.
3. Environmental Aspects of Commercial Radioactive Waste Management, DOE/ET-0029, Volume 1-3, May 1979.

TABLE 1. SUMMARY SHEET

COMMERCIAL HIGH-LEVEL NUCLEAR WASTE REPOSITORY

REFERENCE ENERGY SYSTEM

Deep Geologic Repository Facility Capable of Handling Solidified High-Level Wastes and Transuranic Wastes From the Reprocessing of Spent Fuel; Located 600 m Deep in Each of Two Candidate Rock Media, Salt and Basalt; Retrievable for Disposal; Packaging Facility Included in Surface Operations. Construction Time Is 10 Years, Mining Operations Taking Place During the Last 7 Years.

FACILITY OPERATING PARAMETERS

	Repository for Reprocessing Wastes	
	Salt	Basalt
Average Annual Capacity (MTHM):	3,000	3,000
Total Equivalent Capacity (MTHM):	62,000	56,000
Total Electrical Energy Represented (Btu):	49×10^{15}	44×10^{15}
Operating Lifetime (yr):	19	18

PROCESS FLOW

Note: The Environmental Points of Interest Labeled in The Flowchart Are Discussed in Further Detail in Section II.

RESOURCES USED

	Quantities Used				Per 10^{12} Btu Energy Produced	
	Reference Energy System Annual Levels					
	English Units Salt	English Units Basalt	Metric Units Salt	Metric Units Basalt	Salt	Basalt
Water	7.1×10^8 gal	12×10^8 gal	27×10^6 liters	45×10^6 liters	1.5×10^3 gal	2.7×10^3 gal
Energy						
Construction						
Propane	8.5×10^3 ft ³	14×10^3 ft ³	0.24×10^3 m ³	0.40×10^3 m ³	1.7 ft ³	3.1 ft ³
Diesel Fuel	0.83×10^6 gal	1.1×10^6 gal	2.4×10^5 m ³	4.0×10^5 m ³	130 gal	240 gal
Gasoline	0.48×10^6 gal	0.79×10^6 gal	1.8×10^5 m ³	3.0×10^5 m ³	87 gal	179 gal
Electricity	1.6×10^6 kWh	2.7×10^6 kWh	1.6×10^6 kWh	2.7×10^6 kWh	330 kWh	610 kWh
Operation						
Diesel Fuel	3.5×10^6 gal	3.4×10^6 gal	13×10^3 m ³	13×10^3 m ³	1.3×10^3 gal	1.4×10^3 gal
Coal	81×10^6 tons	79×10^6 tons	74×10^6 tonnes	72×10^6 tonnes	32 tons	32 tons
Electricity	110×10^3 kWh	127×10^3 kWh	110×10^3 kWh	127×10^3 kWh	43×10^3 kWh	52×10^3 kWh
Steam	570×10^3 tons	860×10^3 tons	790×10^3 tonnes	780×10^3 tonnes	340 tons	350 tons
Operational Materials						
Concrete	59×10^3 ft ³	63×10^3 ft ³	1.7×10^3 m ³	1.8×10^3 m ³	23 ft ³	25 ft ³
Steel	4.8×10^3 tons	13×10^3 tons	4.4×10^3 tonnes	12×10^3 tonnes	1.9 tons	5.2 tons
Personnel						
Construction (10 yr)	2.0×10^3 Workers	3.8×10^3 Workers	—	—	0.22 Workers	0.59 Workers
Operation	1.3×10^3 Workers	1.5×10^3 Workers	—	—	0.39 Workers	0.48 Workers
Total Usage						
Construction Materials						
Concrete	3.9×10^6 ft ³	6.7×10^6 ft ³	110×10^3 m ³	190×10^3 m ³	79 ft ³	150 ft ³
Steel	20×10^3 tons	33×10^3 tons	18×10^3 tonnes	30×10^3 tonnes	0.41 tons	0.75 tons
Copper	260 tons	460 tons	240 tonnes	420 tonnes	5.4×10^{-3} tons	11×10^{-3} tons
Zinc	68 tons	120 tons	62 tonnes	110 tonnes	1.4×10^{-3} tons	2.7×10^{-3} tons
Aluminum	51 tons	85 tons	46 tonnes	77 tonnes	1.0×10^{-3} tons	1.9×10^{-3} tons
Lumber	92×10^3 ft ³	155×10^3 ft ³	2.6×10^3 m ³	4.4×10^3 m ³	1.9 ft ³	3.5 ft ³
Land						
Fenced, restricted	2000 ac	2000 ac	800 ha	800 ha	41×10^{-3} ac	45×10^{-3} ac
Federally controlled	7900 ac	7900 ac	3200 ha	3200 ha	193×10^{-3} ac	179×10^{-3} ac
Surface facilities	440 ac	540 ac	180 ha	220 ha	9.1×10^{-3} ac	12×10^{-3} ac

TABLE 1. (Continued)

COMMERCIAL HIGH-LEVEL NUCLEAR WASTE REPOSITORY

COSTS

	Reference Energy System (May 1981 \$)		Per 10 ¹² Btu	
	Salt	Basalt	Salt	Basalt
Construction (10 yr)	$\$1.6 \times 10^8$	$\$3.1 \times 10^8$	$\$33 \times 10^3$	$\$70 \times 10^3$
Operation	$\$1.6 \times 10^8$	$\$2.4 \times 10^8$	$\$33 \times 10^3$	$\$55 \times 10^3$

ENVIRONMENTAL RESIDUALS

	Quantities Released				Per 10 ¹² Btu Energy Produced	
	Reference Energy System: Annual Levels				Salt	Basalt
	English Units Salt	English Units Basalt	Metric Units Salt	Metric Units Basalt	Salt	Basalt
<u>Air Pollutants</u>						
<u>Radiological</u>						
Construction						
Radon-220	1.1×10^{-3} Ci	2.0 Ci			0.16×10^{-6} Ci	0.32×10^{-3} Ci
Radon-222	1.6×10^{-3} Ci	1.7 Ci			0.23×10^{-6} Ci	0.27×10^{-3} Ci
Lead-210	0.13×10^{-6} Ci	0.14×10^{-3} Ci			19×10^{-12} Ci	0.022×10^{-6} Ci
Lead-212	1.7×10^{-6} Ci	3.0×10^{-3} Ci			0.24×10^{-6} Ci	0.47×10^{-6} Ci
Lead-214	1.6×10^{-3} Ci	1.7 Ci			0.23×10^{-6} Ci	0.27×10^{-3} Ci
Bismuth-210	1.6×10^{-3} Ci	1.7 Ci			0.23×10^{-6} Ci	0.27×10^{-3} Ci
Operation				negligible		
<u>Fossil Fuel Combustion Products</u>						
Construction						
CO	1400 tons	2400 tons	1300 tonnes	2100 tonnes	0.20 tons	0.37 tons
Hydrocarbons	63 tons	100 tons	57 tonnes	94 tonnes	9.0×10^{-3} tons	17×10^{-3} tons
NO _x	270 tons	440 tons	240 tonnes	400 tonnes	0.038 tons	0.070 tons
SO _x	16 tons	27 tons	14 tonnes	24 tonnes	2.3×10^{-3} tons	4.2×10^{-3} tons
Particulates	16 tons	27 tons	14 tonnes	24 tonnes	2.3×10^{-3} tons	4.2×10^{-3} tons
Operation						
CO	170 tons	170 tons	150 tonnes	150 tonnes	0.070 tons	0.067 tons
Hydrocarbons	58 tons	60 tons	53 tonnes	54 tonnes	0.023 tons	0.024 tons
NO _x	990 tons	1000 tons	895 tonnes	940 tonnes	0.35 tons	0.42 tons
SO _x	700 tons	670 tons	630 tonnes	610 tonnes	0.27 tons	0.27 tons
Particulates	30 tons	29 tons	27 tonnes	27 tonnes	0.011 tons	0.012 tons
<u>Dust</u>						
Construction						
Host	1,000 tons	1,700 tons	930 tonnes	1,600 tonnes	0.14 tons	0.26 tons
Arid	14,000 tons	23,000 tons	13,000 tonnes	22,000 tonnes	2.0 tons	3.8 tons
Solid Wastes	2.4×10^6 tons	5.0×10^6 tons	2.1×10^6 tonnes	4.6×10^6 tonnes	340 tons	800 tons
<u>Water Pollutants</u>						
				Not Determined		
Thermal Discharge	40×10^9 Btu	37×10^9 Btu	40×10^9 mega-joules	39×10^9 mega-joules	15×10^6 Btu	15×10^6 Btu

OCCUPATIONAL SAFETY AND HEALTH

	Reference Energy System Annual Average		Per 10 ¹² Btu	
	Salt	Basalt	Salt	Basalt
<u>Nonradiological</u>				
Disabling injuries	50	130	.010	0.029
Fatalities (a)	1.0	2.6	0.20×10^{-3}	0.59×10^{-3}
<u>Radiological</u>				
Construction	0.026 man-rem	890 man-rem	3.7×10^{-6} man-rem	0.14 man-rem
Operation	7.4×10^3 man-rem	7.2×10^3 man-rem	2.9 man-rem	2.9 man-rem

(a) Fatalities include permanent disabling injuries.

II. PROCESS DESCRIPTION AND ENVIRONMENTAL POINTS OF INTEREST

The model repository consists of: 1) surface facilities for waste receiving and handling and for mining and general operations support, and 2) subsurface facilities for waste handling and emplacement and for mined rock removal. The diagram in Figure 1 depicts the general process scheme with associated input materials and environmental points of interest.

Environmental points of interest have been identified in Figure 1 by circled numbers and are characterized and discussed in the following sections. These points of interest identify the principal sources of radioactive and non-radioactive releases from the model repository and the major uses of water, fuel and land resources.

Construction and design of the surface facilities are generally similar for either a repository handling spent fuel or one handling reprocessing wastes. The subsurface area is assumed to be 2000 acres in all cases, and has conventional room and pillar construction, with 200 to 400 acres occupied by shafts, service areas, corridors and intact rock. The basic design requires three shafts with an additional shaft for the transport of contact-handled TRU (CH-TRU) wastes in the reprocessing waste repository, and an additional shaft in basalt formations to allow for the removal of a larger amount of mined rock. In basalt, the mining technique is that of conventional drill and blast and in salt an electric-powered continuous mining unit is used to cut away the rock.

In the spent-fuel repository, spent-fuel elements are received in shipping casks and transferred to a packaging facility, where the spent-fuel assemblies are removed, inspected for damage, and encased in helium-filled canisters. The helium provides a means for detecting leaks. Damaged or leaking canisters are first transported to an overpack cell, where they are encased in an overpack canister that is welded shut. Those canisters that are acceptable are then transported to the canistered-waste shaft and lowered into the repository for delivery to an emplacement room. All of these operations are carried out remotely with shielding provided for transporters.

The wastes are emplaced in holes lined with steel sleeves and sealed with removable concrete plugs, except in the repository in salt where BWR canisters are stored upright in trenches, allowing for closer spacing due to the lower heat-transfer rates compared to PWR canisters.

It is assumed that the waste form of the HLW from the reprocessing facilities is that of a solidified borosilicate glass. Each canister contains the solidified HLW resulting from the processing of 3 MTHM of fuel. Canisters of HLW and remotely handled TRU wastes (RH-TRU) are received and prepared for emplacement in a manner similar to that of the once-through fuel cycle scheme. In the case of a repository in salt, HLW and RH-TRU canisters are lowered into vertical holes in the emplacement rooms. In the basalt formation, the RH-TRU

FIGURE 1. PROCESS FLOWCHART WITH ENVIRONMENTAL POINTS OF INTEREST — GEOLOGIC REPOSITORY FOR NUCLEAR WASTES

canisters are placed upright in room-length trenches and supported by storage racks. Shielded forklifts stack contact-handled TRU waste pallets and boxes along the walls of the CH-TRU emplacement rooms.

For the initial five-year emplacement period, the wastes are considered to be retrievable. During this period of retrievability, rooms are left open (no backfill) and the stability of the waste packages and the repository itself are monitored. After this time, as they reach capacity, the storage rooms are backfilled with crushed rock from the mined rock storage area. Current proposed regulations in regard to performance requirements call for a 50-year retrievability period, which would affect the quantities presented here somewhat, particularly waste rock storage. For this conceptual design, however, the wastes are considered "recoverable" rather than easily retrievable, after backfilling, until the entire repository is backfilled, sealed and decommissioned.

The total waste capacity of the model repository when full varies for a given rock type and waste type according to differences in their respective thermal load limits and differing stabilities. The mechanical and thermal properties of salt require more intact rock to be left between spaces (increased pillar width) to provide structural stability. The controlling thermal criteria are: 1) the estimated heat load that the rock can contain without compromising the integrity of the repository, and 2) the thermal output of the canisters after emplacement, which is a function of waste-type and age. To illustrate a result of the thermal criteria, the emplacement holes are spaced further apart in salt.

Total waste capacity expressed in terms of equivalent metric tons of heavy metal from spent fuel for each type of repository is presented in Table 2. Note that the reprocessing waste repository in basalt has the capacity for more than twice the HLW canisters compared to the repository in salt. This is due to the thermal and structural limits on salt identified above. The capacity in terms of equivalent MTHM, however, is more nearly equal for the repositories in salt and basalt. This is primarily due to the use of smaller diameter HLW canisters in basalt, thus reducing the overall capacity for MTHM equivalent waste. The relative quantities of HLW to TRU waste as shown in Table 2 are different because of the five-year cooling period for HLW. Subsequent repositories will emplace more equivalent quantities of both HLW and TRU, but with a total capacity of much less as the newer, more radioactive wastes are received. Much of the waste on hand now has cooled more than five years.

In the case of the repository for spent fuel, each canister's thermal output is constant, and limited to that of a single fuel assembly that has had a five-year cooling period. In this case, canister spacing is the controlling factor in total capacity. The repository in basalt, as shown in Table 2, is capable of receiving more than twice the amount of spent fuel that can be stored in the salt repository.

Table 2. Capacities of the Model Repository When Full

Repository Type	Salt		Basalt	
	Containers	Equivalent MTHM ^a	Containers	Equivalent MTHM ^a
<u>Reprocessing Waste</u>				
HLW Canisters	25,800	62,200	63,000	56,000
RH-TRU Canisters	26,900	99,700 ^b	24,700	91,500 ^b
RH-TRU Drums	399,000		367,000	
CH-TRU Boxes	4,150		3,810	
CH-TRU Drums	264,000		242,000	
Total		161,900		147,500
Total ^c		71,200		73,800
<u>Spent Fuel</u>				
PWR Canisters	68,200	31,500	162,700	75,100
BWR Canisters	104,000	19,600	246,300	46,500
Total		51,100		121,600

- Total amounts of waste expressed in terms of the equivalent metric tons of heavy metal, chiefly uranium, contained in the original fuel.
- Transuranic waste that is remotely or contact-handled and packaged according to its radiation level.
- Capacity if HLW and TRU wastes are emplaced at the same equivalent rate, which will be the case in subsequent repositories. The five-year "cooling" period for HLW will initially cause a disproportionate amount of TRU waste to be emplaced.

The model repository in each case is assumed to operate on a five-day week with three shifts a day. The operational phase of the repository for spent fuel wastes ranges from 16 years if in salt, to 25 years in basalt. The repository for reprocessing wastes will reach capacity in about 18 years for both geologic media.

References

- Final Environmental Impact Statement -- Management of Commercially Generated Radioactive Wastes, DOE/EIS-0046F, Vol. 1, Section 5.3, October 1980.
- Technology for Commercial Radioactive Waste Management, DOE/ET-0028, Vol. 4, Sections 7.3-7.5, May 1979.
- Disposal of High-Level Radioactive Wastes in Geologic Repositories, 10 CFR Part 60, U. S. Nuclear Regulatory Commission, Proposed Rule, 46 F.R. 35280, July 8, 1981.

1 Radiologic Releases

Releases during construction and operation consist of naturally occurring gaseous radionuclides, principally radon and its decay products and are greater for repositories in basalt.

Routine radiological releases from the model repository during construction will consist of naturally occurring radon and its daughter products released from the rock in the process of mining the repository. The expected annual release of these radionuclides is listed in Table 3. The mine air is filtered in the mine ventilation system, so that no particulate releases of radioactive material are expected.

Table 3. Annual Releases of Naturally Occurring Radionuclides to Air from the Construction of Geologic Repositories for Spent Fuel and Fuel Reprocessing Wastes

Nuclide	Repository for Spent Fuel, Ci		Repository for Fuel Reprocessing Waste, Ci	
	Salt	Basalt	Salt	Basalt
²²⁰ Rn	9.3×10^{-4}	3.1	1.1×10^{-3}	2.0
²²² Rn	1.3×10^{-3}	2.7	1.6×10^{-3}	1.7
²¹⁰ Pb	1.1×10^{-7}	2.3×10^{-4}	1.3×10^{-7}	1.4×10^{-4}
²¹² Pb	1.4×10^{-6}	4.7×10^{-3}	1.7×10^{-6}	3.0×10^{-3}
²¹⁴ Pb	1.3×10^{-3}	2.7	1.6×10^{-3}	1.7
²¹⁰ Bi	1.3×10^{-3}	2.7	1.6×10^{-3}	1.7

Routine radiological releases from geologic repositories during normal operation will consist principally of radon emanating from exposed rock faces and radon decay products. These releases will also occur from backfilling operations but are negligible compared to radon releases during repository construction. Exhaust air from the mine is processed through a roughing filter and two high-efficiency particulate filters prior to discharge from the mine ventilation stack.

Estimated annual releases due to minor incidents involving canister leakage during routine handling of wastes were developed by weighting all identified minor accident releases by their predicted frequencies. Allowances were made for unidentified minor accidents and frequency uncertainties. The estimated integrated annual releases for postulated spent fuel canister failures (leakage) are shown in Table 4.

Table 4. Estimated Integrated Annual Release Due to Minor Accidents for a Spent Fuel Repository²

<u>Nuclide</u>	<u>Ci</u>
⁸⁵ Kr	5
¹⁴ C	1×10^{-4}
¹²⁹ I	1×10^{-5}
³ H	1×10^{-2}

In the model repository handling reprocessed wastes, the release to the mine atmosphere due to contact-handled TRU drum rupture is estimated to be a factor of 2.5×10^{-5} of the activity in one drum of TRU. If this release is combined with an air filtration decontamination factor (DF) of 10^7 , then the estimated integrated annual release fraction is 3.6×10^{-12} , which is considered negligible.²

References

1. Final Environmental Impact Statement -- Management of Commercially Generated Radioactive Wastes, DOE/EIS-0046F, Vol. 1, Section 5.4, October 1980.
2. Technology for Commercial Radioactive Waste Management, DOE/ET-0028, Vol. 4, Sections 7.4-7.5, May 1979.

② Nonradioactive Gaseous Emissions

Airborne particulates and gaseous combustion products from diesel machinery operation and surface burning of coal during mining and operation are expected to meet Federal standards.

Nonradioactive emissions from repository construction include airborne dust and pollutants generated from fossil-fueled machinery operation during surface facility construction and from mining operations. Burning of fossil fuels results in air pollutant emissions, but concentrations in air at the fenceline are expected to be within the limits set by 40 CFR 50.¹ Estimates of emissions from combustion of fuels released during construction given in Table 5 were derived from the fossil fuel requirements for construction of the repository and annualized over the total ten-year construction period.

Table 5. Estimated Annual Quantities of Emissions from Burning of Fossil Fuels During Construction of a Geologic Repository²

Pollutant, tons	Spent Fuel		Reprocessing Wastes	
	Salt	Basalt	Salt	Basalt
CO	870	2200	970	1700
Hydrocarbons	40	98	44	73
NO _x	170	420	190	310
SO _x	10	25	11	19
Particulates	10	25	11	19

The combustion products released to the air from operational activities at the model repository include those from the burning of diesel fuel and from the surface burning of coal. Estimated annual emissions released during the operational life of the model repository listed in Table 6, were derived from the fuel requirements and associated emission factors and annualized over the various lifetimes of the repository types.

Table 6. Annual Quantities of Emissions Released to the Atmosphere During Operation of a Geologic Repository²

Pollutant, tons	Spent Fuel		Reprocessing Wastes	
	Salt	Basalt	Salt	Basalt
CO	165	160	170	170
Hydrocarbons	60	60	58	60
NO _x	1000	1100	990	1000
SO _x	670	660	700	670
Particulates	30	30	30	29

References

1. U. S. Code of Federal Regulations, Title 40, Chapter 50.
2. Final Environmental Impact Statement -- Management of Commercially Generated Radioactive Wastes, DOE/EIS-0046F, Vol. 1, Section 5.4, October 1980.

3 Dust Emissions

Airborne dust from rock storage piles and from rock handling is greatest for operations in basalt, but the potential for environmental damage is greatest for salt deposited on nearby soil and vegetation.

The major nonradiological effluent from facility construction is dust generated from surface operations, rock transport and rock storage piles. Dust from mining and transport within the mine is filtered in the mine ventilation system. The amount of dust generated is site specific, depending on climatological factors. Table 7 lists the estimated dust emissions for two diverging climates for both repository types and rock media. This data is based on emission factors for rock storage piles under maximum conditions (dry and windy) with no control techniques, and on the rock mining rate.

Table 7. Annual Maximum Dust Emissions from Surface Handling of Mined Material

Climate	Spent Fuel (tons/yr)		Reprocessing Wastes (tons/yr)	
	Salt	Basalt	Salt	Basalt
Moist	890	2,600	1,000	1,700
Arid	12,000	37,000	14,000	23,000

Maximum and average suspended particulates at the repository fenceline (1.6 km from the repository center) are presented in Table 8. The primary Federal Air Quality Standard for suspended particulate matter is 75 g/m³ computed as an annual geometric mean.

The lower values for salt in Tables 7 and 8 are due primarily to the ability of salt to absorb water vapor, so that salt storage piles quickly crust over.

Table 8. Dust Concentration at Repository Fenceline, ¹ g/m³

Climate	Spent Fuel				Reprocessing Wastes			
	Salt		Basalt		Salt		Basalt	
	max	avg	max	avg	max	avg	max	avg
Moist	110	66	330	190	130	71	210	130
Arid	1,400	790	4,100	2,400	1,600	930	2,600	1,600

Reference

1. Environmental Aspects of Commercial Radioactive Waste Management, DOE/ET-0029, Vol. 2, Sections 9.0 and 10.3, May 1979.

4 Solid Waste

Solid waste in the form of mined rock is left in surface storage piles and amounts to 14-17 million tons for the model repository in salt and 35-49 million tons for the repository in basalt.

In the process of excavating repository subsurface areas, mined rock is brought to the surface and stored onsite. When retrievable emplacement operations are complete, a portion of the rock is returned to the mine as backfill and rock not used for backfill remains piled on the surface. Quantities of mined rock stored for both types of repositories in salt and basalt are presented in Table 9. The larger amounts of mined material in the basalt repository are due to a higher mining extraction ratio compared to salt. That is, the mechanical and thermal properties of salt require that more intact rock be left between rooms (increased pillar width). If a fifty-year retrievability period is required, the amount of rock stored on the surface will be appreciably greater.

Table 9. Permanent Onsite Surface Storage of Mined Rock
(x 10⁶) Left After Backfilling

	Spent Fuel Repository (tons x 10 ⁶)	Reprocessing Waste Repository (tons x 10 ⁶)
Salt	14	17
Basalt	49	35

Reference

1. Final Environmental Impact Statement -- Management of Commercially Generated Radioactive Wastes, DOE/EIS-0046F, Vol. 1, Section 5.3, October 1980.

⑤ Liquid Effluents

Surface runoff water from storage piles and effluents from mine water pumping are potential sources of water pollution.

Runoff of water from surface stockpiles, particularly of salt into local surface and groundwaters is a potential source of contamination. This is not the case with basalt since it generally does not contain noxious soluble substances. Mitigating measures proposed for salt stockpiles include impermeable liners (hypalon covered with clay) to serve as groundwater barriers, runoff drainage systems into evaporation ponds or treatment plants for salt removal, and coverage of the stockpiles with asphalt.^{1,2}

Sanitary waste is collected in a sewer system and treated or disposed of in accordance with state and Federal regulations.

References

1. Environmental Aspects of Commercial Radioactive Waste Management, DOE/ET-0029, Vol. 2, Section 9.1, May 1979.
2. Final Environmental Impact Statement -- Management of Commercially Generated Radioactive Wastes, DOE/EIS-0046F, Vol. 1, Section 5.4, October 1980.

6 Thermal Releases

Thermal discharges to the environment consist of heat released to the atmosphere from combustion in fossil-fueled machinery and of heat generated by the buried nuclear waste which is transmitted to the host rock but with a negligible increase in temperature.

Heat released from buried nuclear waste will increase the temperature of the geologic formation in which it is buried and may alter the physical and chemical properties of the formation. Some of the heat will eventually be transferred via conduction to the atmosphere and, if the temperatures and temperature gradients have not exceeded values that would cause damage to the formation or adversely affect the containment integrity or the environment, the formation will return essentially to its initial state. The maximum surface temperature increase in any case is not expected to exceed about 0.5°C.¹

Heat is released to the environment from the operational activities of the repository, primarily the combustion of fossil fuels for heating and equipment handling, but also from the waste between the time of arrival on-site and the time of final closing off of the tunnel in which it is emplaced.

Table 10. Annual Thermal Releases to the Atmosphere During Operation of the Model Repository

	Spent Fuel		Reprocessing Wastes	
	Salt	Basalt	Salt	Basalt
Heat (Btu)	23×10^9	35×10^9	40×10^9	37×10^9

Reference

1. Final Environmental Impact Statement -- Management of Commercially Generated Radioactive Wastes, DOE/EIS-0046F, Vol. 1, Section 5, October 1980.

III. PHYSICAL REQUIREMENTS

Surface land commitments for the repository will be 2000 acres. Underground drilling activities will be restricted on an additional 8000 acres surrounding the repository. Material and resource requirements are greater for a repository constructed in basalt.

Land Use

The land-use requirements for the model geologic repository in salt and basalt are tabulated in Table 11 for both spent fuel and reprocessing wastes. The model repository in basalt requires additional land for surface facilities due to the greater amounts of rock to be handled.

Table 11. Land-Use Commitments for Construction of an 800-ha Geologic Repository

<u>Land Use</u>	<u>In Salt</u>	<u>In Basalt</u>
Surface Facilities, acres		
Spent fuel repository	440	690
Reprocessing waste repository	440	540
Access roads and railroads, acres	20	20
Mineral and surface rights, acres (fenced restricted area)	2000	2000
Additional land on which only subsurface activities will be restricted, acres	7900	7900

The major resource commitments for the construction of the model repository for each type of waste and rock are listed in Table 12. The resource commitments for operation of the repository are listed in Tables 13 and 14.

Table 12. Average Annual Resource Commitments for the Construction Phase of the Model Repository

Resource	Spent Fuel		Reprocessing Waste	
	Salt	Basalt	Salt	Basalt
<u>Materials^a</u>				
Concrete, ft ³	3.5×10^6	8.8×10^6	3.9×10^6	6.7×10^6
Steel, tons	18×10^3	44×10^3	20×10^3	33 x
Copper, tons	240	620	260	460
Zinc, tons	61	150	68	120
Aluminum, tons	45	120	51	85
Lumber, ft ³	81×10^3	210×10^3	92×10^3	155×10^3
<u>Energy Resources</u>				
Propane, ft ³	7.8×10^3	19×10^3	8.5×10^3	14×10^3
Diesel fuel, gal	0.58×10^6	1.4×10^6	0.63×10^6	1.1×10^6
Gasoline, gal	4.2×10^6	1.1×10^6	0.48×10^6	0.79×10^6
Electricity, kWh	1.4×10^6	3.6×10^6	1.1×10^6	2.6×10^6
<u>Water Use</u> , gal	6.3×10^6	16×10^6	7.1×10^6	12×10^6

a. One-time acquisition, not annualized.

Table 13. Average Annual Resource Commitments for the Operational Phase of Spent Fuel Geologic Repositories

Materials	Salt	Basalt
Canister Overpacks, steel, tons	3.6	5.1
Retrievability Sleeves, steel, tons	1.3×10^3	6.6×10^3
Concrete Plugs, ft ³	14×10^3	9.1×10^3
<u>Energy</u>		
Electricity, kWh	94×10^6	130×10^6
Diesel Fuel, gal	3.5×10^6	3.4×10^6
Coal, tons	81×10^3	80×10^3

Table 14. Average Annual Resource Commitments for the Operational Phase of Fuel Reprocessing Waste Geologic Repositories

<u>Materials</u>	<u>Salt</u>	<u>Basalt</u>
Canister Overpacks, ^{a,b} steel, tons	1.2	1.2
Drum Packs, steel, tons	3.1	3.0×10^3
Retrievability Sleeves, ^c steel, tons	1.7×10^3	10×10^3
Concrete Plugs, ^c ft ³	59×10^3	63×10^3
<u>Energy</u>		
Electricity, kWh	110×10^6	127×10^6
Coal, tons	81×10^3	79×10^3
Diesel fuel, gal	3.5×10^6	3.4×10^6
Steam, tons	870×10^3	860×10^3

- a. Overpack requirements are based on 0.1% of canisters received leaking or damaged.
- b. HLW canister and sleeve diameters change with time as necessary to maintain canister heat output within limits.
- c. Sleeves and plugs needed for first five years only, but are annualized over the total operational phase.

Reference

1. Final Environmental Impact Statement -- Management of Commercially Generated Radioactive Wastes, DOE/EIS-0046F, Vol. 1, Section 5.4, October 1980.

IV. PERSONNEL REQUIREMENTS

The average annual manpower requirements for the construction of a repository range from 1700 for a repository in salt to 5000 for a repository in basalt.

Manpower requirements for the construction and operation of the model geologic repository are summarized in Table 15. The manpower requirements are much lower for a repository in salt. The total number of man-years reflects the varying operational life for each repository scheme.

Table 15. Estimated Manpower Requirements for Construction and Operation of a Geologic Repository

	Spent Fuel		Reprocessing Wastes	
	Salt	Basalt	Salt	Basalt
<u>Construction (man-years)</u>				
Annual ^a	1,700	5,000	2,000	3,800
Total ^b	10×10^3	37×10^3	11×10^3	26×10^3
<u>Operation (man-years)</u>				
Annual	870	1,100	1,300	1,500
Total lifetime ^c	11×10^3	19×10^3	19×10^3	21×10^3

- a. Average annual employment (3-year peak).
- b. Over the 10-year period of construction and mining.
- c. Over the operational lifetime of the repository for reprocessing waste which is 19 years in salt and 18 years in basalt. For the repository for spent fuel the lifetimes are 16 years and 25 years, respectively.

Reference

1. Final Environmental Impact Statement -- Management of Commercially Generated Radioactive Wastes, DOE/EIS-0046F, Vol. 1, Section 5.4, October 1980.

V. OCCUPATIONAL SAFETY AND HEALTH

The risk of nonradiological fatalities and disabling injuries is greater for a repository in a basalt medium than a salt medium. Radiation exposure to employees is principally from naturally occurring radon and from the handling of occasionally defective waste canisters.

The number of predicted injuries (temporarily disabling) and fatalities (or permanently disabling injuries) associated with surface facility construction and underground mining operations for the model spent fuel or fuel reprocessing waste repository are presented in Table 16. These predictions are based on an injury rate of 13.6 temporarily disabling injuries per million hours of construction (National Safety Council 1974) for the surface facilities, and an injury rate of 25 temporarily disabling injuries per million man-hours for underground mining (other than coal). A fatality rate of 0.17 fatalities (or permanently disabling injuries) per million man-hours of construction for the surface facilities and 0.53 fatalities per million man-hours for underground mining (other than coal) were used.

Table 16. Estimates of Nonradiological Disabling Injuries and Fatalities Associated with Repository Construction Based Upon Current Industrial Statistics for Similar Operations

	Spent Fuel		Reprocessing Waste	
	Salt (51,000 MTHM)	Basalt (122,000 MTHM)	Salt (62,000 MTHM)	Basalt (59,000 MTHM)
Surface Facility Construction				
• Temporarily Disabling Injuries	70	70	84	84
• Fatalities and Permanently Disabling Injuries	1	1	1	1
Underground Mining Operations				
• Temporarily Disabling Injuries	370	1700	420	1200
• Fatalities and Permanently Disabling Injuries	8	37	9	25
Total				
• Temporarily Disabling Injuries	440	1800	500	1300
• Fatalities and Permanently Disabling Injuries	9	38	10	26

Routine radiological releases from the model repository during construction consist of naturally occurring radon and its daughter products released during mining. The 70-year whole-body dose commitment to the work force, assuming a seven-year construction period, ranges from 0.18 man-rem for a repository in salt to 6200 man-rem for a repository in basalt.¹ These differences are accounted for by the radionuclide content of the respective rocks.

During the operation of the repository, routine releases consist of radon emanating from the exposed rock, and the radon decay products. These releases are negligible compared to those incurred during construction. Doses to the work force during operation include contributions from the receiving, handling and emplacement of the canisters and estimated minor accidents. The estimated 70-year whole-body doses for the model repository are summarized in Table 17. The doses are based on operational lifetimes and permissible exposure limits. The data suggest individual worker doses of about 1 rem per year over the repository loading period.

Table 17. 70-Year Whole-Body Dose to the Work Force During Operation of the Model Geologic Repository

	<u>Spent Fuel</u>		<u>Reprocessing Wastes</u>	
	<u>Salt</u>	<u>Basalt</u>	<u>Salt</u>	<u>Basalt</u>
Man-rem	4.3×10^3	1.1×10^4	1.4×10^5	1.3×10^5

Reference

1. Final Environmental Impact Statement -- Management of Commercially Generated Radioactive Wastes, DOE/EIS-0046F, Vol. 1, Section 5.4, October 1980.

VI. DECOMMISSIONING

After the initial five-year retrievability period, and after all storage rooms have been filled with waste and are backfilled, the remainder of the repository underground areas are decommissioned. All corridors and underground areas and finally the repository shafts are backfilled to the surface with crushed rock or other media. After sealing the shafts, the surface facilities are decontaminated and/or dismantled, and the repository location is monumented.

VII. LONG-TERM ENVIRONMENTAL RESIDUALS

The quantities of radionuclides expected to be released to the accessible environment from a repository after it is closed range from zero to small quantities released very slowly over thousands of years due to failure of the engineered containment system, intrusion of groundwater, and the slow transport to the accessible environment. The probability of large, catastrophic releases is very, very small.

The long-term environmental residuals from a spent fuel or HLW geologic repository are heat and some small releases of radionuclides. The decay of the radionuclides within the wastes generates heat which will increase the temperature of the surrounding rock and eventually the surface. The maximum increase in surface temperature above the repository will be less than 0.5°C .

The repositories will be designed and the sites chosen with the engineering goal that no radionuclides will leave the area of the repository and enter the biosphere. Two types of mechanisms or events that have been postulated that could cause releases. The first type are various accidents related to meteorite impact, volcanism, accelerated erosion or mining. Such events could possibly result in direct releases from a repository, but in a well designed repository on a well chosen site, the probability of releases due to these actions can be extremely small (see Appendix B).

The second type of mechanism that could result in releases of radionuclides to the environment would require repository failure due to saturation of the repository with groundwater, the slow corrosion of the canisters and other barriers containing the waste form, the leaching of the radionuclides from the waste package by the groundwater, and then transport of the radionuclides by the groundwater to the environment. All of these processes are slow and would mean that if the radiation were released to the environment, it would be released in small quantities over a period of thousands of years. In such a long time frame, much of the radiation will be eliminated through radioactive decay.

In an attempt to establish an upper limit on the amount of radionuclides that could reach the accessible environment in any one year or lifetime, several researchers constructed simple models of these complex phenomena to establish the worst case or upper limits on the releases.^{2,3} In these studies, saturation of the repository with groundwater and failure of the canister is assumed at a certain time after closure. Radionuclides are assumed to be leached away at a constant rate and transported via groundwater to the environment. Figure 2 presents the inflow of radionuclides into the environment as a function of time based on these assumptions.⁴ Table 18 presents time and peak activity of

Figure 2. Inflow of Radionuclides to the Accessible Environment from HLW Equivalent to one MTHM of Spent Fuel (Conservative KBS Case).

releases of the key radionuclides for each of the cases.⁵ Releases of radionuclides due to saturation of a spent fuel repository with water were also calculated by KBS. Those results are similar and are presented in Appendix B.

Such worst case studies have shown that the maximum annual releases of all nuclides are less than 3×10^{-3} Ci/yr per ton of spent fuel or equivalent HLW (or 4×10^{-3} Ci/yr per 10^{12} Btu produced) and that for most years, the releases are orders of magnitude less (see Appendix B).

Table 18. Maximum Inflow of Radionuclides to the Accessible Environment from HLW Equivalent to One MTHM of Spent Fuel, Assuming Repository Saturation With Groundwater and Canister Failure After 1,000 Years^a

	"Conservative" ^b		"Realistic" ^b	
	Time (years)	Activity (Ci/yr/MTHM)	Time (years)	Activity (Ci/yr/MTHM)
Zr 93	4E6	3E-7	--	0
Tc 99	6E3	4E-4	1.6E4	4E-6
I 129 ^c	6E3	9E-9	1.6E4	9E-11
Cs 135	4E5	2E-6	8E6	2E-9
Ra 226	5E4	9E-9	6E5	8E-11
Th 229	9E4	3E-8	3E6	5E-10
Th 230	5E4	9E-10	6E5	9E-12
U 233	5E4	3E-6	5E6	7E-8
U 234	3E4	6E-7	5E5	2E-9
Np 237	2E5	8E-6	3E6	3E-9
Pu 239	6E5	4E-11	--	0

- Based on KBS, reference 3. Released activities are normalized to the HLW produced from one MTHM of spent fuel, which produced approximately 0.79×10^{12} Btu (or 26×10^{-3} GWe-yrs) of electrical energy.
- "Conservative" case assumes a glass leaching time of 30,000 years, groundwater transit time of 400 years. "Realistic" case assumes a glass leaching time of 3 million years, groundwater transit time of 10,000 years, higher retardation factors for neptunium and plutonium.
- Only 1 percent of the I-129 present in spent fuel is assumed present in the HLW. Most of the I-129 and C-14 are assumed released during reprocessing.

References

1. U. S. Department of Energy, Final Environmental Impact Statement -- Management of Commercially Generated Radioactive Wastes, DOE/EIS-0046F, Vol. 1, Section 5.5, October 1980.
2. Nuclear Fuel Safety Project, Handling and Final Storage of Unreprocessed Spent Nuclear Fuel, Vol. II, "Technical" Karnbranslesakerhet, Stockholm, Sweden, Chapter 8, 1978.
3. Nuclear Fuel Safety Project, Handling of Spent Nuclear Fuel and Final Storage of Vitrified High-Level Reprocessing Waste, Vol. IV "Safety Analysis," Karnbranslesakerhet, Stockholm, Sweden, Chapter 6, 1978.
4. Ibid., p. 71.
5. Ibid., pp. 90 and 102.

APPENDIX A COST INFORMATION

The model repository construction cost estimates include owner's costs as well as facility construction. Owner's costs are defined as: land acquisition, startup costs, owner's staff costs and other costs incurred by the owner. Facility construction costs include the costs of all labor, equipment (including waste transport and emplacement equipment), buildings and structures, improvements and shaft, corridor and room mining, shaft sealing and backfilling and architect-engineer services. Interest during construction is not included in the owners' costs for these estimates, but is included in construction expenditures prior to facility start-up when calculating unit costs.

Construction and mining capital cost estimates for the model repository by waste type and media are given in Table A-1. It is assumed that the repository is ready to start waste emplacement operations at the beginning of year 6 (beginning of year 1 is the beginning of construction) and that the entire repository is mined out at the conclusion of year 10.

Operating costs are defined to include direct labor, operating materials, utilities, hole drilling and/or trenching, sleeve and canister emplacement, overhead and contingency costs. Table A-2 tabulates total lifetime operating costs by repository type and media, broken down into expenditures.

Table A-1. Capital Cost Estimates by Expenditure for Construction
of the Model Geologic Repository, May 1981 dollars x 10⁶

	Spent Fuel		Reprocessing Wastes	
	Salt	Basalt	Salt	Basalt
Surface Facilities	248	272	288	296
Shafts and Hoists	134	193	142	206
Underground Facilities	22	22	22	22
Mining	427	2,060	490	1,387
Backfilling	109	346	125	228
Total Field Costs	939	2,892	1,066	2,136
A/E Services	71	84	81	93
Owner's Costs	111	345	127	255
Contingency	275	844	323	628
TOTAL*	1,400	4,200	1,600	3,100

- Escalation is not included; costs are in terms of May 1981 dollars.

Table A-2. Total Operating Costs by Expenditure
for the Model Geologic Repository,
May 1981 dollars x 10⁶

	Spent Fuel		Reprocessing Wastes	
	Salt	Basalt	Salt	Basalt
Labor	300	553	664	664
Materials	63	498	300	775
Utilities	95	174	111	127
Hole Trenching/Drilling	95	1,186	127	206
Sleeve Placement	8	55	8	32
Overhead	79	111	95	79
Contingencies	<u>158</u>	<u>648</u>	<u>324</u>	<u>474</u>
TOTAL*	798	3,225	1,628	2,356

* Escalation factor is not included; costs are in terms of May 1981 dollars.

It can be seen from Tables A-1 and A-2 that construction cost differences between repository waste types are insignificant, but since mining costs account for 30 to 50 percent of total construction costs, the repository in basalt is significantly higher due to the higher mining cost for basalt. Operating costs are also higher for a repository in basalt because of its greater capacity and longer operating lifetime. The estimated uncertainty in these totals is +25 percent.

The unit cost per kgHM is included for comparison of cost relationships in Table A-3 which also summarizes total facility capital and operating costs. Unit costs are costs per unit of production sufficient to recover all construction costs, including interest, and to pay for all operating and de-commissioning expenses. Because of the preliminary nature of the conceptual repository, uncertainty in mining procedures and in the cost of money, the overall uncertainty in the total unit cost is estimated to be +50 percent.

Table A-3. Summary of Total Capital and Operating Costs and Unit Costs for the Model Geologic Repository, May 1981 dollars x 10⁶

Costs	Spent Fuel		Reprocessing Wastes	
	Salt	Basalt	Salt	Basalt
Construction and Mining (x 10 ⁶ \$)*	1,396	4,164	1,595	3,111
Operating (x 10 ⁶ \$)	798	3,225	1,628	2,356
Unit Cost \$/kgHM**	70	117	64	126

* Includes decommissioning costs.

** The weighted cost of capital for the Federal Government is assumed to be 7%.

Since construction and mining, which account for most of the cost, are completed in the first five years of operation, the cost of money has a substantial effect on the unit cost. For example, a cost of money of 0 percent would reduce unit costs in Table A-3 from 35 to 50 percent and a cost of money of 10 percent would increase unit costs 20 to 35 percent.

References

1. Technology for Commercial Radioactive Waste Management, DOE/ET-0028, Vol. 4, Section 7, and Appendix 7A, May 1979.
2. U. S. Department of Energy, Final Environmental Impact Statement Management of Commercially Generated Radioactive Wastes, DOE/EIS-0046F, Vol. I, Section 5.6, October 1980.

APPENDIX B

CHARACTERIZATION OF THE LONG-TERM ENVIRONMENTAL RESIDUALS FROM A GEOLOGIC REPOSITORY

INTRODUCTION

This appendix characterizes the possible long-term environmental residuals from a deep geologic repository. Because such considerations are weighted heavily for this technology only, the residuals are not listed in the summary. The repositories will be designed and the sites chosen with the goal that the environmental residuals will be acceptably small, e.g., that hardly any radionuclides will leave the area of the repository and enter the biosphere. To try to achieve that goal, the repository designers will rely on an engineered system and a natural system to contain and isolate the radionuclides. The engineered system includes the waste form, waste package and underground facility. The site features and characteristics constitute the natural system.

The natural system -- the geologic setting -- will contain the waste at the repository, and severely restrict leakage or migration from it, by its natural barriers. Sites for repositories will be chosen that are geologically very stable and have limited groundwater, the primary means by which radionuclides could be transported from a repository to the biosphere.

The engineered system will serve to contain the waste at the repository by means of multiple physical barriers. There has been extensive research in the United States on the design and performance of the various individual components of the waste package system, under expected conditions. The conceptual waste package used in these performance studies includes the following: The waste form itself being the first containment barrier for the waste. The canister serves as a corrosion resistant protective barrier, and as an absorber for nuclides and heat. The overpack provides an extension of the same functions, with chemical durability being the chief design criteria. The emplacement filler materials are used between these components to either relieve mechanical stresses or to serve as a heat transfer medium. The hole sleeve serves to maintain open emplacement holes in the repository floor, and can also be considered as a barrier.

Even under adverse conditions, the release of radionuclides to the near field around the repository will be at a very slow rate controlled by the initial leaching and subsequent decomposition of the canister and then the natural leaching away of the radionuclides from the waste form. These processes are inherently very slow and even under very adverse conditions could take thousands to a million years. Over that period, many of the radioactive isotopes will have decayed into stable, non-radioactive elements.

During the first several hundred years following emplacement of the wastes, both the radioactivity of and the heat generated by the wastes are attributable mainly to the decay of the short-lived nuclides, primarily fission products. By about one thousand years both the radioactivity and heat generated will have diminished by about three orders of magnitude. As the decay of the long-lived isotopes, primarily actinides, begins to dominate, both the radioactivity and thermal output and thermal gradient of the wastes continue to fall until almost one hundred thousand to one million years after emplacement. By that time both will have diminished by about 5 orders of magnitude and both heat and radioactivity become roughly constant due to the ingrowth of daughter isotopes, primarily Ra 225, Ra 226 and their daughters. Figures B-1 and B-2 show the decrease with time of quantities of radionuclides in spent fuel and HLW.

The area surrounding the emplaced wastes will not return to temperatures near those before the wastes were emplaced until after 10^4 years. An example² of the temperature increases in rock formations surrounding a model repository are given in Figure B-3. The increased and varied temperature in the near field surrounding a repository adds uncertainty to attempts to model or calculate the transport of radioisotopes through the geologic environment.

This appendix discusses the long-term environmental residuals from a spent fuel or HLW repository. Most attempts to model the very long-term behavior (hundreds to millions of years after closure) have taken a twofold approach. The phenomena very close to the waste package and repository, where heat is a major influence, is modeled with complex computer codes. This area is referred to as "near-field." The area from approximately 1 meter outside the repository to the accessible environment is referred to as the "far field." Safety and risk studies predicting the radionuclide releases have generally assumed failure of the waste package and engineered containment system in the near field, and then modeled the slow leaching of the radionuclides from the waste and their transport via groundwater to the environment. These studies have thus established "worst case" or at least very conservative limits on the radionuclide releases from a repository in that very little credit is taken for the natural and engineered barriers that could be in place.

The following section discusses the methods used to model the long-term far-field releases in the event of repository failure. Following it, results from selected conservative studies are presented. The fourth section discusses the "near-field" phenomena that could mitigate the releases modeled in the "conservative" cases.

Figure B-1. Decrease in radiation for radionuclides in spent fuel as a function of time (Reference 1).

Figure B-2. Decrease in quantities of radionuclides in high-level waste as a function of time. Reprocessing takes place ten years after discharge of spent fuel (Reference 1).

Figure B-3. Temperature increase in the rock formation around the final repository 50 and 600 years after disposition (in degrees Celsius, Reference 2).

B.2 MODELING LONG-TERM FAR FIELD RELEASES OF RADIONUCLIDES

Many studies^{1,3-13} have been undertaken to characterize and quantify the releases of radionuclides to the environment that would occur due to failure of the repository. Most researchers have concluded that the greatest releases would occur if the repository became saturated with groundwater during its early post-closure phase, the groundwater leached the radionuclides from their packages, and the dissolved radionuclides were transported by the groundwater to the biosphere via an aquifer hydrologically connected to a surface body of water. Figure B-4 represents a generic description of the groundwater release scenario.

Figure B-4. Groundwater Release Scenario

Other studies have examined the possibility of direct radiation releases from repositories due to various accidents, including: repository breach by meteorite, drilling, solution mining, faulting, volcanism, erosion, and criticality.¹⁴ The probability that these postulated accidents would occur is thought to be extremely low. In some cases, however, such as breach by drilling, it is not possible to reasonably estimate the probability. In other cases, the probability is so low as to be essentially zero. Clairborne and Gera estimated the probability of a meteorite capable of striking the surface over the repository and producing a crater 2 km in diameter at the surface to be 2×10^{-13} per year.¹⁵ The site selection criteria will rule out emplacement in areas of volcanic activity or substantial resource potential.

Radionuclide Releases Due to Groundwater

The entry of radionuclides into the biosphere is generally characterized by a limited number of critical parameters. The entry processes have been modeled based on first principles combined with laboratory and/or experimental data.

The typical parameters used for modeling radionuclide releases to the biosphere are: time of initial breach of canister, leach rate, groundwater travel time, radionuclide travel time, and dilution rate in the biosphere.

Figure B-5 shows a typical cross-sectional view of a repository located in a deep geologic setting.

Figure B-5. Cross section of Repository in Deep Geologic Setting.

The breach of the canister is basically a long-term near-field effect. The time of breach is dependent on several variables including the type and thickness of material(s) used in the canister, the form of waste -- HLW or spent fuel, the temperature of the canister, the internal pressure of the canister, the hydrostatic groundwater pressure, the chemical characteristics of the liquid (groundwater) that may come into contact with it leading to possible stress corrosion, and residual stresses resulting from the manufacturing process (welding, for example) of the canister. Studies show that the time frame for canister failure ranges between 100 and 1,000,000 years. This range represents a wide spectrum of engineering capability and manufacturing cost. For example, several studies have suggested carbon steel or

stainless steel canisters.¹⁶ Others such as the Swedish KBS study have proposed aluminum oxide ceramic materials or a copper or titanium outer case with an inner lead shielding.¹⁷ The encapsulation materials can be selected with the intention of ensuring very good durability and long service life, however, the breaching of the canister is predicted to occur within the time frame mentioned above.

After the canister is penetrated, the next step in the failure process is the slow decomposition of the canisters. It is clear that despite a local penetration of a canister, it is unlikely that the HLW or spent fuel will immediately be exposed in its entirety to leaching action of deep groundwaters. The decomposition of the canister is dependent on the general corrosion properties of the materials chosen for the canister, the rate of groundwater flow around the canister, and the solubility of the corrosion products.

The leaching of the HLW or spent fuel is a very slow process which is dependent on many variables including the type of repository host material (salt, basalt, granite, shale, etc.), the waste form, the temperature, the surface of waste exposed to groundwater, and the chemical composition of the reaction products between the water and waste. It is hypothesized that leaching is a combined process of diffusion-controlled ion exchange and pure dissolution of the matrix material. The matrix material for HLW could be one of many types of glass. Leach rates are normally reported in units of weight loss per unit of surface area per unit of time ($\text{g}/\text{cm}^2\text{-day}$). However, for nuclear waste repositories the rate is generally reported in units of fraction of radionuclide inventory per year. The leach rate varies from $10^{-3}/\text{yr}$ to $3 \times 10^{-5}/\text{yr}$ for high-level wastes and $10^{-6}/\text{yr}$ for spent fuel.

Barring any of the direct release scenarios enumerated earlier, the only mechanism for radionuclides to reach man's environment is by groundwater transport. In the near field (approximately one meter) transport can take place by diffusion, but over long distances between the repository and bodies of fresh water, the waste material will be carried by groundwater flow. The water flows in fissures and intergranular spaces in geologic formations. Most substances migrate at a much slower rate than the water due to reaction with the surface of the fissures, and with the material in the fissures. The factors which determine the time taken for an element to move through the distance are the water velocity, the retention factor and the distance. The groundwater velocity is determined by the hydraulic gradient, the permeability constant and the porosity. All of these quantities are site-specific and cannot be properly evaluated without experimental data from the actual proposed site. The groundwater transit time has been calculated by various researchers and falls in range of 100 to 100,000 years; a site would probably be considered unsuitable if its transit time was less than 1000 years.

Since most nuclides react chemically with the surrounding geologic media, they may migrate more slowly than the groundwater. As a result of this retardation or retention effect, the radioactive isotopes have more time to decay. Various chemical reactions such as ion exchange processes, ion adsorption, reversible precipitation and mineralization contribute to the retention of the

waste products. Retention may be expressed as the ratio of groundwater velocity to nuclide velocity. The results of important experimental work¹⁸ to determine retention factors for some radioactive nuclides are given in Table B-1. If these factors are multiplied times the groundwater travel time, the result is the time required by the nuclide to travel a given distance.

Table B-1. Retention Factors for Radionuclides¹⁸

Element	Retention Factor Short Contact Time	Retention Factor Long Contact Time
Uranium	1,900	23,000
Radium	1,200	48,000
Neptunium	1,900	23,000
Plutonium	2,800	5,700
Strontium	120	1,500

Once the radionuclides reach the biosphere there are a variety of transport media, such as water and air, which will distribute or concentrate the waste particles.

B.3 CONSERVATIVE RESULTS FROM SELECTED STUDIES

For the past 25 years, the United States has been involved in many geologic and environmental studies, the goal of which was to provide the basis for the design, construction and operation of deep geologic repositories for radioactive wastes. These studies have been conducted by numerous Federal agencies and organizations, and independent groups, such as the National Academy of Sciences. Concurrently, there has been an effort by a number of other countries and international groups, such as the International Atomic Energy Agency. These studies, for the most part, have determined that deep geologic disposal operations should result in minimal environmental impact.

Several groups have used simple codes with conservative assumptions to model the release of radionuclides from geologic repositories. Most of the models and methods employed are actually very similar. As discussed in the previous section, there are only four critical parameters in these studies: the time of initial leaching of the waste, the leach rate, the groundwater travel time and the radionuclide travel time. Most of the studies differ principally on the values for these parameters and the methods employed to calculate the distribution of the radionuclides in the biosphere and their subsequent dose to man. These studies can be considered conservative in that they assume early failure of the canister, and then flow of groundwater from the repository directly to the biosphere. Each of these assumptions is considered conservative in a well designed repository on a good site.

A comprehensive assessment of radionuclide storage and disposal was performed by the Swedish power utilities Nuclear Fuel Safety Project (KBS). These studies are unique in that they include the results for both high-level waste and spent fuel for a specific site, and are based on original in-situ data for a granite repository. These series of studies, which are summarized in references 1 and 17, are supported by more than 100 individual technical reports. The conclusion of a recent study¹⁹ is that the KBS studies represent the broadest scope and most thorough work and yet are intrinsically conservative.

The KBS studies used the ORNL code ORIGIN to determine the initial inventory of radionuclides expected to be present in the HLW and spent fuel, and the code GETOUT (developed by Burkholder, et al.,²⁰ for the U. S. waste program) to calculate the transport of the radionuclides from the repository to the biosphere. Although the KBS studies proposed a wide range of engineered barriers (see the following section) to prevent and/or mitigate the consequences of inflow or water into the repository, their reference or conservative release studies assumed either little or no credit for these barriers. For the reference HLW case,²¹ canister failure and the start of leaching was assumed after 1,000 years.

Similar calculations were made in the KBS study on the safety of a geologic repository for unprocessed spent fuel.²² In this study, spent fuel assemblies were assumed to be placed in canisters fabricated from lead and copper. KBS studies indicated that neither mechanical stress or corrosion attack would be expected to give rise to canister penetration within one million years.²³ They therefore assumed, for their pessimistic case, canister penetration after 100,000 years. Results for this case with groundwater transit times of 400 years are presented in Figure B-6.

Results for the pessimistic HLW and spent fuel cases are similar, except that initial releases occur much later for the spent fuel case due to the assumption of 100,000 year canister life. In both cases, the first isotopes to reach the environment are TC-99 and I-129. Several of the longer-lived fission products and all of the actinides appear much later because they are retarded by sorption effects within the geologic media.

Similar models and assumptions have been used in other studies. Table B-2 presents a comparison of two studies with the KBS HLW results. Both Burkholder, et al.,²⁴ and Grimwood²⁵ used models similar to those used in the KBS study. Both studies assumed early failure of the waste canisters and assumed little credit for engineered or geologic barriers. The dominant isotopes released are listed in Table B-2. Burkholder's analysis includes C-14, as well as tritium and iodine isotopes found in spent fuel but likely released at the reprocessing plant. In all of the cases, when repository failure occurs

Figure B-6. Inflow of Radionuclides to the Accessible Environment per MTHM of Spent Fuel ("Conservative" KBS case, Reference 22).

Table B-2. Maximum Inflow Rate of Radionuclides to the Accessible Environment from HLW Equivalent to One MTHM of Spent Fuel, After Repository Saturation with Groundwater and Canister Failure

	Burkholder, et al. ^a		Hill and Grimwood		KBS (Pessimistic) ^c	
	Activity (Ci/yr/MTHM)	Time (years)	Activity (Ci/yr/MTHM)	Time (years)	Activity (Ci/yr/MTHM)	Time (years)
Tc 99	2E-3	2.5E2	3E-3	2E2	4E-4	5E3
C-14	7E-4	1.7E3	--	--	--	--
I-129	1E-5	2.5E2	8E-6	2E2	9E-9	5E3
Ra-226	5E-6	2.1E6	5E-8	1E6	9E-9	5E4
Np-237	8E-5	1.5E4	2E-5	1E4	8E-6	2E5

a. Reference 24, canister failure begins after 2000 years.

b. Reference 25, canister failure after 1000 years.

c. Reference 21, canister failure after 1000 years.

after 1,000 years, sufficient time will have elapsed that the medium-lived isotopes such as SR-90 and Cs-137 will have decayed completely. The first isotopes to reach the environment are Tc-99 and I-129. The transport of most of the other dominant isotopes by the groundwater is retarded to varying degrees. They may therefore appear thousands to hundreds of thousands of years later. As the next section will discuss, when the effects of engineered barriers in the repository are considered, these isotopes may decay completely before reaching the accessible environment.

"NEAR FIELD" PHENOMENA AND THE MITIGATION OF RELEASES

The previous section discussed potential releases from a repository when "enveloping" assumptions were made about the phenomena and processes occurring in the near field zone of the repository. The models assumed saturation of the repository with groundwater, breach of the waste package, leaching of the radionuclides, and their subsequent transport to the biosphere. The mined geologic disposal system proposed by DOE will have multiple independent natural and man-made barriers to prevent or mitigate such occurrences. The natural system associated with the site will provide barriers by: 1) providing waste containment for a given period of time; 2) providing isolation by limiting radionuclide mobility to the biosphere; and 3) assisting in keeping man away from the waste. Engineered barriers associated with the waste package and repository system will provide containment of the waste, delaying the time and retarding the rate of release of radionuclides to the far-field environment. These engineered barriers can function in many ways. They can delay groundwater contact with the waste form, limit the rate of release of radionuclides once groundwater contact has occurred, change characteristics of the near-field groundwater, or provide physical barriers and warning devices to intruders from future generations.

The waste package includes everything placed in the repository waste emplacement hole, e.g., the waste form itself, a stabilizer material, a canister, an overpack and/or sleeve, and a special backfill material between the outer sleeve and the host rock. The first barrier, the backfill, would be relatively impermeable to water. Any residual water passing through the backfill would encounter a sleeve, an overpack, or both, made of corrosion-resistant materials. The canister and, finally, the waste form itself would provide additional barriers. If all these barriers were to fail and some of the radionuclides were leached away from the waste form, the nuclides would still have to travel through the package components. The backfill or other parts of the system would then function as a sorptive barrier to retard or minimize the movement of selected nuclides. Thus, the total waste package system can be designed to minimize the radionuclide inventory entering the natural system. By chemically and physically limiting radionuclide mobility and delaying radionuclide releases, a substantial decay occurs before radionuclides enter the natural system, where there would be additional delay and decay due to sorption reactions with surrounding rock materials along the groundwater path.

In addition to the waste package system, the engineered barriers in a repository structure will include the backfill used in the disposal rooms and the seals in the shafts and boreholes that penetrate the repository.

In order to accurately model the mitigating effects of the engineered barriers in the near-field region of the repository, many phenomena, including mechanical stresses, heat flow, chemical interaction and radiation, must be considered. For some of those phenomena, complex computer models have been developed. For others, models are still rudimentary. The interactions between the waste package components and the host rock fall into six general classes of problems: 1) the movement of fluids like groundwater to the vicinity of the waste package,²⁶ 2) the corrosion of the canister and sleeve materials by these fluids or by the local fluids in the rock, 3) the dissolution of the waste matrix by groundwater containing the added corrosion products, 4) the sorption of radionuclides in the rocks and in the engineered systems, 5) the absorption of radiation emitted from the waste, and 6) the alteration of chemical phases and properties in the vicinity of the canisters. A detailed study of these interactions could predict the kinds, amounts, and chemical state of the radionuclides available for entry into the groundwater system. Such a study, however, has only been done by making simplifying assumptions. Each of the six classes of problems can be separated well enough for individual, but not totally independent, study. Efforts are currently underway by DOE and others to refine and couple the individual models and codes to describe the more complex phenomena that are not independent.

At their current state of development, models for these near field phenomena associated with the engineered barriers can show the major effects that can occur in the near field. Their results can be used in generating conservative inputs, such as the delay prior to groundwater contact with the waste or release rate from the repository, to analyses that predict the long-term performance of the total repository system. Further development and coupling of the codes will improve the details of the predictions and will make possible less conservative, more realistic analyses of overall long-term performance.

Several recent studies have been performed that take credit for some of the natural and engineered barriers. These studies have made either more realistic assumptions for the simple models described in the previous sections or have used more complex models and codes to describe the phenomena. Several studies have also examined the net effect of particular barriers on particular parameters that enter into the calculations and examined the sensitivity of the net releases to these parameters.

In addition to the conservative cases examined, the KBS studies also applied their models to more realistic cases, which took some credit for near-field phenomena. In the reference KBS HLW case,²⁷ dissolution of the vitrified glass waste was assumed to occur linearly over 30,000 years. Since the proposed waste package assumed the canister would be surrounded by a sand-clay backfill of limited permeability to water, the more realistic KBS case assumed a limited supply of water. This resulted in a leaching of 3×10^{-7} of the

the original glass per year or complete dissolution over a period of 3 million years. Based on geological studies of potential sites, a groundwater transit time of 10,000 years was assumed more realistic than the 400 years of the reference case. When more realistic retardation factors based on experimental evidence were also included, the net effect was to reduce the maximum releases to the environment by a factor of 100 or more and delay the appearance of the principal radionuclides by thousands of years. Table B-3 presents a comparison of the reference and realistic KBS HLW cases.

The KBS spent fuel studies²⁸ also examined the effects of natural and engineered barriers. The waste package consisted of a lead and copper canister, surrounded with compacted bentonite clay. Under that configuration, the service life of the canister was judged to be hundreds of thousands of years. For the reference dispersal calculations, the first canisters were assumed to be penetrated after 100,000 years. The "conservative" case assumed a groundwater transit time of 400 years and retention factors based on short contact times. A more "realistic" case was also analyzed that assumed a longer groundwater transit time (3,000 years) and larger retention factors due to the slower groundwater transit. A comparison of these two cases is presented in Table B-4. The C-14 and I-129 have the same retardation factor for both cases and are only reduced slightly. The maximum releases of most of the other isotopes are appreciably lower. KBS also investigated the sensitivity of the results for the two cases to several of the variables, including groundwater transit time, canister lifetime and dispersion phenomena.

Similar results were also reported in performance assessment of a spent fuel repository in hard rock conducted for the International Nuclear Fuel Cycle Evaluation.²⁹ That study assumed a stainless steel spent fuel canister lined with lead and backfilled with bentonite clay. It also assumed simultaneous failure of canisters after 100 years, but took credit for the low permeability of the compacted bentonite barrier. Water movement was analyzed with a three-dimensional flow model. Output from that model was input into the one-dimensional transport model GETOUT used by Burkholder, KBS and others. These analyses resulted in leach times of over 200,000 years and an average groundwater travel time of 11,700 years. With the exception of I-129 which migrates with the groundwater travel time, the radionuclide travel time for the other nuclides was generally on the order of geologic ages of hundreds of millions of years, permitting most of the nuclides to decay. Maximum discharge rates for I-129 occurred after 11,000 years and were about 3×10^{-6} Ci/yr per MTHM of spent fuel. The other expected nuclides were Cs-135 and the actinides, all of which peaked at about 400 million years with total activities of less than 2×10^{-7} Ci/yr per MTHM of spent fuel.

Other studies have evaluated the effects of specific engineered barriers on the potential releases from a repository. Cloninger, et al.,³⁰ for example, looked at the net effect of delaying groundwater contact with the waste form and limiting the rate of release of radionuclides in the groundwater once contact had occurred. The general results were similar to those of KBS and others.

Table B-3. Maximum Inflow of Radionuclides to the Accessible Environment from HLW Equivalent to One MTHM of Spent Fuel, Assuming Repository Saturation With Groundwater and Canister Failure After 1,000 Years^a

	"Conservative" ^b		"Realistic" ^b	
	Time (years)	Activity (Ci/yr/MTHM)	Time (years)	Activity (Ci/yr/MTHM)
Zr 93	4E6	3E-7	--	0
Tc 99	6E3	4E-4	1.6E4	4E-6
I 129 ^c	6E3	9E-9	1.6E4	9E-11
Cs 135	4E5	2E-6	8E6	2E-9
Ra 226	5E4	9E-9	6E5	8E-11
Th 229	9E4	3E-8	3E6	5E-10
Th 230	5E4	9E-10	6E5	9E-12
U 233	5E4	3E-6	5E6	7E-8
U 234	3E4	6E-7	5E5	2E-9
Np 237	2E5	8E-6	3E6	3E-9
Pu 239	6E5	4E-11	--	0

- Based on KBS, reference 27. Released activities are normalized to the HLW produced from one MTHM of spent fuel, which produced approximately 0.79×10^{12} Btu (or 26×10^{-3} GWe-yr) of electrical energy.
- "Conservative" case assumes a glass leaching of 30,000 years, groundwater transit time of 400 years. "Realistic" case assumes a glass leaching time of 3 million years, groundwater transit time of 10,000 years, and higher retardation factors for neptunium and plutonium.
- Only 1% of the I-129 present in spent fuel is assumed present in the HLW. Most of the I-129 and C-14 are assumed released during reprocessing.

Table B-4. Maximum Inflow of Radionuclides to the Accessible Environment from One MTHM of Spent Fuel, Assuming Repository Saturation with Groundwater and Canister Penetration After 100,000 Years^a

	"Conservative" ^b		"Realistic" ^b	
	Time (years)	Activity (Ci/yr/MTHM)	Time (years)	Activity (Ci/yr/MTHM)
C-14	1E5	5E-12	1E5	4E-12
Zr 93	2E6	2E-6	---	---
C 99	1E5	2E-5	3E6	2E-9
I 129	1E5	8E-8	1E5	8E-8
Cs 135	6E5	5E-7	1E7	3E-8
Ra 226	9E5	2E-6	7E7	3E-7
Th 229	9E5	2E-6	7E7	1E-15
Th 230	9E5	9E-7	7E7	3E-7
Pa 231	9E5	6E-7	7E7	1E-7
U 233	9E5	2E-6	7E7	4E-16
U 234	9E5	1E-6	7E7	7E-7
U 235	9E5	6E-8	7E7	5E-8
U 236	9E5	9E-7	7E7	1E-7
U 238	9E5	7E-7	7E7	7E-7
Np 237	9E5	2E-6	7E7	4E-16
Pu 242	1E6	3E-7	---	---

a. Based on KBS, reference 28. Released activities are normalized to one MTHM of spent fuel, which produced approximately 0.79×10^{12} Btu (or 0.026 GWe-yr) of electrical energy.

b. "Conservative" case assumes water transit time of 400 years and pessimistic retention factors. "Realistic" case assumes 3,000 year water transit time and KBS "best estimate" retention factors.

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APPENDIX C
SUMMARY TABLE FOR A GEOLOGIC
REPOSITORY FOR SPENT FUEL

TABLE 1. SUMMARY SHEET FOR SPENT FUEL

COMMERCIAL HIGH-LEVEL NUCLEAR WASTE REPOSITORY

REFERENCE ENERGY SYSTEM

Mined Geologic Repository Facility Capable of Handling Spent Fuel From the Once-Through Uranium Cycle; Located 600 m Deep in Each of Two Candidate Rock Media, Salt and Basalt; Retrievable Emplacement for the First 5 Years of Operation With Optional Permanent Disposal; Packaging Facility Included in Surface Operations; Construction Time Is 10 Years, Mining Operations Taking Place During the Last 7 Years.

FACILITY OPERATING PARAMETERS

	Repository for Spent Fuel	
	Salt	Basalt
Average Annual Capacity (MTHM):	3,200	4,864
Total Equivalent Capacity (MTHM):	51,000	76,960
Total Electrical Energy Represented (Btu):	40×10^{15}	60×10^{15}
Operating Lifetime (yr):	16	25

PROCESS FLOW

RESOURCES USED

	Quantities Used				Per 10^{12} Btu Energy Produced	
	Reference Energy System Annual Usage					
	English Units Salt	English Units Basalt	Metric Units Salt	Metric Units Basalt	Salt	Basalt
Water						
Construction	6.3×10^6 gal	16×10^6 gal	24×10^6 liters	61×10^6 liters	1.6×10^3 gal	1.7×10^3 gal
Energy						
Construction						
Propane	7.8×10^3 ft ³	19×10^3 ft ³	0.22×10^3 m ³	0.54×10^3 m ³	1.9 ft ³	2.0 ft ³
Diesel Fuel	0.58×10^6 gal	1.4×10^6 gal	2.2×10^3 m ³	5.4×10^3 m ³	140 gal	200 gal
Gasoline	0.42×10^6 gal	1.1×10^6 gal	1.6×10^3 m ³	4.0×10^3 m ³	105 gal	110 gal
Electricity	1.4×10^6 kWh	3.6×10^6 kWh	1.4×10^6 kWh	3.6×10^6 kWh	350 kWh	370 kWh
Operation						
Diesel Fuel	3.5×10^6 gal	3.4×10^6 gal	13×10^3 m ³	13×10^3 gal	1.4×10^3 gal	890 gal
Coal	81×10^3 tons	80×10^3 tons	75×10^3 tonnes	72×10^3 tonnes	32 tons	21 tons
Electricity	94×10^6 kWh	130×10^6 kWh	94×10^6 kWh	130×10^6 kWh	37×10^3 kWh	33×10^3 kWh
Operational Materials						
Concrete	14×10^3 ft ³	9.1×10^3 ft ³	0.40×10^3 m ³	0.26×10^3 m ³	5.7 ft ³	2.4 ft ³
Steel	1.3×10^3 tons	6.6×10^2 tons	1.2×10^3 tonnes	6.0×10^2 tonnes	0.52 tons	1.7 tons
Personnel						
Construction (10 yr)	1.7×10^3 Workers	5.0×10^3 Workers	—	—	0.25 Workers	0.38 Workers
Operation	870 Workers	1.1×10^3 Workers	—	—	0.27 Workers	0.20 Workers
Total Usage						
Construction Materials						
Concrete	3.5×10^6 ft ³	8.8×10^6 ft ³	100×10^3 m ³	250×10^3 m ³	87 ft ³	91 ft ³
Steel	18×10^3 tons	44×10^3 tons	16×10^3 tonnes	40×10^3 tonnes	0.44 tons	0.46 tons
Copper	240 tons	820 tons	220 tonnes	560 tonnes	6.0×10^{-3} tons	6.4×10^{-3} tons
Zinc	61 tons	150 tons	56 tonnes	140 tonnes	1.5×10^{-3} tons	1.6×10^{-3} tons
Aluminum	45 tons	120 tons	41 tonnes	110 tonnes	1.1×10^{-3} tons	1.3×10^{-3} tons
Lumber	81×10^3 ft ³	210×10^3 ft ³	2.3×10^6 m ³	5.9×10^6 m ³	2.0 ft ³	2.2 ft ³
Land						
Fenced, restricted	2000 ac	2000 ac	800 ha	800 ha	50×10^{-3} ac	21×10^{-3} ac
Federally controlled	7900 ac	7900 ac	3200 ha	3200 ha	200×10^{-3} ac	82×10^{-3} ac
Surface facilities	440 ac	690 ac	180 ha	280 ha	11×10^{-3} ac	7.2×10^{-3} ac

TABLE 1. SUMMARY SHEET FOR SPENT FUEL (Continued)

COMMERCIAL HIGH-LEVEL NUCLEAR WASTE REPOSITORY

COSTS

	Reference Energy System		Per 10^{12} Btu	
	(May 1981 \$)			
	Salt	Basalt	Salt	Basalt
Construction (10 yr)	$\$1.4 \times 10^9$	$\$4.2 \times 10^9$	$\$35 \times 10^3$	$\$44 \times 10^3$
Operation	$\$0.80 \times 10^9$	$\$3.2 \times 10^9$	$\$20 \times 10^3$	$\$33 \times 10^3$

ENVIRONMENTAL RESIDUALS

	Quantities Used				Per 10^{12} Btu	
	Reference Energy System				Energy Produced	
	English Units Salt	English Units Basalt	Metric Units Salt	Metric Units Basalt	Salt	Basalt
<u>Air Pollutants</u>						
<u>Radionuclides</u>						
Construction						
Radon-220	0.93×10^{-3} Ci	3.1 Ci	—	—	0.16×10^{-6} Ci	0.23×10^{-3} Ci
Radon-222	1.3×10^{-3} Ci	2.7 Ci	—	—	0.23×10^{-6} Ci	0.20×10^{-3} Ci
Lead-210	0.11×10^{-6} Ci	0.23×10^{-3} Ci	—	—	19×10^{-12} Ci	17×10^{-6} Ci
Lead-212	1.4×10^{-6} Ci	4.7×10^{-3} Ci	—	—	0.24×10^{-9} Ci	0.34×10^{-6} Ci
Lead-214	1.3×10^{-3} Ci	2.7 Ci	—	—	0.23×10^{-6} Ci	0.20×10^{-3} Ci
Bismuth-210	1.3×10^{-3} Ci	2.7 Ci	—	—	0.23×10^{-6} Ci	0.20×10^{-3} Ci
Operation						
Krypton-85	5 Ci	5 Ci	—	—	2×10^{-3} Ci	1.32×10^{-3} Ci
Carbon-14	0.1×10^{-3} Ci	0.1×10^{-3} Ci	—	—	0.04×10^{-6} Ci	26×10^{-9} Ci
Iodine-129	0.01×10^{-3} Ci	0.01×10^{-3} Ci	—	—	0.4×10^{-6} Ci	2.6×10^{-9} Ci
Tritium	0.01 Ci	0.01 Ci	—	—	4.0×10^{-3} Ci	2.6×10^{-6} Ci
<u>Fossil Fuel Combustion Products</u>						
Construction						
CO	1200 tons	3200 tons	1100 tonnes	2900 tonnes	0.22 tons	0.23 tons
Hydrocarbons	57 tons	140 tons	51 tonnes	130 tonnes	9.9×10^{-3} tons	0.010 tons
NO _x	240 tons	600 tons	214 tonnes	540 tonnes	.041 tons	0.044 tons
SO _x	14 tons	36 tons	13 tonnes	33 tonnes	2.5×10^{-3} tons	2.6×10^{-3} tons
Particulates	15 tons	36 tons	13 tonnes	33 tonnes	2.6×10^{-3} tons	2.6×10^{-3} tons
Operation						
CO	170 tons	160 tons	150 tonnes	148 tonnes	0.066 tons	0.042 tons
Hydrocarbons	60 tons	62 tons	54 tonnes	56 tonnes	0.024 tons	0.016 tons
NO _x	1000 tons	1100 tons	940 tonnes	960 tonnes	0.41 tons	0.28 tons
SO _x	550 tons	660 tons	610 tonnes	600 tonnes	0.27 tons	0.17 tons
Particulates	30 tons	30 tons	27 tonnes	27 tonnes	0.012 tons	7.7×10^{-3} tons
<u>Dust</u>						
Construction						
Hoist	890 tons	2,600 tons	810 tonnes	2,400 tonnes	0.15 tons	0.19 tons
And	12,000 tons	37,000 tons	11,000 tonnes	34,000 tonnes	2.1 tons	2.7 tons
<u>Solid Wastes</u>	2.0×10^6 tons	5.0×10^6 tons	1.9×10^6 tonnes	6.3×10^6 tonnes	360 tons	370 tons
<u>Water Pollutants</u>						
Not Determined						
<u>Thermal Discharge</u>	23×10^9 Btu	36×10^9 Btu	24×10^9 megajoule	37×10^9 megajoule	9.2×10^6 Btu	9.2×10^6 Btu

ENVIRONMENTAL SAFETY AND HEALTH

	Reference Energy System		Per 10^{12} Btu	
	Annual Average			
	Salt	Basalt	Salt	Basalt
<u>Nonradiological</u>				
Disabling injuries	44.0	180.0	0.011	0.019
Fatalities (a)	0.9	3.8	0.23×10^{-3}	0.39×10^{-3}
<u>Radiological</u>				
Construction	0.026 man-rem	890 man-rem	4.6×10^{-6} man-rem	0.064 man-rem
Operation	0.27×10^3 man-rem	0.44×10^3 man-rem	0.11 man-rem	0.11 man-rem
(a) Fatalities include permanent disabling injuries.				

GLOSSARY

actinides	The series of elements beginning with actinium, Atomic No. 89, continuing through lawrencium, No. 103.
background radiation	The radiation in man's natural and undisturbed environment. It results from cosmic rays and the naturally radioactive elements of the earth, including those from within the human body.
borosilicate glass	A silicate glass containing at least 5 percent boric acid and used to vitrify calcined waste.
CH-TRU wastes	Contact-handled transuranic waste, so packaged that it can be handled by workers without extensive shielding.
Curie (Ci)	A special unit of activity where 1 Ci equals 3.7×10^{10} spontaneous nuclear disintegrations per second.
contingency (cost)	The amount of money added to the estimated cost of a project to cover certain areas of cost uncertainty and reduce the probability of understating the project cost estimate.
decommissioning	Preparations taken for retirement from active service of nuclear facilities, accompanied by the execution of a program to reduce or stabilize radioactive contamination. The objective is to place the facility in such a condition that future risk to public safety is within acceptable bounds.
decontamination factor (DF)	The ratio of the initial amount of a nuclide in a stream (specified in terms of concentration or activity) to the final amount of that nuclide following a given removal treatment.
dose commitment	The total dose to a reference organ or the whole body which will accrue during the remaining lifetime of the individual, due to the intake of a radionuclide. Once ingested or inhaled, the radioactive material may continue to give the person a dose even though the person does not inhale or ingest any more of it; such exposure can continue for a lifetime, as much as 70 years.

GLOSSARY

far-field	The zone that encompasses the host rock, the adjacent rocks, and the entire region in which far-reaching effects may occur.
fuel residue waste (FRW)	Solid wastes consisting of the residue (fuel element hardware and chopped cladding material) after the bulk of fuel core material, including the actinides and fission products, has been dissolved in nitric acid.
host rock	The geologic medium in which the waste is emplaced.
high-level radioactive waste (HLW)	<ol style="list-style-type: none">1) Irradiated reactor fuel.2) Liquid wastes resulting from the operation of the first cycle solvent extraction system, or equivalent, and the concentrated wastes from subsequent extraction cycles, or equivalent, in a facility for reprocessing irradiated reactor fuel, and3) Solids into which such liquid wastes have been converted.
man-rem	A unit for considering the collective radiation dose received by a group of people. One man-rem is equivalent to the amount of radiation dose received by one person exposed to one rem, two persons exposed to one-half rem, etc.
MTHM	Metric tons of heavy metal (usually refers to reactor fuel, in which the heavy metals are uranium and plutonium).
near-field	The zones within, or closely adjacent to, the repository structure.
RH-TRU wastes	Remotely handled TRU wastes having a surface dose greater than 0.2 R/hr. Such packages require extensive shielding and/or remote handling to protect operating personnel.
(roentgen equivalent man)	A quantity used in radiation protection to express the effective dose equivalent for all forms of ionizing radiation.

GLOSSARY

retention factor	The ratio of groundwater velocity to nuclide velocity which gives a measure of the rate of migration of nuclides.
roentgen	A unit for measuring gamma or X-ray radiation. is defined by measuring the effect of the radiation on air, and is that amount of gamma or X-rays required to produce 1 electrostatic unit of charge in cubic centimeter of dry air under standard conditions of temperature and pressure.
transuranic (TRU)	Elements with atomic numbers greater than 92. They include, among others, neptunium, plutonium, americium and curium.

ACRONYMS AND ABBREVIATIONS

A-E	Architect-engineer
ALARA	As low as reasonably achievable
BIOPATH	A computer code that assesses radiation doses to man
British thermal unit
	Boiling water reactor
CFR	Code of Federal Regulations
CH	Contact-handled
Ci	Curie
DF	Decontamination Factor
DOE	Department of Energy
ECIR	Environmental Characterization Information Report
EPA	Environmental Protection Agency
ft ³	Cubic feet
g/cm ²	Grams per square centimeter
GETOUT	A computer code which calculates the rate of nuclide migration in groundwater
ha	Hectare
kgHM	Kilograms of heavy metal
kWh	Kilowatt-hour
ℓ	Liter
MJ	Megajoules
MT	Metric tons
MTHM	Metric tons of heavy metal
m/s	Meters per second
³	Micrograms per cubic meter
NRC	Nuclear Regulatory Commission

ACRONYMS AND ABBREVIATIONS

ORIGEN	A computer code to calculate the isotopic composition of irradiated nuclear fuel
Pu	Plutonium
PWR	Pressurized water reactor
R	Roentgen
rem	Roentgen equivalent man
RH	Remotely handled
TRU	Transuranic
yr	Year

Indirect Coal Liquefaction Plant (Lurgi Fischer-Tropsch Process)

Environmental Characterization Information Report

October 1981

**U.S. Department of Energy
Assistant Secretary for Environmental
Protection, Safety, and
Emergency Preparedness
Office of Environmental Analysis**

CONTENTS

	<u>Page</u>
I. SUMMARY.	A.4-4
II. PROCESS DESCRIPTION AND ENVIRONMENTAL POINTS OF INTEREST	A.4-8
A. Plant Utilities.	A.4-11
1. Run-of-Mine Coal to Coal Preparation.	A.4-11
2. Solid Waste from Coal Preparation	A.4-11
3. Fugitive Dust from Coal Preparation	A.4-15
4. Controlled Runoff from Onsite Storage	A.4-16
5. Fugitive Dust from Onsite Coal Storage.	A.4-17
6. Coal to Lurgi Gasifier.	A.4-18
7. Coal to Utility Power Plant	A.4-20
8. Process-Derived Gaseous and Liquid Fuels.	A.4-24
9. Flue Gas from Utility Power Plant	A.4-27
10. Makeup Water Supply and Onsite Storage.	A.4-37
11. Evaporative and Drift Losses from the Wet Cooling Towers	A.4-38
12. Cooling Tower Blowdown	A.4-39
13. Wastewater Streams from the Utility Power Plant	A.4-40
14. Bottom Ash from Coal Combustion in the Utility Power Plant	A.4-41
15. Fly Ash from Particulate Control of Utility Power Plant Flue Gas	A.4-43
16. Sludge from SO ₂ Control of Utility Power Plant Flue Gas	A.4-44
17. Lime/Limestone Requirement and Makeup Water for SO ₂ Control	A.4-47
18. Oxygen Supply	A.4-50
B. Lurgi Coal Gasification.	A.4-51
19. Lockhopper Vent Gas from Lurgi Gasifier	A.4-52
20. Flare Gases from the Lurgi Gasifier	A.4-55
21. Gasifier Ash.	A.4-56
C. Shift Conversion and Gas Cleaning.	A.4-59
22. Acid Gas to the Sulfur Recovery Unit.	A.4-60
23. Tail Gas of Stretford Sulfur Recovery Unit.	A.4-61
24. Sulfur Byproduct	A.4-62
25. Spent Catalysts from Raw Gas Shift and Fisher-Tropsch Fractionation/Blending	A.4-63

CONTENTS (continued)

	<u>Page</u>
D. Fisher-Tropsch Synthesis, Fractionation, and Product Blending	A.4-64
26. Combustion Product Gases from Gas-Fired Process Heaters	A.4-65
27. Catalyst Regeneration Offgases	A.4-66
28. CO ₂ Vented from the Hydrogen Purification Unit to the Atmosphere	A.4-67
29. Synthetic Natural Gas (SNG) Drying Unit Vent Stream	A.4-68
30. Storage Evaporative Emissions	A.4-69
31. Magnetite Iron Ore Feed (Fe ₃ O ₄) to Fisher-Tropsch Catalyst Preparation Plant	A.4-70
32. Catalyst Preparation Plant Tailings	A.4-71
33. Spent Fischer-Tropsch (F-T) Synthesis Catalyst	A.4-72
34. Hydrocarbon Liquid and Gas Products	A.4-73
35. Vacuum Residue "Bottoms" from the F-T Product Fractionation Unit	A.4-75
E. Resource Recovery and Wastewater Treatment	A.4-76
36. Gas Liquor Stream from Gas Cooling and Purification Units	A.4-77
37. Other Process Wastewaters	A.4-78
38. Wastewater to Biological Treatment	A.4-79
39. Treated and Reclaimed Wastewater	A.4-81
40. Sludge from Wastewater Biological Treatment Unit	A.4-83
41. Ammonia Byproduct Removed from Wastewater	A.4-86
42. Tar, Heavy Oil, and Phenols as Utility Boiler Fuel	A.4-87
43. Separated H ₂ S-Rich Gas Streams	A.4-88
F. Solid Waste Handling and Disposal	A.4-89
44. Direct Solid Waste Landfill	A.4-90
45. Secure Solid Waste Disposal	A.4-92
III. PHYSICAL REQUIREMENTS	A.4-93
IV. PERSONNEL	A.4-95
V. OCCUPATIONAL SAFETY AND HEALTH	A.4-96
APPENDIX A: TRACE ELEMENT ANALYSIS	A.4-97
APPENDIX B: MATERIAL BALANCE	A.4-103
APPENDIX C: SULFUR MATERIAL BALANCE	A.4-106
APPENDIX D: STORAGE EVAPORATIVE EMISSION FORMULAS AND CALCULATIONS	A.4-108
APPENDIX E: COST ESTIMATES	A.4-113
GLOSSARY	A.4-117
ACRONYMS AND ABBREVIATIONS	A.4-119

I. SUMMARY

This Environmental Characterization Information Report (ECIR) for the Indirect Liquefaction of Coal using the Lurgi/Fischer-Tropsch (F-T) process and low-sulfur Wyoming subbituminous coal has been prepared from the latest available environmental and technical information collected from several sources. Although this report is process-specific with respect to the gasification and product synthesis steps, other portions of the assumed design are treated in a generic manner and will vary as a function of site-specific characteristics or conditions.

The typical plant chosen for characterization will process 28,000 tons per day of subbituminous coal to produce 45,000 fuel oil equivalent (FOE) barrels per day in a product slate including synthetic natural gas, gasoline, diesel fuel, heavy fuel oil, alcohols, butane, liquefied petroleum gas (LPG), propane liquefied petroleum gas, and excess electrical power totaling approximately 3.3 MWe. The process also produces marketable byproducts such as sulfur and anhydrous ammonia. The plant is assumed to be a "grass roots" facility operating in a self-sufficient mode at a surface coal mine-mouth site in the West (Wyoming). The process is assumed to be generating all power needed by the facility, both electric and steam, through combustion of a portion of the input coal and various energy-containing process waste or byproduct streams. The plant is assumed to be utilizing maximum water recycle technology and as such will have minimal liquid discharges from the facility.

The process plant operating parameters, resources needed, and the environmental residuals and products associated with the coal liquefaction plant are presented in this section of the summary table (Table 1). Annual resource usage and pollutant discharges are shown in English and Metric units assuming an annual plant capacity factor of 92 percent or 336 days per year of operation.

In addition to annual quantities, the summary table gives quantities in terms of 10^{12} Btu of energy produced. These figures are provided to allow comparison between different energy processes and to facilitate application of the information in computer models.

The supporting information and calculation procedures for the data are given in Section II. Environmental points of interest are discussed individually, giving a brief description of the pollutants or resources involved, standards to be met, example calculations showing the derivation of quantities, scaling laws or guidelines, and extrapolation methods to adjust to other conditions, and a bibliography of cited references. Specific environmental regulations are discussed in the individual sections. The calculations of allowable emission levels are based on current or projected Federal regulations applicable to new plants.

Section III discusses the overall physical requirements of the plant for land, water, and air. A glossary of terms are included as an appendix to this report.

TABLE 1. SUMMARY SHEET
COAL LIQUEFACTION (INDIRECT)

REFERENCE ENERGY SYSTEM

Mine-Mouth Plant Located in Wyoming. Using Low-Sulfur Subbituminous Coal; Utility Power Plant to Provide Steam, Air Separation Plant to Provide Oxygen; Lurgi Pressurized Dry Ash Gasifier and Fischer-Tropsch Synthesis; Environmental Controls Include Electrostatic Precipitators for Particulate Control, SO₂ Scrubbers for SO₂ Control, Stretford Process for Sulfur Recovery, Lurgi Rectisol Process for H₂S Removal, Lurgi Solvolysis Process for Phenol Removal, Chemtec/Lurgi Process for Ammonia Recovery; and Onsite Solid Waste Disposal and Onsite Water Treatment for Recirculation to Minimize Discharge.

FACILITY OPERATING PARAMETERS

Size:	45 x 10 ³ bbl/day fuel oil equivalent
	6 x 10 ⁶ Btu/bbl fuel oil equivalent
Annual Capacity Factor:	92%
Annual Energy Production:	90.7 x 10 ¹² Btu
Process Thermal Efficiency:	57.7%
Lifetime:	30 yr

RESOURCES USED

Code No.	Resource	Quantities Used		
		Reference Energy System Annual Levels*		Per 10 ¹² Btu Energy Produced*
		English Units	Metric Units	
1	<u>Coal</u>			
6	Run of mine (ROM) coal	9.3 x 10 ⁶ tons	8.5 x 10 ⁶ tonnes	10.3 x 10 ⁴ tons
7	Gasifier feed (well sized)	7.66 x 10 ⁶ tons	6.97 x 10 ⁶ tonnes	8.4 x 10 ⁴ tons
10	Power plant (fines)	1.67 x 10 ⁶ tons	1.5 x 10 ⁶ tonnes	1.8 x 10 ⁴ tons
18	Makeup water	3.2 x 10 ⁹ gal (9820 acre-ft)	1.2 x 10 ¹⁰ liters	3.5 x 10 ⁷ gal
	Steam	12.7 x 10 ⁶ tons	11.6 x 10 ⁶ tonnes	4.0 x 10 ⁴ tons
	Oxygen	1.8 x 10 ⁶ tons	1.6 x 10 ⁶ tonnes	2.0 x 10 ⁴ tons
17	<u>Raw Materials</u>			
31	Limestone	12.4 x 10 ³ tons	11.3 x 10 ³ tonnes	137 tons
	Magnetite iron ore feed (catalyst)	27.3 x 10 ³ tons	24.8 x 10 ³ tonnes	301 tons
	<u>Land (30 yr Plant Lifetime)</u>	<u>Total Levels</u>		
	Plant space	630 acres	255 ha	7 acres
	Solid waste disposal	252 acres	102 ha	3 acres

*Based on assumed 92% capacity factor.

TABLE 1. (Continued)
COAL LIQUEFACTION (INDIRECT)

RESOURCES USED (Continued)

Code No.	Resource	Quantities Used		
		Annual Levels*		Per 10 ¹² Btu Energy Produced
		English Units	Metric Units	
	<u>Personnel</u>			
	Plant construction	5200 people/yr (for 4 yr)	N.A.	N.A.
	Plant operation	696 people		
	<u>Capital Costs (Construction)</u>	\$1,887 x 10 ⁶ (total)	N.A.	\$20.8 x 10 ⁶ (total)
	<u>Control costs (construction)</u>	\$174.9 x 10 ⁶ (total)		\$1.93 x 10 ⁶ (total)
	<u>Operation and Maintenance Costs</u>	\$151.5 x 10 ⁶ /yr	N.A.	\$1.67 x 10 ⁶ /yr

*Based on assumed 92% capacity factor.

ENVIRONMENTAL RESIDUALS AND PRODUCTS

		Quantities Released			
Code No.	Residual or Product	Annual Levels*		Per 10 ¹² Btu Energy Produced	Regulatory Compliance Levels
		English Units	Metric Units		
(9)	Air Pollutants**				
(19)	Sulfur dioxide (SO ₂)	3.56 x 10 ³ tons	3.23 x 10 ³ tonnes	39.2 tons	***
(26)	Oxides of nitrogen (NO _x)	8.55 x 10 ³ tons	7.8 x 10 ³ tonnes	94.0 tons	
(27)	Total suspended particulates (TSP)	0.26 x 10 ³ tons	0.24 x 10 ³ tonnes	2.9 tons	
	Nonmethane hydrocarbons (HC)	1.6 x 10 ³ tons	1.5 x 10 ³ tonnes	17.6 tons	
	Carbon monoxide (CO)	3.73 x 10 ³ tons	3.39 x 10 ³ tonnes	41.4 tons	
	Carbon dioxide (CO ₂)	11.0 x 10 ⁶ tons	10.0 x 10 ⁶ tonnes	12 x 10 ⁴ tons	
	Arsenic (As)	36.7-77.2 lb	33.4-70.3 kg	0.40-0.85 lb	
	Beryllium (Be)	5.07-5.7 lb	4.6-5.2 kg	0.056-0.063 lb	
	Cadmium (Cd)	13.2-33.9 lb	6.0-15.4 kg	0.14-0.37 lb	
	Manganese (Mn)	19.9-24.1 lb	9.0-10.9 kg	0.22-0.27 lb	
	Lead (Pb)	14.9-349 lb	6.8-158.0 kg	0.164-3.85 lb	
	Selenium (Se)	11.3 lb	5.1 kg	0.12 lb	
	Uranium (U)	14.4 lb	6.5 kg	0.16 lb	
	Zinc (Zn)	64.5 lb	29.2 kg	0.71 lb	
	Radium-226 (Ra-226)	0.73 x 10 ⁻³ Ci/yr		0.008 x 10 ⁻³ Ci/yr	
(11)	Airborne water from cooling tower drift and evaporation	2.33x 10 ⁹ gal	8.85 x 10 ¹² liters	257 x 10 ⁵ gal	
(29)	Steam in SNG drying unit vent gas	9.10 x 10 ³ tons	8.28 x 10 ³ tonnes	100.0 tons	
(3)	Fugitive dust from coal preparation and storage	Not Determined			
(27)	Catalyst regeneration offgases	Not Available			
	<u>Water Pollutants</u>				
(4)	Runoff from coal storage	Not Determined			
	Water runoff from water treatment ponds	Negligible			

*Based on assumed 92% capacity factor.

**See cumulative air emissions, Table B-3 of Appendix B.

***NSPS for this facility do not exist; however, current standards for power plants would apply to the Utility Section of this facility.

TABLE 1. (Continued)
COAL LIQUEFACTION (INDIRECT)

ENVIRONMENTAL RESIDUALS AND PRODUCTS (Continued)					
Code No.	Residual or Product	Quantities Released		Per 10 ¹² Btu Energy Produced	Regulatory Compliance Levels
		Annual Levels*			
		English Units	Metric Units		
	<u>Solid Wastes</u>				
(2)	Solid waste from coal preparation	93 x 10 ³ tons	84.8 x 10 ³ tonnes	1025 tons	
(14)	Bottom ash (wet) from utility boiler	22.2 x 10 ³ tons	20.3 x 10 ³ tonnes	246 tons	
(15)	Fly ash (dry) from precipitator	68.5 x 10 ³ tons	62.3 x 10 ³ tonnes	755 tons	
(16)	Limestone sludge from SO ₂ control	23.3 x 10 ³ tons	21.2 x 10 ³ tonnes	257 tons	
(21)	Ash from gasifier (wet)	500 x 10 ³ tons	455 x 10 ³ tonnes	5513 tons	
(40)	Sludge from wastewater treatment	42 x 10 ³ tons	38.3 x 10 ³ tonnes	463 tons	
(25)	Spent catalyst from raw gas shift and Fischer-Tropsch	Not Available			
(32)	Catalyst preparation tailings (iron ore)	13.6 x 10 ³ tons	12.4 x 10 ³ tonnes	150 tons	
(33)	Other spent Fischer-Tropsch catalyst	9.0 x 10 ³ tons	8.2 x 10 ³ tonnes	99.2 tons	
	<u>Products</u>				
(34)	Synthetic natural gas (SNG)	58.2 x 10 ⁹ scf	1.65 x 10 ⁹ m ³	64.2 x 10 ⁷ scf	
	Gasoline	4.6 x 10 ⁶ bbl	731 x 10 ³ m ³	5.1 x 10 ⁴ bbl	
	Alcohol	0.67 x 10 ⁶ bbl	7.99 x 10 ⁴ m ³	0.74 x 10 ⁴ bbl	
	Diesel and heavy fuel oil	0.997 x 10 ⁶ bbl	9.07 x 10 ⁵ m ³	1.1 x 10 ⁴ bbl	
	Propane LPG	370 x 10 ³ bbl	4.4 x 10 ⁴ m ³	4079 bbl	
	Butane LPG	49 x 10 ³ bbl	5.8 x 10 ³ m ³	540 bbl	
(24)	Sulfur	20.5 x 10 ³ tons	18.6 x 10 ³ tonnes	0.22 x 10 ³ tons	
(41)	Ammonia	34.2 x 10 ³ tons	31.1 x 10 ³ tonnes	377 tons	
	Surplus electrical power	3.3 MWe			
(8)	Recovered energy	16 x 10 ¹² Btu		0.018 Btu	
(39)	Recovered water for cooling tower makeup	1.89 x 10 ⁹ gal	5.0 x 10 ⁸ liters	20.8 x 10 ⁷ gal	

*Based on assumed 92% capacity factor.

*Based on assumed 92% capacity factor.

OCCUPATIONAL SAFETY AND HEALTH

	Coal Liquefaction Plant Construction and Operation			
	Annual		Per 10 ¹² Btu Produced	
	Accidental	Disease	Accidental	Disease
	0.36	0.26	0.0040	0.0029
injuries	11	—	0.12	—

II. PROCESS DESCRIPTION AND ENVIRONMENTAL POINTS OF INTEREST

Indirect liquefaction refers to those processes for which the primary coal conversion step is gasification. The products from this step are carbon monoxide and hydrogen (known as syngas), and this gas is further reacted to form liquids. In the present study, a Lurgi gasifier is used in conjunction with the Fischer-Tropsch liquefaction process.

To identify the pertinent environmental points of interest in the process flows of a Lurgi/Fischer-Tropsch Indirect Coal Liquefaction plant, several conceptual and general engineering designs of such plants were examined.¹⁻⁷ On the basis of these projected designs and thorough discussions with process engineers and environmental analysts, a representative process design¹ was selected for environmental characterization. In general, the described process is as follows: raw coal, prepared by crushing, washing, and drying is reacted with oxygen and steam in a gasifier to form syngas; some of the syngas is subjected to a shift conversion to increase the (overall) hydrogen to carbon dioxide ratio; acidic gases are removed from the syngas, which then enters the Fischer-Tropsch synthesis reactors and produces a gas, hydrocarbon liquids, and oxygenate liquids; some of these products are fractionated and separated into liquid fuels.

The composite process and facility design discussed herein describes a plant processing 27,800 tons per day of low-sulfur western coal to produce a slate of liquid products equivalent in energy content to 45,000 barrels of fuel oil. To help describe the complete process, the overall facility has been divided into six functional areas: plant utilities; Lurgi coal gasification; shift conversion and gas cleaning; Fischer-Tropsch synthesis, fractionation, and product blending; resource recovery and wastewater treatment; and solid waste handling and disposal. The facility design includes the operating characteristics of all environmental control technologies selected to control the level of environmental emissions and residuals from the process. These include limestone scrubbing and electrostatic precipitators to control the emission levels of sulfur dioxide and particulates from the utility boiler; particulate control (e.g., water sprays, coatings, baghouse filters, etc.) used in connection with coal preparation, coal feed to the gasifier, and ash handling from the gasifier; stripping and biological water treatment for process wastewaters; solid waste disposal by burial or impoundment for all aspects of the process; and sulfur recovery or incineration of various gaseous and liquid wastes from process operation.

The process efficiency calculated on a basis of Btu input versus Btu output in products is 57.7 percent.¹

The overall process flow diagram is shown in Figure 1. Forty-Five points of environmental interest are identified on the flow diagram and discussed and quantified in this section. Items ① through ⑱ deal with utility boiler operation; items ⑲ through ㉑ deal with the gasification function; items ㉒ through ㉕ deal with gas shift conversion and purification; items ㉖ through ㉙ deal with synthesis, fractionation and blending; items ㉚ through ㉝ deal with waste water processing effluents; and solid waste disposal facilities for both direct and secure landfills are discussed in the final section on solid waste.

More details on cost information for the typical plant will be developed for later inclusion in revisions of this ECIR.

References

1. M. Shreiner, "Research Guidance Studies to Assess Gasoline From Coal by Methanol-to-Gasoline and SASOL-Type Fischer-Tropsch Technologies," FE-2447-13, prepared for U.S. Department of Energy by Mobil Research and Development Corporation, August 1978.
2. J. O'Hara et al., "Fischer-Tropsch Complex Conceptual Design/Economic Analysis -- Oil and SNG Production," FE-1775-7, prepared for U.S. Energy Research and Development Administration by Ralph M. Parsons Company, January 1977.
3. U.S. Department of the Interior, Fossil Environmental Impact Statement: Western Gasification Company (WESCO) Coal Gasification Project and Expansion of Navajo Mine by Utah International, Inc., Vols. I and II, FES-76-2, January 1976.
4. M.H. Somerville et al., "A Comparative Study of Effluents and Their Control from Four Dry Ash Lurgi Gasification Plants," prepared for U.S. Department of Energy by the University of North Dakota, Grand Forks, North Dakota, July 1978.
5. M. Ghassemi, K. Crawford, and S. Quinlivan, "Environmental Assessment Report: Lurgi Coal Gasification Systems for SNG," EPA-600/7-79-120, prepared for U.S. Environmental Protection Agency by TRW, Inc., May 1979.
6. Sargent and Lundy Engineers, "Technology Characterization -- Lurgi Coal Gasification Process for Production of High-Btu Synthetic Natural Gas," prepared for Argonne National Laboratory, August 18, 1976.
7. K.A. Rogers et al., "Comparison of Coal Liquefaction Processes," FE-2468-2, prepared for U.S. Department of Energy by the Engineering Societies Commission on Energy, Inc., Washington, D.C., April 1978.

FIGURE 1. PROCESS FLOWCHART WITH ENVIRONMENTAL POINTS OF INTEREST—COAL LIQUEFACTION (INDIRECT)—92% CAPACITY FACTOR

A. Plant Utilities

The design of the conceptual plant assumes that the facility is producing all the electric power and process steam required for operation. The system uses a combination of coal, process byproducts, and combustible waste streams in a power plant boiler whose output is divided as follows: 54 percent for steam to the Lurgi gasifier and 46 percent for electric power, motive power, and heating. The boiler is essentially a pulverized coal boiler using an electrostatic precipitator (ESP) for particulate control and a wet limestone scrubber for SO₂ control. The feature of most environmental interest with respect to this section is the use of the power plant boiler for the combustion of waste and by-product streams. These combined streams will be discussed in this section and in detail individually under their appropriate quantified environmental points of interest. The plant utility section also contains an air separation unit responsible for supplying oxygen to the gasification unit. The balance of the plant utility units function essentially the same as similar units described both in the Western and Eastern Coal-Fired Power Plant ECIRs, and the reader may refer to these documents for additional details.^{1,2}

References

1. U.S. Department of Energy, "Coal-Fired Power Plant (Eastern Coal) Environmental Characterization Information Report," Draft, June 1980.
2. U.S. Department of Energy, "Coal-Fired Power Plant (Western Coal) Environmental Characterization Information Report," Draft, January 1981.

① RUN-OF-MINE COAL TO COAL PREPARATION

The amount of run-of-mine (ROM) coal to the coal preparation plant is 9.3×10^6 tons/yr.

The ROM coal is assumed to be extracted from a western surface mine (strip mine) operating in thick seam subbituminous coal.¹ The mined material is assumed to contain minimal refuse (rock or slate). The material has undergone only rough crushing and sizing to prepare it for transport by way of belt conveyor from the mine site. The ROM coal contains moisture that is both internal to the coal matrix and that has been added by spray equipment in the mine and at conveyor transfer points to control dust. The conveyor is assumed to be covered to minimize loss of material by wind erosion.

The amount of coal entering the preparation plant is determined from the overall thermal efficiency of the process and the individual energy demands in Btu/day of the consuming process units (gasifier and utility boiler). The thermal efficiency of the gasifier will be significantly sensitive to the total set of coal characteristics so the operation must be known for the specific coal to be considered. For rough estimates (± 10 percent), direct substitution of the Btu content of the coal as a scaling factor can be used.

The calculations are as follows:

$$\begin{aligned} \text{Required heat input} &= \left(\frac{1}{(\text{process thermal efficiency})} \right) (6 \times 10^6 \text{ Btu/bbl FOE}) \\ &\quad (\text{net process production bbl/day FOE}) \\ &= \frac{1}{0.577} (6 \times 10^6 \text{ Btu/bbl FOE}) (45 \times 10^3 \text{ FOE/day}) \\ &= 468 \times 10^9 \text{ Btu/day} \end{aligned}$$

Using the coal characteristics of the low-sulfur Wyoming coal assumed for the typical plant operation and assuming that 1-percent or less of the coal is refuse, the amount of ROM coal required for daily plant operation can be calculated as follows:

$$\begin{aligned} \text{ROM coal to preparation plant} &= \frac{(\text{heat input})}{(\text{coal heat content})(1 - \text{rejection rate})} \\ &= \frac{468 \times 10^9 \text{ Btu/day}}{(8500 \text{ Btu/lb})(2000 \text{ lb/ton})(1 - 0.01)} \\ &= 27.8 \times 10^3 \text{ tons/day} \end{aligned}$$

On a yearly basis,

$$\begin{aligned}\text{ROM coal to preparation plant} &= (27.8 \times 10^3 \text{ tons/day})(0.92 \text{ capacity factor})(365 \text{ days/yr}) \\ &= 9.3352 \times 10^6 \text{ tons/yr} \\ &\approx 9.3 \times 10^6 \text{ tons/yr}\end{aligned}$$

The amount of ROM coal required for the preparation plant will be generally proportional to the amount of product desired from the process. Direct proportionality based on overall process thermal efficiency may not hold for large changes in plant capacity, because the consumption of coal for utility boiler operation may not be directly proportional.

Coal preparation facilities will include an area for storage of mined coal to allow continued plant operation should the coal supply be interrupted. This area will be divided into a "live" or working storage area and a "dead" or stockpile area. Coal supplies in the live storage area will be approximately equal to a 6-day plant supply (184×10^3 tons), and coal in dead storage will be equal to approximately a 30-day plant supply (920×10^3 tons). Coal will move in and out of live storage on a daily basis, but coal in dead storage will normally be disturbed only if an interruption in coal supply occurs.

Reference

1. Shreiner, full reference cited on p. 6.

② SOLID WASTE FROM COAL PREPARATION

The solid wastes rejected in coal preparation amount to 0.093×10^6 tons/yr.

Solid waste discharged from the preparation plant consists of shale and sandstone rejected in the cleaning process.^{1,2} The exact composition of this material will vary widely from one grade of coal to another as the site mining conditions change, but the coal content will be kept to a minimum.² The calculation is as follows:

$$\text{Coal preparation waste} = (\text{rejection rate})(\text{ROM coal feed rate})$$

For the conceptual plant,

$$\begin{aligned}\text{Coal preparation waste} &= (0.01)(27.8 \times 10^3 \text{ tons/day}) \\ &= 278 \text{ tons/day}\end{aligned}$$

On a yearly basis,

$$\begin{aligned}\text{Coal preparation waste} &= (278 \text{ tons/day})(0.92 \text{ capacity factor})(365 \text{ days/yr}) \\ &= 0.093 \times 10^6 \text{ tons/yr}\end{aligned}$$

This material is transported with associated moisture back to the mine to be used as backfill. It will be compacted and rehabilitated through revegetation and stabilization techniques along with other mine backfill materials.³ Water control may be necessary for both surface and subsurface drainage of rehabilitated areas.

The production of solid waste for a given coal and a given preparation plant is linearly scalable for changes in plant coal use. As more rock enters in the ROM coal, as in coal having major shale or rock partings, the refuse fraction can be expected to rise accordingly.

References

1. U.S. Environmental Protection Agency, "Environmental Assessment of Coal Cleaning Processes: Technology Overview," EPA-600/7-79-073e, September 1979, p. 47.
2. "West Shows Solid Growth," Coal Age, May 1980, pp. 93-100.
3. Federal Register, "Surface Coal Mining and Reclamation Operations, Permanent Regulatory Program," Vol. 44, No. 50, March 13, 1979, pp. 15435-15439.

③ FUGITIVE DUST FROM COAL PREPARATION

Fugitive or stack particulate emissions from coal preparation are negligible because no thermal drying or mine-site open coal storage is employed, and coal handling facility ventilation systems would be equipped with baghouse filters.

Because the preparation facility functions are confined to screening and crushing of ROM and water sprays are used at transfer points and at screening and crushing operations, there is little opportunity for fugitive dust emissions from the plant.¹ Typical enclosed silo-type coal storage, if used, would add little to these emissions. Exposed pile storage could be the source of windblown dust if no dust control measures such as compacting, water sprays, or surface coatings are used. There is a minimal requirement, however, for mine-site storage for mine-mouth plants and conveyor delivery operations.

Reference

1. U.S. Environmental Protection Agency, Compilation of Air Pollutant Emission Factors, Third Edition, including supplements 1-7, PB 275-525, August 1977, pp. 346-347.

④ CONTROLLED RUNOFF FROM ONSITE COAL STORAGE

The quantity of water runoff from the coal storage area is generally proportional to the surface area of the coal storage piles and the relative quantity of precipitation at the site.

Normal amounts of water that fall on the surface of the coal pile will either be lost to the air through evaporation or be drained to a peripheral drainage channel where it can be routed to the plant water treatment system. The runoff water may contain suspended solids and dissolved solids and would be slightly above neutral because of the alkaline content of the stored coal. The concentration of sulfates would be expected to be less than 1000 mg/l. The concentration of iron and manganese would be low, having values less than 0.8 mg/l and 0.4 mg/l, respectively.¹ Calcium and magnesium are expected to have the highest concentrations, with values of 200 to 400 mg/l and 50 to 250 mg/l, respectively.² The receiving water treatment system is designed to handle such pollutants through settling, neutralization, oil removal, and blending to achieve acceptable water quality for recycling uses in the system.

Water will fall on the surface of the coal piles during heavy rain storms. Although some water will evaporate, percolate into the soil, or remain entrapped in the coal, most water will run off the area by natural drainage. The quantity of water runoff is generally proportional to the surface area of the coal storage pile and the quantity of rainfall during the storm, but will be affected by area contour and texture. Runoff coefficients of 0.726 for the coal storage pile and 0.17 for the exposed land (approximately 20 percent of the coal storage pile surface area) can be used with the appropriate rainfall data.^{3,4}

References

1. F.A. Ferraro, "Treatment of Precipitation Runoff From Coal Storage Piles," Third Symposium on Coal Preparation, NCA/BCR, Louisville, Kentucky, October 1977.
2. E.M. Wewerka et al., "Environmental Contamination From Trace Elements in Coal Preparation Wastes," EPA-600/7-76-007, prepared for U.S. Environmental Protection Agency by Los Alamos Scientific Laboratories, April 1976.
3. D.B. Cox, T.Y.J. Chu, and R.J. Ruane, "Characterization of Coal Pile Drainage," EPA-600/7-79-051, Tennessee Valley Authority, February 1979.
4. J.W. Clar, W.W. Viseman Jr., and M.J. Hammer, Water Supply and Pollution Control, Harper and Row, 1977.

⑤ FUGITIVE DUST FROM ONSITE COAL STORAGE

It is not possible to accurately quantify the fugitive dust emissions from the coal storage area. Wind erosion resulting in airborne dust should not be a significant air pollution source for active piles if dust control measures are maintained.

Coal fines are an inevitable^{1,2} result of coal and handling operations. Dust emissions from the storage areas, especially active storage, can be effectively controlled through the use of surface compaction and, if necessary, water sprays. In addition, oil, asphalt, or latex coatings can be applied to long-term storage piles to control dust emissions. It should also be noted that the surface of a properly compacted long-term storage pile will quickly lose fines, which can become airborne through wind erosion or by settling in the pile, and the dust emissions will drop to a relatively low level unless the pile is physically disturbed.

The dust emissions from an open coal storage pile are not, in general, quantifiable. They are, however, proportional to the exposed surface of the coal pile and generally will increase with increases in surface wind velocity.²

References

① T.H. Pigford et al., "Fuel Cycles for Electrical Power Generation," EEED-101, Teknekron, Inc., Berkeley, California, January 1973.

2. U.S. Environmental Protection Agency, "Survey of Fugitive Dust From Coal Mines," EPA-908/1-78-003, February 1978, pp. 2 and 56.

⑥ COAL TO LURGI GASIFIER

The amount of coal required in the Lurgi gasifier is 7.66×10^6 tons/yr.

Based on the operating characteristics for this plant design, 1.9×10^6 lb/hr or 7.66×10^6 tons/yr¹ of well-sized (1/4 in. to 2 in.) coal required by the gasifier. The number of Lurgi gasifiers is based on coal sized in the range of 1/4 in. to 2 in. Coal fines (minus 1/4 in.) are used as boiler fuel. The coal, a low-sulfur, Wyoming subbituminous coal, is a prime feedstock for the Lurgi dry ash pressure gasifier. The analysis for the design low-sulfur coal is as follows:¹

<u>Proximate Analysis (%)</u>		<u>Ultimate Analysis (%)</u>	
Ash	5.1	C	74.45
Fixed C	33.8	O	19.25
Volatiles	33.1 (includes	H	5.10
material	0.3% sulfur)	N	0.75
Moisture	<u>28.0</u>	S	<u>0.45</u>
	100.0		100.0

Heat value -- 8500 Btu/lb

The trace element concentrations for Wyoming subbituminous coal (ppm) is as follows:²

Ag	0.06-0.43	Ge	-	Sb	0.08-1.5
As	0.57-1.2	Hg	0.11-0.17	Sc	-
B	32	I	-	Se	0.33
Ba	87	In	-	Sn	0.14
Be	0.71-0.8	La	-	Sr	-
Br	-	Li	3.6-15.0	Ta	-
Cd	0.31-0.8	Mo	2.2	Te	-
Ce	-	Mn	2.8-3.4	U	0.88
Co	0.55	Ni	1.7-14	V	10-14
Cr	4.2-16	P	-	W	-
Cs	-	Pb	0.51-12	Y	-
Cu	8.9-10	Rb	-	Zn	0.23-8
F	65-67	Ru	-	Zr	-
Ga	-				

In subsequent sections of this ECIR, values from this coal analysis are used to calculate the resources and residuals associated with operation of the plant, e.g., in item (17), the ash content of the coal is used to calculate the amount of bottom ash from combustion. If a coal different from the one shown in the above table were used, the values from the new coal analysis would be substituted in the equations.

References

1. Shreiner, full reference cited on p. 6.
2. M.K. Ghassemi, K. Crawford, and S. Quinlivan, "Environmental Assessment Report: Lurgi Coal Gasification Systems for SNG," EPA-600/7-79-120, prepared for U.S. Environmental Protection Agency by TRW, Inc., May 1979.

⑦ COAL TO UTILITY POWER PLANT

The utility power plant requires 1.67×10^6 tons/yr of coal fines to produce steam for coal gasification, electrical power, motive power, and process heating.

A pulverized coal boiler in the utility power plant supplies the indirect liquefaction plant with all the required steam for coal gasification. In addition to providing steam for the Lurgi gasifier, the generation plant provides steam to generate electricity, provides motive power (e.g., to run turbine-driven compressor motors), and provides for direct heating of process units. Process-derived fuels, such as tars, oils, and combustible gases, are also recycled and burned in the boiler as a part of its fuel source. The boiler is assumed to be of conventional design having a thermal efficiency of 77 percent.¹

For the conceptual design plant, the total steam required is 3,150,700 lb/hr.¹ The steam requirements for the major components are

- 1,700,335 lb/hr of steam for chemical reaction in the Lurgi gasifier¹
- 1,450,365 lb/hr of steam for electrical power, motive power, and heating¹

This equates to an annual requirement of 12.7×10^6 tons of steam for the conceptual plant.

Therefore, the coal fines feed rate to the boiler can be calculated from the following relationships:

$$\text{Thermal efficiency} = \frac{(\text{steam heat rate})}{(\text{coal feed heat rate}) + (\text{supplemental fuels heat rate})}$$

$$E = \frac{S}{C + F}$$

S = steam heat rate, the product of the steam rate and the steam enthalpy

C = coal feed heat rate, the product of coal feed rate and the heating value of coal

F = supplement fuels heat rate; the feed rates of efficient combustible fuels; oil and tar from gas liquor separator, phenol from phenol recovery unit, residue from vacuum towers, and combustible offgas

from the sulfur recovery unit multiplied by their respective heating values

E = thermal efficiency (assumed to be 77 percent)

Assuming a steam enthalpy of 1337 Btu/lb,² the calculation is as follows:

$$(\text{Coal fines feed rate})(8500 \text{ Btu/lb coal}) = C = \frac{S - EF}{E}$$

$$S = (3,150,700 \text{ lb steam/hr})(1337 \text{ Btu/lb steam}) = 4.2125 \times 10^9 \text{ Btu/hr}$$

$$F = 47 \times 10^9 \text{ Btu/day (recovered energy calculated from item (8), Process-Derived Gaseous and Liquid Fuels)}$$

$$F = 1.96 \times 10^9 \text{ Btu/hr}$$

$$\text{Coal fines feed rate} = \frac{(4.2125 \times 10^9 \text{ Btu/hr}) - (0.77)(1.96 \times 10^9 \text{ Btu/hr})}{(0.77)(8500 \text{ Btu/lb})}$$

$$\begin{aligned} \text{Coal fines feed rate} &= 414,700 \text{ lb/hr} \\ \text{(to utility power plant)} &= (414,700 \text{ lb/hr})(24 \text{ hr/day})\left(\frac{1}{2000 \text{ lb/ton}}\right) \\ &= 4.99 \times 10^3 \text{ tons/day} \end{aligned}$$

On a yearly basis,

$$\begin{aligned} \text{Coal fines feed rate} &= (4.99 \times 10^3 \text{ tons/day})(0.92 \text{ capacity factor})(365 \text{ days/yr}) \\ \text{(to utility boiler)} &= 1.67 \times 10^6 \text{ tons/yr} \end{aligned}$$

A portion of the coal fines burned in the boiler is converted to electrical power by using a fraction of the steam to drive steam turbine generators. For the conceptual plant, 61.4 MWe of power is generated to satisfy all of its electrical needs. Of the 61.4 MWe, 3.3 MWe is excess electrical power that may be exported outside the facility for use by others.¹

To determine how much of the coal fines sent to the power plant is converted to 61.4 MWe of electrical power (P), the following information is needed:

- Net heat rate (Q) in Btu/kWh
- Heat content of coal (Q), as fired in Btu/lb

The heat content of the coal (Q) is a parameter given in the coal analysis. The net heat rate ($\dot{Q}$), which varies from plant to plant, is a measure of the amount of heat (Btu) that must be fed into the boiler to produce 1 kWh of electricity at the power grid. Net power delivered to the grid equals total power generated minus power required to operate power plant auxiliaries, including utility plant environmental control equipment (approximately equal to 5 MW for scrubber and ESP on conceptual plant design). Assuming that the energy content of the coal fed into the boilers is converted into electricity with an efficiency of 35 percent, then $\dot{Q} = 9730$ Btu/kWh. Using the above definitions, the amount of coal fines converted to electrical power is as follows:

$$\begin{aligned}\text{Coal fines feed (electrical)} &= \frac{P\dot{Q}}{Q} \left(\frac{1 \times 10^3 \text{ kWe}}{\text{MWe}} \right) \left(\frac{1 \text{ ton}}{2 \times 10^3 \text{ lb}} \right) \left(\frac{24 \text{ hr}}{\text{day}} \right) \\ &= 12 \frac{P\dot{Q}}{Q} \text{ tons/day} \\ &= \frac{12(61.4 \text{ MWe})(9730 \text{ Btu/kWh})}{8500 \text{ Btu/lb}} \\ &= 0.843 \times 10^3 \text{ tons/day}\end{aligned}$$

On a yearly basis,

$$\begin{aligned}\text{Coal fines feed (electrical)} &= (0.843 \times 10^3 \text{ tons/day})(0.92 \text{ capacity factor})(365 \text{ days/yr}) \\ &= 0.28 \times 10^6 \text{ tons/yr}\end{aligned}$$

Hence, nearly 17 percent of the coal fines sent to the utility boiler is converted to electrical power, while the remaining 83 percent is converted to steam for the Lurgi gasifier, motive power, and direct heating.

In the calculations of environmental pollutants, it is assumed that 20 percent of the ash is emitted as bottom ash and that the remaining 80 percent is emitted from the boiler as fly ash.^{1,3} It is also assumed that 10 percent of the sulfur is retained in the bottom ash and fly ash or removed as a result of pyrite removal in the coal pulverizer, and the remaining 90 percent is converted to sulfur dioxide.^{4,5}

The utility power plant produces electricity with an efficiency of 35 percent; approximately 50 percent of the thermal energy is lost by rejection to the condenser. Other thermal losses consist of 10.7 percent sensible heat loss in the flue gas and 4.3 percent from internal thermal losses and plant consumption.

These heat losses pose little environmental concern: heat is rejected directly to the atmosphere. The heat rejected to the main condenser is cooled by closed-cycle cooling towers, and the heat rejected through the cooling tower blowdown line is dissipated into the atmosphere through water treatment/recycling facility holding ponds.

References

1. Shreiner, full reference cited on p. 6.
2. J. H. Perry, Chemical Engineers' Handbook, 4th edition, McGraw Hill, New York, 1963.
3. G.K. Nielsen, ed., 1978 Keystone Coal Industry Coal Manual, Wyoming Powder River Coal, McGraw-Hill, New York, 1978.
4. U.S. Environmental Protection Agency, "Electric Utility Steam Generating Units: Background Information for Proposed Particulate Emission Standards," EPA-450/2-78-006a, July 1978, p. 3-14.
5. Teknekron, Inc., "Comprehensive Standards: The Power Generation Case," EPA-68-01-0561, March 1975, p. 91.

⑧ PROCESS-DERIVED GASEOUS AND LIQUID FUELS

Waste streams of gaseous and liquid fuels can be collected from the indirect coal liquefaction process for combustion in the utility boiler yielding 16.4×10^9 lb/yr of gaseous fuels and 0.827×10^9 lb/yr of liquid fuel or a total of 15.8×10^{12} Btu/yr of recovered energy.

The gaseous and liquid waste streams from the Stretford sulfur recovery unit, the gas liquor separator, the phenol recovery unit, and the Fischer-Tropsch product fractionation and blending units are utilized as fuel in the utility boiler. Thus, the utility boiler not only provides electrical power and steam for the process, but also serves as an incinerator for the destruction of process wastes. Organic wastes can be destroyed if subjected to combustion at a temperature of approximately 1200°C and at a residence time of 2 seconds.¹ Because these conditions are exceeded in pulverized coal-fired boilers, incineration of these waste streams in such boilers is considered to be an effective method of environmental control.

The quantities of liquid and gaseous fuels recovered from the various process units of the indirect coal liquefaction plant are given in the literature² and shown in Table 2. The total quantities of waste gases and liquids incinerated in the boiler are 48.8×10^6 lb/day and 2.5×10^6 lb/day, respectively.

On a yearly basis,

$$\begin{aligned}\text{Gas mass flow rate} &= (48.829 \times 10^6 \text{ lb/day})(0.92 \text{ capacity factor})(365 \text{ days/yr}) \\ &= 16.4 \times 10^9 \text{ lb/yr}\end{aligned}$$

$$\begin{aligned}\text{Liquid mass flow rate} &= (2.463 \times 10^6 \text{ lb/day})(0.92 \text{ capacity factor})(365 \text{ days/yr}) \\ &= 0.827 \times 10^9 \text{ lb/yr}\end{aligned}$$

Table 2. Boiler Incineration Liquids and Gases

Source	Type	Heating Value (Btu/lb)	Mass Flow Rate (lb/day)
Sulfur Recovery (Stretford)	Offgases (combustible)	243 ²	37.1 x 10 ⁶
Gas Liquor Separator	H ₂ S gas	6.5 ³	0.0264 x 10 ⁶
	Tar liquids	15,700 ³	0.873 x 10 ^{6*}
	Oil liquids	16,700 ²	1.24 x 10 ^{6*}
Phenol Recovery (Phenolsolvan Unit)	Phenol liquids	7,800 ²	0.35 x 10 ⁶
Fischer-Tropsch Fractionation and Blending	Gas from H ₂ recovery and naphtha hydrotreating	--	8.45 x 10 ⁶
	Vacuum tower residue liquids from Fischer-Tropsch product fractionation	17,750 ²	0.0485 x 10 ^{6*}
	CO ₂ gas from CO ₂ removal and SMG drying compression	--	1.88 x 10 ⁶
	CO ₂ gas from catalytic reforming and light ends recovery	--	0.447 x 10 ⁶
	CO ₂ gas from C ₅ /C ₆ isomerization	--	0.0478 x 10 ⁶
	CO ₂ gas from gasoline hydrogenation	--	0.0318 x 10 ⁶
	Stack gas from Fischer-Tropsch hydrotreater and fractionation	--	0.846 x 10 ⁶
	Total Gases		48.829 x 10 ⁶ ≈ 48.8 x 10 ⁶
	Total Liquids		2.463 x 10 ⁶ ≈ 2.5 x 10 ⁶

* Denotes liquid fuels

The amount of recovered energy is calculated as follows:

$$\begin{aligned}
 \text{Recovered energy} &= [(\text{gas mass flow rate})(\text{gas heating value})] \\
 &\quad + [(\text{liquid mass flow rate})(\text{liquid heating value})] \\
 &= [(37.1 \times 10^6 \text{ lb offgas/day})(243 \text{ Btu/lb offgas}) \\
 &\quad + (0.0264 \times 10^6 \text{ lb H}_2\text{S/day})(6.5 \text{ Btu/lb H}_2\text{S})] \\
 &\quad + [(0.873 \times 10^6 \text{ lb tar/day})(15,700 \text{ Btu/lb tar}) \\
 &\quad + (1.24 \times 10^6 \text{ lb oil/day})(16,700 \text{ Btu/lb oil}) \\
 &\quad + (0.0485 \times 10^6 \text{ lb vacuum residue/day})(17,750 \text{ Btu/lb vacuum residue}) \\
 &\quad + (0.35 \times 10^6 \text{ lb phenol/day})(7,800 \text{ Btu/lb phenol})] \\
 &= [(9.02 \times 10^9 \text{ Btu/day}) + (0.00017 \times 10^9 \text{ Btu/day})] + \\
 &\quad + [(13.7 \times 10^9 \text{ Btu/day}) + (20.7 \times 10^9 \text{ Btu/day}) \\
 &\quad + (0.86 \times 10^9 \text{ Btu/day}) + (2.73 \times 10^9 \text{ Btu/day})] \\
 &= 47.0 \times 10^9 \text{ Btu/day}
 \end{aligned}$$

On a yearly basis,

$$\begin{aligned}\text{Recovered energy} &= (47.0 \times 10^9 \text{ Btu/day})(0.92 \text{ capacity factor})(365 \text{ days/yr}) \\ &= 15.8 \times 10^{12} \text{ Btu/yr}\end{aligned}$$

The recovered energy amounts to about 10 percent of the required energy input for a coal-feed of 27.8×10^3 tons/day to the indirect coal liquefaction plant.

References

1. A.C., Scurlock, "Incineration in Hazardous Waste Management," SW-141, U.S. Environmental Protection Agency, 1975.
2. Shreiner, full reference cited on p. 6.
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⑨ FLUE GAS FROM UTILITY POWER PLANT

The pollutants and selected trace elements that are part of the flue gas emitted to the ambient atmosphere, after control, are as follows:

Pollutants

SO ₂	3.56 x 10 ³ tons/yr
NO _x	8.55 x 10 ³ tons/yr
TSP	0.26 x 10 ³ tons/yr
HC	0.39 x 10 ³ tons/yr
CO	1.30 x 10 ³ tons/yr
CO ₂	11.0 x 10 ⁶ tons/yr

Trace Elements*

As	36.7 — 77.2 lb/yr
Be	5.07 — 5.70 lb/yr
Cd	13.2 — 33.9 lb/yr
Mn	19.9 — 24.1 lb/yr
Pb	14.9 — 349 lb/yr
Se	11.3 lb/yr
U	14.4 lb/yr
Zn	64.5 lb/yr
Ra-226	0.73 x 10 ⁻³ Ci(gr)/yr (radioactive)

**Selected trace elements (a representative subset of elements in item ⑥, Coal to Lurgi Gasifier)*

SO₂

The amount of SO₂ emitted to the ambient atmosphere for this unit and the coal characteristics selected is 0.2 lb/10⁶ Btu input. The current New Source Performance Standards for SO₂ regulation are summarized below.¹

<u>Uncontrolled Emissions (1b SO₂/10⁶ Btu)</u>	<u>Percent Reduction</u>	<u>Controlled Emissions (1b SO₂/10⁶ Btu)</u>
> 12	> 90	1.2 maximum
12 to 6	90	1.2 → 0.6
6 to 2	90 → 70	0.6 (constant)
< 2	70	< 0.6

Basically, for steam coals burned by utilities with uncontrolled emissions exceeding 12 lb SO₂/10⁶ Btu, SO₂ reductions exceeding 90 percent would be required to limit emissions to a maximum of 1.2 lb SO₂/10⁶ Btu. For those coals whose uncontrolled emissions would range from 12 to 6 lb/10⁶ Btu, a constant 90-percent removal is required, resulting in controlled emissions ranging from 1.2 lb SO₂/10⁶ Btu to 0.6 lb/10⁶ Btu. For coals with sulfur contents that would emit 6 to 2 lb SO₂/10⁶ Btu, a variable removal rate between 90 and 70 percent is required to achieve a constant 0.6 lb SO₂/10⁶ Btu. For example, at 6 lb SO₂/10⁶ Btu, 90-percent removal is required; at 2 lb SO₂/10⁶ Btu, 70 percent is required; and at 3 lb SO₂/10⁶ Btu, 80 percent is needed. In all cases, it should be noted that the controlled emissions are 0.6 lb/10⁶ Btu. If the uncontrolled emissions are less than 2 lb/10⁶ Btu, 70 percent SO₂ removal is then required.

On a yearly basis, with 70-percent SO₂ removal, the amount of SO₂ released in the flue gas is calculated as follows:

$$\begin{aligned}
 \text{SO}_2 &= (0.3) [(\text{sulfur in coal feed}) + (\text{sulfur in process derived fuels})] (2) \\
 &\text{(The factor 2 appears in the above equation because of the mole ratio of SO}_2 \text{ to S.)} \\
 \text{Sulfur in feed coal} &= (0.003)(414,700 \text{ lb/hr})(24 \text{ hr/day})(365 \text{ days/yr}) \left(\frac{1}{2000 \text{ lb/yr}} \right) (0.92 \text{ capacity factor}) \\
 &= 5 \times 10^3 \text{ tons/yr} \\
 \text{Sulfur in process-derived fuels} &= 2.77 \text{ tons/day} \quad \text{(Calculated in item (16), Sludge From SO}_2 \text{ Control of Utility Power Plant Flue Gas)} \\
 &= 930 \text{ tons/yr} \\
 \text{SO}_2 &= (0.3) (5000 \text{ tons/yr} + 930 \text{ tons/yr}) (2) \\
 &= (0.3) (5930 \text{ tons/yr}) (2) \\
 &= 3558 \text{ tons/yr} \\
 &= 3.56 \times 10^3 \text{ tons/yr}
 \end{aligned}$$

The amount of SO₂ emitted per 10⁶ Btu input is calculated as follows:

$$\begin{aligned}
 \frac{\text{lb SO}_2}{10^6 \text{ Btu}} &= \frac{\text{SO}_2 \text{ in flue gas}}{[(\text{Coal fines feed rate})(\text{coal heat content}) + (\text{process-derived fuels heat rate})]} \\
 \text{SO}_2 \text{ in flue gas} &= (3558 \text{ tons/yr})(2000 \text{ lb/ton}) = 7.12 \times 10^6 \text{ lb/yr} \\
 (\text{coal fines feed rate})(\text{coal heat content}) &= (414,700 \text{ lb/hr})(8500 \text{ Btu/lb})(24 \text{ hr/day}) \\
 &\quad (0.92 \text{ capacity factor})(365 \text{ days/yr}) \\
 &= 2.84 \times 10^{13} \text{ Btu/yr} \\
 \text{Process-derived fuels heat rate} &= (1.96 \times 10^9 \text{ Btu/hr})(24 \text{ hr/day})(0.92 \text{ capacity factor})(365 \text{ days/yr}) \\
 &= 1.58 \times 10^{13} \text{ Btu/yr} \\
 \frac{\text{lb SO}_2}{10^6 \text{ Btu}} &= \frac{7.12 \times 10^6 \text{ lb/yr}}{(2.84 \times 10^{13} \text{ Btu/yr}) + (1.58 \times 10^{13} \text{ Btu/yr})} \\
 &= \frac{0.15 \text{ lb}}{10^6 \text{ Btu}}
 \end{aligned}$$

The SO₂ removal requirements for an 8500-Btu/lb coal are illustrated in Figure 2. Seventy-percent SO₂ removal is required up to a sulfur content of 0.9 percent. Between 2.7 and 5.4 percent sulfur content, 90-percent removal is required. If the sulfur content is in the range between 0.9 and 2.7, different removal rates, as shown, are required to maintain the 0.6 lb SO₂/10⁶ Btu input allowable. For the coal used in this ECIR (0.3 percent sulfur and 8500 Btu/lb), 70-percent SO₂ removal is needed because the coal falls below the 0.9-percent level. When the amount of sulfur from process-derived fuels is added to the coal, the percent of sulfur in the coal burned in the boiler is essentially 0.355 percent. With a total of 10 percent sulfur removed as a result of sulfur retained in the bottom ash and fly ash, the sulfur content as seen by the scrubber is 0.3195 percent (0.355 - 0.1 x 0.355). The scrubber will still be required to remove 70 percent to satisfy current regulatory requirements.

Figure 2. Overall SO₂ Reduction Required for an 8500 Btu/lb Coal to Meet Current NSPS Regulations

NO_x

The current New Source Performance Standard (NSPS) for NO_x regulations is 0.6 lb/10⁶ Btu input.¹

The amount of NO_x emitted to the ambient atmosphere is 0.6 lb/10⁶ Btu. The general way of achieving compliance with NO_x emissions is to employ combustion modification techniques.^{2,3} The boiler manufacturer usually includes in his performance guarantee the provision that while firing coal emissions of nitrogen oxides shall be less than 0.6 lb/10⁶ Btu.⁴ Emissions of oxides of nitrogen are limited by low flame and furnace

temperatures, by short residence time of the gases at high temperatures, and by reduced amounts of excess air present in the flame.

$$NO_x = (0.6 \text{ lb}/10^6 \text{ Btu})(28.5 \times 10^{12} \text{ Btu/yr})\left(\frac{1}{2000 \text{ lb/ton}}\right) = 8.55 \times 10^3 \text{ tons/yr}$$

Particulates

The current New Source Performance Standard for particulate regulation is $0.03 \text{ lb}/10^6 \text{ Btu}$ input.

The amount of particulates (i.e., fly ash that is not captured in the electrostatic precipitator or in the scrubber/mist eliminator) emitted to the ambient atmosphere is $0.03 \text{ lb}/10^6 \text{ Btu}$. The amount of ash in the coal used in this ECIR is 5.1 percent. If 80 percent of the ash is emitted as fly ash,^{4,5} the electrostatic precipitator efficiency is 99.6 percent, and an additional 5 percent or more of particulate material passing the precipitator is removed in the SO_2 scrubber, the particulate emission to the atmosphere is given by

$$\text{Particulates} = [(\text{ash fraction in coal})(\text{fly ash fraction})(\text{coal fines feed rate}) \\ (1 - \text{electrostatic precipitator efficiency})]0.95$$

For the utility plant,

$$\begin{aligned} \text{Particulates} &= [(0.051)(0.80)(4.99 \times 10^3 \text{ tons/day})(1 - 0.996)]0.95 \\ &= 0.77 \text{ ton/day} \end{aligned}$$

On a yearly basis,

$$\begin{aligned} \text{Particulates} &= (0.77 \text{ tons/day})(0.92 \text{ capacity factor})(365 \text{ days/yr}) \\ &= 259 \text{ tons/yr} \\ &\approx 0.26 \times 10^3 \text{ tons/yr} \end{aligned}$$

Therefore, the amount of particulate emission to the atmosphere is about 60 percent of the amount allowed by current NSPS.

$$\begin{aligned} \text{Particulates (NSPS)} &= (0.03 \text{ lb}/10^6 \text{ Btu})(28.5 \times 10^{12} \text{ Btu/yr}) \\ &= 0.855 \times 10^6 \text{ lb/yr} \\ &= 428 \text{ tons/yr} \\ \text{or } \frac{259 \text{ tons/yr}}{428 \text{ tons/yr}} &= 0.60 = 60\% \end{aligned}$$

Carbon Monoxide and Hydrocarbons

The amounts of CO and HC emitted to the ambient atmosphere are 2.5 tons/day and 0.75 ton/day, respectively. The emission factors for CO and HC are 1 lb/ton coal burned and 0.3 lb/ton coal burned, respectively.⁶ Hence, the daily emissions of these pollutants are given by

$$\text{CO, HC} = (\text{emission factor})(\text{coal feed rate})$$

For the utility power plant,

$$\begin{aligned}(\text{CO})_{\text{UTILITY}} &= (1 \text{ lb/ton})(4.99 \times 10^3 \text{ tons/day})/2 \times 10^3 \text{ lb/ton} \\ &= 2.5 \text{ tons/day}\end{aligned}$$

$$\begin{aligned}(\text{HC})_{\text{UTILITY}} &= (0.3 \text{ lb/ton})(4.99 \times 10^3 \text{ tons/day})/2 \times 10^3 \text{ lb/ton} \\ &= 0.75 \text{ ton/day}\end{aligned}$$

In addition, carbon monoxide and hydrocarbons are constituents of the offgases sent to the boiler from the sulfur recovery unit, H₂ recovery-naphtha hydrotreating unit and CO₂ removal-SNG drying-compression unit. Some of the CO and HC is oxidized during combustion, forming CO₂ and H₂O; however, for the fraction that is not combusted, estimates are required for the amounts escaping into the atmosphere. In addition, there will be CO and HC gases emitted from the combustion of tars, oils, and phenols recycled to the boiler for incineration. Because of a lack of reliable data, a worst case assumption was made using the thermal energy content of coal (8500 Btu/lb) for a CO emission factor. It was assumed that 1 lb CO is emitted for every 17×10^6 Btu generated from 1 ton of coal burned. Likewise, for the same energy conversion factor, there is 0.3 lb of HC emitted. In contrast, the same number of Btus generated from the combustion of residual oil has an emission factor for CO and HC of 0.476 lb⁶ and 0.357 lb,⁶ respectively. The amount of recovered energy from the waste gases and liquids was calculated in item (8) to be 47.0×10^9 Btu/day. Therefore, the amount of CO and HC emitted by the combustion of these wastes is calculated as follows:

$$\begin{aligned}(\text{CO})_{\text{PROCESS}} &= \left(\frac{1 \text{ lb CO}}{17 \times 10^6 \text{ Btu}} \right) \left(47.0 \times 10^9 \frac{\text{Btu}}{\text{day}} \right) \left(\frac{1}{2000 \text{ lb/ton}} \right) \\ &= 1.38 \text{ tons/day}\end{aligned}$$

$$\begin{aligned}(\text{HC})_{\text{PROCESS}} &= \left(\frac{0.3 \text{ lb HC}}{17 \times 10^6 \text{ Btu}} \right) \left(47.0 \times 10^9 \frac{\text{Btu}}{\text{day}} \right) \left(\frac{1}{2000 \text{ lb/ton}} \right) \\ &= 0.415 \text{ ton/day}\end{aligned}$$

The total CO and HC emissions are

$$\begin{aligned}\text{CO} &= (\text{CO})_{\text{UTILITY}} + (\text{CO})_{\text{PROCESS}} \\ &= 2.5 \text{ tons/day} + 1.38 \text{ tons/day} \\ &= 3.88 \text{ tons/day}\end{aligned}$$

$$\begin{aligned}\text{HC} &= (\text{HC})_{\text{UTILITY}} + (\text{HC})_{\text{PROCESS}} \\ &= 0.75 \text{ ton/day} + 0.415 \text{ ton/day} \\ &= 1.17 \text{ tons/day}\end{aligned}$$

On a yearly basis,

$$\begin{aligned}\text{CO} &= (3.88 \text{ tons/day})(0.92 \text{ capacity factor})(365 \text{ days/yr}) \\ &= 1303 \text{ tons/yr}\end{aligned}$$

$$\begin{aligned}\text{HC} &= (1.17 \text{ tons/yr})(0.92 \text{ capacity factor})(365 \text{ days/yr}) \\ &= 393 \text{ tons/yr}\end{aligned}$$

There are no New Source Performance Standards for carbon monoxide and hydrocarbon emissions. However, an indication of the completeness of a combustion process is the concentration of carbon monoxide (and, to a lesser extent, hydrocarbon concentration). Therefore, pulverized-coal-fired-boiler combustion is adjusted to minimize emissions of carbon monoxide and hydrocarbons for efficient operation and environmental control.

Carbon Dioxide

The amount of CO_2 emitted to the ambient atmosphere is 32.6×10^3 tons/day. During the combustion of bituminous coal, 0.21 lb CO_2 is emitted to the atmosphere for every 10^3 Btu generated.⁷ Hence,

$$(\text{CO}_2)_{\text{UTILITY}} = (\text{emission factor})(\text{coal fines feed rate})(\text{heat content of coal})$$

For the utility power plant,

$$\begin{aligned}(\text{CO}_2)_{\text{UTILITY}} &= (0.21 \text{ lb}/10^3 \text{ Btu})(4.99 \times 10^3 \text{ tons/day})(8.5 \times 10^3 \text{ Btu/lb}) \\ &= 8.9 \times 10^3 \text{ tons/day}\end{aligned}$$

Also, a small amount of CO_2 is released to the atmosphere from the limestone reaction with the SO_2 .⁸ This amount is estimated as follows:

$$\begin{aligned} (\text{CO}_2)_{\text{LIMESTONE}} &= \left(55.1 \text{ tons/day, limestone into scrubber} \right) \left(\frac{44}{100} \cdot \frac{\text{molecular weight of } \text{CO}_2/\text{CaCO}_3}{1} \right) \\ &= 0.024 \times 10^3 \text{ tons/day} \end{aligned}$$

Several unit processes have carbon dioxide offgases being sent to the utility plant boiler to eventually become part of the flue gas emitted to the atmosphere. The names of the unit processes and the amount of carbon dioxide sent to the boiler are shown below:

<u>Process Unit</u>	<u>Carbon Dioxide in Boiler Flue Gas</u>
Sulfur recovery (Stretford)	17,769 tons/day
CO_2 removal and SNG drying-compression	864 tons/day
Catalytic reforming and light ends recovery	34.2 tons/day
C_5/C_6 Isomerization	3.65 tons/day
Polygasoline hydrogenation	2.42 tons/day
Gas-fired process heaters	328 tons/day
Fischer-Tropsch hydrotreater and fractionation	64.7 tons/day
Total	19,066 tons/day

In addition, carbon dioxide is emitted from the boiler combustion of combustible gases, tars, oils, and phenols from process units, as well as environmental control units. Based on the amount of recovered energy from waste streams calculated in item (8) and the fact that 0.21 lb CO_2 is emitted to the atmosphere for every 10^3 Btu generated, the amount of CO_2 emitted is calculated as follows:

$$\begin{aligned} (\text{CO}_2)_{\text{PROCESS COMB.}} &= \left(\text{recovered energy in Btu/day} \right) \left(0.21 \text{ lb } \text{CO}_2 / 10^3 \text{ Btu} \right) \left(\frac{1}{2000} \frac{\text{lb}}{\text{ton}} \right) \\ &= \left(47.0 \times 10^9 \text{ Btu/day} \right) \left(0.21 \text{ lb } \text{CO}_2 / 10^3 \text{ Btu} \right) \left(\frac{1}{2000} \frac{\text{lb}}{\text{ton}} \right) \\ &= 5 \times 10^3 \text{ tons/day} \end{aligned}$$

The total CO_2 from the process is

$$\begin{aligned} (\text{CO}_2)_{\text{PROCESS}} &= (\text{CO}_2)_{\text{PROCESS UNITS}} + (\text{CO}_2)_{\text{PROCESS COMB.}} \\ &= 19,066 \text{ tons/day} + 5000 \text{ tons/day} \\ &= 24,066 \text{ tons/day} \end{aligned}$$

The total amount of CO₂ emitted to the atmosphere is given by

$$\begin{aligned} \text{CO}_2 &= (\text{CO}_2)_{\text{UTILITY}} + (\text{CO}_2)_{\text{LIMESTONE}} + (\text{CO}_2)_{\text{PROCESS}} \\ &= (8.9 \times 10^3 \text{ tons/day}) + (0.024 \times 10^3 \text{ tons/day}) + (24.1 \times 10^3 \text{ tons/day}) \\ &= 33.0 \times 10^3 \text{ tons/day} \end{aligned}$$

On a yearly basis,

$$\begin{aligned} \text{CO}_2 &= (33.0 \times 10^3 \text{ tons/day})(0.92 \text{ capacity factor})(365 \text{ days/yr}) \\ &= 11.0 \times 10^6 \text{ tons/yr} \end{aligned}$$

Trace Elements

Atmospheric emission rates for representative trace elements in coal are calculated as follows:

<u>Element</u>	<u>lb/day at 100% capacity factor</u>	<u>lb/yr at 92% capacity factor</u>
As	0.1095-0.265	36.7-77.2
Be	0.0313-0.0171	5.07-5.70
Cd	0.0393-0.101	13.2-33.9
Mn	0.0592-0.0718	19.9-24.1
Pb	0.0444-1.04	14.9-349
Se	0.0036	11.3
U	0.043	14.4
Zn	0.192	64.5

Trace elements are species found in small quantities in the raw coal. Other elements in addition to the ones listed above are also typically found in Wyoming coals (refer to item (6)). They become distributed among the ash, wastewater, and flue gases. Because many trace elements exhibit preferential concentrations in the smaller particles emitted, about 5 percent of the initial concentrations of most trace elements are emitted to the ambient atmosphere.⁹ Based on recent work at Lawrence Livermore Laboratory, a method was developed to calculate trace element emissions to the atmosphere. The generalized methodology, algorithm, and associated references for calculating trace element emissions are given in Appendix A.

Radionuclides

Analysis of the fly ash produced by combustion of western subbituminous coal has shown that the design plant will discharge into the atmosphere approximately 2.19×10^{-6} Ci/day of radioactive radium-226.

Because over 80 percent of the trace radioactive particles in coal remain with the fly ash after combustion, removal of the fly ash by electrostatic precipitators is the most effective control technology available.¹⁰ Samples from the combustion of Northern Great Plains coal were analyzed for its radium content by the U.S. Geological Survey with results shown below.¹⁰

Concentration of Radioactive Elements in Fly Ash¹¹

$$\text{Radium-226} = 2.95 \times 10^{-12} \text{ Ci/gm or } 1.34 \times 10^{-9} \text{ Ci/lb}$$

Other trace radioactive elements, such as thorium and uranium, are emitted, but pose a much smaller health hazard than radium.

Assuming the total activity released to the environment is through the fly ash escaping the electrostatic precipitators, the daily release of any radioactive isotope may be calculated as follows:

$$\begin{aligned} \text{Activity of isotope } i, \text{ Ci/day} = & (\text{concentration of isotope } i \text{ in fly ash}) \\ & (\text{fly ash generated, tons/day}) \\ & (2000 \text{ lb/ton})(1 - \text{ESPEFFICIENCY}) \end{aligned}$$

For the design plant,

$$\begin{aligned} \text{Radium-226} = & (1.34 \times 10^{-9} \text{ Ci/lb})(204 \text{ tons/day})(2000 \text{ lb/ton})(1 - 0.996) \\ = & 2.19 \times 10^{-6} \text{ Ci/day} \end{aligned}$$

On a yearly basis,

$$\begin{aligned} \text{Radium-226} = & (2.19 \times 10^{-6} \text{ Ci/day})(0.92 \text{ capacity factor})(365 \text{ days/yr}) \\ = & 0.73 \times 10^{-3} \text{ Ci/yr or } 0.73 \times 10^{-3} \text{ gm/yr} \end{aligned}$$

To date, there are no regulations that apply specifically to the release of radioactive pollutants from coal-fired power plants.

References

1. Federal Register, 40 CFR Part 60, "New Source Performance Standards; Electric Utility Steam Generating Units," Vol. 44, No. 113, June 11, 1979.

2. J. Ando, "NO_x Abatement for Stationary Sources in Japan," EPA-600/7-79-205, August 1979.
3. National Academy of Sciences, "Air Quality and Stationary Source Emission Control," Serial No. 94-4, prepared for the Committee on Public Works, U.S. Senate, 1975.
4. U.S. Environmental Protection Agency, "Electric Utility Steam Generating Units: Background Information for Proposed NO_x Emission Standards," EPA-450/2-78-005a, July 1978.
5. Teknekron, Inc., "Comprehensive Standards: The Power Generation Case," EPA No. 68-01-0561, March 1975, p. 91.
6. U.S. Environmental Protection Agency, "Compilation of Air Pollution Emission Factors," 2nd edition, EPA AP-42, 1975.
7. U.S. Department of Energy, "CO₂ Emissions from Synthetic Fuels Energy Sources," August 8, 1979, p. 2, Table 1.
8. Aerospace Corporation, Estimation, April 1980.
9. K.K. Bertin and E.D. Goldbert, *Science*, Vol. 183, 1971, p. 233.
10. V.E. Swanson, "Collection, Chemical Analysis, and Evaluation of Coal Samples," USGA Open File Report 76-468, 1975.
11. Shreiner, full reference cited on p. 6.

⑩ MAKEUP WATER SUPPLY AND ONSITE STORAGE

The total raw water requirement for process operation is 3.2×10^9 gal/yr, and the evaporative water loss from onsite raw water storage totals approximately 66.8×10^6 gal/yr.

The process is a net water consumer and therefore requires a supply of fresh water for its operation. This water is in addition to the moisture contained in the coal feed material. The water source will vary from site to site, but the most common sources can be expected to be from rivers or wells. To reduce the large water demand, the system utilizes an extensive cascading/recycle of water within the process. Details of water flow within the process are given in Appendix B. The yearly fresh water requirement for the process is 3.2×10^9 gal/yr.¹

Because of the uncertain characteristics of water availability throughout many parts of the West, it is normal practice to include an onsite raw water storage facility to act as an emergency supply should the direct supply be inadequate. A 10- to 20-day supply of stored water is normally considered to be required for plant operation. For the plant design considered here, a 20-day supply amounts to 1.91×10^8 gal of water for feed to the utility power plant, process units, and environmental control equipment based on an annual consumption rate of 3.2×10^9 gal. Design criteria include minimum surface area of the ponds to reduce evaporation. Deep ponds allow thermal stratification of the water and selective withdrawal of cooler waters for cooling purposes. In this case, the pond is assumed to have a surface area of 58.6 acres and a depth of 10 ft. The open surface evaporation can be calculated as follows:

$$\begin{aligned} W_{SEV} \text{ gal/yr} &= \frac{(\text{average evaporation rate, in./yr})(\text{surface area, acres})(325,851 \text{ gal/acre-ft})}{12 \text{ in./ft}} \\ &= \left(\frac{42 \text{ in./yr (Ref. 1)}}{12} \right) (58.6 \text{ acres}) (325,851 \text{ gal/acre-ft}) \\ &= 66.8 \times 10^6 \text{ gal/yr} \end{aligned}$$

There are also seepage losses from the reservoir facility, but they can be reduced to a low level through the control or preparation of the pond bottom material.

Reference

1. R.F. Probstein and H. Gold, Water in Synthetic Fuel Production: The Technology and Alternatives, The MIT Press, 1970, pp. 252 and 256.

11 EVAPORATIVE AND DRIFT LOSSES FROM THE WET COOLING TOWERS

Evaporation and drift losses from the cooling towers into the atmosphere are approximately 2.33×10^9 gal/yr.

Evaporation is the loss of water from the circulating cooling water circuit through conversion to water vapor by the rejected heat. Drift loss is the physical entrainment of a portion of the circulating cooling water in the form of small water droplets. Together, evaporation and drift losses account for the major consumptive use of water in wet cooling towers (refer to water balance in Appendix B). If drift eliminators are not used, approximately 0.25 percent of the evaporated water will be lost in the form of drift.

The cooling towers for this indirect coal liquefaction plant cool hot water from two major cooling water circuits: the indirect coal liquefaction process unit heat exchangers and the power plant's condenser. It has been estimated that the cooling tower evaporation and drift losses from the process unit cooling water circuits total 2.13×10^9 gal/yr.¹ Evaporation and drift losses for the power plant generating 61.4 MWe of electricity are calculated from an algorithm² to be 0.2×10^9 gal/yr and 0.5×10^6 gal/yr, respectively. The calculation is based on the following assumptions: (1) 50 percent of the gross heat released from coal combustion is dissipated to the condenser cooling water, (2) the heat of vaporization and convective heat transfer in the Great Plains area is 1430 Btu/lb of water released to the atmosphere, (3) the power plant's net heat rate is 9730 Btu/kWh for converting the energy content of the coal to electricity at an efficiency of 35 percent.

Therefore, the total cooling tower water loss to the atmosphere is

$$\begin{aligned}\text{Cooling tower water loss} &= (2.13 \times 10^9 \text{ gal/yr}) + (0.2 \times 10^9 \text{ gal/yr} + 0.0005 \times 10^9 \text{ gal/yr}) \\ &= 2.33 \times 10^9 \text{ gal/yr}\end{aligned}$$

Cooling tower emissions may condense under certain ambient conditions and cause visibility impairment, fogging, or icing conditions. There are no existing regulations limiting cooling tower losses to the atmosphere.

References

1. Shreiner, full reference cited on p. 6.
2. U.S. Department of Energy, "Coal-Fired Power Plant (Western Coal) Environmental Characterization Information Report," (Draft) Washington, D.C., January 1981.

12 COOLING TOWER BLOWDOWN

Cooling tower blowdown amounts to 0.688×10^9 gal/yr and represents approximately 30 percent of evaporation and drift losses.

The cooling tower blowdown for this plant design amounts to 0.688×10^9 gal/yr.¹ The blowdown water is sent to a holding pond for containment and reuse. Blowdown water, withdrawn as waste from the recirculating cooling water to control buildup of solid and liquid contaminants in the system, typically contain the following environmental residuals: biocides (e.g., chlorine), added for marine and biological growth control, and corrosion inhibitors (e.g., chromates), and a high concentration of total dissolved solids. These residuals will eventually settle to the bottom of the holding pond.

For this plant,

$$W_{\text{BLOWDOWN}} = 0.688 \times 10^9 \text{ gal/yr}$$

And the evaporation and drift losses are

$$W_{\text{EVAP}} = 2.33 \times 10^9 \text{ gal/yr}$$

Hence,

$$\frac{W_{\text{BLOWDOWN}}}{W_{\text{EVAP}}} = \frac{0.688 \times 10^9 \text{ gal/yr}}{2.33 \times 10^9 \text{ gal/yr}} = 0.30 = 30\%$$

Reference

1. Shreiner, full reference cited on p. 6.

13 WASTEWATER STREAMS FROM THE UTILITY POWER PLANT

Wastewater from various water streams used in maintaining power plant operation amount to 0.167×10^9 gal/yr.

Water throughout the West in general is a very valuable and scarce resource. Therefore, the design plant for this area stresses the reduction of water in consumptive usage.¹ This objective requires the power plant water supply to be arranged in a cascade such that the stream containing the wastewater of one process or function becomes the water source of some other function or process. For example, boiler blowdown can be contained in a holding pond where it can be reused for dust control.² The wastewater comes from

$$\begin{aligned}\text{Boiler blowdown}^2 \text{ and demineralizer waste} &= 0.15 \times 10^9 \text{ gal/yr} \\ \text{Cooling water preparation blowdown}^2 &= 0.0168 \times 10^9 \text{ gal/yr} \\ \text{The total utility wastewater} &= (0.15 + 0.0168) \times 10^9 \text{ gal/yr} \\ &= 0.167 \times 10^9 \text{ gal/yr}\end{aligned}$$

The resulting wastewater can be slightly contaminated with oil or chemicals. In a zero discharge design, these streams will either be directly recycled to appropriate uses, treated for recycle, or placed in evaporative disposal ponds. In general, the volume of these streams will increase with power plant size.

References

1. R.F. Probst and H. Gold, Water in Synthetic Fuel Production: The Technology and Alternatives, The MIT Press, 1978, pp. 47-81.
2. Shreiner, full reference cited on p. 6.

14 BOTTOM ASH FROM COAL COMBUSTION IN THE UTILITY POWER PLANT

The amount of wet bottom ash generated is 22.2×10^3 tons/yr. The amount of water lost due to evaporation from the quenched ash is 0.78×10^6 gal/yr, and 1.23×10^6 gal/yr of water is retained in the disposed ash.

As described earlier in item 6, Coal to the Lurgi Gasifier, the quantity of ash in the coal assumed for this plant design is 5.1 percent, and 20 percent of this ash becomes bottom ash.^{1,2} Thus,

$$\begin{aligned}\text{Bottom ash (dry)} &= (\text{ash fraction in coal})(\text{coal fines feed rate})(\text{bottom ash fraction}) \\ &= (0.051)(4.99 \times 10^3 \text{ tons/day})(0.20) \\ &= 50.9 \text{ tons/day}\end{aligned}$$

On a yearly basis,

$$\begin{aligned}\text{Bottom ash (dry)} &= (50.9 \text{ tons/day})(0.92 \text{ capacity factor})(365 \text{ days/yr}) \\ &= 17.1 \times 10^3 \text{ tons/yr}\end{aligned}$$

Bottom ash from a dry bottom pulverized coal boiler is collected and quenched in hoppers located beneath the boiler, where it is sluiced with water to settling ponds or dewatering bins.³ In this plant design, the material will be sent to a direct landfill in the surface mine area.

The amount of water lost due to evaporation and disposal of ash is calculated to be 2×10^6 gal/yr from an algorithm given in the eastern coal-fired power plant ECIR.⁴ Of the total amount of water lost, 0.78×10^6 gal/yr are evaporated during quenching, and 1.23×10^6 gal/yr remains with the disposed ash in the landfill.

The weight of the wet bottom ash delivered to a landfill for disposal is

$$\begin{aligned}\text{Bottom ash (wet)} &= \left[17.1 \times 10^3 \text{ tons/yr} + (1.23 \times 10^6 \text{ gal/yr}) \left(8.33 \text{ lb/gal} \right) \left(\frac{1}{2000 \text{ lb/ton}} \right) \right] \\ &= 17.1 \times 10^3 \text{ tons/yr} + 5.12 \times 10^3 \text{ tons/yr} \\ &= 22.2 \times 10^3 \text{ tons/yr}\end{aligned}$$

References

1. U.S. Environmental Protection Agency, "Electric Utility Steam Generating Units: Background Information for Proposed Particulate Emission Standards," EPA-450/2-78-006a, July 1978, p. 3-14.
2. Teknekron, Inc., "Comprehensive Standards: The Power Generation Case," EPA No. 68-01-0561, March 1975, p. 91.
3. Water Purification Associates, "Final Report: An Assessment of Minimum Water Requirements for Steam-Electric Power Generation and Synthetic Fuel Plants in the Western United States," prepared for Science and Public Policy Program, University of Oklahoma, Contract No. 68-01-1916, August 24, 1976, p. 142.
4. U.S. Department of Energy, "Coal-Fired Power Plant (Eastern Coal) ECIR," Draft, June 1980.

15 FLY ASH FROM PARTICULATE CONTROL OF UTILITY POWER PLANT FLUE GAS

The total amount of fly ash generated is 68.5×10^3 tons/yr.

electrostatic precipitators are used to remove the coal fly ash from flue gas. Eighty percent of the ash in the coal is emitted as fly ash,^{1,2} or

$$\text{Fly ash} = (\text{ash fraction in coal})(\text{coal fines feed rate})(\text{fly ash fraction})$$

For the design plant,

$$\begin{aligned}\text{Fly ash} &= (0.051)(4.99 \times 10^3 \text{ tons/day})(0.80) \\ &= 204 \text{ tons/day}\end{aligned}$$

On an annual basis,

$$\begin{aligned}\text{Fly ash} &= (204 \text{ tons/day})(0.92 \text{ capacity factor})(365 \text{ days/yr}) \\ &= 68.5 \times 10^3 \text{ tons/yr}\end{aligned}$$

Less than 0.4 percent of this amount will be emitted to the ambient atmosphere because approximately 99.6 percent can be captured by the electrostatic precipitator, and 5 to 30 percent of the remainder will be captured in the SO₂ scrubbing system.

From these precipitators, the collected ash is discharged into storage hoppers by rapping. The dry fly ash is transported by pneumatic conveyor from the precipitator to the storage hoppers to be sold as a byproduct or to the SO₂ scrubber sludge disposal facility where it can be used in the sludge fixing process as a drying agent and filler.

References

- U.S. Environmental Protection Agency, "Electric Utility Steam Generating Units: Background Information for Proposed Particulate Emission Standards," EPA-450/2-78-006a, July 1978, p. 3-14.
2. Teknekron, Inc., "Comprehensive Standards: The Power Generation Case," EPA No. 68-01-0561, March 1975, p. 91.

16 SLUDGE FROM SO₂ CONTROL OF UTILITY POWER PLANT FLUE GAS

The amount of scrubber sludge generated (on a dry basis) is 23.3×10^3 tons/yr.

Sulfur composition in the coal used is 0.3 percent. Therefore, coal contribution of sulfur entering the boiler is

$$\begin{aligned} S &= (\text{sulfur fraction in coal})(\text{coal feed rate}) \\ &= (0.003)(4.99 \times 10^3 \text{ tons/day}) \\ &= 14.97 \text{ tons/day} \end{aligned}$$

The total amount of sulfur entering the boiler from coal and sulfur-containing compound gases recycled to the boiler for incineration is

$$S = (\text{sulfur in coal}) + (\text{sulfur in recycled gas})$$

Several unit processes will emit sulfur-containing gaseous compounds that are sent to the boiler for incineration.¹ These units and the equivalent amounts of pure sulfur being sent to the boiler are listed as follows:

<u>Unit</u>	<u>Sulfur-Containing Gaseous Compounds</u>	<u>Mass Flow Rate</u>	<u>Sulfur Content Mass Flow Rate</u>
Sulfur Recovery Unit	H ₂ S	66.8 lb/hr	62.9 lb/hr
	COS	120 lb/hr	64.1 lb/hr
Gas Liquor Separator	H ₂ S	110 lb/hr	103.4 lb/hr
H ₂ Recovery & Naphtha Hydro-treating Subunit in Product Recovery Unit	H ₂ S	0.340 lb/hr	0.32 lb/hr
Total			230.7 lb/hr or 2.77 tons/day

The total amount of sulfur entering the boiler from coal and sulfur-containing compound gases recycled to the boiler for incineration is

$$\begin{aligned} S &= (\text{sulfur in coal}) + (\text{sulfur in recycled gases}) \\ &= 14.97 \text{ tons/day} + 2.77 \text{ tons/day} \\ &= 17.7 \text{ tons/day} \end{aligned}$$

it is assumed that a total of 10 percent of the sulfur is retained² in the bottom ash and fly ash or removed as a result of pyrite removal in the coal pulverizer, and that the remainder of the sulfur is converted to SO₂, then

$$\begin{aligned} \text{SO}_2 &= (0.9)(\text{sulfur entering boiler})(2 \text{ tons SO}_2 / \text{ton sulfur}) \\ &= (0.9)(14.97 \text{ tons/day})(2) \\ &= 26.9 \text{ tons/day} \end{aligned}$$

Thus, 26.9 tons/day of SO₂ enter the scrubber.^{1,3-5} (Note: The factor "2" in this equation is used because every mole of sulfur requires 1 mole of oxygen to form 1 mole of SO₂.) As will be shown in item (17), Lime/Limestone Requirement and Makeup Water for SO₂ Control, the amount of dry limestone used is 36.8 tons/day, i.e., 1.25 times the stoichiometric requirement. This excess 25 percent of the stoichiometric requirement will become part of the sludge residue. It is generally accepted² that the spent slurry consists of 75 percent CaSO₃·H₂O and 25 percent CaSO₄·2H₂O. As was shown in item (9), Flue Gas From Utility Power Plant, the scrubber must operate at 70-percent efficiency to meet the standard. Consequently, the amount of scrubber sludge (dry basis) generated each day is⁶

$$\begin{aligned} \text{Sludge} &= [0.25 (100/64) + (140/64)](\text{scrubber efficiency})(\text{SO}_2 \text{ feed rate}) \\ &= [0.25 (100/64) + (140/64)](0.70)(26.9 \text{ tons/day}) \\ &= 69.4 \text{ tons/day} \end{aligned}$$

On a yearly basis,

$$\begin{aligned} \text{Sludge} &= (69.4 \text{ tons/day})(0.92 \text{ capacity factor})(365 \text{ days/yr}) \\ &= 23.3 \times 10^3 \text{ tons/yr} \end{aligned}$$

where

100/64 = limestone/SO₂ molecular weight ratio

140/64 = (CaSO₃·H₂O and CaSO₄·2H₂O) mixture/SO₂ molecular weight ratio

Under previous Federal New Source Performance Standards limiting sulfur dioxide emissions to 1.2 lb/million Btu for electric utility boilers, no specific percentage of sulfur dioxide reduction over uncontrolled emissions for a particular coal was required. Under this regulation low-sulfur coal having a sulfur content such that less than 1 lb/million Btu would be emitted to the atmosphere was an acceptable control approach for these boilers. Low-sulfur coal in combination with other techniques such as coal cleaning and sulfur dioxide scrubbing were also acceptable approaches for these boilers. Under these regulations, low-sulfur coal was sometimes referred to as "compliance coal" because it could meet or contribute to meeting applicable standards. The feedstock for this plant design is such a coal, having only a 0.3 percent sulfur content. Such coal is still in use in power plants that, due to their date of construction, are subject to the previous Federal New Source Performance Standards regulations. New regulations as explained in item (9), Flue Gas From Utility Power Plant, require a specific percentage of sulfur removal (which is not less than 70 percent for any coal) from the specific coal used.

References

1. Personal Communication, Robert Statnick, (202) 426-2683, Senior Staff Engineer, Office of Energy, Minerals, and Industry, Office of Research and Development, U.S. Environmental Protection Agency, Washington, D.C.
2. Aerospace Corporation, "Controlling SO₂ Emissions from Coal-Fired Steam-Electric Generators: Solid Waste Impact, Vol. II. Technical Discussion," EPA-600/7-78-0446, March 1978.
3. Personal Communication, Walter Stevenson, (919) 541-5477, Staff Scientist, Office of Air Quality Planning and Standards, U.S. Environmental Protection Agency, Raleigh-Durham, North Carolina, April 1980.
4. U.S. Environmental Protection Agency, "Electric Utility Steam Generating Units: Background Information for Proposed SO₂ Emission Standards," EPA-450/2-78-007a, July 1978.
5. U.S. Environmental Protection Agency, "Position Paper on Regulation of Atmospheric Sulfates," EPA-450/2-75-007, September 1975.
6. Shreiner, full reference cited on p. 6.

17 LIME/LIMESTONE REQUIREMENT AND MAKEUP WATER FOR SO₂ CONTROL

The amount of lime/limestone required for flue gas desulfurization is 12.4×10^3 tons of dry CaCO₃/yr, and the amount of makeup water required for desulfurization is 39.6×10^6 gal/yr.

Limestone scrubbing, absorbent utilization is generally 0.8¹ (i.e., the calcium-to-sulfur weight ratio is 1.25) and, as shown in item 9, Flue Gas From Utility Power Plant, Figure 2, the scrubber has to achieve 70-percent removal efficiency to satisfy the SO₂ emission standard. The exact percentage of scrubber removal efficiency will be a function of the standards under which a particular plant must operate. The percentage removal and the limestone required can be expected to be less for utility boilers operating under previous New Source Performance Standards and using low-sulfur coals. (The requirement is given solely in terms of limestone because of the relatively large economic penalty incurred if lime is purchased rather than obtained by calcination of limestone.) The limestone requirement is therefore given by

$$\begin{aligned}\text{Limestone} &= (1.25)(100/64)(\text{SO}_2 \text{ feed rate})(\text{scrubber efficiency}) \\ &= (1.25)(100/64)(26.9 \text{ tons SO}_2/\text{day})(0.70) \\ &= 36.8 \text{ tons dry CaCO}_3/\text{day}\end{aligned}$$

where

$$100/64 = \text{limestone/SO}_2 \text{ molecular weight ratio.}$$

On an annual basis,

$$\begin{aligned}\text{Limestone} &= (36.8 \text{ tons/day})(0.92 \text{ capacity factor})(365 \text{ days/yr}) \\ &= 12.4 \times 10^3 \text{ tons/yr}\end{aligned}$$

For this analysis, a lime/limestone slurry is used in the scrubber; therefore, the amount of makeup water required for flue gas desulfurization should be estimated.

It is assumed that the flue gas is saturated with water vapor upon leaving the scrubber. Typical conditions at this location are $P = 15.056$ psia and $T = 102^\circ\text{F}$, which correspond to flue gas containing

0.127 mole water/mole dry gas.¹ If the fractional weights of carbon (C), sulfur (S), hydrogen (H), oxygen (X), and water (W) in the coal are known, and 15 percent excess air is assumed, it can be shown that the makeup water requirement per unit weight of coal is given by the following relation:²

$$\frac{\text{lb makeup water}}{\text{lb coal fines}} = 12.8 \left(\frac{C}{12} + \frac{S}{32} \right) + 10.5 \left(\frac{H}{4} - \frac{X}{32} \right) - W - \frac{H}{9}$$

Using the coal fines feed rate obtained previously, the above equation can be modified to give the required daily water feed rate, W_{FGD}^1 :

$$W_{FGD}^1, \text{ gal/day} = \left[12.8 \left(\frac{C}{12} + \frac{S}{32} \right) + 10.5 \left(\frac{H}{4} - \frac{X}{32} \right) - W - \frac{H}{9} \right] \left(2.88 \times 10^3 \frac{PQ}{Q} \right)$$

In addition to water vapor leaving with the flue gas, there is also going to be some water leaving with the solid wastes, e.g., $\text{CaSO}_3 \cdot \text{H}_2\text{O}$ and $\text{CaSO}_4 \cdot 2\text{H}_2\text{O}$. It is to be noted that, for the purposes of these calculations, the amount of water of hydration is considered negligible. The amount of water leaving in the solid wastes is a function of the sulfur concentration of coal and the slurry concentration,^{2,3} i.e.,

$$\frac{\text{lb makeup water}}{\text{lb sulfur}} = 5.9 \left(\frac{1 - m}{m} \right)$$

where

m = weight fraction of solids in waste

= (weight of solids)/(weight of solids plus water)

The above equation can similarly be modified to give the required daily water feed rate, W_{FGD}^2 :

$$W_{FGD}^2, \text{ gal/day} = 1.7 \times 10^4 \frac{PQ}{Q} s \left(\frac{1 - m}{m} \right)$$

The total required daily water feed rate is therefore given as

$$W_{FGD} = W_{FGD}^1 + W_{FGD}^2$$

For the conceptual design plant, application of the above equations gives

$$W_{FGD}^1 = 0.117 \times 10^6 \text{ gal/day (vaporized)}$$

$$W_{FGD}^2 = 0.000893 \times 10^6 \text{ gal/day (80 percent solids)}$$

$$W_{FGD} = 0.118 \times 10^6 \text{ gal/day}$$

On an annual basis,

$$\begin{aligned} W_{FGD} &= (0.118 \times 10^6 \text{ gal/day})(0.92 \text{ capacity factor})(365 \text{ days/yr}) \\ &= 39.6 \times 10^6 \text{ gal/yr} \end{aligned}$$

References

1. Aerospace Corporation, "Controlling SO₂ Emissions from Coal-Fired Steam-Electric Generators: Solid Waste Impact, Vol. II. Technical Discussion," EPA-600/7-78-044b, March 1978.
2. R.F. Probstein and H. Gold, Water in Synthetic Fuel Production: The Technology and Alternatives, The MIT Press, 1978, pp. 40-44.
3. Water Purification Associates, "Final Report: An Assessment of Minimum Water Requirements for Steam-Electric Power Generation and Synthetic Fuel Plants in the Western United States," prepared for Science and Public Policy Program, University of Oklahoma, Contract No. 68-01-1916, August 24, 1976, pp. 110-120.

18 OXYGEN SUPPLY

1.8 x 10⁶ tons/yr of oxygen is separated from air for the gasification of coal.

Air is compressed and cooled in the air separation plant to produce the required 449,920 lb/hr of oxygen to react with coal and steam in the gasifier.¹ On a yearly basis,

$$\begin{aligned}\text{Oxygen mass flow rate} &= (449,920 \text{ lb/hr}) \left(\frac{1}{2000 \text{ lb/ton}} \right) (24 \text{ hr/day}) (365 \text{ days/yr}) (0.92 \text{ capacity factor}) \\ &= 1.8 \times 10^6 \text{ tons/yr}\end{aligned}$$

Nitrogen, the other major component of air, is returned to the atmosphere with only a small fraction retained in storage for process operations.

References

1. Shreiner, full reference cited on p. 6.

B. Lurgi Coal Gasification

The Lurgi coal gasification section consists of a battery of 28 operating and 2 standby Lurgi pressurized fixed-bed coal gasification units. Steam (40.8×10^6 lb/day) and oxygen (11×10^6 lb/day) react with the coal (45.6×10^6 lb/day) in the gasifiers to produce a raw gas with an energy content of approximately 350 Btu/Scf, which must undergo further upgrading (partial shift conversion) to match the input requirements of the Fischer-Tropsch synthesis process. The raw gas (94×10^6 lb/day) leaving the gasifiers is composed mostly of carbon monoxide (14.5×10^3 lb/day) and hydrogen (2136 lb/day) along with significant quantities of methane, ethylene, carbon dioxide, hydrogen sulfide, and unreacted steam. Because the gasifier operates in essentially a continuous mode at elevated pressure (500 psig) and temperature (700°F to 1100°F), lockhoppers are located at both the top and bottom of the unit to enable the introduction of sized coal into the reactor vessel and the removal of ash from the reactor vessel, respectively. Low-pressure raw gases escaping the lockhopper recovery-recompression system are vented to the atmosphere through a wet scrubber unit. Ash from each bottom lockhopper is first quenched and then sluiced by the ash handling system to the solid waste handling and disposal section. The gasification reaction along with the input and output components are shown below.

19 LOCKHOPPER VENT GAS FROM LURGI GASIFIER

Vent gas from the Lurgi gasifier lockhoppers amounts to 9.7×10^3 tons/yr after exiting the scrubbers.

Well sized coal is fed to the Lurgi gasifier by means of a lockhopper system. Even though the reaction in the Lurgi gasifier is continuous, because of the nature of the process, venting of gas from the lockhopper occurs intermittently.

To determine the composition of the vented gas, a number of assumptions must be made: (1) the feed lockhopper pressurizing gas has the same composition as the raw synthesis gas entering the raw gas cooling unit, (2) the organic compounds in the vent gas is the same as what is reported in the literature,¹ (3) the fatty acids present in the raw synthesis gas and the vented gas would be the same as the composition of fatty acids in the gas liquor as reported in the literature,² and (4) the trace elements present in the coal would also be present in the raw synthesis gas and the vented gas. The composition of the vented gas before and after the venturi scrubbers is given in Table 3.

The estimated cumulative value given above is based on the assumptions that 3 to 4 percent of the raw synthesis gas is used for lockhopper pressurization, and during lockhopper depressurization, 0.1 percent of the raw synthesis gas flow rate is vented.³ The synthesis gas flow rate is reported to be 3,900,000 lb/hr.^{3,4} Based on these assumptions, the Lurgi gasifier lockhopper vent gas is calculated as follows:

$$\begin{aligned} \text{Lockhopper vent gas} &= (0.001)(\text{raw synthesis gas flow rate}) \\ \text{(before scrubbers)} &= (0.001)(3,900,000 \text{ lb/hr})(24 \text{ hr/day}) \\ &= 93,600 \text{ lb/day} \end{aligned}$$

On a yearly basis,

$$\begin{aligned} \text{Lockhopper vent gas} &= (93,600 \text{ lb/day}) \left(\frac{1}{2000 \text{ lb/ton}} \right) (0.92 \text{ capacity factor}) (365 \text{ days/yr}) \\ \text{(before scrubbers)} &= 15.7 \times 10^3 \text{ tons/yr} \end{aligned}$$

Table 3. Composition of Lockhopper Vent Gas¹

Component	Weight Percent Before Scrubber**	Mass Flow Before Scrubber (lb/hr)	Weight Percent After Scrubber**	Mass Flow After Scrubber (lb/hr)
Carbon dioxide (CO ₂)	37.9	1483	37.9	1483
Carbon monoxide (CO)	15.4	602	15.4	602
Methane (CH ₄)	5.3	206	5.3	206
Ethylene (C ₂ H ₄)	0.064	2.5	0.064	2.5
Carbon oxysulfide (COS)	0.003	0.12	0.003	0.12
Carbonyl [Ni(CO ₄)]	1.5 ppm	0.006	1.5 ppm	0.006
Nitrogen (N ₂)	0.002	8.4	0.002	8.4
Water (H ₂ O)	36.4	1422	0.0	0.0
Hydrogen (H ₂)	2.3	89	2.3	89
Hydrogen sulfide (H ₂ S)	0.138	5.4	0.138	5.4
Tars	0.113	4.4	0.0113*	0.44*
Oils	0.985	38.5	0.0985*	3.85*
Naphtha	0.402	15.7	0.0402*	0.157*
Phenols	0.113	5.2	0.0113*	0.52*
Mercaptans	5.1 ppm	0.02	5.1 ppm	0.02
Thiophenes	4.1 ppm	0.016	4.1 ppm	0.016
Ammonia	0.207	8.1	0.0207*	0.81*
HCN	2.0 ppm	0.008	2.0 ppm	0.008
Aromatic amines	1.0 ppm	0.004	1.0 ppm	0.004
Nitrosamines	0.5 ppm	0.002	0.5 ppm	0.002
PAHs	0.5 ppm	0.002	0.5 ppm	0.002
Fatty acids	0.026	1.0	0.0026*	1.0*
Trace elements	0.5 ppm	0.002	0.5 ppm	0.002
	99.553	3909.38	62.129	2403.0

* Assumed 90-percent scrubber removal efficiency.

** ppm signifies parts per million by weight.

Before venting to the atmosphere, the lockhopper vent gases pass through venturi scrubbers where a portion of the gases and liquids are removed. Assuming the venturi scrubbers remove a fraction of the components as shown in Table 3, then the calculated amount of vented gas existing the scrubbers is

$$\text{Lockhopper vent gas} = (2403 \text{ lb/ton}) \left(\frac{1}{2000 \text{ lb/ton}} \right) (24 \text{ hr/day}) (365 \text{ days/yr}) (0.92 \text{ capacity factor})$$

$$(\text{after scrubbers}) = 9.7 \times 10^3 \text{ tons/yr}$$

The vented gas from the gasifier lockhoppers is applicable to a Lurgi gasifier receiving approximately 45.6×10^6 lb/day of well sized coal and reacting it with 40.8×10^6 lb/day of steam and 11×10^6 lb/day of oxygen. This value should be directly proportional to increases or decreases in gasifier throughput.

References

1. J.G. Cleland et al., "Pollutants From Synthetic Fuels Production: Coal Gasification Screening Test Results," EPA-600/7-79-200, prepared for U.S. Environmental Protection Agency by Research Triangle Institute, Research Triangle Park, North Carolina, August 1979.
2. P.C. Singer et al., "Assessment of Coal Conversion Waste Waters: Characterization and Preliminary Biotreatability," EPA-600/7-78-181, prepared for the U.S. Environmental Protection Agency by the University of North Carolina, September 1978.
3. M.K. Ghassemi, K. Crawford, and S. Quinlivan, "Environmental Assessment Report: Lurgi Coal Gasification Systems for SNG," EPA-600/7-79-120, prepared for U.S. Environmental Protection Agency by TRW, Inc., May 1979.
4. Shreiner, full reference cited on p. 6.

20 FLARE GASES FROM THE LURGI GASIFIER

Intermittent flaring of gasifier waste gases range in value from 0.157×10^6 tons/yr to 0.471×10^6 tons/yr.

During plant or individual gasifier train startup, shutdown, and upset situations, a significant amount of gasifier gas is sent to the flare stack where it is burned. Data are not available for accurately quantifying the amount and composition of such gases being emitted on an annual basis because of the inherent variability of transient operations at different times. Furthermore, routine startup/shutdown operations vary from plant-to-plant, and upset conditions are unpredictable, complicating estimating techniques even more. The greatest amount of flaring will occur during plant startup rather than during the later normal plant operation.

To determine an order-of-magnitude estimate, it was assumed that random and periodic discharges of waste gas to the flare on an average yearly basis amount to 1 to 3 percent of the plant's raw synthesis gas flow rate. The raw synthesis gas flow rate for this plant design is reported to be 3,900,000 lb/hr.¹ Thus, the annual average amount of flare gas is calculated as follows:

$$\begin{aligned} \text{Flare gas} &= (0.01)(3,900,000 \text{ lb/hr}) \left(\frac{1}{2000 \text{ lb/ton}} \right) (24 \text{ hr/day}) (365 \text{ days/yr}) (0.92 \text{ capacity factor}) \\ &\quad \text{to} \\ &\quad (0.03)(3,900,000 \text{ lb/hr}) \left(\frac{1}{2000 \text{ lb/ton}} \right) (24 \text{ hr/day}) (365 \text{ days/yr}) (0.92 \text{ capacity factor}) \\ &= 1.57 \times 10^5 \text{ tons/yr to } 4.71 \times 10^5 \text{ tons/yr} \end{aligned}$$

The waste gas sent to the flare is expected to contain all the components in the raw synthesis gas as described earlier for the lockhopper vent gas.^{2,3} The characteristics of the gas after it has been flared are unknown at this time.

References:

1. Shreiner, full reference cited on p. 6.
2. M.K. Ghassemi, K. Crawford, and S. Quinlivan, "Environmental Assessment Report: Lurgi Coal Gasification Systems for SNG," EPA-600/7-79-120, prepared for U.S. Environmental Protection Agency by TRW, Inc., May 1979.
J.G. Cleland et al., "Pollutants From Synthetic Fuels Production: Coal Gasification Screening Test Results," EPA-600/7-79-200, prepared for U.S. Environmental Protection Agency by Research Triangle Institute, Research Triangle Park, North Carolina, August 1979.

21 GASIFIER ASH

Solids discharge consisting of ash, unreacted coal, and sulfur generated in the Lurgi gasifier and removed for disposal is 391×10^3 tons/yr (dry basis) or 500×10^3 tons/yr (wet basis).

Ash produced from gasification of coal is removed through the gasifier grate, collected in the ash lock, and quenched in the quench chamber with sluice water recycled from the ash handling unit. The dewatered ash is conveyed to ash storage bins for ultimate disposal in a secure landfill.

The coal feed to the gasifier is 1.9×10^6 lb/hr and is 5.1 percent ash.¹ Therefore, the amount of dry mineral ash generated from coal gasification is calculated to be

$$\begin{aligned}\text{Dry mineral ash} &= (\text{percent ash content})(\text{coal feed rate to gasifier}) \\ &= (0.051)(1.9 \times 10^6 \text{ lb/hr})(24 \text{ hr/day}) \\ &= 2.33 \times 10^6 \text{ lb/day}\end{aligned}$$

On a yearly basis,

$$\begin{aligned}\text{Dry mineral ash} &= (2.33 \times 10^6 \text{ lb/day})(0.92 \text{ capacity factor})(365 \text{ days/yr})\left(\frac{1}{2000 \text{ lb/ton}}\right) \\ &= 391 \times 10^3 \text{ tons/yr.}\end{aligned}$$

The mineral ash composition is shown in Table 4.¹

Table 4. Ash Mineral Composition (Dry Basis)¹

	<u>Wt. %</u>		<u>Wt. %</u>
SiO ₂	19.0	SO ₃	7.0
Al ₂ O ₃	14.0	BaO	0.2
Fe ₂ O ₃	6.0	TiO ₂	1.0
MgO	7.8	P ₂ O ₅	1.8
CaO	36.0	Undetermined	<u>4.3</u>
Na ₂ O	2.7	Total	100.0
K ₂ O	0.2		

The ash removed for disposal also contains some ungasified coal (168,912 lb/day), sulfur (1584 lb/day), and 480,000 lb/day of water from the quenching operation.¹ Therefore, the total amount of wet gasifier ash collected for disposal is

$$\begin{aligned}\text{Gasifier ash (wet)} &= (\text{dry mineral ash}) + (\text{ungasified coal}) + (\text{sulfur}) + (\text{water}) \\ &= (2.33 \times 10^6 \text{ lb/day}) + (0.169 \times 10^6 \text{ lb/day}) + (0.001584 \times 10^6 \text{ lb/day}) \\ &\quad + (0.480 \times 10^6 \text{ lb/day}) \\ &= 2.98 \times 10^6 \text{ lb/day}\end{aligned}$$

On a yearly basis,

$$\begin{aligned}\text{Gasifier ash (wet)} &= (2.98 \times 10^6 \text{ lb/day}) \left(\frac{1}{2000 \text{ lb/ton}} \right) (0.92 \text{ capacity factor}) (365 \text{ days/yr}) \\ &= 0.5 \times 10^6 \text{ tons/yr}\end{aligned}$$

To determine the amount of trace elements transferred to the ash during gasification, it was assumed that the distribution of trace elements in the gasifier ash of the conceptual plant is the same as the distribution found at SASOL (Table 5).^{2,3}

Table 5 gives calculated concentrations and mass flow rates of trace elements in the gasifier ash (columns 6 and 5, respectively). The concentration of trace elements in the gasifier ash is larger than the concentrations of the same elements in the coal.

Table 5. Trace Elements in Gasifier Ash

1	2	3	4	5	6
Trace Element	Flow Rate Dry Coal Feed (lb/day)	Conc. of Trace Element in Coal (ppm)	Fraction of Trace Element in Gasifier Ash	Flow Rate of Trace Element in Gasifier Ash (lb/day)	Conc. of Trace Element in Gasifier Ash (ppm)
As	32.856×10^6	0.57-1.2	0.269	5.04-10.6	1.69-3.56
Be	"	0.71-0.80	0.3303	7.70-8.68	2.58-2.91
Cd	"	0.31-0.80	0.59	5.28-13.6	1.77-4.56
F	"	65-67	0.563	1202-1239	403-416
Hg	"	0.11-0.17	0.519	1.88-2.9	0.63-0.97
Pb	"	0.51-12.0	0.942	15.8-371.5	5.3-125
B	"	32	0.900	946.3	317.5
Ni	"	1.7-14.0	0.994	55.5-457	18.6-153
V	"	10.0-14.0	0.999	328-460	110-154

References

1. Shreiner, full reference cited on p. 6.
2. M.K. Ghassemi, K. Crawford, and S. Quinlivan, "Environmental Assessment Report: Lurgi Coal Gasification Systems for SNG," EPA-600/7-79-120, prepared for U.S. Environmental Protection Agency by TRW, Inc., May 1979.
3. M.K. Ghassemi, K. Crawford, and S. Quinlivan, "Environmental Assessment Data Base for High-Btu Gasification Technology, Volumes I & II, Technical Description," EPA-600/7-78-186, prepared for U.S. Environmental Protection Agency by TRW, Inc., September 1978.

C. Shift Conversion and Gas Cleaning

The shift conversion and gas cleaning operations begin with cooling the raw gas by quenching with "recycled gas liquor" to remove dust and heavy tars. The carbon monoxide to hydrogen ratio is adjusted in the shift converter by the following reaction, known as the "water gas shift reaction,"

The resulting synthesis gas is scrubbed in a Rectisol system (chilled methanol scrubber) to remove acid gases (SO_2 , H_2S , CO_2 , etc.) and organics (tars, oils, ammonias, and phenols) prior to its entry into the Fischer-Tropsch section of the process.

The Rectisol unit functions as both a process unit and environmental control unit. It purifies the gas to prevent poisoning the Fischer-Tropsch catalysts in the next section, and it isolates the impurities for further processing and removal to minimize any release of pollutants to the environment. Also included in this process section is a Stretford process unit, which recovers the sulfur in the H_2S -rich stream from the Rectisol unit in the form of sulfur cake as a potentially salable byproduct. Synthesis gas exiting the conversion and cleaning sections is essentially free from sulfur and other contaminants.

② ACID GAS TO THE SULFUR RECOVERY UNIT

Acid gases (gas mixtures containing H_2S) produced in four separate process units and totaling 6.1×10^6 tons/yr are routed to the sulfur recovery unit.

Most sulfur contained in the gasifier feed coal exits the gasifier unit primarily as H_2S (refer to Appendix C, Sulfur Material Balance).¹ The gas purification unit selectively removes sulfur from the gas and sends an H_2S -rich stream to the sulfur recovery unit. Over 95 percent of the sulfur in the gas stream leaving the gasifier is contained in this H_2S -rich stream.¹

A side stream of gas containing some H_2S is routed from the gas purification unit to the naphtha hydrotreating unit to provide the needed naphtha blending stock. There, H_2S is removed from the gas by absorption in an amine tower. The absorbant is regenerated, producing an H_2S -rich gas stream, which is sent to the sulfur recovery unit.

Two remaining sulfur-containing streams routed to the sulfur recovery unit originate in the gas liquor separation unit and the phenol recovery unit. The volume of this gas cannot be directly quantified, but it will contain less than 2 percent of the remaining feed sulfur.¹ Acid gases containing 6.1×10^6 tons/yr of H_2S gas mixtures are sent to the sulfur recovery unit.¹

Remaining constituents in the streams containing residual H_2S and other sulfur-containing compounds and various hydrocarbons after sulfur removal are sent to the boiler as tail gases for incineration. The volume of these streams will essentially be directly proportional to the throughput of the process. The volume of this combined stream will also vary directly with the sulfur content of the feed coal.

Reference

1. Shreiner, full reference cited on p. 6.

23 TAIL GAS OF STRETTFORD SULFUR RECOVERY UNIT

The Stretford unit discharges to the utility boiler for incineration 6.25×10^6 tons/yr of tail gas containing primarily carbon dioxide (CO_2) with less than 10 ppm hydrogen sulfide (H_2S) and approximately 17 ppm carbon oxysulfide (COS).¹

The Stretford process unit is the process exit point to both the gasifier and utility boiler for 60 percent of the sulfur that enters the process in the feed coal. The H_2S -rich gas stream that has been separated from the synthesis gas by the Rectisol unit enters the Stretford unit where elemental sulfur is produced. The tail gas stream, with only small amounts of H_2S and COS (less than 10 ppm and approximately 17 ppm, respectively) remaining, is sent to the boiler as a fuel and to incinerate any undesirable components. The composition of the combustible components of the tail gas is as follows:¹

CH_4	26.0×10^3 tons/yr
C_2H_6	4.1×10^3 tons/yr
CO	15.1×10^3 tons/yr
C_2H_4	7.3×10^3 tons/yr
H	1.4×10^3 tons/yr
Total	90.8×10^3 tons/yr

For a specific coal, the mass flow rate of the tail gas stream will vary directly with process throughput. If a coal with the same Btu content but high-sulfur content were to be used as the process feedstock, the mass flow rate of this stream would increase proportionally.

Reference

1. Shreiner, full reference cited on p. 6.

24 SULFUR BYPRODUCT

The Stretford unit will remove 20.5×10^3 tons/yr of elemental sulfur from the process stream in the form of a sulfur cake.

The Stretford unit removes the sulfur from the gas stream absorption in a sodium carbonate solution. The solution is transferred to a second reactor vessel where H_2S is oxidized by reaction with air. The elemental sulfur is liberated from the liquid and floats to the top as a froth, which is skimmed and dewatered to form a sulfur cake. The Stretford unit will remove 20.5×10^3 tons/yr of elemental sulfur from the process stream in cake form.¹ The cake is considered to be of such quality that it represents a salable byproduct.¹

The amount of byproduct sulfur produced will depend on the sulfur in the feed coal. The efficiency of the Stretford process is essentially constant over a wide range of H_2S concentrations.

Reference

1. Shreiner, full reference cited on p. 6.

25 SPENT CATALYSTS FROM RAW GAS SHIFT AND FISCHER-TROPSCH FRACTIONATION/ BLENDING

Undefined quantities of spent or contaminated catalysts including both solids and sludges will be generated in process operation.

A number of the processing steps involve catalytic reactors: the raw gas shift, methanol synthesis, methanation, naphtha hydrotreating, alkalation, catalytic reformer, C_5/C_6 isomerization, and polymerization units.¹ When the catalysts lose their activity through chemical or physical degradation, they must be regenerated or replaced. Even for those catalysts that can be regenerated, physical deterioration will require their eventual replacement. Because catalysts represent a wide range of materials, their disposal must be considered on an individual basis, but sufficient detail about the characteristics of these materials is not available due to their proprietary nature. This discussion must therefore confine itself to their general characteristics.

At least one of the catalysts, that for the reformer unit, has a platinum-based formulation and is quite valuable. Thus, this material is sent to a metal catalyst reprocessing center after removal. Although the exact composition of other catalysts in the process are not known with certainty, some may contain noble metals, that may also have catalyst reprocess or metal salvage value. It is also known that the material is used and removed in relatively small quantities (tons to tens of tons). If salvage and reprocessing is not a viable option, disposal of the material onsite can be considered. Depending on the chemical constituents and their activity, it should be possible to place dry material in a section of the secure solid waste disposal area. In the case of liquid acid catalysts or associated sludges, neutralization followed by impoundment in a section of the secure solid waste disposal area may also be considered. In either case, the material will require isolation from surface waters.

If it is not practical to handle the material onsite, offsite processing/disposal would be practical in view of the relatively small amount of material involved. In either case, the spent catalysts will be similar to those used in petroleum refining and can be disposed of in same manner.

Reference

1. Shreiner, full reference cited on p. 6.

D. Fischer-Tropsch Synthesis, Fractionation, and Product Blending

The Fischer-Tropsch section of the process is responsible for catalytic liquefaction of the clean synthesis gas and subsequent refining (fractionation, blending, etc.) of the raw liquid making it into a marketable fuel product slate. An important mechanism is the synthesis of hydrocarbons by reacting hydrogen and carbon monoxide in the Fischer-Tropsch synthesis unit. The synthesis process, along with several unit processes in the fractionation section, uses solid catalysts that must be periodically regenerated or replaced. These operations result in generation of offgases or solid wastes for disposal. The section uses a number of process heaters fired with a clean process-derived fuel gas. Heater flue gas is vented directly to the atmosphere. The chief source of fugitive hydrocarbon emissions is evaporative losses from storage tanks and material transfer operations in fractionation and blending units.

26 COMBUSTION PRODUCT GASES FROM GAS-FIRED PROCESS HEATERS

The total flow of combustion product gases from gas-fired process heaters vented to the atmosphere through the boiler flue consists of the following major constituents:¹

CO ₂	=	0.11 x 10 ⁶ tons/yr
N ₂ + inerts	=	0.505 x 10 ⁶ tons/yr
O	=	0.02 x 10 ⁶ tons/yr
H ₂ O	=	<u>0.08 x 10⁶ tons/yr</u>
Total	=	0.72 x 10 ⁶ tons/yr flue gas

Most of the process heaters in the plant are fired with a fuel gas originating primarily in the Fischer-Tropsch product fractionation and light ends recovery unit. The gas is composed primarily of CO₂, methane, ethylene, ethanol, and hydrogen. The fuel gas is essentially free of sulfur and other trace contaminants. Burners are designed to reduce the formation of NO_x.

The combustion gases are injected into the utility boiler to take advantage of their remaining energy content and to dispose of them in air pollution control systems.

The process heaters, the source of this flue gas, have burners that are modular in nature and thus can be assumed to scale in an essentially linear fashion based on changes in overall plant capacity. Because the sources of flue gas are spread among several synthesis and fractionation units, major shifts in the plant product slate may also have an effect on the total volume of such gases.

Reference

1. Shreiner, full reference cited on p. 6.

(27) CATALYST REGENERATION OFFGASES

Information is not available at this time to estimate the total gases that will be vented to the atmosphere during the in-place regeneration of various process catalysts.

Several process units use in situ regenerable catalysts. Regeneration will typically involve the application of heat alone or heat in combination with some gas such as hydrogen or oxygen to remove the materials interfering with the operation of the catalyst. Offgases from this operation may be sent to the boiler for incineration, or they may be vented directly to the atmosphere. Catalysts containing noble metals will probably be sent to a reprocessing facility, in which case offgases will be generated offsite.

(28) CO₂ VENTED FROM THE HYDROGEN PURIFICATION UNIT TO THE ATMOSPHERE

*The hydrogen purification unit removes and vents to the atmosphere
41.5 x 10³ tons/yr of CO₂*

Within the Fischer-Tropsch synthesis, fractionation, and product blending section of the process, a hydrogen purification unit obtains hydrogen-rich offgas from the catalytic reforming, C₅/C₆ isomerization, and gasoline hydrogenation units. The purified hydrogen is used in various steps of the synthesis and blending process. CO₂ totaling 83 x 10⁶ lb/yr is removed from the cooled gas stream using a molecular sieve and is vented to the atmosphere.¹

Reference

1. Shreiner, full reference cited on p. 6.

(29) SYNTHETIC NATURAL GAS (SNG) DRYING UNIT VENT STREAM

The SNG drying unit vents 9.1×10^3 tons/yr of steam (H_2O) to the atmosphere.

The SNG stream coming from the CO_2 removal unit contains excess moisture. This gas stream is dried by water absorption in cool triethylene glycol (TEG). Water-rich TEG is regenerated by heating, which drives off water vapor. The SNG drying unit vents 2259 lb/hr (9.1×10^3 tons/yr) of steam to the atmosphere. TEG vapor is refluxed back to the drying unit holding tank in an air-cooled condenser as a method of environmental control.¹

Reference

1. Shreiner, full reference cited on p. 6.

30 STORAGE EVAPORATIVE EMISSIONS

Hydrocarbon emissions from product storage tanks amount to 378 tons/yr.

Evaporative emissions occur from volatile liquid hydrocarbon products stored in fixed-roof and floating-roof tanks on the plant site. Liquefied gas products normally do not release vapors because they are stored in pressure vessel tanks fitted with pressure relief valves.

Evaporative emissions are normally estimated empirically.^{1,2} The evaporative emissions from fixed-roof storage tanks are composed of breathing losses and working losses. Breathing losses are caused by variations in ambient temperature. Working losses are caused by displacement of vapors during tank filling.

Evaporative emissions from floating-roof storage tanks consist of standing storage losses and withdrawal losses. Standing storage loss is vapor leakage from the gap between the tank roof and wall. Withdrawal loss is caused by evaporation of liquid hydrocarbon clinging to the tank wall during pump-down of the tank. The evaporative emissions for the plant storage area were calculated in Appendix D and are summarized in the table below:

Product ³	Number of Tanks	Tank Type	Capacity/Tank (bbl) ³	Vapor Emissions (tons/yr)
Gasoline	2	Floating Roof	112,000	202
Diesel Oil	1	Fixed Roof	38,000	2.4
Fuel Oil	1	Fixed Roof	11,000	0.07
Lurgi Oil	1	Fixed Roof	13,900	55.3
Lurgi Tar	1	Fixed Roof	6,356	29.5
Alcohol	1	Floating Roof	34,000	32.7
Phenols	1	Fixed Roof	6,275	16.4
Methanol	1	Fixed Roof	1,000	5.8
Diisopropyl Ether	1	Fixed Roof	1,500	4.7
Naphtha				
Hydrotreater Feed	1	Floating Roof	22,000	6.6
F-T Product				
Hydrotreater Feed	1	Floating Roof	188,000	12.8
Reformer Unit Feed	1	Floating Roof	24,000	10.0
Total				378

References

1. "Evaporation Loss From Fixed-Roof Tanks," API Bulletin 2518, June 1972.
2. "Evaporation Loss From External Floating-Roof Tanks," API Bulletin 2517, Second Edition, February 1980.
3. Shreiner, full reference cited on p. 6.

31 MAGNETITE IRON ORE FEED (Fe_3O_4) TO FISCHER-TROPSCH CATALYST PREPARATION PLANT

The total iron ore feed for the process is 27,270 tons/yr.

The catalyst for the Fischer-Tropsch synthesis unit is prepared from iron ore (Fe_3O_4) onsite. The ore undergoes three steps in catalyst preparation: purification, fusion and size reduction, and catalyst reduction. In the purification and size reduction steps, some of the raw material is discharged to the environment (see item 32, Catalyst Preparation Plant Tailings). The balance of the material goes on to the reduction process to become usable catalyst.

Annual iron ore requirements are calculated as follows:

Number of reactors x tons of catalyst per reactor = tons of catalyst in service

$\frac{365 \text{ days per yr} \times \text{capacity factor}}{\text{days (life of catalyst)}} = \text{changes of catalyst per yr}$

Changes per yr x catalyst in service = total catalyst required per yr

Production ratio (iron ore feed rate/catalyst produced) x total catalyst required per yr
= total iron ore feed required per yr

Assuming a 3.03 production ratio,¹ the required iron ore feed is calculated as

4 (reactors in service) x 335 tons/reactor = 1340 tons in service

$\frac{365 \text{ days per yr} \times 0.92 \text{ capacity factor}}{50 \text{ days catalyst life}} = 6.71 \text{ changes per yr}$

6.71 changes per yr x 1340 tons in service = 9000 tons total catalyst required

3.03 catalyst production ratio x 9000 tons total catalyst required
= 27,270 tons/yr iron ore feed required

The values given above are based on literature describing the SASOL I complex operation, a scale-up of 2.1 from the reactors described in References 1 and 2, and basic operating assumptions of this plant design. In general, catalyst (hence, iron ore) requirements will be directly proportional to the throughput of the plant for a given product slate.

References

1. Shreiner, full reference cited on p. 6.
2. "Production of Petrochemical Raw Materials by the Fischer-Tropsch Process," Union Rheinische Braunkohlen Kraftstoff A.G., January 1976.

32 CATALYST PREPARATION PLANT TAILINGS

13,630 tons/yr of tailings consisting primarily of Fe_3O_4 ore fines are discharged from the Fischer-Tropsch (F-T) catalyst preparation process.

During initial crushing and sizing operations of raw magnetite ore (Fe_3O_4), fines are removed using an air separation table. These fines represent 50 percent of the raw ore feed and are disposed of in the secure solid waste disposal area.¹

The quantity of Fe_3O_4 tailings produced annually can be calculated from annual catalyst requirements, yield ratio of catalyst per ton of raw ore feed material, and rejection rate of raw fines in the preparation process. The calculations are as follows:

$$\begin{aligned} C_{FT} &= Y_R \times C_T \times R_R \\ &= (3.03 \text{ tons ore/ton catalyst})(9000 \text{ tons/yr})(50 \text{ percent raw feed rejection rate}) \\ &= 13,635 \text{ tons/yr raw feed tailings} \end{aligned}$$

Where

- C_{FT} = total catalyst preparation feed tailings
- Y_R = the preparation process production ratio expressed as tons of raw ore required to make 1 ton of catalyst
- C_T = total tons of catalyst required yearly
- R_R = the percentage of raw material rejection to tailing fines in the preparation process

Reference

1. Shreiner, full reference cited on p. 6.

33 SPENT FISCHER-TROPSCH (F-T) SYNTHESIS CATALYST

Based on a 50-day catalyst life, a total of 9000 tons/yr of F-T synthesis catalyst will be disposed of in a secure solid waste disposal area.

During normal operation of the F-T synthesis unit, periodic replacement of the catalyst is required. This replacement is necessitated by both physical and chemical deterioration. It is assumed that the spent catalyst will require disposal in a secure solid waste disposal area.

The quantity of catalyst requiring disposal can be calculated knowing the number of reactors in the plant complex, the catalyst capacity of each reactor, and the expected catalyst life.^{1,2} The calculation is as follows:

$$\begin{aligned} C_T \text{ (tons/yr)} &= (C_R)(R_W) \left(\frac{(0.92 \text{ capacity factor})(365 \text{ days/yr})}{C_L} \right) \\ &= (335 \text{ tons/reactor})(4 \text{ reactors}) \left(\frac{(0.92 \text{ capacity factor})(365 \text{ days/yr})}{50 \text{ days}} \right) \\ &= 9000 \text{ tons/yr} \end{aligned}$$

Where

- C_T = total tons of catalysts required per year
 C_R = tons of catalyst required for each reactor
 R_W = the number of reactors
 C_L = projected catalyst life in days

References

1. Shreiner, full reference cited on p. 6.
2. "Production of Petrochemical Raw Materials by the Fischer-Tropsch Process," Union Rheinische Braunkohlen Kraftstoff A.G., January 1976.

34 HYDROCARBON LIQUID AND GAS PRODUCTS

The liquefaction plant will produce 45,000 barrels per day fuel oil equivalent or 0.27×10^{12} Btu/day.

The two major fuel products are synthetic natural gas and gasoline. Other fuel products include propane liquefied petroleum gas (LPG), butane liquefied petroleum gas, diesel oil, heavy fuel oil, and alcohols. The synthetic natural gas is essentially pure methane, and all of the Fischer-Tropsch products are of upgraded quality.

In addition to fuels, other marketable byproducts include sulfur, anhydrous ammonia, and excess electrical power. The quantified product slate is presented in Table 6.

The product slate is the result of the gasification of 22,800 tons/day of well sized coal and combustion of 5000 tons/day of coal fines for steam and electricity from an overall input of 27,800 tons/day of ROM coal. The other feedstocks include 52,499 tons/day of water, 75,850 tons/day of air, small quantities of chemicals, solvents, and catalysts.

Products and byproducts of indirect coal liquefaction may possess toxic properties and could present a problem to the general public. Such materials could be subject to the provisions of the Toxic Substances Control Act.

Whether the Fischer-Tropsch products are distinctly different in their toxic properties from the familiar petroleum derivatives is not known. In general, the problem can be eliminated by exercising proper precautions during the products' storage, transportation, and use.

Table 6. Product Slate¹

Products

Synthetic natural gas (SNG)	58.2×10^9 scf/yr
Gasoline	4.6×10^6 bbl/yr
Propane liquefied petroleum gas (LPG)	370×10^3 bbl/yr
Butane liquefied petroleum gas (LPG)	49×10^3 bbl/yr
Diesel oil	775×10^3 bbl/yr
Heavy fuel oil	222×10^3 bbl/yr
Alcohols	0.67×10^6 bbl/yr

Byproducts

Sulfur	20.5×10^3 tons/yr
Anhydrous ammonia	34.2×10^3 tons/yr
Excess electrical power	3.3 MWe

Although this plant design produces a product slate containing a high percentage of synthetic natural gas (SNG), the ratio of gas to liquid fuels can be lowered by changing the amount of synthesis gas which is reformed and liquefied in a Fischer-Tropsch synthesis unit. In this plant design, however, an increase in liquid fuel production will result in an overall decrease in process thermal efficiency. Such a shift would also result in an increase in the environmental residuals associated with operation of the liquefaction and blending units.

Reference

1. Shreiner, full reference cited on p. 6.

35) VACUUM RESIDUE "BOTTOMS" FROM THE F-T PRODUCT FRACTIONATION UNIT

16.27 x 10⁶ lb/yr of vacuum residue bottoms are produced in the F-T product fractionation unit and sent to the utility boiler as boiler fuel.¹

The F-T synthesis unit produces a liquid stream that contains a wide range of feedstock materials including heavy "oils." This heavy material is not used in the F-T product blending operation and must be removed to make the other stream components suitable for product blending. Separation is accomplished in a vacuum tower from which the bottoms are removed to be used as boiler fuel. The material is much like a residual crude oil and is used as a fuel supplement for the onsite utility boiler. It is essentially free from sulfur and trace metals. Therefore, products of combustion should be primarily CO₂, H₂O, NO_x, and N₂.

The quantity of this material produced will be proportional to process throughput for a given coal and F-T synthesis operating conditions. As the overall process operating conditions are modified to shift the product slate toward heavy hydrocarbons, the fraction of this material will increase.

Reference

1. Shreiner, full reference cited on p. 6.

E. Resource Recovery and Wastewater Treatment

The resource recovery and wastewater treatment section accepts gas liquor from the shift conversion and gas cleaning sections and wastewater from other sections of the process. It removes various coal-derived components for utilization or disposal. The treated effluent is a water stream suitable for reuse in certain process units. The gas liquor separator, phenol recovery unit, and ammonia recovery unit recover components having fuel or chemical feedstock value. Components having fuel value are routed to the boiler.

Other less contaminated wastewater streams are combined. The total effluent of the section is fed to the biological treatment unit prior to recycle to achieve acceptable water quality.

36 GAS LIQUOR STREAM FROM GAS COOLING AND PURIFICATION UNITS

The gas liquor separator unit received 6.8×10^6 tons/yr of gas liquor containing oils, tars, phenols, ammonia, fatty acids, trace elements, CO_2 , H_2S , and water.

Gas liquor from the cooling and purification units contain several byproducts as well as wastewater from several process units. Resource recovery and wastewater treatment units remove and recover usable stream components and allow recycle of the final wastewater effluent stream.^{1,2}

Removal of the majority of the components from the water effluent is necessary before the water (approximately 12.4×10^9 lb/yr)¹ can be reused (e.g., utility plant cooling tower makeup). Removal of combustible components for use as a process fuel source or salable byproduct also improves the process economics.³

The gas liquor separator unit receives 13.6×10^9 lb/yr (6.8×10^6 tons/yr) of gas liquor containing oils, tars, phenols, ammonia, fatty acids, trace elements, CO_2 , H_2S , and water.¹ The volume of this stream will be proportional to plant throughput. Changes in composition and flow can be expected if the coal changes. In general, as the volatile fraction of coal increases, tar, oil, and phenol levels will increase. Trace element levels in the tar and oil will vary with trace constituent levels in the coal and be partitioned as shown in Table 5 (item 21, Gasifier Ash).

References

1. Shreiner, full reference cited on p. 6.
2. M. Ghassemi, K. Crawford, and S. Quinlivan, "Environmental Assessment Report: Lurgi Coal Gasification Systems for SNG," EPA-600/7-79-120, prepared for U.S. Environmental Protection Agency by TRW, Inc., May 1979.
3. U.S. Department of Energy, "Processing Needs and Methodology for Wastewater From the Conversion of Coal, Oil Shale and Biomass to Synfuels," in process, Environmental Control Technology Division.

37 OTHER PROCESS WASTEWATERS

Approximately 0.53×10^9 gal/yr of acidic wastewater from the gas purification unit and F-T synthesis and fractionation units compose the feed stream to the biological treatment unit.

Acidic wastewater streams from the process areas downstream from the gas cooling and purification, amount to 0.53×10^9 gal/yr.¹ This "sour" wastewater does not contain significant amounts of heavy hydrocarbons (tar, oil, and phenols). The acidic wastewater stream bypasses product recovery units and enters bio-treatment to reduce the small amounts of contaminants that may be present. The major contaminant is fatty acids (approximately 44.08×10^6 lb/yr).¹ They must be neutralized in the final wastewater effluent stream.^{2,3}

This stream may be processed in an individual treatment system or combined into other wastewater streams that will neutralize its acidic level. In this plant design, a conventional activated-sludge biological treatment unit is used for proper treatment of the combined wastewater streams.^{2,3,4}

References

1. Shreiner, full reference cited on p. 6.
2. D.T. Goldstein and D. Yung, "Water Conservation and Pollution Control in Coal Conversion Processes," EPA-600/7-77-065, prepared for U.S. Environmental Protection Agency by Water Purification Associates, Cambridge, Massachusetts, June 1977.
3. F.H. Verhoff and M.K. Choi, "Sour Water Stripping of Coal Gasification Waste Water," METC/CR-79/23, prepared for U.S. Department of Energy by West Virginia University, Morgantown, West Virginia, May 1979.
4. M. Ghassemi et al., "Applicability of Petroleum Refinery Technologies to Coal Conversion," EPA-600/7-78-190, prepared for U.S. Environmental Protection Agency by TRW, Inc., October 1978.

38 WASTEWATER TO BIOLOGICAL TREATMENT

2.0 x 10⁶ gal/yr of wastewater enter the biological treatment unit for final treatment prior to reuse.

Wastewater entering the biological treatment unit amounts to 1.5 x 10⁹ gal/yr from the ammonia recovery unit and 0.53 x 10⁹ gal/yr from other process units (item 37, Other Process Wastewaters). Pollutants in the wastewater can be classified into two categories: trace elements and organics. Table 7 shows trace elements and organics that may be expected in the wastewater stream.^{1,2}

Biological treatment reduces the organic content of wastewater. The unit also removes some trace elements from the water into the sludge. Estimates of this removal are contained in the discussion of item 40, Sludge From Wastewater Biological Treatment. The organic component that is biologically active will be reduced by aerobic digestion, leaving primarily water and CO₂.^{3,4,5}

Table 7. Constituents of Combined Wastewater Streams Entering Biological Treatment Unit^{1,2}

Trace Elements

Arsenic	Lead
Beryllium	Manganese
Boron	Mercury
Cadmium	Nickel
Fluorine	Vanadium

Organics

Acetic Acid	3-Methylcatechol	Biphenyl
Aniline	3-Methylphenol	Chrysene
Butanoic Acid	3-Methylpyridine	Dibenzofuran
Hexanoic Acid	3,5-Xylenol	Ethylbenzene
Pentanoic Acid	3,6-Dimethylcatechol	Fluoranthene
Phenol	4-Methyl Resorcinol	Fluorene
Propanoic Acid	4-Methylcatechol	Indan
Pyridine	4-Methylphenol	Methanethiol
Resorcinol	1-Methylpyridine	Naphthalene
2-Methylphenol	5-Methyl Resorcinol	Perylene
2-Methylpropionic Acid	Acenaphthylene	Phenanthrene
3-Methylpyridine	Benz(a)anthracene	Pyrene
4-Dimethylpyridine	Benzo(a)pyrene	Quinoline
2,4-Xylenol	Benzo(e)pyrene	Toluene
2,5-Dimethylpyridine	Benzo(g,h,i)perylene	O-Xylene
3-Methylbutanoic Acid		

References

1. M.K. Ghassemi, K. Crawford, and K. Quinlivan, "Environmental Assessment Data Base for High-Btu Gasification Technology, Vol. I and II," EPA-600/7-78-186a,b, prepared for U.S. Environmental Protection Agency by TRW Inc., September 1978.
2. J.G. Cleland et al., "Pollutants from Synthetic Fuels Production: Coal Gasification Screening Test Results," EPA-600/7-79-200, prepared for U.S. Environmental Protection Agency by Research Triangle Institute, Research Triangle Park, North Carolina, August 1979.
3. P.C. Singer et al., "Assessment of Coal Conversion Waste Waters: Characterization and Preliminary Biotreatability," EPA-600/7-78-181, prepared for U.S. Environmental Protection Agency by the University of North Carolina, September 1978.
4. V.C. Stamoudis and R.G. Luthy, "Biological Removal of Organic Constituents in Quench Water From a Slagging, Fixed-Bed Coal Gasification Pilot Plant," ANL/PAG-1, prepared for U.S. Department of Energy by Argonne National Laboratory, Argonne, Illinois, February 1980.
5. V.C. Stamoudis and R.G. Luthy, "Biological Removal of Organic Constituents in Quench Waters From High-Btu Coal Gasification Pilot Plants (Hygas and SFB/BFERC)," ANL/PAG-2, prepared for U.S. Department of Energy by Argonne National Laboratory, Argonne, Illinois, February 1980.

39 TREATED AND RECLAIMED WASTEWATER

2.89 x 10⁹ gal/yr of water processed or recovered is available for various plant functions.

The major quantity of treated wastewater (1.89 x 10⁹ gal/yr)¹ is used as cooling tower makeup water in this plant design. Smaller amounts of treated wastewater are recycled to the Fischer-Tropsch synthesis unit (0.098 x 10⁹ gal/yr)¹ and the catalytic polymerization and HF alkylation unit (0.048 x 10⁹ gal/yr).¹ The total amount of treated wastewater recycled to process units is 2.04 x 10⁹ gal/yr.

Wastewater reclaimed from cooling tower blowdown (0.688 x 10⁹ gal/yr),¹ cooling tower water preparation blowdown (0.0168 x 10⁹ gal/yr),¹ and boiler blowdown including demineralizer waste (0.15 x 10⁹ gal/yr)¹ amounts to 0.85 x 10⁹ gal/yr and is stored in a holding pond for reuse (e.g., 0.04 x 10⁹ gal/yr)¹ as gasifier ash sludge water. The remainder of the wastewater in the holding pond (0.81 x 10⁹ gal/yr) is available for other uses, such as dust control. Water not used is lost through evaporation from the surface of the pond.

The total amount of treated and reclaimed wastewater available for recycle is

$\begin{aligned}\text{Reclaimed water} &= \text{treated wastewater} + \text{holding pond wastewater} \\ &= 2.04 \times 10^9 \text{ gal/yr} + 0.85 \times 10^9 \text{ gal/yr} \\ &= 2.89 \times 10^9 \text{ gal/yr}\end{aligned}$
--

Cooling tower water can enter the environment by evaporation, drift (entrained droplets), and blowdown. Expected composition of recycle water from a Lurgi high-Btu coal gasification plant was estimated in a recent study.² The recycle stream composition reported in that study is shown in Table 8. Although this ECIR addresses indirect liquefaction plants, not SNG plants, the recycle water composition should be similar because the Lurgi gasifier employed in the design of the ECIR model plant is essentially the same as that in the SNG plant study, and it produces 75 percent of the total quantity of wastewater. Additionally, wastewater from gasification is of much greater environmental concern than wastewater from the F-T liquefaction and product upgrading sections. Gasification wastewater contains all refractory, toxic, carcinogenic organic compounds, and trace elements. The wastewater treatment scheme in the plant design considered here is the same as that of the recent SNG study.¹ Estimates of trace elements contained in this stream is shown in Table 7. Trace elements in wastewater are related to levels in the feed coal.

Table 8. Recycled Water Stream Composition¹

<u>Component</u>	<u>mg/l</u>
BOD	8
COD	400
TSS	5
Phenol	1
Cyanide	0.6
Thiocyanate	5
Ammonia	0.9
Sulfide	0.06
Chloride	266
Oil	1

References

1. Shreiner, full reference cited on p. 6.
2. "Coal Conversion Control Technology, Vol. I, Environmental Regulations Liquid Effluents," PB80-126469, prepared for Industrial Environmental Research Laboratory, Research Triangle Park, North Carolina, by Pullman Kellogg Inc., October 1979.

40 SLUDGE FROM WASTEWATER BIOLOGICAL TREATMENT UNIT

The amount of sludge generated by the biological treatment unit is 42,447 tons/yr (wet basis) and is disposed of in a secure landfill.

Sludge from the biological treatment unit consists of water, spent organisms, solids, and dissolved material. Table 9 lists examples of trace elements² and nondegradable organics³ that may be present in the sludge from the biological treatment unit. Because certain organics and trace elements are soluble in water, a portion of these materials remain in the treated water.

Table 9. Examples of Potential Constituents in Wastewater

Acenaphthylene	Chrysene	Arsenic
Anthracene	Fluoranthene	Beryllium
Benz(a)anthracene	Fluorene	Cadmium
Benzo(g,h,i)perylene	Naphthalene	Mercury
Benzo(a)pyrene	Phenanthrene	Lead
Benzo(e)pyrene	Pyrene	

The amount of sludge disposed of can be calculated based on water entering the Biological Treatment Unit, water exiting the unit for recycle, and the rate of sludge production on a dry basis per pound of wastewater treated.^{1,2,3}

The calculation is as follows:

$$W_S = W_I - W_O$$

$$S_D = W_I \times S_R$$

$$S_T = W_S + S_D$$

Where

W_S = water in sludge (lb/hr)

W_I = water into process unit (lb/hr)

W_O = water leaving process unit (lb/hr)

S_R = rate of sludge production (lb/lb of treated water)

S_D = weight of dry sludge (lb/hr)

S_T = total wet weight of sludge (lb/hr or tons/yr)

For the design plant,

$$W_S = 2,103,050 \text{ lb/hr} - 2,093,348 \text{ lb/hr}$$

$$= 9702 \text{ lb/hr}$$

$$S_D = 2,130,050 \text{ lb/hr} \times 0.396 \text{ lb/lb of treated water}$$

$$= 832 \text{ lb/hr}$$

$$S_T = 9702 \text{ lb/hr} + 832 \text{ lb/hr}$$

$$= 10,534 \text{ lb/hr total wet sludge to disposal}$$

On a yearly basis,

$$S_T = \frac{(10,534 \text{ lb/hr})(24 \text{ hr/day})(365 \text{ days/yr})(0.92 \text{ capacity factor})}{2000 \text{ lb/ton}}$$

$$= 42,447 \text{ tons/yr}$$

This sludge will be sent to a secure landfill for impoundment. Evaporation or groundwater percolation will be the only possible route for release of any constituents to the environment.

Reference

1. U.S. Department of the Interior, "Fossil Environmental Impact Statement: Western Gasification Company (WESCO) Coal Gasification Project and Expansion of Navajo Mine by Utah International, Inc., Vols. I and II," FES-76-2, January 1976.

2. M.K. Ghassemi, K. Crawford, and S. Quinlivan, "Environmental Assessment Report: Lurgi Coal Gasification Systems for SNG," EPA-600/7-79-120, prepared for U.S. Environmental Protection Agency by TRW Inc., May 1979.
3. J.G. Cleland et al., "Pollutants from Synthetic Fuels Production Coal Gasification Screening Test Results," EPA-600/7-79-200, prepared for U.S. Environmental Protection Agency by Research Triangle Institute, Research Triangle Park, North Carolina, August 1979.

④1 AMMONIA BYPRODUCT REMOVED FROM WASTEWATER

A total of 34.2×10^3 tons/yr of chemical-grade ammonia is removed from the wastewater stream.

The wastewater stream entering the phenol recovery unit contains small amounts of phenols and fatty acids along with a significant amount of ammonia that must be removed to facilitate optimal biological treatment. The ammonia recovery unit consists of a steam stripper and scrubber. The unit provides a wastewater effluent that is a suitable feed for the wastewater biological treatment unit. A total of 34.2×10^3 tons/yr of chemical-grade ammonia is recovered from the wastewater stream.¹

Ammonia quality is of agricultural grade. It contains less than 5 weight percent water and is considered a commercially salable byproduct.¹

Wastewater effluent from ammonia recovery contains small amounts of phenols, dissolved CO_2 and H_2S , ammonia, and 1.5×10^9 gal/hr of water and is sent to the biological treatment unit.

Reference

1. Shreiner, full reference cited on p. 6.

42 TAR, HEAVY OIL, AND PHENOLS AS UTILITY BOILER FUEL

Gas liquor separator and phenol recovery units remove 0.35×10^9 lb/yr of tar, 0.42×10^9 lb/yr of heavy oil, and 0.12×10^9 lb/yr of phenols for boiler fuels.

Gas liquor fed to the gas liquor separation unit is first fed to gravity separation tanks to remove tar and oil. The gas liquor separation unit operates at better than 99-percent removal efficiency. The liquor stream is then sent to phenol recovery where raw phenols are removed by solvent extraction with di-isopropyl ether (phenosolvan process). The process operates at over 96-percent removal efficiency. The wastewater containing ammonia as its major contaminant is fed to ammonia recovery.¹ Removal here provides an effluent that, after ammonia removal, is amenable to biotreatment.

Successful removal of the tars, oils, and phenols is a critical aspect of wastewater stream treatment. The gas liquor separator and phenol recovery units remove 0.35×10^9 lb/yr of tar, 0.42×10^9 lb/yr of heavy oil, and 0.12×10^9 lb/yr of phenols to be used as boiler fuels.¹

The quantities of these materials will be directly proportional to the process throughput for a given feed coal. Changes in feed coal characteristics will affect the quantities of the respective constituents in the gas liquor stream.

Reference

1. Shreiner, full reference cited on p. 6.

④3 SEPARATED H₂S-RICH GAS STREAMS

Gas streams separated from the liquor stream containing 4.4×10^3 tons/yr of H₂S are sent to the utility boiler for incineration.

During the tar and oil separation process, dissolved gases, most H₂S, are removed by ammonia scrubbers and sent to the sulfur recovery unit.

A gas liquor stream from the lockhopper gas recompression unit containing H₂S is sent to the gas liquor separation unit. The separated gas stream is too small to include in the sulfur recovery unit feed. Therefore, this gas stream, amounting to 0.0264×10^6 lb/day (4.4×10^3 ton/yr) is routed to the utility boiler for incineration.

Reference

1. Shreiner, full reference cited on p. 6.

F. Solid Waste Handling and Disposal

The solid waste handling and disposal section is divided into two segments: direct landfill for nonhazardous or special exception wastes and "secure" solid waste disposal for wastes known to be considered hazardous or which require special disposal by law.

Runoff water from direct landfill facilities may sometimes require control to prevent erosion or improve its quality by treatment for recycle or discharge.

A secure solid waste disposal facility is designed to properly isolate wastes that contain contaminated water or that may contaminate subsurface aquifers. Control consists of impoundment in lined ponds from which the only possible release for liquids is evaporation.

44 DIRECT SOLID WASTE LANDFILL

The utility power plant and associated pollutant controls generate 114×10^3 tons/yr (wet basis) of solids and sludges for disposal in the direct solid waste landfill.

Solid waste to be placed in direct landfill consist of bottom ash sludge from the utility boiler and fly ash from the electrostatic precipitator, combined with dewatered scrubber sludge to form a material suitable for disposal. A portion of the fly ash (approximately equal to 25 percent) not required in the sludge fixing process is suitable as a building material or can be disposed of directly in the landfill. The amount of fly ash required in the sludge disposal process will depend on unreacted limestone in the sludge, ash alkalinity, sludge moisture, and desired fixed-material properties. In some instances, all the fly ash and additional lime may be necessary to properly fix the sludge material.^{1,2} Dewatered bottom ash is disposed of directly in the landfill with the fixed sludge.

The volume of this material is be determined from information presented in items (14), (15), and (16) as follows:

$$\begin{aligned}\text{Weight of total solids} &= (\text{bottom ash}) + (\text{fly ash}) + (\text{scrubber sludge}) \\ &= (22.2 \times 10^3 \text{ tons/yr}) + (68.5 \times 10^3 \text{ tons/yr}) + (23.3 \times 10^3 \text{ tons/yr}) \\ &= 114 \times 10^3 \text{ tons/yr}\end{aligned}$$

The average density of this material is 88.6 lb/ft^3 .³ The volume of the material is calculated as follows:²

$$\begin{aligned}\text{Volume of solids} &= \frac{(\text{tons/yr of solids})(\text{pounds per ton})}{(\text{material density, lb/ft}^3)} \\ &= \frac{(114,000 \text{ tons/yr})(2000 \text{ lb/ton})}{(88.6 \text{ lb/ft}^3)} \\ &= 2.57 \times 10^6 \text{ cubic ft/yr} \\ &\text{or } 77 \times 10^6 \text{ cubic ft/30-yr lifetime of plant}\end{aligned}$$

Assuming a depth of 30 feet for depositing the solid waste, the total surface area required is

$$\text{Area} = \left(\frac{77 \times 10^6 \text{ ft}^3}{30 \text{ ft}} \right) \left(\frac{1}{43,560 \text{ ft}^2/\text{acre}} \right)$$

Area = 59 acres

Radon Emanation From Solid Waste Storage

As a result of trace amounts of radium occurring naturally in coal, the ash from combustion will emit small amounts of the gas radon-222.^{3,4} However, the depth at which the material will typically be buried will reduce radon emissions at the surface to virtually zero.

Even if the solid wastes were placed near or on the surface, radon emissions would be well within the EPA limits established for uranium mill tailings.⁵ Radon emissions from coal wastes are not regulated.

References

1. P.P. Leo and J. Rossoff, "Controlling SO₂ Emissions from Coal-Fired Steam-Electric Generators: Solid Waste Impact," EPA-600/7-78-044b, Aerospace Corporation, March 1978.
2. R.B. Fling et al., "Disposal of Flue Gas Cleaning Wastes: EPA Shawnee Field Evaluation -- Third Annual Report," EPA-600/7-80-011, Aerospace Corporation, January 1978.
3. V.E. Swanson, "Collection, Chemical Analysis, and Evaluation of Coal Samples," USGS Open File Report 76-468, 1975.
M.I. Goldman, "Energy: What About the Waste?" Chemical Engineering Progress, November 1979, p. 65.
5. Federal Register, Interim Cleanup Standards for Inactive Uranium Processing Sites -- EPA, Vol. 45, No. 79, April 22, 1980, pp. 27366-27375.

45 SECURE SOLID WASTE DISPOSAL

Certain solid waste materials generated may contain toxic or hazardous materials that cannot be discharged and must be disposed of at a confined site. This site will require approximately 193 acres of space.

Toxic or hazardous material must be disposed of in an impervious impoundment from which only evaporation can occur. A total depth of 30 ft is considered typical. The impoundment must be lined with a natural sealing material such as bentonite clay or a water-impermeable plastic or rubber liner preventing subsoil contamination.

To determine the required size of such an impoundment, the dry volume of the gasifier ash and catalysts and the amount of water associated with the sludge must be calculated.

The majority of the material sent to this disposal site will be gasifier ash. The amount of wet gasifier ash was estimated to be approximately 500×10^3 tons/yr in item 21, Gasifier Ash. The density of this material can be expected to be similar to coal-fired boiler ash or 131 to 162 lb/ft³. Based on the lower density value and further assuming a 30-ft depth of material and a 30-yr lifetime for the plant, the disposal area for gasifier ash can be calculated as follows:

$$\begin{aligned}\text{Volume} &= \frac{\text{weight of ash produced/yr} \times \text{30-yr plant life}}{\text{density (wt/ft}^3\text{)}} \\ &= \frac{500 \times 10^3 \text{ tons/yr} \times 2000 \text{ lb/ton} \times 30 \text{ yr}}{131 \text{ lb/ft}^3} \\ &= 229.0 \times 10^6 \text{ ft}^3 \\ \text{Disposal area (depth of 30 ft)} &= \frac{\text{volume (ft}^3\text{)}}{30 \text{ ft}} \left(\frac{1}{43,560 \text{ ft}^2/\text{acre}} \right) \\ &= \frac{229 \times 10^6 \text{ ft}^3}{30 \text{ ft}} \left(\frac{1}{43,560 \text{ ft}^2/\text{acre}} \right) \\ &= 175 \text{ acres}\end{aligned}$$

Assuming the balance of the solid wastes (e.g., catalyst tailings, spent catalysts, and other material) to secure disposal will require an additional 10 percent land area for their disposal, then

$$\begin{aligned}\text{Total disposal area} &= \text{disposal area (gasifier ash)} + (0.1 \times \text{disposal area (gasifier ash)}) \\ &= 175 + (0.1 \times 175) \\ &= 193 \text{ acres}\end{aligned}$$

III. PHYSICAL REQUIREMENTS

Water

Maximum water requirements are estimated for the design plant to be 3.2×10^9 gal/yr. Some of this water is recovered, treated in the water treatment facility, and recycled back to the plant (see Section II, Item 39, Treated and Reclaimed Wastewater). Eventually, this water is lost primarily through evaporation and drift losses in the cooling towers and by dust control.

The number of gallons of makeup water (W) needed per gallon of fuel oil equivalent (FOE) product is determined as follows:

$$\begin{aligned}\frac{W}{FOE} &= \frac{3.2 \times 10^9 \text{ gal/yr}}{(45 \times 10^3 \text{ bbl/day FOE})(365 \text{ days/yr})(0.92 \text{ capacity factor})(42 \text{ gal/bbl})} \\ &= \frac{3.2 \times 10^9 \text{ gal/yr water}}{6.35 \times 10^8 \text{ gal/yr product}} \\ &= 5.04 \text{ gal water/gal product}\end{aligned}$$

The holding pond contains 0.85×10^9 gal/yr of water of which 0.04×10^9 gal/yr is recycled for use as gasifier ash sluice water and the remaining 0.81×10^9 gal/yr is available for other uses, such as dust control. The water in the holding pond could be treated for reuse as process makeup water; the water demand could then be reduced from 3.2×10^9 gal/yr to 2.39×10^9 gal/yr. The number of gallons of makeup water needed per gallon of fuel oil equivalent product then becomes

$$\begin{aligned}\frac{W}{FOE} &= \frac{2.39 \times 10^9 \text{ gal/yr}}{6.35 \times 10^8 \text{ gal/yr}} \\ &= 3.76 \text{ gal water/gal product}\end{aligned}$$

Land

The physical layout of a coal liquefaction plant site will vary and depend on factors such as water availability, cost of land, waste disposal requirements, plant location, and design capacity. The SASOL I Coal Liquefaction Plant in South Africa produces 37,000 bbl/day and occupies approximately 3800 acres or a ratio of 9.7 bbl/day/acre.¹ Using the same ratio, a 45,000-barrel-per-day fuel oil equivalent indirect coal liquefaction plant might occupy as much as 4600 acres.

Land needed for buildings is a small portion of site requirements. The bulk of the land is needed for coal storage, raw water storage, onsite waste disposal, water recycle facilities, and process units. Plant space (which includes process unit space but excludes onsite waste disposal area) is estimated to be 630 acres.² Solid waste disposal area for the design plant was estimated at 252 acres (30-ft depth) for the 30-yr lifetime of the plant (Section F, Solid Waste Handling and Disposal). Of the 252 acres, 59 acres are needed for a direct solid waste landfill, and 193 acres are needed for a secure solid waste disposal area.

Coal preparation facilities at a surface mine site will be minimal. Initial screening and crushing will normally be included in the site area for the mine excavation. The refuse from the preparation plant will typically be placed back in the mine as part of the fill. Thus, there are no land requirements for preparation waste disposal.³

References

1. U.S. Environmental Protection Agency, "SASOL: South Africa's Oil From Coal Story -- Background for Environmental Assessment," EPA 600/8-80-002, January 1980.
2. U.S. Department of Energy, Comparative Assessment of Health and Safety Impacts of Coal Use, DOE/EV-0069, Office of Technology Assessment, Washington, D.C., March 1980.
3. Personal Communication, Phillip Halch, Roberts and Schaefer Engineers and Contractors, Chicago, Illinois, April 1980.

IV. PERSONNEL

Personnel requirements for coal liquefaction plant construction vary over time. Operating labor requirements are reasonably steady. Construction of the indirect coal liquefaction plant could require as much as 5200 men working a 40-hr week over a period of 4 yr.^{1,2} The maximum construction work force equates to (5200 men)(4 yr) = 20,800 man-yr.

The indirect coal liquefaction facility involves two major plants: utility power plant and coal liquefaction plant. For the utility power plant, 0.089 person/MWe/shift is recommended.³ This includes personnel for support, operation, and maintenance. The utility power plant produces an equivalent of 360 MWe of electrical power. (61.4 MWe is actually electrical power. The remaining power is in the form of steam for coal gasification and heating.) A power plant of this size would require 32 persons/shift or 96 persons/day. Operation and maintenance of the Lurgi gasifier, Fischer-Tropsch process units, and environment control units require about 600 personnel.¹ Therefore, the number of personnel needed annually for plant operation and maintenance is calculated as follows:

$$\text{Power plant} = (360 \text{ MWe}) \left(0.089 \frac{\text{persons/MWe}}{\text{shift}} \right) (3 \text{ shifts/day}) = 96 \text{ people/day}$$

$$\begin{array}{ll} \text{Lurgi gasifier, Fischer-Tropsch} & \\ \text{Process Units and Environmental Control Units} & = 600 \text{ people/day} \end{array}$$

$$\text{Total} \quad 696 \text{ people/day}$$

References

1. Department of the Interior, "Western Gasification Company (WESCO) Coal Gasification Project and Expansion of Navajo Mine by Utah International Inc., San Juan County, New Mexico," Final Environmental Statement, Bureau of Reclamation, January 14, 1976.
2. Shreiner, full reference cited on p. 6.
3. Personal Communication, J.W. Holt, Jr., Powerplants Branch, Rural Electrification Administration, Washington, D.C., April 1980.

V. OCCUPATIONAL SAFETY AND HEALTH

Occupational safety and health impacts for an indirect coal liquefaction plant were estimated from limited statistical data.¹ Because few coal conversion plants exist in the world, health and safety data are nearly nonexistent. Nevertheless, projections have been made from pilot plant studies and analogies of processes handling or producing similar materials (e.g., coal coking and oil refining).

Projections of health and safety data for the construction and operation of a direct coal liquefaction plant (SRC II) have been estimated.¹ These data should be representative of the same effects from indirect coal liquefaction, because similar processes and materials are involved. Thus, the projected deaths and injuries for the plant are as follows:

	Coal Liquefaction Plant Construction & Operation (cases/yr)	
	Accidental	Disease*
Deaths	0.36	0.26
Injuries	11	-

* Includes general public from SO₂ emissions.

Reference

1. U.S. Department of Energy, Comparative Assessment of Health and Safety Impacts of Coal Use, DOE/EV-0069, Office of Technology Impacts, Washington, D.C., March 1980.

APPENDIX A. TRACE ELEMENT ANALYSIS

During coal combustion, trace elements distribute among bottom ash, fly ash, and flue gas and thus may be emitted into the environment. During coal gasification, most trace elements are distributed in ash, tars, oils, and gas liquor. For this plant design, tars and oils from coal gasification are sent to the boiler for incineration. Based on pulverized coal boiler experience, about 80 percent of the ash present in coal is charged as fly ash, and the remainder is discharged as bottom ash.^{1,2} The more volatile trace elements concentrate preferentially in the fly ash.³⁻⁶ About 5 percent of the initial concentrations of most trace elements pass the ESP and can be emitted to the atmosphere assuming none is collected downstream in the SO₂ scrubbing system.⁷ Based on recent work conducted by Lawrence Livermore Laboratory (LLL), it is possible to quantitatively estimate trace element concentrations escaping the ESP if coal composition and certain operating parameters are known.⁸ The methodology is presented below.

Data required:

- Trace element concentrations in coal (C_i , $i=1,2,\dots,n$, $\mu\text{g/g}$)
- Coal feed rates to utility boiler and gasifier (F_1 and F_2 respectively, g/sec)
- Plant steam heat rate output; steam generated for coal gasification, electrical power, motive power, and process heating (S)
- Overall boiler thermal efficiency (η_p)
- Electrostatic precipitator overall efficiency (η_{ESP})

Definitions:

Plant total heat rate input = (plant steam heat rate output)/(overall thermal efficiency)
 $= S/\eta_p$

(Consumption) _{i} = (trace element i mass flow rate)/(plant total heat rate input)
 $= (C_i F)/S/\eta_p$

Trace element distribution from gasification byproducts = Percent distribution of trace element i in tars (D_T) _{i} and oils (D_O) _{i} sent to the boiler for incineration from the coal gasifier

- ESP efficiency ratio = (1-ESP overall efficiency)/(1-ESP overall efficiency used in LLL study)
= (1- η_{ESP})/(1-0.97)
- (Atmospheric emission rate)_i = (stack emission of trace element i)/(plant total heat rate input)
- (AER)_i = atmospheric emission rate for trace element i, which passes through the ESP and scrubber
- (Penetration)_i = (100%) (atmospheric emission rate)_i/(consumption)_i
= given in following Table A-1.

Procedure:

1. Determine
 - Plant total heat rate input
 - ESP efficiency ratio
 - Mass flow rates of trace elements into utility boiler from coal feed and gasifier waste fuels
 - Consumption_i
2. Obtain penetration_i from Table A-1
3. Atmospheric emission rate_i = (penetration)_i(consumption)_i
(ESP efficiency ratio)/100

$$(AER, \mu g/joule)_i = (penetration)_i (C_i F)/(S/\eta_p), \mu g/joule$$

$$(1 - \eta_{ESP})/(1 - 0.97)$$

For the design plant,

- Steam mass flow rate = 3,150,700 lb/hr
- Coal feed rate to utility boiler (F₁) = 414,700 lb/hr
- Coal feed rate to gasifier (F₂) = 1,901,324 lb/hr

Trace element concentrations (C_i) = Values given in item (6), Coal to Lurgi Gasifier

Overall boiler thermal efficiency (η_p) = 77% from item (7), Coal to Utility Power Plant

Electrostatic precipitator efficiency (η_{ESP}) = 99.6% from item (9), Flue Gas From Utility Power Plant

Trace element distribution in tar from gasifier (D_T)_i = Refer to Table A-3

Trace element distribution in oil from gasifier (D_O)_i = Refer to Table A-3

$$S = (3,150,700 \text{ lb steam/hr})(1337 \text{ Btu/lb steam})(2.93 \times 10^{-4} \text{ kWh/Btu}) \\ (1000 \text{ watts/kW})(1 \text{ joule/sec/watt})$$

$$= 12.3 \times 10^8 \text{ J/sec}$$

$$F_1 = (414,700 \text{ lb coal/hr})(454 \text{ g/lb})(1 \text{ hr}/3600 \text{ sec})$$

$$= 5.2 \times 10^4 \text{ g/sec}$$

$$F_2 = (1,901,324 \text{ lb coal/hr})(454 \text{ g/lb})(1 \text{ hr}/3600 \text{ sec})$$

$$= 24 \times 10^4 \text{ g/sec}$$

Table A-1. Penetration of Elements Contained in Particles Emitted From an ESP-Equipped Coal-Fired Generating Unit (%)^a

Element	ESP Unit ^a	Element	ESP Unit ^a
Al	1.1 ± 0.1	Mo	5.1 ± 1.2
As	11.5 ± 3.0	Mn	1.6 ± 0.5
Ba	4.0 ± 0.8	Na	1.55 ± 0.09
Be	0.9 ± 0.3	Pb	5.5 ± 1.1
Br	0.14 ± 0.08	Rb	1.3 ± 0.1
Ca	1.3 ± 0.2	Sb	7.7 ± 0.7
Cd	8.8 ± 3.0	Sc	1.46 ± 0.06
Ce	1.29 ± 0.09	Se	7.7 ± 0.8
Co	2.5 ± 0.3	Sr	2.0 ± 0.3
Cr	3.8 ± 0.3	Ta	1.3 ± 0.1
Cs	1.2 ± 0.2	Th	1.32 ± 0.08
Fe	1.32 ± 0.09	Ti	1.51 ± 0.03
Ga	4.4 ± 0.7	U	3.7 ± 0.4
In	5.4 ± 0.7	V	3.7 ± 0.6
K	1.0 ± 0.3	W	7.2 ± 2.2
La	1.29 ± 0.07	Zn	6.3 ± 0.8
Mg	1.2 ± 0.4	Zr	1.4 ± 0.3

^a Number of samples was eight unless otherwise indicated.

Table A-2 shows trace element concentrations for a low-sulfur subbituminous western (Wyoming) coal taken from Reference 9. These values are consistent with the coal characteristics given in Reference 9 and shown in item ⑥, Coal to Lurgi Gasifier, and the coal feed assumed in Reference 10. Calculated trace element mass flow rates entering the boiler (F_1C_1) and the gasifier (F_2C_1) are also listed.

Table A-2. Trace Element Concentrations and Mass Flow Rates

Trace Element	Concentration, C_1 , in Coal ($\mu\text{g/g}$)	Mass Flow Rate Entering Boiler, F_1C_1 ($\mu\text{g/s}$)	Mass Flow Rate Entering Gasifier, F_2C_1 ($\mu\text{g/s}$)
As	0.57 - 1.2	2.96×10^4 - 6.24×10^4	13.7×10^4 - 28.8×10^4
Be	0.71 - 0.8	3.69×10^4 - 4.16×10^4	17.0×10^4 - 19.2×10^4
Cd	0.31 - 0.8	1.61×10^4 - 4.16×10^4	7.44×10^4 - 19.2×10^4
Mn	2.8 - 3.4	14.6×10^4 - 17.7×10^4	67.2×10^4 - 81.6×10^4
Pb	0.51 - 12.0	2.65×10^4 - 62.4×10^4	12.2×10^4 - 288×10^4
Se	0.33	1.72×10^4	7.92×10^4
U	0.88	4.58×10^4	21.1×10^4
Zn	0.23 - 8.0	1.2×10^4 - 41.6×10^4	5.5×10^4 - 192×10^4

A trace element mass flow rate balance was conducted according to the flow diagram shown in Figure A-1, in order to determine the consumption of each trace element and the atmospheric emission rates. To calculate these values, the distribution of the trace elements in tar and oil from the gasifier must be known. It was assumed that the distribution of trace elements from the Lurgi gasifier in this plant design is the same as the distribution from the Lurgi gasifier at the SASOL plant¹¹ shown in Table A-3. The distribution of trace elements in tar and oil from coal gasification is listed in Table A-3 along with the trace element mass flow rates in the tar and oil streams and the (consumption)_i.

Table A-3. Trace Element Distributions and Mass Flow Rates

Trace Element	Trace Element Distribution From Gasifier ¹¹		Trace Element Mass Flow Rate in Tar ($D_T F_2 C_1$)($\mu\text{g/s}$)		Trace Element Mass Flow Rate in Oil ($D_O F_2 C_1$)($\mu\text{g/s}$)		(consumption) _i ($F_1 C_1 + D_T F_2 C_1 + D_O F_2 C_1$)
	Tar (D_T) (%)	Oil (D_O) (%)					
As	1.9	3.9	0.26×10^4	- 0.54×10^4	0.534×10^4	- 1.12×10^4	3.75×10^4 - 7.9×10^4
Be	17.0	0.3	2.89×10^4	- 3.26×10^4	0.051×10^4	- 0.0576×10^4	6.63×10^4 - 7.48×10^4
Cd	0.6	1.4	0.045×10^4	- 0.115×10^4	0.104×10^4	- 0.269×10^4	1.76×10^4 - 4.54×10^4
Mn	0	0	0	0	0	0	14.6×10^4 - 17.7×10^4
Pb	4.3	0	0.525×10^4	- 12.4×10^4	0	0	3.18×10^4 - 74.8×10^4
Se	-	-	0	0	0	0	1.72×10^4
U	-	-	0	0	0	0	4.58×10^4
Zn	-	-	0	0	0	0	1.2×10^4 - 41.6×10^4

Figure A-1. Trace Element Distribution

An example atmospheric emission rate is calculated for the higher concentration of arsenic ($1.2 \mu\text{g/g}$) as follows:

$$\begin{aligned}
 (AER)_{As} &= \left[\frac{(\text{penetration})_{As} (C_{As} F)}{(S/N_p)} \right] \left[\frac{1-ESP}{1-0.97} \right] \\
 &= \left[\frac{(0.115)(7.9 \times 10^4 \mu\text{g/s})}{12.3 \times 10^8 \text{ J/s}/0.77} \right] \left[\frac{1-0.996}{1-0.97} \right] \\
 &= 0.758 \times 10^{-6} \mu\text{g/J}
 \end{aligned}$$

On a daily basis,

$$\begin{aligned}
 (AER)_{As} &= (0.758 \times 10^{-6} \mu\text{g/J})(S/N_p)(3600 \text{ sec/hr})(24 \text{ hr/day})(1 \times 10^{-6} \text{ g}/\mu\text{g})(1 \text{ lb}/454 \text{ g}) \\
 &= (0.758 \times 10^{-6} \mu\text{g/J})(12.3 \times 10^8 \text{ J/s}/0.77)(3600 \text{ sec/hr})(24 \text{ hr/day}) \\
 &\quad (1 \times 10^{-6} \text{ g}/\mu\text{g})(1 \text{ lb}/454 \text{ g}) \\
 &= 0.23 \text{ lb/day}
 \end{aligned}$$

Annual and daily atmospheric emission rates for the trace elements are as follows:

Element	(AER) ₁	
	lb/day at 100% Capacity Factor	lb/yr at 92% Capacity Factor
As	0.1094-0.23	36.7-77.2
Be	0.0151-0.0170	5.07-5.7
Cd	0.0392-0.101	13.2-33.9
Mn	0.0593-0.0717	19.9-24.1
Pb	0.0444-1.04	14.9-349
Se	0.037	11.3
U	0.043	14.4
Zn	0.192	64.5

References

1. U.S. Environmental Protection Agency, "Electric Utility Steam Generating Units: Background Information for Proposed Particulate Emission Standards," EPA-450/2-78-006a, July 1978, p. 3-14.
2. Teknekron, Inc., "Comprehensive Standards: The Power Generation Case," EPA No. 68-01-0561, March 1975, p. 91.
3. D.F.S. Natusch, J.R. Wallace, and C.A. Evans, Jr., Science, Vol. 183, No. 4121, 1974, pp. 202-204.
4. N.E. Bolton et al., "Trace Element Measurement at the Coal-Fired Allen Steam Plant, Progress Report, June 1971 - January 1973," ORNL-NSF-EP-43, March 1973.
5. N.E. Bolton et al., "Trace Element Measurements at the Coal-Fired Allen Steam Plant, Progress Report, February 1973 - July 1973," ORNL-NSF-EP-62, 1974.
6. G.E. Gordon et al., "Study of the Emissions from Major Air Pollution Sources and Their Atmospheric Interactions," University of Maryland Department of Chemistry and Institute for Fluid Dynamics and Applied Mathematics, College Park, Maryland, 1974.
7. K.K. Bertine and E.D. Goldbert, Science, Vol. 173, No. 233, 1971.
8. J.M. Ondov, R.C. Ragaini, and A.H. Biermann, "Emissions and Particle-Size Distributions of Minor and Trace Elements at Two Western Coal-Fired Power Plants Equipped with Cold-Side Electrostatic Precipitators," Environmental Science and Technology, Vol. 13, 1979, pp. 946-953.
9. M. Ghassemi, K. Crawford, and S. Quinlivan, Environmental Assessment Report: Lurgi Coal Gasification Systems for SNG, EPA-600/7-79-120, prepared for U.S. Environmental Protection Agency by TRW, Inc., May 1979.
10. M. Shreiner, "Research Guidance Studies to Assess Gasoline from Coal by Methanol-to-Gasoline and SASOL-Type Fischer-Tropsch Technologies," prepared for U.S. Department of Energy by Mobil Research and Development Corporation, August 1978.
11. M. Ghassemi, K. Crawford, and S. Quinlivan, "Environmental Assessment Data Base for High Btu Gasification Technology," Vol. II, App. A, B, C, EPA-600/7-78-186b, prepared for U.S. Environmental Protection Agency by TRW, Inc., September 1978.

APPENDIX B. MATERIAL BALANCE

Although a detailed material balance requires information not now available and is beyond the scope of this document, a general mass balance of the process has been completed for this plant design and is presented in Table B-1. Additional details relating to the water balance are presented in Table B-2 and Figure B-1 to illustrate the major sources and consumptive uses of water. Note that some of the process units consume water (e.g., gasification and shift conversion) while others create water (e.g., methanation in the Fischer-Tropsch synthesis section). However, the majority of the water supplied to the process is eventually lost through evaporation to the atmosphere.

Most of the air pollutants from the facility are emitted from the utility power plant because the boiler is used to incinerate process waste material. However, there are three other major sources of air emissions from the facility: gasifier lockhopper, hydrogen purification unit, and storage tank field. The contributions of air pollutants from each individual unit to the total facility emissions are presented in Table B-3.

Table B-1. General Material Balance

<u>Process Input</u>	<u>Mlb/hr</u>	<u>Process Output</u>	<u>Mlb/hr</u>
Coal, as mined	2,316.0	Ash	147.8
Air	7,309.6	Products, including	
Water	3,319.9	alcohols	519.7
Other	7.9	Byproducts	13.7
		Blowdown water	837.9
		Stack and evaporation losses	1,428.4
		Other	5.9
Total	12,953.4	Total	12,953.4

Table B-2. Water Flow Balance (gal/yr)

<u>Input</u>		<u>Output</u>	
Fresh water makeup	3.2×10^9	Evaporation loss from cooling towers	2.33×10^9
Moisture in coal feed to gasifiers	0.515×10^9	De-aerator loss to atmosphere	0.00967×10^9
Condensation from air separation plant	0.019×10^9	Ash sludge vent to atmosphere	0.022×10^9
		Reacted water in product	0.54×10^9
		Water in holding pond	0.81×10^9
		Ash deposit water loss	0.018×10^9
Total water supply	3.734×10^9 $= 3.73 \times 10^9$	Total water loss	3.72967×10^9 $= 3.73 \times 10^9$

Internal Streams

(A) 0.85×10^9 gal/yr
blowdown from
cooling towers and boiler
to holding pond	(D) 1.565×10^9 gal/yr
wastewater	(G) 0.04×10^9 gal/yr
from holding pond
to ash handling
(B) 0.0993×10^9 gal/yr
BFW to process	(E) 0.468×10^9 gal/yr
wastewater	(H) 1.89×10^9 gal/yr
treated water to
cooling tower makeup
(C) 0.018×10^9 gal/yr
water in ash
from lockhoppers	(F) 0.53×10^9 gal/yr
water product
from methanator	(I) 0.146×10^9 gal/yr
treated water
to Fischer-Tropsch synthesis

Figure B-1. Water Supply-Loss Network

Table B-3. Cumulative Air Emissions From the Facility

Source	Pollutant (tons/yr)					
	SO ₂	NO _x	TSP	HC	CO	CO ₂
Boiler flue*	3.56×10^3	8.55×10^3	0.26×10^3	0.39×10^3	1.30×10^3	10.9×10^6
Gasifier lockhopper vent**	-	-	-	0.84×10^3	2.43×10^3	5.98×10^3
Hydrogen purification vent†	-	-	-	-	-	41.5×10^3
Gas-fired process heaters	-	-	-	-	-	0.11×10^6
Storage tank vent**	-	-	-	0.378×10^3	-	-
Total	3.56×10^3	8.55×10^3	0.26×10^3	1.6×10^3	3.73×10^3	11.0×10^6

* Values from item ⑨, Flue Gas From Utility Power Plant

** Values from item ⑬, Lockhopper Vent Gas From Lurgi Gasifier

† Value from item ⑳, CO₂ Vented From the Hydrogen Purification Unit to the Atmosphere

** Value from item ㉑, Storage Evaporative Emissions

APPENDIX C. SULFUR MATERIAL BALANCE

Coal assumed for this ECIR is Wyoming subbituminous coal. The sulfur content is low (0.3 percent), but the ultimate fate of sulfur is of primary concern. Some of the sulfur is converted in the liquefaction process to sulfur dioxide and eventually released to the atmosphere.

The coal feed from strip mining operations to the coal preparation facility is 1158 tons/hr. Therefore, the amount of sulfur being fed to the plant is 3.47 tons/yr. Of this amount, 2.85 tons/hr is fed to the Lurgi gasifier, and 0.62 ton/hr is fed to the utility boiler. In addition to sulfur from coal, the boiler receives 0.115 ton/hr of sulfur from process-derived fuels (i.e., waste products from the coal liquefaction processes having some heat value). Assuming New Source Performance Standards apply, then 70 percent of the sulfur fed to the utility boiler must be removed. Of the 70 percent removed, 10 percent, or 0.0735 ton/hr, is in boiler ash and 60 percent, or 0.441 ton/hr, is in scrubber sludge. The remaining 30 percent, or 0.22 ton/hr of sulfur, is released as SO_2 in the flue gas to atmosphere.

Of the 2.85 tons/hr of sulfur entering the gasifier, 0.115 ton/hr, which is part of the process-derived fuel, is burned in the utility boiler, and 0.033 ton/hr becomes part of the gasifier ash (0.016 ton/hr of this amount is sulfur contained in ungasified coal). The remainder becomes part of the raw synthetic gas stream (with the exception of 0.0017 ton/hr vented from the gasifier lockhoppers). The Stretford recovery unit yields 2.54 tons/hr of salable sulfur product.

A fraction of sulfur (0.15 ton/hr) is retained in other waste streams and 0.01 ton/hr is disposed of as part of the sludge after-treatment in the wastewater treatment facility. The overall sulfur balance is shown in Figure C-1 and itemized in Table C-1.

Figure C-1. Sulfur Material Balance Flow Sheet

Table C-1. Sulfur Material Balance
(tons/hr)

Input (sulfur in coal)	Environmental Point of Interest	
Coal to gasifier	⑥	2.85
Coal to utility	⑦	0.62
Total sulfur in coal		3.47
Output (as sulfur)		
Lockhopper vent gas	⑲	0.0017
Gasifier ash	⑳	0.033
Product from Stretford recovery	㉔	2.54
Sludge from wastewater treatment	㉚	0.01
Utility boiler ash	⑭	0.0735
Utility scrubber flue gas	⑨	0.22
Utility scrubber sludge	⑯	0.441
Other waste streams		0.15
Total sulfur output		3.47

APPENDIX D. STORAGE EVAPORATIVE EMISSION FORMULAS AND CALCULATIONS

Formulas for estimating storage tank evaporative losses developed by the American Petroleum Institute^{1,2} are presented below.

Calculation for Estimating Fixed-Roof Storage Tank Losses:

The total evaporative emissions are made up of

- Breathing loss
- Working loss

The breathing loss is calculated by the following equation:

$$L_y = 0.024 \left(\frac{P}{T_{4.7} - P} \right)^{0.68} D^{1.73} H^{0.51} T^{0.5} F_p C$$

where

- L_y = breathing loss, bbl/yr
- P = true vapor pressure at bulk liquid temperature, psia
- D = tank diameter, ft
- H = average outage,¹ ft, including a correction for roof volume
- T = average daily ambient temperature change, °F (difference between U.S. Weather Bureau average daily recorded maximum and minimum temperature)
- F_p = paint factor,¹ determined from field tests
- C = adjustment factor¹ for small-diameter tanks ($C = 1$ for tanks 30 ft in diameter or larger)

The working loss is calculated by the following equation:

$$F_w = \frac{3 PV}{10,000} K_T$$

where

F_W = working loss, bbl/yr

P = true vapor pressure, psia

V = volume of liquid pumped into tank, bbl

K_T = turnover factor from Figure 11 of Reference 1

An example calculation of the amount of vapor emissions from a 38,000-barrel³ diesel oil fixed-roof storage tank is given below.

The breathing loss is calculated as follows:

$$L_Y = 0.024 \left(\frac{P}{14.7-P} \right)^{0.68} D^{1.73} h^{0.51} T^{0.5} F_p C$$

The diameter of the tank is calculated from the known tank volume (VOL) of 38,000 barrels:

$$Vol = \frac{\pi D^2}{4} h$$

Assuming $h/D = 1/2$, then

$$\begin{aligned} Vol &= \frac{\pi D^3}{8} \\ D &= \left(\frac{8 Vol}{\pi} \right)^{1/3} \\ &= \left[\frac{8 \times 38,000 \text{ bbl} \times 42 \text{ gal/bbl} \times \frac{1}{7.48} \text{ gal/ft}^3}{\pi} \right]^{1/3} = 82 \text{ ft} \end{aligned}$$

and

h = 41 ft

P = 0.01 psia, the vapor pressure of diesel fuel at 70°F

H = 24 ft, the outage corresponding to a tank of these dimensions

T = 30°F, assumed temperature change (conservative)

F_p = 1.33, paint factor for aluminum paint

Then,

$$L_y = (0.024) \left(\frac{0.01}{14.7-0.01} \right)^{0.68} (82)^{1.73} (24)^{0.51} (30)^{0.5} (1.33) \\ = 12.7 \text{ bbl/yr}$$

The working loss is calculated as follows:

$$F_w = \frac{3 PV}{10,000} K_T$$

where

V = 924,667 bbl/yr, the annual flow rate of diesel oil into the tank³

P = 0.01 psia, the vapor pressure of diesel fuel at 70°F

K_T = 1.0, the value for less than 50 turnovers/yr

The number of turnovers is = $\frac{924,667 \text{ bbl/yr}}{38,000 \text{ bbl}} = 24/\text{yr}$

Then

$$F_w = \frac{3(0.01)(924,667)}{10,000} (1.0) \\ = 2.77 \text{ bbl/yr}$$

where

Total emissions = L_y + F_w = 12.7 + 2.77 = 15.5 bbl/yr

Using the density of diesel fuel = 7.5 lb/gal

Total emissions = (15.5 bbl/yr)(7.5 lb/gal)(42 gal/bbl) $\left(\frac{1}{2000 \text{ lb/ton}} \right)$

Total emissions = 2.44 tons/yr

Calculation for Estimating Floating-Roof Storage Tank Losses:

The total evaporative emissions are made up of

- Standing storage loss
- Withdrawal loss

The standing storage loss is calculated by the following equation:

$$L_s = K_S V^n P^* D M_v K_c$$

where

L_S = standing storage loss, lb/yr

K_S = seal factor,² lb-mole/ft (mi/hr)ⁿ yr

V = average wind speed, mi/hr

n = seal-related wind speed exponent,² dimensionless

P^* = vapor pressure function (dimensionless)

$$P^* = \frac{(P/P_a)}{\left[1 + \left(1 - \frac{P}{P_a}\right)^{0.5}\right]^2}$$

where

P = true vapor pressure at ambient temperature, psia

P_a = average atmospheric pressure at tank location, psia

D = tank diameter, ft

M_v = average molecular weight of vapor, lb/lb-mole

K_C = product factor, dimensionless

= 0.4 for crudes

= 1.0 for refined stock

Withdrawal Loss:

This is calculated as

$$L_W = \frac{(0.943) Q C W_1}{D}$$

where

L_W = withdrawal loss, lb/yr

Q = average throughput, bbl/yr

C = shell clingage factor,² bbl/1000 ft²

W_1 = average stock liquid density, lb/gal

D = tank diameter, ft

An example calculation of the amount of vapor emissions from two gasoline storage tanks (floating-roof type) each having a capacity of 112,000 barrels³ is given below.

The standing storage loss is calculated as follows:

$$L_s = K_s V^n P^* D M_v K_c$$

For welded tanks,² conservative values of K_s and n are:

$$\begin{aligned} K_s &= 1.2 \\ n &= 2.3 \end{aligned}$$

$$V = 9 \text{ mi/hr, assumed average wind speed}$$

$$P = 6.3 \text{ psia, vapor pressure of gasoline at } 70^\circ\text{F}$$

$$P_a = 14.7 \text{ psia, average atmospheric pressure}$$

Then

$$\begin{aligned} P^* &= \left[\frac{(P/P_a)}{1 + \left(1 - \frac{P}{P_a}\right)^{0.5}} \right]^2 \\ &= \left[\frac{(6.3/14.7)}{1 + \left(1 - \frac{6.3}{14.7}\right)^{0.5}} \right]^2 = 0.14 \text{ (vapor pressure function)} \end{aligned}$$

The diameter of the tank is calculated from the known tank volume of 112,000 barrels³ assuming $h/D = 1/2$:

$$\begin{aligned} D &= \left(\frac{8 \text{ Vol}}{\pi} \right)^{1/3} \\ &= \left[\frac{8 \times 112,000 \text{ bbl} \times 42 \text{ gal/bbl} \times \frac{1}{7.48} \text{ gal/ft}^3}{\pi} \right]^{1/3} \\ &= 116.9 \text{ ft} \end{aligned}$$

Therefore, the storage tank diameter,

$$D = 120 \text{ ft}$$

$$h = 60 \text{ ft}$$

Then

$$\begin{aligned}L_s &= (1.2)(9)^{2.3} (0.14) (120) (64) \text{ lb/yr} \\&= 202,200 \text{ lb/yr for each tank} \\&= 404,400 \text{ lb/yr for two tanks} \\&= 202 \text{ tons/yr for two tanks}\end{aligned}$$

The withdrawal loss is calculated as follows:

$$L_w = \frac{(0.943) Q C W_1}{D}$$

where

$$\begin{aligned}Q &= 4.48 \times 10^6 \text{ bbl/yr, annual throughput} \\C &= 0.0015, \text{ shell clingage factor}^2 \\W_1 &= 5.12 \text{ lb/gal, liquid density}\end{aligned}$$

Then

$$\begin{aligned}L_w &= \frac{(0.943) (4.48 \times 10^6) (0.0015) (5.12)}{120} \\&= 270 \text{ lb/yr} \\&= 0.135 \text{ ton/yr}\end{aligned}$$

The total evaporative emissions are then calculated as follows:

$$\begin{aligned}\text{Total emissions} &= L_s + L_w \\&= 202 \text{ tons/yr} + 0.135 \text{ ton/yr} \\&= 202.1 \text{ tons/yr}\end{aligned}$$

References

1. "Evaporation Loss From Fixed-Roof Tanks," API Bulletin 2518, June 1972.
2. "Evaporation Loss From External Floating-Roof Tanks," API Bulletin 2517, Second Edition, February 1980.
3. M. Schreiner, "Research Guidance Studies to Assess Gasoline from Coal by Methanol-to-Gasoline and SASOL-Type Fischer-Tropsch Technologies," FE-2447-13, prepared for U.S. Department of Energy by Mobil Research and Development Corporation, August 1978.

APPENDIX E. COST ESTIMATES

Cost estimates for the indirect coal liquefaction plant are based on 1977 dollars.¹ Construction costs for each process unit are given in Table E-1. Note that environmental control costs, with the exception of wastewater treatment costs, are intertwined with process unit costs. The environmental control costs amount to about \$16.2x10⁶.

Table E-1. Process Unit Construction Costs¹

Process Equipment	Construction Cost, 10 ⁶ \$	Process Equipment	Construction Cost, 10 ⁶ \$
Gasification, shift, cooling purification, and recovery	414.9	Oxygen production	110.1
Hydrocarbon recovery	19.4	Boiler, main superheater, stackgas precipitator, and scrubber	146.6*
H ₂ recovery	8.8	Superheater	1.6
Methanation	12.0	Instrument and plant air	0.6
CO ₂ removal	9.2	Coal handling	65.6
SNG drying and compression	3.1	Ash handling	5.8
Fischer-Tropsch synthesis	76.4	BFW preparation	20.6
Naphtha hydrotreating	3.7	CW makeup preparation	0.5
Fischer-Tropsch product fractionation	14.5	CW towers	23.3
Fischer-Tropsch product hydrogenation	6.6	Power generation	10.6
Hydrotreated product fractionation	3.8	Wastewater treatment	26.3*
Catalytic reforming	7.3	Blowdown facilities	2.7
C ₅ /C ₆ isomerization	5.3	Storage	8.6
Catalytic polymerization	4.1	Interconnecting piping	20.4
HF alkylation	2.2	Refrigeration	27.1
Poly gasoline hydrogenation	2.4	Gasoline blending	2.0
Light ends recovery	2.2	Fischer-Tropsch catalyst preparation	27.7
H ₂ purification	2.7	Miscellaneous (water ponds, tankage)	3.4
Alcohol recovery	11.0		
Miscellaneous (control house, pipe rack)	26.6	B. Subtotal	503.5
A. Subtotal	636.2		
A. Subtotal	\$ 636.2 x 10 ⁶		
B. Subtotal	\$ 503.5 x 10 ⁶		
Total	\$1139.7 x 10 ⁶		

*Includes environmental control costs.

The total plant investment is divided into depreciable capital and expense capital as shown in Table E-2. Depreciable capital amounts to $\$1863 \times 10^6$ and expense capital amounts to $\$23.5 \times 10^6$.¹ Note that environmental studies and impact report costs amount to $\$2 \times 10^6$ and are 8.5 percent of the capital cost expenses.

Operation and maintenance costs for the indirect coal liquefaction plant are given in Table E-3. The operating and maintenance costs per year amount to $\$151.5 \times 10^6$.

Table E-2. Plant Investment Breakdown¹

Depreciable Capital	Investment, $10^6\$$
Process equipment	1139.7
Infrastructure	<u>46.4</u>
Subtotal construction cost	1186.1
Engineering and design (11.5 percent of construction cost)	<u>136.4</u>
Subtotal	1322.5
Contractor fee	<u>16.0</u>
Subtotal contractor cost	1338.5
Other project costs (project management, overtime premium, construction worker's compensation)	1608.0
Estimating allowance (15 percent of other project costs)	<u>242.0</u>
Subtotal	1850.0
Royalties	<u>13.0</u>
Total depreciable capital	1863.0
<u>Expense Capital</u>	
Sales tax	18.5
Catalyst and chemicals	3.0
Environmental studies and impact reports	<u>2.0</u>
Total expense capital	23.5
Total depreciable capital	1863.0
Total expense capital	<u>23.5</u>
Total capital cost	$1886.5 = \$1887 \times 10^6$

Table E-3. Operation and Maintenance Costs¹

Item	10 ⁶ \$/yr
Labor plus supervision	
Operating	10.2
Maintenance	<u>33.2</u>
Subtotal	43.4
Supplies	
Operating	2.5
Maintenance	<u>22.2</u>
Subtotal	24.7
Water	1.4
Catalyst and chemicals	5.9
Administration and general overhead	<u>26.1</u>
Local taxes and insurance	<u>50.0</u>
Total	151.5

Reference

1. M. Shreiner, "Research Guidance Studies to Assess Gasoline From Coal by Methanol-to-Gasoline and SASOL-Type Fischer-Tropsch Technologies," FE-2447-13, prepared for U.S. Department of Energy by Mobil Research and Development Corporation, August 1978.

GLOSSARY

Blowdown	Water that is periodically removed from either the cooling towers recycle or the boiler steam recycle to prevent accumulation of total dissolved solids.
Bottom ash	Residues of coal combustion that are collected and removed from the boiler.
Capacity factor	Actual plant output divided by the output that would be achieved if the plant were to operate at capacity continuously.
Circulating water	Cooling water supplied to the main condenser in the generating plant that is cooled by the cooling towers.
Clarifiers	Process unit for removal of total suspended solids in makeup water.
Cooling tower drift loss	Water aerosol emitted to the atmosphere from the cooling towers.
Cooling tower evaporation loss	Evaporated water emitted to the atmosphere from the cooling towers.
Curie	Disintegration rate for 1 gram of radioactive radium (1 curie = 3.7×10^{10} disintegrations per second).
Dead storage	Long-term coal storage.
Electrostatic	Particulate removal unit used to remove fly ash in the flue gas.
Flue gas	Combustion gases.
Flue gas desulfurization	Environmental control device used to remove a high percentage of the sulfur dioxide in the flue gas.
Fly ash	Ash carried out of the boiler in the flue gas.
Fugitive emissions	Uncontrolled emission, such as windblown dust from a coal pile.
Leaching	Dissolution of soluble material from a solid matrix.

Net station heat rate ($\dot{Q}$)	Amount of fuel input (in Btu/hr) necessary to generate 1 kWh of electricity.
Pyritic material	Inorganic sulfide compounds found in coal.
Recycle water	Water collected and reused.
Run-of-mine coal	Coal as it comes from the mine prior to any preparation.
Secure landfill	A landfill lined with material impervious to water such as plastic or clay, and used to contain and isolate toxic residue.
Sludge	Wet residue generated from an environmental control device (e.g., from a lime/limestone flue gas desulfurization unit).

ACRONYMS AND ABBREVIATIONS

As	arsenic
bbl	barrel
Be	beryllium
Btu	British thermal unit
C	carbon
C	coal feed heat rate
Cd	cadmium
CI	curie
CO	carbon monoxide
CO ₂	carbon dioxide
E	thermal efficiency
ECIR	Environmental Characterization Information Report
ESP	electrostatic precipitator
F	supplement fuels heat rate
F-T	Fischer-Tropsch
ft	foot
ft ³	cubic foot
FOE	fuel oil equivalent
gal	gallon
H	hydrogen
HC	hydrocarbons
H ₂ O	water
H ₂ S	hydrogen sulfide
kg	kilogram
l	liter
lb	pound
LPG	liquid petroleum gas
m ³	cubic meter
mg	milligram (10 ⁻³ gram)
Mn	manganese
MW	megawatt
MWe	megawatt -- electrical
N	nitrogen
NO _x	nitrogen oxides
NSPS	New Source Performance Standards
O	oxygen
P	electrical power
Pb	lead
ppm	parts per million
psia	pound-force per square inch absolute
psig	pound-force per square inch gauge
Q	net heat rate
Q _h	heat content of coal
Ra-226	radium-226
ROM	run-of-mine
S	steam heat rate
S	sulfur

Se	selenium
scf	standard cubic foot
SNG	synthetic natural gas
SO ₂	sulfur dioxide
TEG	triethylene glycol
TSP	total suspended particulates
U	uranium
WSEV	surface evaporation
yr	year
Zn	zinc

Colony TOSCO II Oil Shale Process

Environmental Characterization Information Report

January 1982

U.S. Department of Energy
Assistant Secretary for Environmental
Protection, Safety, and
Emergency Preparedness
Office of Environmental Analysis

CONTENTS

	<u>Page</u>
I. SUMMARY	A.5-4
II. INTRODUCTION	A.5-10
III. PROCESS DESCRIPTION AND ENVIRONMENTAL POINTS OF INTEREST	A.5-12
1. Mining of Oil Shale.	A.5-12
2. Air Emissions From Mining.	A.5-17
3. Particulate Emissions From Raw Shale Crushing and Transport.	A.5-20
4. Fugitive Dust From On-Site Shale Storage	A.5-24
5. Potential Runoff From On-Site Shale Storage.	A.5-27
6. Spent Shale Exiting Retort	A.5-29
7,8. Particulate Emissions and Sludge From Spent Shale Moisturizing Drum Wet Scrubber	A.5-31
9. Spent Shale Disposal Pile and Runoff	A.5-34
10,11. Air Emissions and Sludge From Raw Shale Preheater Wet Scrubbers.	A.5-36
12,13. Air Emissions and Sludge From Elutriator Wet Scrubbers	A.5-39
14. Foul Water From Fractionator to Water Treatment/Recycle. . . .	A.5-42
15. Byproduct Fuel Gas, Butane/Butylene Fuel, and LPG for Plant Fuel and for Marketing	A.5-43
16. Trapped Residues From DEA Filter to Disposal	A.5-46
17. Hydrogen Production.	A.5-47
18. Air Emissions From Hydrogen Generation	A.5-49
19. Solid Wastes From Hydrogen Generation.	A.5-52
20. Treated Naphtha to Blending.	A.5-53
21. Air Emissions From Naphtha Hydrogenation Unit.	A.5-54
22. Solid Wastes From Naphtha Hydrogenator	A.5-56
23. Treated Gas Oil to Blending.	A.5-58
24. Low Sulfur Syncrude Production.	A.5-59
25. Diesel Fuel Production for On-Site Consumption	A.5-61
26. Air Emissions From Gas Oil Hydrogenator.	A.5-62
27. Solid Wastes From Gas Oil Hydrogenator	A.5-64
28. Anhydrous Ammonia Production	A.5-66
29. Liquid Sulfur Production	A.5-67
30. Air Emissions From Tail Gas Incinerator.	A.5-69
31. Disposal of Solid Waste From Claus Unit and Wellman-Lord Unit	A.5-70
32. Byproduct Coke Production.	A.5-71
33. Air Emissions From Delayed Coker Furnace	A.5-73
34. Foul Water to Water Treatment and Recycle.	A.5-75
35. Solid, Liquid, and Gaseous Discharges and Losses From the Water Treatment and Recycling Facilities	A.5-76

CONTENTS (continued)

	<u>Page</u>
IV. PHYSICAL REQUIREMENTS.	A.5-80
V. PERSONNEL.	A.5-86
VI. OCCUPATIONAL SAFETY AND HEALTH	A.5-87
APPENDIX A: THE TOSCO II RETORTING PROCESS (INDIRECT MODE).	A.5-90
APPENDIX B: FACILITY AND ENVIRONMENTAL CONTROL COSTS.	A.5-92
APPENDIX C: METHODS FOR MINING OIL SHALE.	A.5-94
APPENDIX D: COMPONENTS OF MAJOR PROCESS STREAMS	A.5-95
APPENDIX E: POLLUTANTS EXITING ON-SITE STEAM BOILER	A.5-99
GLOSSARY.	A.5-100
ACRONYMS AND ABBREVIATIONS.	A.5-103

I. SUMMARY

This Environmental Characterization Information Report (ECIR) for Oil Shale, Surface Retorting: Colony TOSCO II Process (Indirect Mode) has been prepared from the latest available environmental and technical information collected from a number of sources. The plant chosen for characterization is a 47×10^3 bbl/day syncrude equivalent facility.

The process, assumed plant operating parameters, resources needed, and environmental residuals and products associated with the plant are presented in this section in the summary table (Table 1). Annual resource usage and pollutant discharges are shown in English and metric units, assuming an annual plant capacity factor of 90 percent.

In addition to annual quantities, the summary table gives quantities in terms of 10^{12} Btu of energy (syncrude) produced. These figures are provided to allow comparison between different energy processes and to facilitate application of the information in computer models.

The supporting information and calculation procedures for the data are given in Section III. Thirty-five environmental points of interest are discussed individually, giving a brief description of the pollutants or resources involved, standards to be met, example calculations showing the derivation of quantities, scaling laws and extrapolation methods to adjust to other conditions (where applicable), and a bibliography of cited references. The calculations of allowable emission levels are based on current Federal regulations that are known or assumed to be applicable to oil shale facilities. At this point in time, there are no New Source Performance Standards for emissions relating to oil shale facilities. However, Best Available Control Technology (BACT) guidelines have been defined for the Colony TOSCO II oil shale process via the Prevention of Significant Deterioration (PSD) permit process. Also, the State of Colorado has established an emission limitation for oil shale production and refining.

Section IV discusses the overall physical requirements of the plant for land and water; Section V gives the approximate number of personnel involved in constructing and operating a commercial-scale oil shale facility; and Section VI briefly describes the occupational health and safety hazards associated with oil shale mining and processing. The TOSCO II retorting process, cost information analysis, various mining techniques, identification of major stream components, and pollutants from the on-site steam boiler are included as appendices to this report. A glossary and a listing of acronyms and abbreviations used follow the appendices.

TABLE 1. SUMMARY SHEET

OIL SHALE, SURFACE RETORTING: COLONY TOSCO II PROCESS (INDIRECT MODE)

REFERENCE ENERGY SYSTEM

Mine-Mouth Plant Located on the Dow West Property Near Parachute Creek in Colorado; Underground Room and Pillar Mining Method Is Used; Gaseous Byproduct-Fuel Fired Utility Boiler To Produce Steam; TOSCO II Indirect Mode Retorting Method; On-Site State-of-the-Art Upgrading and Prerrefining Facilities; Environmental Controls Include: Wet Suppression, Baghouse Filters, and Wet Scrubbers for Particulate Control, Claus Process for Sulfur Recovery (H_2S and SO_2 Control), Wellman-Lord Tail Gas Incinerator/ SO_2 Scrubber, Ammonia Recovery Unit, Acid Gas Removal Process; On-Site Water Treatment and Recycling Facilities; and On-Site Solid Waste Disposal Via Landfill and Revegetation.

FACILITY OPERATING PARAMETERS

Facility Size:	47×10^3 bbl/day syncrude equivalent
Annual Capacity Factor:	90%
Annual/Energy Production	36.5×10^{12} Btu
Shale Oil Extraction Efficiency:	$(15.4 \times 10^6 \text{ bbl/yr})^*$
Upgrading for Shale Oil to Syncrude Efficiency:	90%
Lifetime:	20 yr
Feedstock Grade:	35 gal/ton
*At 5.6×10^6 Btu/bbl	

PROCESS FLOW

TABLE 1. (Continued)

OIL SHALE, SURFACE RETORTING: COLONY TOSCO II PROCESS (INDIRECT MODE)

RESOURCES USED

Code No.	Resource	Quantities Used		Per 10 ¹² Btu Energy Produced (Syncrude Equivalent)
		Reference Energy System Annual Usage*		
	<u>Explosives</u>			
①	ANFO for rubblization	6.01 × 10 ³ tons	5.45 × 10 ³ tonnes	70.8 tons
	<u>Fuel</u>			
①	Run-of-mine oil shale	22.3 × 10 ⁶ tons	20.2 × 10 ⁶ tonnes	263 × 10 ³ tons
⑮	By-product fuel gas for onsite consumption	409 × 10 ³ tons	371 × 10 ³ tonnes	4.82 × 10 ³ tons
	— Hydrogen generation unit			
	— Gas oil hydrogenation unit			
	— Naphtha hydrogenation unit			
	— Delayed coking process			
	— Utility boilers			
⑮	By-product butane/butylene for plant fuel	71.7 × 10 ³ tons	65.0 × 10 ³ tonnes	844 tons
⑳	By-product diesel fuel for mine and processed shale disposal operations	125 × 10 ³ gal	19.9 × 10 ⁶ liters	1.47 × 10 ³ bbl
	<u>Water</u>			
	Makeup water from Colorado River	3.07 × 10 ³ bbl	11.6 × 10 ⁹ liters	36.2 × 10 ⁶ gal
	Miscellaneous water input	471 × 10 ⁶ gal	1.78 × 10 ⁹ liters	5.55 × 10 ⁶ gal
	<u>Land (20 yr)</u>			
	Land for mine development			
	— Surface	42 acres	17 hectares	—
	— Underground	4100 acres	1659 hectares	—
	Land for solids disposal	800 acres	323 hectares	—
	Land for basic site facilities	175 acres	71 hectares	—
	Roads and conveyors	355 acres	144 hectares	—
	<u>Personnel</u>			
	Plant construction (3 yr)	2500 to 2700 personnel	—	—
	Plant operation	1040 personnel	—	—
	<u>Materials for Construction, Operation and Maintenance (over 20-yr period)</u>			
	Concrete	110,000 cu yd	84,106 meters ³	1.30 × 10 ³ cu yd
	Steel (reinforcement, hardworked)	44,000 tons	39,600 tonnes	518 tons
	Electric power	51.2 × 10 ⁶ Btu	15 × 10 ⁶ kWh	603 × 10 ⁶ Btu
	Fuel	540 × 10 ⁹ Btu		6.36 × 10 ⁹ Btu
	Oil shale	434 × 10 ⁶ tons	390 × 10 ⁶ tonnes	5.11 × 10 ⁶ tons

*Annual rate unless otherwise specified.

COSTS

	Reference Energy System	Per 10 ¹² Btu Energy Produced	Remarks
		(1975 \$)	
<u>Facility</u>			
Construction	\$960 × 10 ⁶ total	\$11.1 × 10 ⁶ total	
Operation and maintenance		Not Determined	
<u>Environmental Control</u>	(\$30.8-\$61.6) × 10 ⁶ /yr	(\$0.4-\$0.7) × 10 ⁶ /yr	\$2 to \$4 per barrel syncrude

TABLE 1. (Continued)

OIL SHALE, SURFACE RETORTING: COLONY TOSCO II PROCESS (INDIRECT MODE)

ENVIRONMENTAL RESIDUALS

Code No.	Residuals	Quantities Released		
		Reference Energy System Annual Levels		Per 10 ¹² Btu Energy Produced (syncrude equivalent)
		English Units	Metric Units	
	Air Pollutants*			
(2)	Mining and Blasting			
	— Total suspended solids (TSP)	2.97 tons	2.69 tonnes	0.0350 tons
	— Sulfur dioxide (SO ₂)	—	—	—
	— Nitrogen oxides (NO _x)	982 tons	894 tonnes	11.6 tons
	— Nonmethane hydrocarbons (HC)	197 tons	179 tonnes	2.32 tons
	— Carbon monoxide (CO)	1731 tons	1570 tonnes	20.4 tons
(3)	Particulates from crushing	201 tons	182 tonnes	2.37 tons
(4)	Particulates from shale storage**	16.5 tons	15.0 tonnes	0.194 tons
(7)	Particulates from shale moisturizer	868 tons	870 tonnes	11.3 tons
(10) & (12)	Total from shale preheater and elutriator			
	— TSP	1808 tons	1640 tonnes	21.3 tons
	— SO ₂	573 tons	520 tonnes	6.75 tons
	— NO _x	5622 tons	5099 tonnes	66.2 tons
	— HC	1065 tons	966 tonnes	12.5 tons
	— CO	183 tons	166 tonnes	2.15 tons
(18)	Hydrogen generation reforming furnaces			
	— TSP	45.1 tons	40.9 tonnes	0.531 tons
	— SO ₂	107 tons	97.1 tonnes	1.26 tons
	— NO _x	323 tons	293 tonnes	3.80 tons
	— HC	6.24 tons	5.66 tonnes	0.0735 tons
	— CO	39.0 tons	35.4 tonnes	0.459 tons
(18)	Carbon dioxide (CO ₂) from CO ₂ stripper	2.07 × 10 ⁶ tons	1.88 × 10 ⁶ tonnes	24.4 × 10 ³ tons
(21) (26)	Total from naphtha and gas oil hydrogenators			
(33)	Delayed coker furnaces and reboiler			
	— TSP	12.9 tons	11.7 tonnes	0.152 tons
	— SO ₂	31.4 tons	28.5 tonnes	0.370 tons
	— NO _x	92.8 tons	84.2 tonnes	1.09 tons
	— HC	2.31 tons	2.10 tonnes	0.0272 tons
	— CO	12.1 tons	10.9 tonnes	0.143 tons
(30)	SO ₂ from tailgas incineration	372 tons	337 tonnes	4.38 tons
	Water Discharge and Losses			
(5)	Potential runoff from coarse shale storage	652 × 10 ³ tons	2.47 × 10 ⁶ liters	7.68 × 10 ³ gal
(35)	Consumptive uses			
	— Mining, crushing, moisturizing revegetation, oil/water sludge	980 × 10 ⁶ to 1.28 × 10 ⁹ gal	3.71 × 10 ⁶ to 4.84 × 10 ⁸ liters	11.5 × 10 ⁶ to 15.1 × 10 ⁶ gal
	— Storage and shipping, fire and potable water, hydrotreater, utility and general process consumption, slop oil tank	995 × 10 ⁶ gal	3.77 × 10 ⁹ liters	11.7 × 10 ⁶ gal
(35)	Pyrolysis unit and cooling tower evaporation and drift	1.49 × 10 ⁹ gal	5.6 × 10 ⁹ liters	17.6 × 10 ⁶ gal
(35)	Coker unit evaporative losses	33.1 × 10 ⁶ gal	120 × 10 ⁶ liters	390 × 10 ³ gal
(35)	Miscellaneous losses	47.0 × 10 ⁶ gal	180 × 10 ⁶ liters	554 × 10 ³ gal

TABLE 1. (Continued)

OIL SHALE, SURFACE RETORTING: COLONY TOSCO II PROCESS (INDIRECT MODE)

ENVIRONMENTAL RESIDUALS (Continued)

		Quantities Released		
		Reference Energy System Annual Levels		
Code No.	Residuals	English Units	Metric Units	Per 10 ¹² Btu Energy Produced (syncrude equivalent)
Solid Wastes				
3 & 4	Total dust from baghouse filters	66.6 × 10 ³ tons	60.4 × 10 ³ tonnes	784 tons
(6)	Processed shale (dry)	17.5 × 10 ⁶ tons	15.9 × 10 ⁶ tonnes	206 × 10 ³ tons
(8), (11), (13)	Total sludge from wet scrubbers	962 × 10 ³ tons	872 × 10 ³ tonnes	11.3 × 10 ³ tons
(16)	Total trapped residue from DEA filters	386 tons	350 tonnes	4.55 tons
(19), (22)	Total spent catalysts (max. avg.)	437 tons	396 tonnes	5.15 tons
(27), (31)				
(22), (27)	Total proprietary waste (arsenic content)	360-580 tons (95.4 tons)	327-526 tonnes (86.5 tonnes)	4.24-6.83 tons (1.12 tons)
(35)	Waste flocculent	197 tons	179 tonnes	2.32 tons
(35)	Proprietary coagulant aid	8.21 tons	7.45 tonnes	0.0967 tons
(9)	Total solid wastes	18.5 × 10 ⁶ tons	16.8 × 10 ⁶ tonnes	218 × 10 ³ tons

*Emission following control devices, where applicable.

**No capacity factor.

PRODUCTS AND BY-PRODUCTS

Code No.	Product or By-Product	Quantities Produced		Per 10 ¹² Btu Energy Produced	Remarks
		Reference Energy System Annual Production			
		English Units	Metric Units		
	<u>Marketable By-Products</u>				
(15)	Liquid petroleum gas (LPG)	1.42 × 10 ⁶ bbl	226 × 10 ⁶ liters	16.6 × 10 ³ bbl	
(28)	Anhydrous ammonia (NH ₃)	44.3 × 10 ³ tons	40.2 × 10 ³ tonnes	518 tons	
(29)	Liquid sulfur	63.7 × 10 ³ tons	57.8 × 10 ³ tonnes	744 tons	
(32)	Coke	263 × 10 ³ tons	239 × 10 ³ tonnes	3.07 × 10 ³ tons	
	<u>Upgrade Shale Oil Product</u>				
(24)	Syncrude	15.4 × 10 ⁶ bbl	2.45 × 10 ⁹ liters	178 × 10 ³ bbl	

OCCUPATIONAL SAFETY AND HEALTH

	Underground Mining		Surface Retorting		Remarks
	Annual	Per 10 ¹² Btu	Annual	Per 10 ¹² Btu	
Deaths	0.92	0.01	0.15	0.002	
Injuries	40.8	0.44	17.1	0.180	

References

1. U. S. Environmental Protection Agency, Environmental Perspective on the Emerging Oil Shale Industry, by EPA Oil Shale Research Group, edited by Edward R. Bates (Industrial Environmental Research Laboratory) and Terry L. Thoen (Office of Energy Policy Coordination -- Region VIII), EPA-600/2-80-205a, 1980.
2. U. S. Department of the Interior, Final Environmental Impact Statement, Proposed Development of Oil Shale Resources, Vol. I and II, by The Colony Development Operation for Bureau of Land Management (DOI), 1977.
3. U. S. Environmental Protection Agency, A Preliminary Assessment of the Environmental Impacts of Oil Shale Development, by TRW Environmental Engineering Division for EPA, EPA-600/7-77-069, July 1977.

II. INTRODUCTION

Oil shale is a fine-grained sedimentary rock containing varying amounts of organic material called kerogen. When heated to about 900°F, a minimal residence time is required for the kerogen to fully decompose into hydrocarbons and a carbonaceous residue. Upon cooling, these hydrocarbons condense into a heavy liquid called shale oil, which after upgrading can be refined into different fuel products, such as gasoline, jet fuel, and diesel fuel.

Although there are several different techniques for mining and retorting oil shale, surface retorting is, technologically speaking, at a stage of potential industrial scale-up. This document presents a typical surface retorting technology, the TOSCO II process -- one of several surface retorting technologies considered to be amenable to early commercialization.

It is important to remember that there is currently no commercial oil shale industry in the United States; the industry is still in the initial stages of development. The data base on oil shale activities exists for relatively small-scale facilities and must be considered first-generation information. More accurate pollutant data are needed, and this is currently being obtained through sponsored RD&D by the U. S. Department of Energy, other Federal agencies, and private industry. Therefore, when estimates are given for a commercial-sized system capable of producing 47×10^3 bbl/day syncrude equivalent, the data have been scaled up to a system this size. For lack of a better method, scaling (when required) is assumed to be linear. In addition, there are instances when data needed to define emission factors are deficient (e.g., mining operations), and for these cases, information is taken from similar operations (e.g., rock, coal).

Thus, even though the best information that is presently available is used in this report, note that environmental problems associated with air emissions, water quality, and long-term solid waste disposal exist. The approach taken is to present one possible solution to these problems; the actual components and operating characteristics of a full-sized commercial system may differ from the system described herein. This document, however, still serves a useful function in that reasonable first order approximations for resource requirements and pollutant and residual emissions are delineated, and an accurate, qualitative description of oil shale activities associated with the present Colony TOSCO II process is given. As better information becomes available from demonstration facilities; it will be incorporated in future updates of this document.

It must be noted that the annual rate values are calculated directly from original data. As a result, these numbers may not compare precisely with those calculated via the rounded numbers given in the equations.

References

1. U. S. Environmental Protection Agency, Environmental Perspective on the Emerging Oil Shale Industry, by EPA Oil Shale Research Group, edited by Edward R. Bates (Industrial Environmental Research Laboratory) and Terry L. Thoen (Office of Energy Policy Coordination -- Region VIII), EPA-600/2-80-205a, 1980.
2. U. S. Department of Energy, Western Oil Shale Development: A Technology Assessment, Vol. 2: Technology Characterization and Production Scenarios (Draft), by Battelle for DOE, Contract No. DE-AC06-76RLO 1830, June 1981.

III. PROCESS DESCRIPTION AND ENVIRONMENTAL POINTS OF INTEREST

Based on available information about the Colony TOSCO II process in particular, and other surface retorting schemes in general, a composite 47 x 10³ bbl/day syncrude equivalent facility is described. The plant is assumed to be a mine-mouth facility located on the Dow West property, near Parachute Creek in Colorado, with on-site capabilities to upgrade the shale oil into refined syncrude suitable for processing in a conventional petroleum refinery. Facilities are also available to upgrade the retort gas so it can be combusted in an on-site boiler to generate steam. Pollutant emission controls assumed for this plant have been used in commercial industries and are well established. The shale used in the characterization has a Fischer assay of 35 gal/ton; the retorting process has a recovery efficiency of 95 percent; and the conversion of shale oil to syncrude has a process efficiency of 90 percent.^{2,3}

Environmental points of interest have been identified in Figure 1 and are discussed in the following sections. Items ① and ② deal with mining; ③ deals with shale preparation; ④ and ⑤ deal with on-site shale storage; ⑥ through ⑭ deal with the retort and disposal area; ⑮ through ⑳ deal with upgrading the shale oil to syncrude; and ㉑ deals with pollutant discharges and water losses from the water treatment and recycling facilities. In addition to the environmental points of interest, each section includes a brief description of that portion of the process. This information is presented to enhance reader understanding of the contributing factors associated with environmental emissions and syncrude production.

A description of the TOSCO II retorting process is given in Appendix A, cost information for the plant is given in Appendix B, options for mining oil shale are presented in Appendix C, components of major process streams are identified in Appendix D, and pollutants exiting the steam boiler are quantified in Appendix E.

References

1. U. S. Environmental Protection Agency, Environmental Perspective on the Emerging Oil Shale Industry, by EPA Oil Shale Research Group, edited by Edward R. Bates (Industrial Environmental Research Laboratory) and Terry L. Thoen (Office of Energy Policy Coordination -- Region VIII), EPA-600/2-80-205a, 1980, p. 13.
2. U. S. Department of Energy, Western Oil Shale Development: A Technology Assessment, Vol. 2: Technology Characterization and Production Scenarios (Draft), by Battelle for DOE, Contract No. DE-AC06-76RLO 1830, June 1981.
3. U. S. Department of the Interior, Final Environmental Impact Statement, Proposed Development of Oil Shale Resources, Vol. I and II, by The Colony Development Operation for Bureau of Land Management (DOI), 1977.

FIGURE 1.
PROCESS FLOWCHART WITH ENVIRONMENTAL POINTS OF INTEREST QUANTIFIED
COLONY TOSCO II OIL SHALE MINING, RETORTING, AND UPGRADING PROCESS
(90% Capacity Factor)

1 Mining of Oil Shale

To produce 15.4×10^6 bbl/yr (syncrude equivalent), 22.3×10^6 tons/yr of oil shale must be mined. 6.01×10^3 tons/yr of ANFO will be needed.

A conventional underground room and pillar mining method will be employed by the Colony Development Operation to extract the oil shale within the 60 foot thick Mahogany zone on the Dow West Property in Colorado. This mining method consists of drilling, charging, blasting, wetting of rock piles, loading, hauling, scaling, and roof bolting. These activities take place concurrently, with the exception of blasting which occurs three times daily during shift changes to minimize personnel exposure. Also for miner safety, a mine ventilation system (consisting of six 50 foot high by 30 foot wide ventilation shafts located at various sites along the cliff face) operates continuously to supply and circulate air to the mine, and to clear dust, blast fumes and residual diesel exhaust fumes out of the mine.

Seven 30 foot by 30 foot adits provide entry to the mine and will widen to 50 feet inside the mine. Mining is conducted in two benches, each 30 feet high (deep), with 50 to 60 foot square by 60 foot high pillars remaining as support structures. First, mine drifts 30 feet wide are formed on the upper bench by drilling horizontal holes into the walls, charging the holes with an explosive ammonium nitrate-fuel oil (ANFO) mixture, and blasting the shale loose. The broken shale then is loaded and hauled to the primary crushers located on the portal bench outside the mine. The roof and pillar walls are inspected and scaled to remove loosened shale, and the roof is bolted for added support to prevent cave-ins. The lower bench is mined in a similar manner except with the blast holes drilled vertically into the floor of the upper bench. Overall, 60 percent of the shale in the mine will be extracted.

The quantity of ANFO needed to rubblize the oil shale is directly related to the quantity of oil shale required to produce 47,000 bbl/day syncrude oil equivalent. The annual oil shale processing requirement can be determined from the Fischer assay of the oil shale being mined (35 gal/ton average for Colony's Dow West property), the retorting recovery efficiency (95 percent for the TOSCO^{1,3} process), and the upgrading conversion to synfuel efficiency (90 percent). Therefore, assuming that the heating values of the shale oil and crude petroleum are approximately the same:

Quantity of oil shale (shale feed rate)⁴

- = (barrels of syncrude equivalent)(gal/bbl)/[(Fischer assay of shale)(retort recovery eff.)(conversion to syncrude eff.)]
- = $[(47 \times 10^3 \text{ bbl/day})(42 \text{ gal/bbl})]/[(35 \text{ gal/ton})(0.95)(0.9)]$
- = 66×10^3 tons/day

Since the plant capacity factor* is estimated to be 90 percent,¹ the annual shale requirement is:

Quantity of oil shale (shale feed rate)

$$\begin{aligned} &= (66 \times 10^3 \text{ tons/day})(365 \text{ days/yr})(0.9 \text{ capacity factor}) \\ &= 21.7 \times 10^6 \text{ tons/yr} \end{aligned}$$

This amount of oil shale is capable of yielding the following annual quantity of syncrude oil equivalent.

Barrels of syncrude equivalent

$$\begin{aligned} &= (47 \times 10^3 \text{ bbl/day})(365 \text{ days/yr})(0.9 \text{ capacity factor}) \\ &= 15.4 \times 10^6 \text{ bbl/yr} \end{aligned}$$

Although 66,000 TPD of oil shale enters the retorting facilities, a larger quantity is to be mined in order to compensate for the losses incurred (prior to retorting) at the raw shale processing (crushing) and storage facilities. This quantity, on a daily basis, is

Raw oil shale mined¹

$$\begin{aligned} &= (61,000 \text{ TPSD})/(0.9 \text{ capacity factor}) \\ &= 67,778 \text{ tons/day} \end{aligned}$$

On an annual basis

Raw oil shale mined

$$\begin{aligned} &= (67,778 \text{ tons/day})(365 \text{ days/yr})(0.9 \text{ capacity factor}) \\ &= 22.3 \times 10^6 \text{ tons/yr} \end{aligned}$$

* Annual capacity factor is only included for annual production rates, where applicable.

Based on experimental data, an average of 0.54 pounds of ANFO explosive mixture is required to rubble one ton of oil shale⁴ for a two-bench mining process.² Therefore, on a daily basis:

Quantity of ANFO

- = (shale feed rate)(ANFO-shale ratio)/(lbs/ton)
- = (67,778 tons/day)(0.54 lbs ANFO/ton shale)/(2000 lbs/ton)
- = 18.3 tons/day

On an annual basis,

Quantity of ANFO

- = (18.3 tons/day)(365 days/yr)(0.9 capacity factor)
- = 6.01×10^3 tons/yr

References

1. U. S. Department of the Interior, Final Environmental Impact Statement, Proposed Development of Oil Shale Resources, Vol. I and II, by The Colony Development Operation for Bureau of Land Management (DOI), 1977, pp. II-10, II-15, II-17.
2. U. S. Environmental Protection Agency, A Preliminary Assessment of the Environmental Impacts from Oil Shale Developments, by TRW Environmental Engineering Division for EPA, EPA-600/7-77-069, July 1977, pp. 12.
3. U. S. Department of Energy, Western Oil Shale Development: A Technology Assessment, Vol. 2: Technology Characterization and Production Scenario (Draft), by Battelle for DOE, Contract No. DE-AC06-76RLO 1830, June 1977, pp. 65.
4. U. S. Department of Energy, Oil Shale Surface Retorting, Environmental Characterization Information Report, Edition 1, January 1981, pp. 8, 9.

② Air Emissions From Mining

Wet suppression and catalytic converters are used to control particulates, HC, NO_x, and CO emissions which result from mine equipment and mining activities. The corresponding annual emissions (after control) are: particulates, 2.97 tons/yr; hydrocarbons, 197 tons/yr; nitrogen oxides, 83 tons/yr; and carbon monoxide, 1,731 tons/yr.

Particulates

Major dust generating activities within the mine include drilling, loading, hauling, and blasting, with minor contributions from charging, scaling, and roof bolting. Blasting is done for one hour at the end of each shift (three times daily), while the remaining on-shift mining activities are done 21 hours per day.^{1,2} Wet suppression and baffled settling, which are used to reduce the potential particulate (dust) emissions, have an efficiency of 98.5 percent. On a daily basis, controlled particulate emissions from mining activities are estimated to be:

Particulate (dust) emissions^{1,2}

$$\begin{aligned} &= [(241 \text{ lbs/hr from blasting})(3 \text{ hrs/day}) + (23 \text{ lbs/hr from other activities})(21 \text{ hrs/day})](1-0.985)/(2,000 \text{ lbs/ton}) \\ &= 9.05 \times 10^{-3} \text{ tons/day} \end{aligned}$$

On an annual basis,

Particulate (dust) emissions

$$\begin{aligned} &= (9.05 \times 10^{-3} \text{ tons/day})(365 \text{ days/yr})(0.9 \text{ capacity factor}) \\ &= 2.97 \text{ tons/yr} \end{aligned}$$

Water used for wet suppression is Colorado River water pumped from the mine bench booster pump station. This water stream is a portion of the physical

requirements for water presented in Section IV. On a daily basis, the quantity of water used for wet suppression in the mine approximates

Water for dust control²

$$\begin{aligned} &= (350 \text{ gal/min})(60 \text{ mins/hr})(24 \text{ hrs/day}) \\ &= 504 \times 10^3 \text{ gal/day} \end{aligned}$$

On an annual basis,

Water for dust control

$$\begin{aligned} &= (504 \times 10^3 \text{ gal/day})(365 \text{ days/yr})(0.9 \text{ capacity factor}) \\ &= 166 \times 10^6 \text{ gal/yr} \end{aligned}$$

This averages 7.6 gallons of water per ton of shale mined.

Other Emissions

Diesel fuel-powered mining equipment releases additional potential air pollutants -- hydrocarbons (HC), nitrogen oxides (NO_x), and carbon monoxide (CO). The only control measures used are the catalytic converters mounted on the equipment. Blasting also contributes to the NO_x and CO emission rates but only to a small extent. An estimate, on a daily basis, of these pollutant emissions from the mine equipment are²

$$\begin{aligned} \text{HC} &= (22.7 \text{ kgm/hr})(2.2 \text{ lbs/kgm})(21 \text{ hrs/day})/(2,000 \text{ lbs/ton}) \\ &= 0.524 \text{ tons/day} \end{aligned}$$

$$\begin{aligned} \text{NO}_x &= (113.4 \text{ kgm/hr})(2.2 \text{ lbs/kgm})(21 \text{ hrs/day})/(2,000 \text{ lbs/ton}) \\ &= 2.62 \text{ tons/day} \end{aligned}$$

$$\begin{aligned} \text{CO} &= (199.6 \text{ kgm/hr})(2.2 \text{ lbs/kgm})(21 \text{ hrs/day})/(2,000 \text{ lbs/ton}) \\ &= 4.61 \text{ tons/day} \end{aligned}$$

On an annual basis,

$$\begin{aligned}\text{HC} &= (0.524 \text{ tons/day})(365 \text{ days/yr})(0.9 \text{ capacity factor}) \\ &= 172 \text{ tons/yr}\end{aligned}$$

$$\begin{aligned}\text{NO}_x &= (2.62 \text{ tons/day})(365 \text{ days/yr})(0.9 \text{ capacity factor}) \\ &= 861 \text{ tons/yr}\end{aligned}$$

$$\begin{aligned}\text{CO} &= (4.61 \text{ tons/day})(365 \text{ days/yr})(0.9 \text{ capacity factor}) \\ &= 1,514 \text{ tons/yr}\end{aligned}$$

The amount of diesel fuel consumed during mining and processed shale disposal operation is a byproduct of the upgrading facilities and totals

Diesel Fuel Consumed²

$$\begin{aligned}&= (16,000 \text{ gal/day})/(42 \text{ gal/bbl}) \\ &= 381 \text{ bbl/day}\end{aligned}$$

On an annual basis,

Diesel Fuel Consumed

$$\begin{aligned}&= (381 \text{ bbl/day})(365 \text{ days/yr})(0.9 \text{ capacity factor}) \\ &= 125 \times 10^3 \text{ bbl/yr}\end{aligned}$$

References

1. U. S. Department of Energy, Western Oil Shale Development: A Technology Assessment, Vol. 2: Technology Characterization and Production Scenarios (Draft), by Battelle for DOE, Contract No. DE-AC06-76RLO 1830, June 1981, pp. 46, 19, 46.
2. U. S. Department of the Interior, Final Environmental Impact Statement, Proposed Development of Oil Shale Resources, Vol. I and II, by The Colony Development Operation for Bureau of Land Management (DOI), 1977, pp. II-17, II-37, II-73.

3 Particulate Emissions From Raw Shale Crushing and Transport

About 201 tons/yr of dust will be released to the atmosphere from the crushers and the conveyor transfer points. Another 61.1×10^3 tons/yr will be captured by various control measures and sent to the shale disposal pile.

Shale crushing operations consist of two crushing stages. The first stage, primary crushing, is located on the portal bench just outside the mine. The run-of-mine shale is unloaded onto a grizzly where large pieces (3 to 4 feet) are broken down prior to entering the primary crusher. The primary crusher reduces the shale to 10- to 12-inch pieces which are transported to the secondary crusher via totally enclosed conveyors. The secondary crusher is located on the plateau near the retorting and upgrading facilities. Crushed ore exits the secondary crushing facilities sized at minus one-half inch (retort feed size).^{1,2}

Particulate emissions are produced and released at the crushing facilities and at transfer points along the transport routes. Baghouse filters (with a 99.7 percent efficiency) are used at the crushing facilities to reduce fugitive dust emissions.^{1,3} Water spray also may be used to reduce the quantity of airborne particulates.

Particulate emissions from the primary crushing facilities, on a daily basis, are

Particulate emissions^{1,2}

$$\begin{aligned} &= (3.3 \text{ kgm/hr})(2.2 \text{ lbs/kgm})(24 \text{ hrs/day})/(2000 \text{ lbs/ton}) \\ &= 0.087 \text{ tons/day} \end{aligned}$$

On an annual basis,

Particulate emissions

$$\begin{aligned} &= (0.087 \text{ tons/day})(365 \text{ days/yr})(0.9 \text{ capacity factor}) \\ &= 28.6 \text{ tons/yr} \end{aligned}$$

Particulate emissions from the secondary crushing facilities, on a daily basis, are

Particulate emissions^{1,2}

- = (14.9 kgm/hr)(2.2 lbs/kgm)(24 hrs/day)/(2000 lbs/ton)
- = 0.393 tons/day

On an annual basis,

Particulate emissions

- = (0.393 tons/day)(365 days/yr)(0.9 capacity factor)
- = 129 tons/yr

Particulate emissions from transfer points along the conveyor routes which escape capture by the particulate control devices (99.5 percent efficiency)⁴ are quantified below, on a daily basis.

Particulate emissions^{2,3}

- = (11.07 lbs/hr)(24 hrs/day)/(2,000 lbs/ton)
- = 0.133 tons/day

On an annual basis,

Particulate emissions

- = (0.133 tons/day)(365 days/yr)(0.9 capacity factor)
- = 43.6 tons/yr

Total particulate emissions from the crushers and the conveyor transfer points, on an annual basis, are

Total particulate emissions

$$\begin{aligned} &= (28.6 + 129 + 43.6) \text{ tons/year} \\ &= 201 \text{ tons/yr} \end{aligned}$$

Dust captured at the crushing facilities and at the covered conveyor transfer points is sent to the spent shale disposal pile. The amount of dust captured at each of these points can be determined from the controlled particulate emission rate and the control device efficiency (identified on pages 17 and 18). Results indicate that, on a daily basis, dust is captured at a rate of

Captured dust

$$\begin{aligned} &= \left[\frac{(\text{primary} + \text{secondary crushing emissions})(\text{control eff.})}{(1 - \text{control eff.})} \right] + \left[\frac{(\text{transfer point emissions})(\text{control eff.})}{(1 - \text{control eff.})} \right] \\ &= \left[\frac{(0.087 \text{ tons/day} + 0.393 \text{ tons/day})(0.997)}{(1 - 0.997)} \right] + \left[\frac{(0.133 \text{ tons/day})(0.995)}{(1 - 0.995)} \right] \\ &= 186 \text{ tons/day} \end{aligned}$$

On an annual basis,

Captured dust

$$\begin{aligned} &= (186 \text{ tons/day})(365 \text{ days/yr})(0.9 \text{ capacity factor}) \\ &= 61.1 \times 10^3 \text{ tons/yr} \end{aligned}$$

References

1. U. S. Department of Energy, Western Oil Shale Development: A Technology Assessment, Vol. 2: Technology Characterization and Production Scenario (Draft), by Battelle for DOE, Contract No. DE-AC06-76RLO 1830, June 1981, pp. 25, 27, 28.
2. U. S. Department of the Interior, Final Environmental Impact Statement, Proposed Development of Oil Shale Resources, Vol. I and II, by The Colony Development Operation for Bureau of Land Management (DOI), 1977, pp. II-18, II-21, II-23.
3. U. S. Environmental Protection Agency, Pollution Control Guidance Document for Oil Shale, Vol. II: The TOSCO II/Colony Case Study, Preliminary Draft, November 1980, document in production, September 1981, pp. 36, 37.
4. U. S. Environmental Protection Agency, Environmental Perspective on the Emerging Oil Shale Industry, by EPA Oil Shale Research Group, edited by Edward R. Bates (Industrial Environmental Research Laboratory) and Terry L. Thoen (Office of Energy Policy Coordination -- Region VIII), EPA-600/2-80-205a, 1980, p. 137.

④ Fugitive Dust From On-Site Shale Storage

Baghouse filters are used on the fine ore storage silos to reduce fugitive dust emissions to 16.5 tons/yr. At the same time, 5,476 tons/yr of dust are captured by the baghouse filters and sent to the spent shale disposal pile. Fugitive dust from the coarse shale storage pile is unquantifiable.

Storage facilities are provided for both the coarse shale (exiting the primary crushers) and the fine shale (exiting the secondary crushers). No storage facilities are needed for run-of-mine ore. Should the primary crusher or conveying system fail, the coarse ore storage pile is sufficiently stocked to keep the downstream processing facilities operating for 30 days.¹ This is equivalent to

Coarse ore storage

- = (oil shale mined)(stockpile supply capacity)
- = (67,778 tons/day)(30 days)
- = 2.03×10^6 tons

Since this stockpile is open storage, the potential fugitive dust emissions is directly dependent on low level air disturbances and their frequency.² As a result, the dust emissions are not, in general, quantifiable.³ Wet suppression is used as a control measure to limit fugitive dust emissions from the coarse ore storage pile.

The total water consumed for dust control at the primary crushers and the coarse ore storage areas, on a daily basis, is

Water for dust control (primary crusher, conveyor, and coarse ore storage)

- = (150 gal/min)(60 min/hr)(24 hrs/day)
- = 216×10^3 gal/day

On an annual basis,

Water for dust control (primary crusher, conveyor, and coarse ore storage)

$$\begin{aligned} &= (216 \times 10^3 \text{ gal/day})(365 \text{ days/yr})(0.9 \text{ capacity factor}) \\ &= 70.9 \times 10^6 \text{ gal/yr} \end{aligned}$$

Section IV (Physical Requirements) incorporates this stream into its detailed water balance.

Finely crushed ore (minus 1/2 inch) is stored in contained storage silos where sufficient ore is available to keep the retort operating for 5 hours if the secondary crushing facilities should fail. This amounts to

Fine ore storage

$$\begin{aligned} &= [(\text{oil shale retort feed rate}) + (\text{preheater raw shale loss}) \\ &\quad + (\text{storage silo raw shale loss})](\text{storage supply capacity}) / \\ &\quad (\text{hrs/day}) \\ &= [(66,000 \text{ tons/day}) + (2.91 \text{ tons/day} + 1454 \text{ tons/day}) \\ &\quad + (0.05 \text{ tons/day} + 16.7 \text{ tons/day})](5 \text{ hrs}) / (24 \text{ hrs/day}) \\ &= 14,057 \text{ tons} \end{aligned}$$

For the fine ore storage silos, fugitive dust is controlled with baghouse filters (99.7 percent efficiency) and controlled emissions total, on a daily basis,

Fugitive dust^{1,4}

$$\begin{aligned} &= (1.9 \text{ kgm/hr})(2.2 \text{ lbs/kgm})(24 \text{ hrs/day}) / (2,000 \text{ lbs/ton}) \\ &= 0.05 \text{ tons/day} \end{aligned}$$

On an annual basis,

Fugitive dust

- = (0.05 tons/day)(365 days/yr)(0.9 capacity factor)
- = 16.5 tons/yr

Dust captured by the baghouse filters is sent to the spent shale disposal pile. This quantity, on a daily basis, is

Captured dust

- = (fine ore storage dust emissions)(control eff.)/
(1 - control eff.)
- = (0.05 tons/day)(0.997)/(1 - 0.997)
- = 16.7 tons/day

On an annual basis,

Captured dust

- = (16.7 tons/day)(365 days/year)(0.9 capacity factor)
- = 5,476 tons/yr

References

1. U. S. Department of the Interior, Final Environmental Impact Statement, Proposed Development of Oil Shale Resources, Vol. I and II, by The Colony Development Operation for Bureau of Land Management (DOI), 1977, pp. II-18, II-23, II-75.
2. U. S. Department of Energy, Western Oil Shale Development: A Technology Assessment, Vol. 2: Technology Characterization and Production Scenarios (Draft), by Battelle for DOE, Contract No. DE-AC06-76RLO 1830, June 1981, p. 29.
3. U. S. Department of Energy, Oil Shale Surface Retorting, Environmental Characterization Information Report, Edition 1, January 1981, p. 19.
4. U. S. Environmental Protection Agency, Pollution Control Guidance Document for Oil Shale, Vol. II: The TOSCO II/Colony Case Study, Preliminary Draft, November 1980, document in production, September 1981, pp. 118.

5 Potential Runoff From On-Site Shale Storage

Water runoff from coarse ore storage pile averages 652×10^3 gal/yr.

Since the coarse ore storage pile is an open stockpile, rainwater (the major contributor) and water from dust suppression contribute to potential leachate problems from runoff. Trace elements and organic compounds which may leach out of the raw shale may affect surface water and groundwater quality. One opinion is that there is no more risk of intrusion than for shale eroding along natural outcrops. This statement, however, requires additional field test evaluations to support its validity.

The potential annual runoff represents approximately 10 percent of the average annual precipitation in the Parachute Creek area. Therefore, if the stockpile covers an area of 15 acres² and the average annual precipitation is 16 inches,² the potential annual runoff is

Coarse ore storage pile runoff

$$\begin{aligned}
 &= (15 \text{ acres})(43,560 \text{ sq ft/acre})(16 \text{ in/yr})(0.1 \text{ runoff factor}) \\
 &\quad (7.48 \text{ gal/cu ft})/(12 \text{ in/ft}) \\
 &= 652 \times 10^3 \text{ gal/yr}
 \end{aligned}$$

In reality, rainfall in the Parachute Creek area is not constant throughout the year. Sources² show that 80 percent of the annual rainfall occurs during the months of April, May, and June. A percent distribution of the monthly rainfall and the monthly runoff rate associated with the coarse ore storage pile is as follows:

% of Annual Rainfall			Runoff Rate (gal/month)	% of Annual Rainfall			Runoff Rate (gal/month)
October	2.24		14.6×10^3	April	9.72		63.4×10^3
November	2.66		17.3×10^3	May	60.09		391.8×10^3
December	1.69		11.0×10^3	June	13.35		87.0×10^3
January	1.53		10.0×10^3	July	2.89		18.8×10^3
February	1.76		11.5×10^3	August	-		-
March	2.68		17.5×10^3	September	1.39		9.1×10^3

No mention of controlling runoff from this storage area can be found in the available literature on the TOSCO II oil shale process. However, it must be noted that such runoff represents an unknown potential for surface water and groundwater pollution.

References

1. U. S. Environmental Protection Agency, Environmental Perspective on the Emerging Oil Shale Industry, by EPA Oil Shale Research Group, edited by Edward R. Bates (Industrial Environmental Research Laboratory) and Terry L. Theom (Office of Energy Policy Coordination -- Region VIII), EPA-600/2-80-205a, p. 86.
2. U. S. Department of the Interior, Final Environmental Impact Statement, Proposed Development of Oil Shale Resources, Vol. I and II, by The Cold Development Operation for Bureau of Land Management (DOI), 1977, p. II-23, III-126, III-141.

6 Spent Shale Exiting Retort

17.5 x 10⁶ tons/yr of spent shale will be generated.

After 66,000 tons/day of raw shale are retorted to generate 47,000 bbl/day of syncrude equivalent, a large quantity of spent shale remains and must be disposed of in an environmentally acceptable manner. The quantity of retorted shale which requires disposal, on a daily basis, is

Retorted shale (dry)¹

= 53,200 tons/day

On an annual basis,

Retorted shale (dry)

= (53,200 tons/day)(365 days/yr)(0.9 capacity factor)

= 17.5 x 10⁶ tons/yr

This quantity represents approximately 80.6 percent by weight of the raw shale feed stream.

Since the retorted shale exits the pyrolysis area at a temperature of approximately 900°F, a rotating drum cooler is used to cool the material down to approximately 300°F and to recover this process heat by producing steam. Water provided to the shale cooler, on a daily basis, equals

Water for shale cooler³

= (205 gal/min/train)(6 trains)(60 min/hr)(24 hrs/day)

= 1.77 x 10⁶ gal/day

On an annual basis,

Water for shale cooler

- = $(1.77 \times 10^6 \text{ gal/day})(365 \text{ days/yr})(0.9 \text{ capacity factor})$
- = $582 \times 10^6 \text{ gal/yr}$

References

1. U. S. Department of the Interior, Final Environmental Impact Statement, Proposed Development of Oil Shale Resources, Vol. II and II, by The Colony Development Operation for Bureau of Land Management (DOI), 1977, pp. II-49, II-63, II-75.
2. U. S. Environmental Protection Agency, Pollution Control Guidance Document for Oil Shale, Vol. II: The TOSCO II/Colony Case Study, Preliminary Draft, November 1980, document in production, September 1981, pp. 20.
3. U. S. Department of Energy, Western Oil Shale Development: A Technology Assessment, Vol. 2: Technology Characterization and Production Scenarios (Draft), by Battelle for DOE, Contract No. DE-AC06-76RLO 1830, June 1981, pp. 37, 39.

7 & 8 Particulate Emissions and Sludge From Spent Shale Moisturizing Drum Wet Scrubber

Wet scrubbers are used to reduce the dust emission from spent shale moisturizing to 957 tons/yr. The captured dust is disposed of as a sludge and totals 58.9×10^3 tons/yr.

Prior to disposal, the retorted shale exits the cooler and passes through a moisturizing drum for further cooling (from 300°F down to 200°F) and moisturizing (approximately 14 percent by weight). Water used for wetting the shale is NH_3 -, H_2S -, and CO_2 -free recycled process water which, on a daily basis, amounts to

Water for shale moisturizing^{1,3,4}

$$\begin{aligned} &= (1,500 \text{ gal/min})(60 \text{ min/hr})(24 \text{ hrs/day}) \\ &= 2.16 \times 10^6 \text{ gal/day} \end{aligned}$$

On an annual basis,

Water for shale moisturizing

$$\begin{aligned} &= (2.16 \times 10^6 \text{ gal/day})(365 \text{ days/yr})(0.9 \text{ capacity factor}) \\ &= 710 \times 10^6 \text{ gal/yr} \end{aligned}$$

Section IV (Physical Requirements) incorporates this stream into its detailed water balance.

Trace metals, such as arsenic, mercury, iron, chromium and zinc still remain in this stripped water and present a potential environmental health problem. Reports show that these trace metals can be released into the environment via direct volatilization and carry-over on particulates.⁴ Actual quantity (if any) released during spent shale moisturizing is not known.

Suspended particulates are produced when the retorted shale passes through the moisturizing drum. Wet scrubbers with a control efficiency of 98.4 percent³

are used to capture a majority of the suspended particulates. The particulate emissions which escape to the atmosphere, on a daily basis, total

Controlled particulate emissions from moisturizing drum wet scrubbers^{1,2,3}

$$= (18.4 \text{ kgm/hr/train})(6 \text{ trains})(2.2 \text{ lbs/kgm})(24 \text{ hrs/day}) / (2000 \text{ lbs/ton})$$

$$= 2.91 \text{ tons/day}$$

On an annual basis,

Controlled particulate emissions from moisturizing drum wet scrubbers

$$= (2.91 \text{ tons/day})(365 \text{ days/yr})(0.9 \text{ capacity factor})$$

$$= 957 \text{ tons/yr}$$

The wet scrubbers use water to capture the suspended particulates. This results in the formation of a sludge which is disposed of along with the spent shale. Incorporating the 98.4 percent control efficiency, the quantity of sludge produced, on a daily basis, is

Sludge (dry) from moisturizing drum wet scrubbers^{1,2}

$$= (\text{particulate emissions})(\text{control efficiency}) / (1 - \text{control efficiency})$$

$$= (2.91 \text{ tons/day})(0.984) / (1 - 0.984)$$

$$= 179 \text{ tons/day}$$

On an annual basis,

Sludge (dry) from moisturizing drum wet scrubbers

= 175 tons/day)(365 days/yr)(0.9 capacity factor)

= 58.9×10^3 tons/yr

References

1. U. S. Environmental Protection Agency, Technological Overview Reports for Eight Shale Oil Recovery Processes, by TRW Environmental Engineering Division for EPA, EPA-600/7/79-075, March 1979, p. 43.
2. U. S. Department of the Interior, Final Environmental Impact Statement, Proposed Development of Oil Shale Resources, Vol. I and II, by The Colony Development Operation for Bureau of Land Management (DOI), 1977, pp. II-29, II-49.
3. U. S. Department of Energy, Western Oil Shale Development: A Technology Assessment, Vol. 2: Technology Characterization and Production Scenarios (Draft), by Battelle for DOE, Contract No. DE-AC06-76 RLO 1830, June 1981, p. 57.
4. U. S. Environmental Protection Agency, Environmental Perspectives on the Emerging Oil Shale Industry, by EPA Oil Shale Research Group, edited by Edward R. Bates (Industrial Environmental Research Laboratory) and Terry L. Thoem (Office of Energy Policy Coordination -- Region VIII), EPA-600/2-80-205a, 1980, p. 52.

9 Spent Shale Disposal Pile and Runoff

The spent shale disposal pile is made up of 18.5×10^6 tons/yr of solid waste from various process areas. Runoff will be negligible most of the time and will be sent to pyrolysis water storage.

The spent shale disposal pile actually consists of spent shale (stream 1), raw shale dust (streams 3 and 4), wet scrubber sludges (streams 8, 11, and 13), spent catalysts (streams 19, 22, 27, and 31), proprietary wastes (22 and 27), other miscellaneous solids (streams 16 and 35), and any moisture associated with these streams. An estimate of the total solid wastes, on an annual basis, is

Total solid wastes (dry) to disposal pile

$$= 18.5 \times 10^6 \text{ tons/yr}$$

Disposal of this material must be managed carefully in order to minimize leaching of soluble salts and soluble carbonaceous components. Plans are to construct a processed shale embankment in the form of a compacted landfill. Over the 20 year life of the plant, nearly 800 acres will be used to dispose of the solids, and will undergo revegetation. First, topsoil will be removed ahead of filling and will be stockpiled for reuse as topsoil in areas where successful revegetation depends on it (i.e., slopes, southern exposures, etc.).

The embankment will be in the form of an earthen dam retaining an earth fill, and will consist of compacted spent shale and solid wastes. The compacted landfill will have a typical average density of 85 to 95 lbs/cu ft. Springs and seeps will be capped and diverted away from the disposal area and into the drainage system. The drainage system essentially is present to capture runoff from the disposal area via drainage flumes. Once final contours of the landfill have been prepared, approximately 7 to 10 inches of water will be used to leach the salts down into the landfill. This will prepare the landfill for revegetation. Plans for revegetation include 45 percent grasses, 40 percent shrubs, and 15 percent forbs.

The quantity of water required for revegetation starts at 70 gal/min for the first 12 years and then increases to 700 gal/min. A daily and annual equivalent to these quantities are shown below.

Water for revegetation

- = (70 to 700) gal/min (60 min/hr)(24 hrs/day)
- = 100.8×10^3 to 1.01×10^6 gals/day

Water for revegetation

- = (100.8×10^3 to 1.01×10^6) gal/day (365 days/yr)
(0.9 capacity factor)
- = 33.1×10^6 to 331.0×10^6 gal/yr

Section IV (Physical Requirements) incorporates this water stream into its detailed water balance.

Runoff attributed to spent solids disposal will be negligible except during the months of May and June. During this period, runoff will be captured and stored in the Davis Gulch Reservoir, and overflow will be sent to pyrolysis water storage.

Runoff from spent solids disposal (May and June)¹

- = (1200 gal/min)(60 min/hr)(24 hrs/day)
- = 1.73×10^6 gals/day
- = (1.73×10^6 gals/day)(60 days/yr)
- = 103×10^6 gals/yr (avg.)

References

1. U. S. Department of the Interior, Final Environmental Impact Statement, Proposed Development of Oil Shale Resources, Vol. I and II, by The Colony Development Operation for Bureau of Land Management (DOI), 1977, pp. II-60, II-63, II-64, II-66, II-75.
2. U. S. Environmental Protection Agency, Technological Overview Reports for Eight Shale Oil Recovery Processes, by TRW Environmental Engineering Division for EPA, EPA-600/7-79-075, March 1979, p. 50.

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Air Emissions and Sludge From Raw Shale Preheater Wet Scrubbers

A total of 957 tons/yr of particulates will be emitted from the scrubbers, while 478×10^3 tons/yr of particulates are captured as a sludge and diverted to the spent shale pile. Other gaseous emissions include: sulfur dioxide, 200 tons/yr; nitrogen oxides, 5,176 tons/yr; carbon monoxide, 172 tons/yr; and hydrocarbons, 1,064 tons/yr.

As the hot flue gas from the ceramic ball heater passes through the fluid bed containing the raw crushed shale, residual hydrocarbons (HC) within the gas stream are reduced via incineration while the sulfur dioxide content of the flue gas is reduced via absorption into the shale.* The gas stream then passes through a wet scrubber (99.8 percent particulate removal efficiency) prior to exiting to the atmosphere. The air emissions leaving the wet scrubbers (all six trains), on a daily basis, are²

Particulate emissions

$$\begin{aligned} &= (110.4 \text{ kgm/hr})(2.2 \text{ lbs/kgm})(24 \text{ hrs/day})/(2000 \text{ lbs/ton}) \\ &= 2.91 \text{ tons/day} \end{aligned}$$

SO₂ emissions

$$\begin{aligned} &= (23.1 \text{ kgm/hr})(2.2 \text{ lbs/kgm})(24 \text{ hrs/day})/(2000 \text{ lbs/ton}) \\ &= 0.61 \text{ tons/day} \end{aligned}$$

NO_x emissions

$$\begin{aligned} &= (596.8 \text{ kgm/hr})(2.2 \text{ lbs/kgm})(24 \text{ hrs/day})/(2000 \text{ lbs/ton}) \\ &= 15.7 \text{ tons/day} \end{aligned}$$

CO emissions

$$\begin{aligned} &= (19.8 \text{ kgm/hr})(2.2 \text{ lbs/kgm})(24 \text{ hrs/day})/(2000 \text{ lbs/ton}) \\ &= 0.52 \text{ tons/day} \end{aligned}$$

HC emissions

$$\begin{aligned} &= (122.7 \text{ kgm/hr})(2.2 \text{ lbs/kgm})(24 \text{ hrs/day})/(2000 \text{ lbs/ton}) \\ &= 3.24 \text{ tons/day} \end{aligned}$$

* This applies to each train within the retort process area.

On an annual basis,

Particulate emissions

- = (2.91 tons/day)(365 days/yr)(0.9 capacity factor)
- = 957 tons/yr

SO₂ emissions

- = (0.61 tons/day)(365 days/yr)(0.9 capacity factor)
- = 200 tons/yr

NO_x emissions

- = (15.7 tons/day)(365 days/yr)(0.9 capacity factor)
- = 5176 tons/yr

CO emissions

- = (0.52 tons/day)(365 days/yr)(0.9 capacity factor)
- = 172 tons/yr

HC emissions

- = (3.24 tons/day)(365 days/yr)(0.9 capacity factor)
- = 1064 tons/yr

The wet scrubbers use water to capture the suspended particulates. This results in the formation of a sludge which is disposed of along with the spent shale. Incorporating the 99.8 percent control efficiency, the quantity of sludge produced, on a daily basis, is

Sludge (dry) from shale preheater wet scrubber^{1,2}

- = (particulate emissions)(control efficiency)/
(1 - control efficiency)
- = (2.91 tons/day)(0.998)/(1 - 0.998)
- = 1454 tons/day

On an annual basis,

Sludge (dry) from shale preheater wet scrubbers

- = (1454 tons/day)(365 days/yr)(0.9 capacity factor)
- = 478×10^3 tons/yr

References

1. U. S. Department of Energy, Western Oil Shale Development: A Technology Assessment, Vol. 2: Technology Characterization and Production Scenarios (Draft), by Battelle for DOE, Contract No. DE-AC06-76RLO 1830, June 1981, p. 54, 57.
2. U. S. Department of the Interior, Final Environmental Impact Statement Proposed Development of Oil Shale Resources, Vol. I and II, by The Colony Development Operation for Bureau of Land Management (DOI), 1977, pp. II-29, II-59.

12

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13

Air Emissions and Sludge From Elutriator Wet Scrubbers

The elutriator wet scrubber captures 425×10^3 tons/yr of particulates from the steam superheater flue gas. Another 851 tons/yr of particulates escape along with the following gaseous pollutants: sulfur dioxide, 373 tons/yr; nitrogen oxides, 446 tons/yr; carbon monoxide, 11.3 tons/yr; and hydrocarbons, 1.13 tons/yr.

Once the ceramic balls exit the pyrolysis drum and are separated from the spent shale, they pass through an elutriator and continue on to the ball heater for reheating and recycle.* Within the elutriator, warm flue gas from the steam superheater is used to remove residual shale dust from the ceramic balls. The dust becomes entrained in the gas and must be removed. The gas passes through multiple cyclone separators and a wet scrubber (with a 99.8 percent particulate removal efficiency) to reduce its suspended particulate content. The gas streams exiting the wet scrubbers² (all six trains) will include, on a daily basis, the following air emissions.

Particulate emissions

$$= (98.1 \text{ kgm/hr})(2.2 \text{ lbs/kgm})(24 \text{ hrs/day})/(2000 \text{ lbs/ton})$$

$$= 2.59 \text{ tons/day}$$

SO₂ emissions

$$= (43.0 \text{ kgm/hr})(2.2 \text{ lbs/kgm})(24 \text{ hrs/day})/2000 \text{ lbs/ton}$$

$$= 1.14 \text{ tons/day}$$

NO_x emissions

$$= (51.4 \text{ kgm/hr})(2.2 \text{ lbs/kgm})(24 \text{ hrs/day})/(2000 \text{ lbs/ton})$$

$$= 1.36 \text{ tons/day}$$

CO emissions

$$= (1.3 \text{ kgm/hr})(2.2 \text{ lbs/kgm})(24 \text{ hrs/day})/(2000 \text{ lbs/ton})$$

$$= 3.4 \times 10^{-2} \text{ tons/day}$$

HC emissions

$$= (0.13 \text{ kgm/hr})(2.2 \text{ lbs/kgm})(24 \text{ hrs/day})/(2000 \text{ lbs/ton})$$

$$= 3.4 \times 10^{-3} \text{ tons/day}$$

* This applies to each train within the retort process area.

On an annual basis,

Particulate emissions

- = (2.59 tons/day)(365 days/yr)(0.9 capacity factor)
- = 851 tons/yr

SO₂ emissions

- = (1.14 tons/day)(365 days/yr)(0.9 capacity factor)
- = 373 tons/yr

NO_x emissions

- = (1.36 tons/day)(365 days/yr)(0.9 capacity factor)
- = 446 tons/yr

CO emissions

- = (0.034 tons/day)(365 days/yr)(0.9 capacity factor)
- = 11.3 tons/yr

HC emissions

- = (3.4 x 10⁻³ tons/day)(365 days/yr)(0.9 capacity factor)
- = 1.13 tons/yr

The wet scrubbers use water to capture the suspended particulates. This results in the formation of a sludge which is disposed of along with the spent shale. Incorporating the 99.8 percent control efficiency, the quantity of sludge produced, on a daily basis, is

Sludge (dry) from elutriator wet scrubbers^{1,2}

- = (particulate emissions)(control efficiency)/
(1 - control efficiency)
- = (2.59 tons/day)(0.998)/(1 - 0.998)
- = 1292 tons/day

On an annual basis,

Sludge (dry) from elutriator wet scrubbers

- = (1292 tons/day)(365 days/yr)(0.9 capacity factor)
- = 425×10^3 tons/yr

References

1. U. S. Department of Energy, Western Oil Shale Development: A Technology Assessment, Vol. 2: Technology Characterization and Production Scenarios (Draft), by Battelle for DOE, Contract No. DE-AC06-76RLO 1830, June 1981, pp. 54, 59.
2. U. S. Department of the Interior, Final Environmental Impact Statement, Proposed Development of Oil Shale Resources, Vol. I and II, by The Colony Development Operation for Bureau of Land Management (DOI), 1977, pp. II-29, II-59.

14

Foul Water From Fractionator to Water Treatment/Recycle

The fractionator produces 201×10^6 gal/yr of foul water which is sent to a foul water stripper.

The gas produced from shale retorting within the pyrolysis drum (from all six trains) is sent to a fractionator where the moisture is condensed and various hydrocarbon fractions (gas, naphtha, gas oil, and bottoms oil) separated. The hydrocarbon streams are sent to various upgrading units while the foul water stream is sent to the foul water stripper within the water treatment area. On a daily basis, the foul water extraction rate equals

Foul water from fractionator^{1,2}

$$= (425 \text{ gals/min})(60 \text{ mins/hr})(24 \text{ hrs/day})$$

$$= 612 \times 10^3 \text{ gals/day}$$

On an annual basis,

Foul water from fractionator

$$= (612 \times 10^3 \text{ gals/day})(365 \text{ days/yr})(0.9 \text{ capacity factor})$$

$$= 201 \times 10^6 \text{ gals/yr}$$

The percent composition (by weight) of this foul water stream is as follows.²

H ₂ O	98.52%
CO ₂	0.43%
NH ₃	0.36%
H ₂ S	0.05%
Unidentified	0.64%

References

1. U. S. Department of the Interior, Final Environmental Impact Statement, Proposed Development of Oil Shale Resources, Vol. II and II, by The Colony Development Operation for Bureau of Land Management (DOI), 1977, p. II-75.
2. U. S. Environmental Protection Agency, Pollution Control Guidance Document for Oil Shale, Vol. II: The TOSCO II/Colony Case Study, Preliminary Draft, November 1980, document in production, September 1981, pp. 62.

15

Byproduct Fuel Gas, Butane/Butylene Fuel, and LPG for Plant Fuel and for Marketing

In addition to syncrude, the following byproducts are produced: LPG, 1.42×10^6 bbl/yr; butane/butylene, 71.7×10^3 tons/yr; and treated fuel gas, 409×10^3 tons/yr.

Of the various hydrocarbon-rich streams exiting the fractionator, the raw gas and naphtha streams are sent to the gas recovery and treating unit. At this point, the raw naphtha is separated from the raw gas via absorption into a rich oil stream. The naphtha within the stream is then stabilized, recovered, and sent to the naphtha hydrotreater (stream 20) for further processing. Stabilization of the raw naphtha produces a C_3/C_4 overhead gas which is sent to a treater and splitter to separate and recover the liquid petroleum gas (LPG) and the butane/butylene liquid fuel (Cs). The recovered LPG byproduct is sold. This quantity, on a daily basis, totals

LPG production^{1,2}

= 4330 bbl/day

On an annual basis,

LPG production

= (4330 bbl/day)(365 days/yr)(0.9 capacity factor)

= 1.42×10^6 bbl/yr

The C_4 liquid fuel has a heating value of 19,500 Btu/lb and is consumed totally within the plant.³ The C_4 liquid fuel production rate, on a daily basis, equals

Butane/Butylene liquid fuel production²

= $(18.2 \times 10^3 \text{ lbs/hr})(24 \text{ hrs/day})/(2000 \text{ lbs/ton})$

= 218 tons/day

On an annual basis,

Butane/Butylene liquid fuel production

- = (218 tons/day)(365 days/yr)(0.9 capacity factor)
- = 71.7×10^3 tons/yr

The raw gas, which remains after the naphtha-rich oil stream is withdrawn, passes through an absorber and a gas treating column where entrained heavy oils and sulfur compounds (i.e., H_2S) are extracted, respectively. The extracted oil-rich stream is recycled to the fractionator while the extracted sulfur-laden stream is sent to an amine (the sulfur absorbing medium) regenerator where a sulfur-laden acid gas is released. The acid gas is then sent to the sulfur recovery unit (stream 29).

Once the raw gas (now referred to as treated fuel gas) is stripped of heavy oils and sulfur compounds, it has a heating value of 20,300 Btu/lb and is consumed totally within the plant. A portion is used to produce hydrogen and is burned by the reforming furnaces in the hydrogen generating unit (stream 17 and 18, respectively), while the remaining fuel gas is used as plant fuel. On a daily basis, the total quantity of treated fuel gas produced is

Treated fuel gas production²

- = $(103.7 \times 10^3 \text{ lbs/hr})(24 \text{ hrs/day})/(2000 \text{ lbs/ton})$
- = 1.24×10^3 tons/day

On an annual basis,

Treated fuel gas production

- = $(1.24 \times 10^3 \text{ tons/day})(365 \text{ days/yr})(0.9 \text{ capacity factor})$
- = 409×10^3 tons/yr

An approximate breakdown (by weight percent) of the fuel gas constituents² is:

HC	87.63%
CO	8.08%
CO ₂	0.76%
H ₂ S	0.03%
Unidentified	3.50%

No potential pollutants are emitted by this stream.

References

1. U. S. Department of Energy, Western Oil Shale Development: A Technology Assessment, Vol. 2: Technology Characterization and Production Scenarios (Draft), by Battelle for DOE, Contract No. DE-AC06-76RLO 1830, June 1981, p. 65.
2. U. S. Environmental Protection Agency, Pollution Control Guidance Document for Oil Shale, Vol. II: The TOSCO II/Colony Case Study, Preliminary Draft, November 1980, document in production, September 1981, pp. 20, 63.
3. U. S. Department of the Interior, Final Environmental Impact Statement, Proposed Development of Oil Shale Resources, Vol. I and II, by The Colony Development Operation for Bureau of Land Management (DOI), 1977, p. II-53.

16 Trapped Residues From DEA Filter to Disposal

The DEA filter captures approximately 193 tons/yr of diatomaceous earth and also another 193 tons/yr of deactivated carbon particles for a total of 386 tons/yr solid waste. This residue is disposed of in the spent shale pile.

Within the gas recovery and treating unit, acid gas is removed from the raw gas stream (thereby producing treated fuel gas) with a regenerated secondary amine (diethanolamine, or DEA) solution. Since the amine solution is recycled, it passes through a filter to remove any undesirable particles. Every two weeks the trapped residue captured by the DEA filter is removed and disposed of in the retorted shale disposal pile. This residue mainly is composed of diatomaceous earth and deactivated carbon particles which are quantified on an annual basis below.

Diatomaceous earth particles to spent shale disposal¹

- = (8.25 tons/2 weeks)(52 weeks/yr)(0.9 capacity factor)
- = 193 tons/yr

Deactivated carbon particles to spent shale disposal¹

- = (8.25 tons/2 weeks)(52 weeks/yr)(0.9 capacity factor)
- = 193 tons/yr

References

1. U. S. Department of the Interior, Final Environmental Impact Statement, Proposed Development of Oil Shale Resources, Vol. I and II, by The Colony Development Operation for Bureau of Land Management (DOI), 1977, p. 49.

17 Hydrogen Production

Hydrogen used for naphtha and gas oil hydrogenation is produced at the rate of 71×10^3 tons/yr via a steam-reforming process. 149×10^3 tons/yr of treated fuel gas is consumed to produce the hydrogen.

Hydrogen is needed for naphtha and gas oil hydrogenation (streams 20 and 23, respectively) and is produced by a conventional steam reforming process which uses steam and treated fuel gas (produced by the gas recovery and treating unit, stream 15). The quantity of fuel gas used to produce hydrogen, on a daily basis, is

Treated fuel gas, reformed with steam to produce hydrogen¹

$$\begin{aligned} &= (37.7 \times 10^3 \text{ lbs/hr})(24 \text{ hrs/day})/(2000 \text{ lbs/ton}) \\ &= 452 \text{ tons/day} \end{aligned}$$

On an annual basis,

Treated fuel gas, reformed with steam to produce hydrogen

$$\begin{aligned} &= (452 \text{ tons/day})(365 \text{ days/yr})(0.9 \text{ capacity factor}) \\ &= 149 \times 10^3 \text{ tons/yr} \end{aligned}$$

The fuel gas passes through a series of units which convert the sulfur constituents to hydrogen sulfide (H_2S) compounds, absorb these H_2S compounds out of the fuel gas stream, and recycle them to the gas recovery and treating unit. The desulfurized fuel gas then is mixed with superheated steam and sent to the reforming furnaces. The resulting reformed gas, mainly consisting of hydrogen (H_2), carbon monoxide (CO), carbon dioxide (CO_2), and excess steam, then passes through high and low temperature shift converters where the CO content of the gas is reduced to a minimum by conversion to CO_2 . The CO_2 -rich gas is scrubbed with a regenerated lean solution for CO_2 removal. Finally, the gas stream is passed through a methanator to react any remaining carbon oxides with hydrogen (forming methane). The resulting hydrogen production rate, on a daily basis, equals

Hydrogen production¹

- $(18 \times 10^3 \text{ lbs/hr})(24 \text{ hrs/day})/(2000 \text{ lbs/ton})$
- 216 tons/day

On an annual basis,

Hydrogen production

- $(216 \text{ tons/day})(365 \text{ days/yr})(0.9 \text{ capacity factor})$
- $71.0 \times 10^3 \text{ tons/yr}$

The hydrogen is sent to the naphtha and gas oil hydrogenation units.

Reference

1. U. S. Environmental Protection Agency, Pollution Control Guidance Document for Oil Shale, Vol. II: The TOSCO II/Colony Case Study, Preliminary Draft, November 1980, document in production, September 1981, pp. 63, 65.

18 Air Emissions From Hydrogen Generation

122 x 10³ tons/yr of treated fuel gas is used to generate process heat for the steam reforming furnace. Combustion of this fuel gas results in 45.1 tons/yr of particulate emissions and the following gaseous emissions: sulfur dioxide, 107 tons/yr; nitrogen oxides, 323 tons/yr; hydrocarbons, 6.24 tons/yr; and carbon monoxide, 39.0 tons/yr.

The steam reforming furnaces used for the production of hydrogen also consume some of the treated fuel produced by the gas recovery and treating unit (stream 15). The fuel gas consumption rate, on a daily basis, is

Treated fuel gas consumed by reforming furnaces¹

$$\begin{aligned} &= (15,517 \text{ lbs/hr/furnace})(2 \text{ furnaces})(24 \text{ hrs/day})/(2000 \text{ lbs/ton}) \\ &= 372 \text{ tons/day} \end{aligned}$$

On an annual basis,

Treated fuel gas consumed by reforming furnaces

$$\begin{aligned} &= (372 \text{ tons/day})(365 \text{ days/yr})(0.9 \text{ capacity factor}) \\ &= 122 \times 10^3 \text{ tons/yr} \end{aligned}$$

Combustion of this fuel gas produces air emissions which are released into the environment. These air emissions are quantified, on a daily basis, below.¹

Particulate emissions from steam reformers

$$\begin{aligned} &= (5.2 \text{ kgm/hr})(2.2 \text{ lbs/kgm})(24 \text{ hrs/day})/(2000 \text{ lbs/ton}) \\ &= 0.137 \text{ tons/day} \end{aligned}$$

SO₂ emissions from steam reformers

$$\begin{aligned} &= (12.38 \text{ kgm/hr})(2.2 \text{ lbs/kgm})(24 \text{ hrs/day})/(2000 \text{ lbs/ton}) \\ &= 0.327 \text{ tons/day} \end{aligned}$$

NO_x emissions from steam reformers

- = (37.3 kgm/hr)(2.2 lbs/kgm)(24 hrs/day)/(2000 lbs/ton)
- = 0.985 tons/day

CO emissions from steam reformers

- = (4.5 kgm/hr)(2.2 lbs/kgm)(24 hrs/day)/(2000 lbs/ton)
- = 0.119 tons/day

HC emissions from steam reformers

- = (0.72 kgm/hr)(2.2 lbs/kgm)(24 hrs/day)/(2000 lbs/ton)
- = 0.019 tons/day

On an annual basis,

Particulate emissions from steam reformers

- = (0.137 tons/day)(365 days/yr)(0.9 capacity factor)
- = 45.1 tons/yr

SO₂ emissions from steam reformers

- = (0.327 tons/day)(365 days/yr)(0.9 capacity factor)
- = 107 tons/yr

NO_x emissions from steam reformers

- = (0.985 tons/day)(365 days/yr)(0.9 capacity factor)
- = 323 tons/yr

CO emissions from steam reformers

- = (0.119 tons/day)(365 days/yr)(0.9 capacity factor)
- = 39.0 tons/yr

HC emissions from steam reformers

- = (0.019 tons/day)(365 days/yr)(0.9 capacity factor)
- = 6.24 tons/yr

Additional emissions which exit the hydrogen generating unit result from the regeneration of the CO₂ scrubbing solution. After the lean scrubbing solution has absorbed the CO₂ out of the CO₂-rich reformed gas stream, the rich scrubbing solution enters a regenerator where the CO₂ is removed by heating and the resulting lean solution is recycled. The CO₂ is released to the atmosphere at a daily rate of

CO₂ emissions from solution regenerator^{1,2}

$$\begin{aligned} &= (238,300 \text{ kgm/hr})(2.2 \text{ lbs/kgm})(24 \text{ hrs/day})/(2000 \text{ lbs/hr}) \\ &= 6.29 \times 10^3 \text{ tons/day} \end{aligned}$$

On an annual basis,

CO₂ emissions from solution regenerator

$$\begin{aligned} &= (6.29 \times 10^3 \text{ tons/day})(365 \text{ days/yr})(0.9 \text{ capacity factor}) \\ &= 2.07 \times 10^6 \text{ tons/yr} \end{aligned}$$

References

1. U. S. Department of the Interior, Final Environmental Impact Statement, Proposed Development of Oil Shale Resources, Vol. I and II, by The Colony Development Operation for Bureau of Land Management (DOI), 1977, pp. II-33, II-34.
2. U. S. Department of Energy, Western Oil Shale Development: A Technology Assessment, Vol. 2: Technology Characterization and Production Scenarios (Draft), by Battelle for DOE, Contract No. DE-AC06-76RLO 1830, June 1981, p. 73.

19 Solid Wastes From Hydrogen Generation

Approximately 51.7 tons of spent catalyst will be produced each year by the hydrogen generating unit.

The major solid wastes produced by the hydrogen generating unit are spent reaction catalysts. Catalysts are used at various points during the hydrogen production sequence and are identified below:

- A hydrodesulfurization, or HDS, catalyst (cobalt molybdate) in the HDS reactor enhances the conversion of fuel gas sulfur compounds to H_2S .
- A zinc oxide (ZnO) catalyst in the ZnO guard bed removes any trace sulfur from the desulfurized fuel gas prior to reforming.
- An iron (Fe) and chromium (Cr) oxide shift catalyst and a copper (Cu) and zinc (Zn) oxide shift catalyst in the high temperature and low temperature CO shift converters, respectively, enhance the conversion of CO to CO_2 within the reformed gas.
- A nickel-based methanation catalyst in the methanator enhances the reaction between hydrogen and residual carbon oxides present within the product hydrogen gas stream.

These catalysts require periodic replacement with the spent catalysts being disposed of in the spent shale pile. Quantities and frequency are presented below.

Spent HDS catalyst	Spent Fe-Cr oxide catalyst
= 55 tons/3 years	= 50 tons/5 years
= 18.3 tons/yr (avg.)	= 10 tons/yr (avg.)
Spent ZnO/ZnS catalyst	Spent Cu-Zn oxide catalyst
= 20 tons/3 years	= 50 tons/3 years
= 6.7 tons/yr (avg.)	= 16.7 tons/yr (avg.)

Reference

1. U. S. Department of the Interior, Final Environmental Impact Statement, Proposed Development of Oil Shale Resources, Vol. I and II, by The Colony Development Operation for Bureau of Land Management (DOI), 1977, p. II-49.

20 Treated Naphtha to Blending

The hydrotreater produces 907×10^3 tons/yr of treated naphtha by purifying the stabilized naphtha from the gas recovery and treating unit.

stabilized naphtha from the gas recovery and treating unit is sent to the naphtha hydrogenation unit for further purification. To accomplish this, the stabilized naphtha is blended with recycled hydrogen and make-up hydrogen (from the hydrogen unit) and sent through a furnace to achieve reaction temperature. The naphtha/hydrogen stream then enters a reactor where, in the presence of a hydrodenitrogenation (HDN) catalyst, essentially all nitrogen and sulfur are removed from the naphtha and all olefins are saturated. Following the addition of wash water to the reaction product stream, the resulting sour water (water containing hydrogen sulfide and ammonia) is separated from the naphtha stream and sent to the ammonia separation unit.

Occurring simultaneously within the separator, unreacted hydrogen gas is separated out of the naphtha stream and recycled. The resulting naphtha stream then passes through an absorber where its overhead gases contact a treated gas oil stream (stream 23). This oil stream absorbs the heavier hydrocarbons out of the overhead gas and exits with the treated naphtha stream, while the light hydrocarbon gases are returned to the gas recovery and treating unit.

The treated naphtha produced by this unit, on a daily basis, equals

Treated naphtha¹

$$\begin{aligned} &= (230 \times 10^3 \text{ lbs/hr})(24 \text{ hrs/day})/(2000 \text{ lbs/ton}) \\ &= 2.76 \times 10^3 \text{ tons/day} \end{aligned}$$

On an annual basis,

Treated naphtha

$$\begin{aligned} &= (2.76 \times 10^3 \text{ tons/day})(365 \text{ days/yr})(0.9 \text{ capacity factor}) \\ &= 907 \times 10^3 \text{ tons/yr} \end{aligned}$$

Reference

1. U. S. Environmental Protection Agency, Pollution Control Guidance Document for Oil Shale, Vol. II: The TOSCO II/Colony Case Study, Preliminary Draft, November 1980, document in production, September 1981, pp. 66.

21 Air Emissions From Naphtha Hydrogenation Unit

Some fuel oil from the gas recovery and treating unit is burned to produce process heat for the naphtha hydrogenator. Air emissions amount to 0.781 tons/yr of particulates and the following quantities of gaseous compounds: sulfur dioxide, 1.56 tons/yr; nitrogen oxides, 5.20 tons/yr; carbon monoxide, 0.781 tons/yr; and hydrocarbons, 0.399 tons/yr.

A portion of the fuel oil produced by the gas recovery and treating unit is used to fuel the furnace in the naphtha hydrogenation unit. The combustion of this fuel will produce potential air pollutants which will be emitted into the atmosphere. Quantities for these air emissions, on a daily basis, are ^{1,2}

Particulate emissions from naphtha hydrogenation unit

$$\begin{aligned} &= (0.09 \text{ kgm/hr})(2.2 \text{ lbs/kgm})(24 \text{ hrs/day})/(2000 \text{ lbs/ton}) \\ &= 2.38 \times 10^{-3} \text{ tons/day} \end{aligned}$$

SO₂ emissions from naphtha hydrogenation unit

$$\begin{aligned} &= (0.18 \text{ kgm/hr})(2.2 \text{ lbs/kgm})(24 \text{ hrs/day})/(2000 \text{ lbs/ton}) \\ &= 4.75 \times 10^{-3} \text{ tons/day} \end{aligned}$$

NO_x emissions from naphtha hydrogenation unit

$$\begin{aligned} &= (0.6 \text{ kgm/hr})(2.2 \text{ lbs/kgm})(24 \text{ hrs/day})/(2000 \text{ lbs/ton}) \\ &= 1.58 \times 10^{-2} \text{ tons/day} \end{aligned}$$

CO emissions from naphtha hydrogenation unit

$$\begin{aligned} &= (0.09 \text{ kgm/hr})(2.2 \text{ lbs/kgm})(24 \text{ hrs/day})/(2000 \text{ lbs/ton}) \\ &= 2.38 \times 10^{-3} \text{ tons/day} \end{aligned}$$

HC emissions from naphtha hydrogenation unit

$$\begin{aligned} &= (0.046 \text{ kgm/hr})(2.2 \text{ lbs/kgm})(24 \text{ hrs/day})/(2000 \text{ lbs/ton}) \\ &= 1.21 \times 10^{-3} \text{ tons/day} \end{aligned}$$

On an annual basis

Particulate emissions from naphtha hydrogenation unit

$$\begin{aligned} &= (2.38 \times 10^{-3} \text{ tons/day})(365 \text{ days/yr})(0.9 \text{ capacity factor}) \\ &= 0.781 \text{ tons/yr} \end{aligned}$$

SO₂ emissions from naphtha hydrogenation unit

$$\begin{aligned} &= (4.75 \times 10^{-3} \text{ tons/day})(365 \text{ days/yr})(0.9 \text{ capacity factor}) \\ &= 1.56 \text{ tons/yr} \end{aligned}$$

NO_x emissions from naphtha hydrogenation unit

$$\begin{aligned} &= (1.58 \times 10^{-2} \text{ tons/day})(365 \text{ days/yr})(0.9 \text{ capacity factor}) \\ &= 5.20 \text{ tons/yr} \end{aligned}$$

CO emissions from naphtha hydrogenation unit

$$\begin{aligned} &= (2.38 \times 10^{-3} \text{ tons/day})(365 \text{ days/yr})(0.9 \text{ capacity factor}) \\ &= 0.781 \text{ tons/yr} \end{aligned}$$

HC emissions from naphtha hydrogenation unit

$$\begin{aligned} &= (1.21 \times 10^{-3} \text{ tons/day})(365 \text{ days/yr})(0.9 \text{ capacity factor}) \\ &= 0.399 \text{ tons/yr} \end{aligned}$$

1. U. S. Department of the Interior, Final Environmental Impact Statement, Proposed Development of Oil Shale Resources, Vol. I and II, by The Colony Development Operation for Bureau of Land Management (DOI), 1977, pg. II-39.
2. U. S. Environmental Protection Agency, Pollution Control Guidance Document for Oil Shale, Vol. II: The TOSCO II/Colony Case Study, Preliminary Draft, November 1980, document in production, September 1981, pp. 118.

22 Solid Wastes From Naphtha Hydrogenator

An annual total of 60 to 80 tons of proprietary solid wastes are removed from the naphtha hydrogenation process area and are discarded in the spent shale disposal pile. This quantity includes 8.21 tons/yr (of which 3 lbs/yr are soluble) arsenic which are removed from the stabilized naphtha stream. Another 75 tons/yr of spent HDN catalyst will go to the disposal pile.

Solid wastes from the naphtha hydrogenation unit consist of arsenic, spent proprietary catalyst, and spent HDN catalyst. The arsenic comes from the stabilized naphtha stream (prior to sulfur and nitrogen removal) and is extracted from the stream with the aid of a proprietary catalyst located within the arsenic guard reactors. The arsenic then is combined with an inert compound to form a solid waste and is disposed of in the spent shale disposal area. The arsenic removal rate, on a daily basis, is

Arsenic removal and disposal¹

$$\begin{aligned} &= (50 \text{ lbs/day}) / (2000 \text{ lbs/ton}) \\ &= 0.025 \text{ tons/day} \end{aligned}$$

On an annual basis,

Arsenic removal and disposal

$$\begin{aligned} &= (0.025 \text{ tons/day}) (365 \text{ days/yr}) (0.9 \text{ capacity factor}) \\ &= 8.21 \text{ tons/yr} \end{aligned}$$

About 3 pounds of the 8.21 tons of arsenic is soluble per year.¹

The total waste (which consists of both the arsenic and the inert compound) from the arsenic guard reactors is sent to the spent shale disposal pile at an annual rate of

Spent proprietary solids to disposal¹

$$= 60 \text{ to } 80 \text{ tons/yr}$$

The HDN catalyst which aids in removing nitrogen and sulfur from the stabilized naphtha also must be periodically replaced. This is done annually at a rate of

Spent HDN catalyst to disposal¹

= 75 tons/yr

The spent catalysts are disposed of along with the spent shale.

Reference

1. U. S. Department of the Interior, Final Environmental Impact Statement, Proposed Development of Oil Shale Resources, Vol. I and II, by The Colony Development Operation for Bureau of Land Management (DOI), 1977, pp. II-38, II-49.

23 Treated Gas Oil to Blending

1.19 x 10⁶ tons/yr of treated gas oil will be produced by refining (in a hydrogenator) gas oil from the pyrolysis fractionator and from the delayed coker.

Gas oil from the pyrolysis fractionator and from the delayed coker is sent to the gas oil hydrogenation unit for refining. The gas oil stream is mixed with recycled hydrogen and make-up hydrogen (from the hydrogen unit) and sent through a furnace to achieve reaction temperature. The mixture then passes through arsenic guard reactors and on to the main reactors where, in the presence of a hydrodenitrogenation (HDN) catalyst, a majority of the nitrogen (a refining catalyst poison) and essentially all of the sulfur (a potential air pollutant) are removed from the stream and unsaturated hydrocarbons are saturated. Following the addition of wash water to the reaction product stream, the resulting sour water (water containing H₂S and NH₃) is separated from the reaction product stream and sent to the ammonia separation unit (stream 28). At the same time, within the separator, unreacted hydrogen is separated out of the reactor effluent gas oil stream and recycled.

The washed gas oil stream then passes through a low pressure separator (to flash off-gases) and on to a fractionator. At this point, the gas oil stream is fractionated into overhead gas, raw naphtha, diesel fuel, and treated gas oil. The overhead gas and naphtha streams, along with the flash off-gases, are sent to the gas recovery and treating unit; the diesel fuel is consumed on-site; and the treated gas oil is sent to blending.

The treated gas oil produced by this unit, on a daily basis, equals

Treated gas oil¹

$$\begin{aligned} &= (302 \times 10^3 \text{ lbs/hr})(24 \text{ hrs/day})/(2000 \text{ lbs/ton}) \\ &= 3,624 \text{ tons/day} \end{aligned}$$

On an annual basis,

Treated gas oil

$$\begin{aligned} &= (3,624 \text{ tons/day})(365 \text{ days/yr})(0.9 \text{ capacity factor}) \\ &= 1.19 \times 10^6 \text{ tons/yr} \end{aligned}$$

Reference

1. U. S. Environmental Protection Agency, Pollution Control Guidance Document for Oil Shale, Vol. II: The TOSCO II/Colony Case Study, Preliminary Draft, November 1980, document in production, September 1981, pp. 66.

24 Low Sulfur Syncrude Production

Treated naphtha is mixed with treated gas to produce 15.4×10^6 bbl of low sulfur syncrude every year. The total heating value of this much syncrude is 84.9×10^{12} Btu.

The treated naphtha stream (stream 20) from the naphtha hydrogenation unit and the treated gas oil stream (stream 23) from the gas oil hydrogenation unit are blended to form a low sulfur (less than 0.001 weight percent) oil which is pipelined from the plant facilities and marketed. This oil is the syncrude product and is produced, on a daily basis, at a rate of

Syncrude production = 47,000 bbl/day

On an annual basis,

Syncrude production²

$$\begin{aligned} &= (47 \times 10^3 \text{ bbl/day})(365 \text{ days/yr})(0.9 \text{ capacity factor}) \\ &= 15.4 \times 10^6 \text{ bbl/yr} \end{aligned}$$

The heating value of this syncrude is calculated as follows:

Annual heating value of syncrude produced

$$\begin{aligned} &= (\text{Daily production, bbl/day})(\text{days/year})(\text{capacity factor}) \\ &\quad (\text{oil shale density, lbs/bbl})(\text{heating value, Btu/lb})^* \\ &= (47,000 \text{ bbl/day})(365 \text{ days/yr})(0.9 \text{ capacity factor}) \\ &\quad (281.87 \text{ lb/bbl})(19,500 \text{ Btu/lb}) \\ &= 84.9 \times 10^{12} \text{ Btu/yr} \end{aligned}$$

* Reference 3.

References

1. U. S. Department of the Interior, Final Environmental Impact Statement, Proposed Development of Oil Shale Resources, Vol. I and II, by The Colony Development Operation for Bureau of Land Management (DOI), 1977, p. II-37.
2. U. S. Environmental Protection Agency, Pollution Control Guidance Document for Oil Shale, Vol. II: The TOSCO II/Colony Case Study, Preliminary Draft, November 1980, document in production, September 1981, pp. 20.
3. U. S. Department of Energy, Environmental Control Costs for Oil Shale Processes, Office of Technology Impacts, DOE/EV-0055, October 1979, pp. 85, 86.

25 Diesel Fuel Production for On-Site Consumption

125 x 10³ barrels of diesel fuel are produced annually as a byproduct from the gas oil hydrogenator. All of this diesel fuel is consumed on-site.

In addition to the treated gas oil, the gas oil hydrogenation unit also produces a diesel fuel byproduct. The diesel fuel produced is sent to the mine and the processed shale disposal areas to be used on-site to power mobile equipment. Production rate, on a daily basis, equals

Diesel fuel production¹

$$\begin{aligned} &= (16 \times 10^3 \text{ gal/day}) / (42 \text{ gal/bbl}) \\ &= 381 \text{ bbl/day} \end{aligned}$$

On an annual basis,

Diesel fuel production

$$\begin{aligned} &= (381 \text{ bbl/day})(365 \text{ days/yr})(0.9 \text{ capacity factor}) \\ &= 125 \times 10^3 \text{ bbl/yr} \end{aligned}$$

Reference

1. U. S. Department of the Interior, Final Environmental Impact Statement, Proposed Development of Oil Shale Resources, Vol. I and II, by The Colony Development Operation for Bureau of Land Management (DOI), 1977, p. II-37.

26**Air Emissions From Gas Oil Hydrogenator**

Combustion of gas oil in the gas oil hydrogenator furnace and in the fractionator reboiler leads to emission of 7.8 tons/yr of particulates and the following quantities of gaseous pollutants: sulfur dioxide, 18.5 tons/yr; nitrogen oxides, 54.6 tons/yr; carbon monoxide, 6.94 tons/yr; and hydrocarbons, 1.13 tons/yr.

A portion of the treated fuel gas (stream 15) produced by the gas recovery and treating unit is used to fuel the gas oil hydrogenation feed furnaces and fractionator reboiler. The combustion of this fuel produces potential air pollutants which are emitted to the atmosphere. Air emissions associated with the furnaces and reboiler, on a daily basis, total

Air emissions^{1,2}

$$= (\text{furnace emissions} + \text{reboiler})(\text{lbs/kgm})(\text{hrs/day})/(\text{lbs/ton})$$

Particulate emissions

$$= (0.2 \text{ kgm/hr} + 0.7 \text{ kgm/hr})(2.2 \text{ lbs/kgm})(24 \text{ hrs/day})/ \\ (2000 \text{ lbs/ton})$$

$$= 2.38 \times 10^{-2} \text{ tons/day}$$

SO₂

$$= (0.41 \text{ kgm/hr} + 1.72 \text{ kgm/hr})(2.2 \text{ lbs/kgm})(24 \text{ hrs/day})/ \\ (2000 \text{ lbs/ton})$$

$$= 5.62 \times 10^{-2} \text{ tons/day}$$

NO_x

$$= (1.2 \text{ kgm/hr} + 5.1 \text{ kgm/hr})(2.2 \text{ lbs/kgm})(24 \text{ hrs/day})/ \\ (2000 \text{ lbs/ton})$$

$$= 0.166 \text{ tons/day}$$

CO

$$= (0.2 \text{ kgm/hr} + 0.6 \text{ kgm/hr})(2.2 \text{ lbs/kgm})(24 \text{ hrs/day}) / (2000 \text{ lbs/ton})$$

$$= 2.11 \times 10^{-2} \text{ tons/day}$$

HC

$$= (0.04 \text{ kgm/hr} + 0.09 \text{ kgm/hr})(2.2 \text{ lbs/kgm})(24 \text{ hrs/day}) / (2000 \text{ lbs/ton})$$

$$= 3.43 \times 10^{-3} \text{ tons/day}$$

On an annual basis,

Particulates

$$= (2.38 \times 10^{-2} \text{ tons/day})(365 \text{ days/yr})(0.9 \text{ capacity factor})$$
$$= 7.81 \text{ tons/yr}$$

SO₂

$$= (5.62 \times 10^{-2} \text{ tons/day})(365 \text{ days/yr})(0.9 \text{ capacity factor})$$
$$= 18.5 \text{ tons/yr}$$

NO_x

$$= (0.166 \text{ tons/day})(365 \text{ days/yr})(0.9 \text{ capacity factor})$$
$$= 54.6 \text{ tons/yr}$$

CO

$$= (2.11 \times 10^{-2} \text{ tons/day})(365 \text{ days/yr})(0.9 \text{ capacity factor})$$
$$= 6.94 \text{ tons/yr}$$

HC

$$= (3.43 \times 10^{-3} \text{ tons/day})(365 \text{ days/yr})(0.9 \text{ capacity factor})$$
$$= 1.13 \text{ tons/yr}$$

References

1. U. S. Department of the Interior, Final Environmental Impact Statement, Proposed Development of Oil Shale Resources, Vol. I and II, by The Colony Development Operation for Bureau of Land Management (DOI), 1977, p. II-36.
2. U. S. Environmental Protection Agency, Pollution Control Guidance Document for Oil Shale, Vol. II: The TOSCO II/Colony Case Study, Preliminary Draft, November 1980, document in production, September 1981, pp. 118.

27 Solid Wastes From Gas Oil Hydrogenator

Approximately 300 to 500 tons of proprietary solid wastes are removed each year from the gas oil hydrogenation process area and are discarded in the spent shale disposal pile. This quantity includes 87.2 tons/yr (of which 28 lbs/yr are soluble) arsenic which are removed from the gas oil stream. Another 230 tons/yr of HDN catalyst are spent to remove nitrogen and sulfur from the gas oil and are also disposed of in the shale waste pile.

Solid wastes from the gas oil hydrogenation unit consist of arsenic, spent proprietary catalyst, and spent HDN catalyst. The arsenic comes from the gas oil stream and is extracted from the stream (prior to sulfur and nitrogen removal) with the aid of a proprietary catalyst located within the arsenic guard reactors. The arsenic then is combined with an inert compound to form a solid waste and is disposed of in the spent shale disposal area. The arsenic removal rate, on a daily basis, is

Arsenic removal and disposal¹

$$\begin{aligned} &= (531 \text{ lbs/day}) / (2000 \text{ lbs/ton}) \\ &= 0.266 \text{ tons/day} \end{aligned}$$

On an annual basis,

Arsenic removal and disposal

$$\begin{aligned} &= (0.266 \text{ tons/day})(365 \text{ days/yr})(0.9 \text{ capacity factor}) \\ &= 87.2 \text{ tons/yr} \end{aligned}$$

About 28 pounds of the 87.2 tons of arsenic is soluble per year.¹

The total waste (which consists of both the arsenic and the inert compound) from the arsenic guard reactors is sent to the spent shale disposal pile at an annual rate of

Spent proprietary solid to disposal¹

= 300 to 500 tons/yr

The HDN catalyst which aids in the removal of nitrogen and sulfur from the gas oil also must periodically be replaced. This is done annually at a rate of

Spent HDN catalyst to disposal¹

= 230 tons/yr

The spent catalysts are disposed of along with the spent shale.

Reference

1. U. S. Department of the Interior, Final Environmental Impact Statement, Proposed Development of Oil Shale Resources, Vol. I and II, by The Colony Development Operation for Bureau of Land Management (DOI), 1977, pp. II-36, II-49.

28

Anhydrous Ammonia Production

The sour water streams from the naphtha and gas oil hydrogenation units contain dissolved light hydrocarbon gas, hydrogen sulfide, and ammonia. 44.3×10^3 tons of anhydrous ammonia are stripped from the sour water streams annually as a byproduct. The hydrocarbon gas is removed and recycled to the gas treating unit; the H_2S is stripped and sent to the sulfur recovery unit.

Liquid anhydrous ammonia is extracted from the sour water streams exiting the naphtha and gas oil hydrogenation units. The sour water first is degassed prior to being sent to a sour water feed storage area. The resulting light hydrocarbon gas is recycled to the gas recovery and treating unit. From the storage area, the degassed sour water is sent to a H_2S stripper where pH control is used to separate the H_2S gas from the sour water stream. The H_2S gas stream is sent to the sulfur recovery unit while the desulfurized sour water stream is sent to an ammonia stripper. Again pH control, along with distillation, is used to strip and recover anhydrous ammonia from the water stream. The stripped water is returned to the hydrogenators as wash water while the anhydrous ammonia byproduct is compressed, cooled, and sent to storage for future marketing. The liquid ammonia production rate, on a daily basis, is

Anhydrous ammonia production¹

$$= (11,250 \text{ lbs/hr})(24 \text{ hrs/day})/(2000 \text{ lbs/ton})$$

$$= 135 \text{ tons/day}$$

On an annual basis

Anhydrous ammonia production

$$= (135 \text{ tons/day})(365 \text{ days/yr})(0.9 \text{ capacity factor})$$

$$= 44.3 \times 10^3 \text{ tons/yr}$$

Reference

1. U. S. Environmental Protection Agency, Pollution Control Guidance Document for Oil Shale, Vol. II: The TOSCO II/Colony Case Study, Preliminary Rough Draft, November 1980, document revision in progress, October 1981, p. 67.

29 Liquid Sulfur Production

Acid gas streams from various processes are treated with a three-stage Claus plus tail gas cleanup sequence to remove the sulfur as a liquid. A total of 63.7×10^3 tons of liquid sulfur is produced annually.

Acid gas streams which are produced by various process units within the shale oil upgrading and prerefining sequence contain potential pollutants (essentially H_2S) which, according to the Clean Air Act, must be controlled through the use of Best Available Control Technology (BACT). The BACT has been defined for the Colony TOSCO II via the PSD (Prevention of Significant Deterioration) permit process. The PSD requirement for the acid gas streams states that a 99.6 percent SO_2 removal efficiency must be achieved via a three-stage Claus plus tail gas cleanup sequence.¹ A brief description of this technology follows.

Acid gas streams from the gas recovery and treating unit, the ammonia separation unit, and the foul water stripper enter a reaction furnace where a controlled air stream is introduced to combust approximately one-third of the H_2S to SO_2 .² Combustion of the H_2S raises the furnace temperature to approximately $1200^\circ F$ and produces sufficient SO_2 (stoichiometrically) to react with the H_2S to form elemental sulfur. The sulfur-producing reaction is initiated within the furnace and continues within the three downstream stage converters.

As the partially converted gas passes through the reaction furnace, it is partially cooled in a steam generating section and is further cooled in an external condenser. The resulting gases which exit the condenser are then subjected to the three stages of reheat, catalytic conversion, and condensation. Each condenser generates steam and condenses out a liquid sulfur stream. The third condenser also emits a tail gas stream. The sulfur stream is collected in a sulfur pit and sent to storage for future marketing. Liquid sulfur production, on a daily basis, is

Liquid sulfur production³

$$\begin{aligned} &= (173 \text{ long tons/day})(2240 \text{ lbs/long ton})/(2000 \text{ lbs/ton}) \\ &= 194 \text{ tons/day} \end{aligned}$$

On an annual basis,

Liquid sulfur production

- = (194 tons/day)(365 days/yr)(0.9 capacity factor)
- = 63.7×10^3 tons/yr

References

1. U. S. Environmental Protection Agency, Environmental Perspective on the Emerging Oil Shale Industry, by EPA Oil Shale Research Group, edited by Edward R. Bates (Industrial Environmental Research Laboratory) and Terry L. Thoen (Office of Energy Policy Coordination -- Region VIII), EPA-600/2-80-205a, p. 258.
2. U. S. Environmental Protection Agency, Pollution Control Guidance Document for Oil Shale, Vol. II: The TOSCO II/Colony Case Study, Preliminary Draft, November 1980, document in production, September 1981, pp. 44.
3. U. S. Department of the Interior, Final Environmental Impact Statement, Proposed Development of Oil Shale Resources, Vol. I and II, by The Colony Development Operation for Bureau of Land Management (DOI), 1977, p. II-1.

30

Air Emissions From Tail Gas Incinerator

The tail gas from the Claus sulfur recovery unit is treated further in a Wellman-Lord tail gas incinerator. After the treatment, the gas emitted to the atmosphere contains 372 tons/yr of SO₂.

The tail gas emitted from the Claus sulfur recovery unit is sent to a Wellman-Lord tail gas incineration unit for further treatment. Within this unit, H₂S is converted to SO₂ and recycled to the Claus unit.

The Claus unit tail gas first is incinerated and cooled within the Wellman-Lord unit. Then, the combustion product is quenched and cooled further prior to entrance into an SO₂ absorber. Within the absorber, the gas is cleaned and emitted to the atmosphere. The quantity of SO₂ remaining in the cleaned gas, on a daily basis, is

SO₂ emissions¹

$$\begin{aligned} &= (42.91 \text{ kgm/hr})(2.2 \text{ lbs/kgm})(24 \text{ hrs/day})/(2000 \text{ lbs/ton}) \\ &= 1.13 \text{ tons/day} \end{aligned}$$

On an annual basis,

SO₂ emissions

$$\begin{aligned} &= (1.13 \text{ tons/day})(365 \text{ days/yr})(0.9 \text{ capacity factor}) \\ &= 372 \text{ tons/yr} \end{aligned}$$

The SO₂-rich absorbent material is sent to an evaporator-crystallizer where the SO₂ gas is evaporated for recycle to the Claus unit, and the absorbent material is regenerated for recycle.

Reference

1. U. S. Department of the Interior, Final Environmental Impact Statement, Proposed Development of Oil Shale Resources, Vol. I and II, by The Colony Development Operation for Bureau of Land Management (DOI), 1977, p. II-43.

31

Disposal of Solid Waste From Claus Unit and Wellman-Lord Unit

Spent alumina catalyst from the Claus sulfur recovery unit totals about 80 tons/yr. A negligible amount of sodium sulfite is released by the Wellman-Lord unit. Both waste streams are diverted to the spent shale pile.

The Claus sulfur recovery unit employs alumina catalysts to promote the sulfur production reaction within the three stage converters. These catalysts require periodic replacement. As a result, the spent catalysts are removed and sent to the spent shale pile for disposal. The spent catalysts' quantity and replacement frequency are

Spent alumina catalysts to disposal¹

- = 160 tons/2 yrs
- = 80 tons/yr (avg.)

The Wellman-Lord tail gas incinerator unit releases a purge stream of the regenerated SO₂ absorbent (sodium sulfite). This stream is small in quantity and is sent to the pyrolysis scrubber makeup tank for eventual disposal with the spent shale.

Reference

1. U. S. Department of the Interior, Final Environmental Impact Statement, Proposed Development of Oil Shale Resources, Vol. I and II, by The Colony Development Operation for Bureau of Land Management (DOI), 1977, p. II-44, II-49.

32

Byproduct Coke Production

The heavy bottoms oil stream from the pyrolysis gas stream fractionator is thermally cracked to produce 263×10^3 tons of marketable byproduct coke every year.

In addition to the gas, naphtha, and gas oil streams, the pyrolysis gas stream fractionator also produces a heavy bottoms oil stream. This bottoms oil is sent through a delayed coking process where lighter hydrocarbons and coke are produced according to the following sequence of events.

The bottoms oil is sent to a coker fractionator where lighter hydrocarbons (gas, raw naphtha, and gas oil) are flashed from the bottoms oil, leaving a heavy oil stream. The gas and raw naphtha streams are sent to the gas recovery and treating unit for processing, while the gas oil stream is sent to the gas oil hydrogenation unit for further upgrading. The heavy oil stream exits the bottom of the coker fractionator and passes through a furnace where it achieves cracking temperature. The heavy oil is then fed into one of two coke drums where coke is produced via thermal cracking. Once formed, the coke is steam-stripped to remove lighter hydrocarbons (the vapors of which are returned to the coker fractionator) and cooled prior to removal from the drum. The coke product is considered marketable.

Approximately 35 percent² of the bottoms oil is converted to coke which, on a daily basis, translates to

Byproduct coke production^{2,3}

= 800 tons/day

On an annual basis,

Byproduct coke production

= (800 tons/day)(365 days/yr)(0.9 capacity factor)

= 263×10^3 tons/yr

References

1. U. S. Environmental Protection Agency, Pollution Control Guidance Document for Oil Shale, Vol. II: The TOSCO II/Colony Case Study, Preliminary Draft, November 1980, document in production, September 1981, pp. 49.
2. U. S. Department of the Interior, Final Environmental Impact Statement, Proposed Development of Oil Shale Resources, Vol. I and II, by The Colony Development Operation for Bureau of Land Management (DOI), 1977, p. II-44.
3. U. S. Department of Energy, Western Oil Shale Development: A Technology Assessment, Vol. 2: Technology Characterization and Production Scenarios (Draft), by Battelle for DOE, Contract No. DE-AC06-76RLO 1830, June 1981, p. 65.

33**Air Emissions From Delayed Coker Furnace**

Treated fuel gas from the gas recovery and treating unit is burned to thermally crack the heavy bottom oil stream. The combustion of this fuel gas results in the following emissions: particulates, 4.34 tons/yr; sulfur dioxide, 11.3 tons/yr; nitrogen oxides, 33.0 tons/yr; carbon monoxide, 4.34 tons/yr; and hydrocarbons, 0.78 tons/yr.

A portion of the treated fuel gas produced by the gas recovery and treating unit (stream 15) is used to fuel the furnace which heats the heavy oil to cracking temperature.¹ Combustion of the fuel produces potential air pollutants which are released to the atmosphere. These emissions are identified and quantified below, on a daily basis.²

Particulate emissions from delayed coker furnace

$$\begin{aligned} &= (0.5 \text{ kgm/hr})(2.2 \text{ lbs/kgm})(24 \text{ hrs/day})/(2000 \text{ lbs/ton}) \\ &= 1.32 \times 10^{-2} \text{ tons/day} \end{aligned}$$

SO₂ emissions

$$\begin{aligned} &= (1.3 \text{ kgm/hr})(2.2 \text{ lbs/kgm})(24 \text{ hrs/day})/(2000 \text{ lbs/ton}) \\ &= 3.43 \times 10^{-2} \text{ tons/day} \end{aligned}$$

NO_x emissions

$$\begin{aligned} &= (3.8 \text{ kgm/hr})(2.2 \text{ lbs/kgm})(24 \text{ hrs/day})/(2000 \text{ lbs/ton}) \\ &= 0.10 \text{ tons/day} \end{aligned}$$

CO emissions

$$\begin{aligned} &= (0.5 \text{ kgm/hr})(2.2 \text{ lbs/kgm})(24 \text{ hrs/day})/(2000 \text{ lbs/ton}) \\ &= 1.32 \times 10^{-2} \text{ tons/day} \end{aligned}$$

HC emissions

$$\begin{aligned} &= (0.09 \text{ kgm/hr})(2.2 \text{ lbs/kgm})(24 \text{ hrs/day})/(2000 \text{ lbs/ton}) \\ &= 2.38 \times 10^{-3} \text{ tons/day} \end{aligned}$$

On an annual basis,

Particulate emissions from delayed coker furnace

$$\begin{aligned} &= (1.32 \times 10^{-2} \text{ tons/day})(365 \text{ days/yr})(0.9 \text{ capacity factor}) \\ &= 4.34 \text{ tons/yr} \end{aligned}$$

SO₂ emissions

$$\begin{aligned} &= (3.43 \times 10^{-2} \text{ tons/day})(365 \text{ days/yr})(0.9 \text{ capacity factor}) \\ &= 11.3 \text{ tons/yr} \end{aligned}$$

NO_x emissions

$$\begin{aligned} &= (0.10 \text{ tons/day})(365 \text{ days/yr})(0.9 \text{ capacity factor}) \\ &= 33.0 \text{ tons/yr} \end{aligned}$$

CO emissions

$$\begin{aligned} &= (1.32 \times 10^{-2} \text{ tons/day})(365 \text{ days/yr})(0.9 \text{ capacity factor}) \\ &= 4.34 \text{ tons/yr} \end{aligned}$$

HC emissions

$$\begin{aligned} &= (2.38 \times 10^{-3} \text{ tons/day})(365 \text{ days/yr})(0.9 \text{ capacity factor}) \\ &= 0.781 \text{ tons/yr} \end{aligned}$$

References

1. U. S. Environmental Protection Agency, Pollution Control Guidance Document for Oil Shale, Vol. II: The TOSCO II/Colony Case Study, Preliminary Draft, November 1980, document in production, September 1981, pp. 50-51.
2. U. S. Department of the Interior, Final Environmental Impact Statement Proposed Development of Oil Shale Resources, Vol. I and II, by The Colony Development Operation for Bureau of Land Management (DOI), 1977, p. II-46.

34 Foul Water to Water Treatment and Recycle

Annually, approximately 14.2×10^6 gallons of foul water is flashed out of the heavy bottoms oil in the delayed coker fractionator. The foul water contains 1% H_2S and is sent to the foul water stripper for recycling.

Within the delayed coker fractionator, water, as well as lighter hydrocarbons, is flashed out of the heavy bottoms oil. The resulting foul water, which is separated out of the lighter hydrocarbons, is sent to the foul water stripper for clean-up and reuse. On a daily basis, this quantity totals

Foul water to foul water stripper¹

$$\begin{aligned} &= (30 \text{ gal/min})(60 \text{ min/hr})(24 \text{ hrs/day}) \\ &= 43.2 \times 10^3 \text{ gal/day} \end{aligned}$$

On an annual basis,

Foul water to foul water stripper

$$\begin{aligned} &= (43.2 \times 10^3 \text{ gal})(365 \text{ days/yr})(0.9 \text{ capacity factor}) \\ &= 14.2 \times 10^6 \text{ gal/yr} \end{aligned}$$

This foul water stream is estimated to be 99 percent water and 1 percent hydrogen sulfide.²

References

1. U. S. Department of the Interior, Final Environmental Impact Statement, Proposed Development of Oil Shale Resources, Vol. I and II, by The Colony Development Operation for Bureau of Land Management (DOI), 1977, p. II-45.
2. U. S. Environmental Protection Agency, Pollution Control Guidance Document for Oil Shale, Vol. II: The TOSCO II/Colony Case Study, Preliminary Draft, November 1980, document in production, September 1981, pp. 50, 61.

35

Solid, Liquid, and Gaseous Discharges and Losses From the Water Treatment and Recycling Facilities

No water will be discharged into surface streams. Instead, water will be consumed, evaporated, or recycled. Approximately 197 tons/yr of lime and alum flocculants, and 8.21 tons/yr of proprietary coagulant aid are disposed of along with the spent shale. An unquantifiable amount of sludge is produced at various other areas within the water treatment facilities and also disposed of with the spent shale. Any potential gaseous pollutants (such as H_2S and NH_3) exiting the foul water stripper are sent to the Claus unit for processing.

The Colony facility is designed to recycle and reuse a large quantity of the process water. This eliminates the necessity to discharge wastewater to surface streams. Associated with this recycle stream are high consumptive/evaporative losses which are replaced at a rate of 6500 gpm. The Colorado River provides the make-up water requirements for Colony's oil shale production facilities.

A large consumptive use of process wastewater is processed shale moisturization. The processed shale embankment also serves as the solid waste disposal facility of the plant. Natural drainage will be diverted from the waste embankment; however, the long-term fate of the materials contained in the processed shale, wastewater and solid wastes is uncertain.

The following figures¹ are representative of water use based on best engineering design. However, there may be additional consumptive and evaporative losses that will become evident only through actual operating experience, some of which may be proprietary.

	<u>gpm</u>	<u>gal/day (10³)</u>	<u>gal/yr (10⁶)</u>
<u>Inputs</u>			
Colorado River	6500	9.36×10^3	3.70×10^3
Oil Water Sewer Process Drains	310	446	147
Raw Shale Surface Moisture	165	238	78.1
Raw Shale Water from Retorting	150	216	70.9
Water from Combustion	370	533	175

Consumptive Uses

Mining Operations	350	504	166
Primary Crusher and Coarse Ore Storage (dust control)	150	216	20.9
Moisturized Processed Shale Pile	1500	2.16×10^3	709
Revegetation	70-700*	101-1010	33.1-331
Oil/Water Separator Sludge Disposal (periodic)	2	2.88	0.946
Product Storage and Shipping			
in Parachute	60	86.4	28.4
Middle Fork Dam	890	1.28×10^3	421
Mine and Utility Fire Water	140	202	66.2
Mine Potable Water	10	14.4	4.73
Potable Water Distribution	15	21.6	7.09
Hydrotreater	448	645	212
General Process Consumption and Losses	282	406	133
Utility Uses	250	360	118
Slop Oil Tank	8	11.5	3.78

Evaporative Losses

Pyrolysis Unit	1620	2.33×10^3	766
Cooling Tower	1530	2.20×10^3	724
Coker	70	101	33.1
Miscellaneous Losses	100	144	47.3

The water treatment facilities designed for the Colony plant are briefly described in the following paragraphs.

A bank intake structure pumps raw water from the Colorado River, and on through a sedimentation process to the plant area. Once the water stream reaches the plant site, it undergoes partial softening. Alum and lime flocculants, and a coagulant aid (a proprietary material supplied by outside contractors) are used to accomplish this. The resulting lime sludge is separated out and pumped (in slurry form) to the pyrolysis unit where it is combined with the processed shale for disposal. The disposal rates of the solid wastes within the lime sludge, on a daily basis, are

* 700 gpm will be used after 12 years of operation.

Lime and alum flocculants to disposal¹

- = (1200 lbs/day)/(2000 lbs/ton)
- = 0.60 tons/day

Proprietary coagulant to disposal¹

- = (50 lbs/day)/(2000 lbs/ton)
- = 0.025 tons/day

On an annual basis,

Lime and alum flocculants to disposal

- = (0.60 tons/day)(365 days/yr)(0.9 capacity factor)
- = 197 tons/yr

Proprietary coagulant aid to disposal

- = (0.025 tons/day)((365 days/yr)(0.9 capacity factor)
- = 8.21 tons/yr

After adjustment of pH with acid and addition of chemical corrosion inhibitors, a portion of the clarified water is used as cooling water makeup to replace that lost by evaporation and blowdown. Potable water treatment includes filtration and chlorination of a stream of clarified water. Boiler feed water is then produced by filtering clarified water followed by softening in a zeolite ion exchange bed, along with the addition of chemicals for corrosion inhibition. Aqueous waste streams from these systems include zeolite regeneration wastes, boiler blowdowns, and cooling water blowdowns. They are used as part of the processed shale moisturizing water and will be tightly bound by the shale into a chemically and physically stable material.

The water and chemicals collected from leaks, drain outs, flushes, washdowns, and storm runoff in the process area will flow through the oily water sewer system to an oil-water separator capable of handling 310 to 1,000 gpm. A surge and guard pond is provided to handle large quantities of water during a period of high storm runoff, but under normal conditions they will receive little flow. These ponds are designed to withstand the probable maximum thunderstorm.

The water effluent from the guard pond is pumped to the pyrolysis water makeup tank for eventual use in moisturizing processed shale. The skimmed oil is sent to a slop oil tank for reprocessing. Water from the slop area in the mine is collected in holding tanks and periodically trucked to the process plant for processing through the oily-water separator. The slop oil tank water is further treated in the foul water stripper.

The sewage treatment system at the plant site collects sewage from all maintenance, operations, laboratory, safety and security facilities. Effluent from the sewer is treated in a secondary package aeration plant where clarified water and sludge are produced.

Sludge from the aeration plant is sent to a sludge surge tank and then to the processed shale moisturizer in the pyrolysis unit. The sludge will ultimately be mixed with the processed shale.

Clarified water from the aeration plant is treated in a hypo-chlorination unit and then discharged into the clean water guard pond. Effluents from the clean water guard pond is used as water to moisturize the processed shale.

An estimated 20,000 gal/day of sludge and clarified water will be produced at the plant site.

The foul water stripper treats the foul water generated during pyrolysis, oil recovery, gas recovery, and coking, removing absorbed ammonia, hydrogen sulfide, and carbon dioxide gases. However, many other chemicals remain in the water and are eventually disposed of with the spent shale. The foul water stripper consists of a conventional distillation column with steam heated reboiler. The H_2S and NH_3 are sent to the sulfur recovery unit (the Claus plant) where the H_2S is converted to elemental sulfur and NH_3 is converted to nitrogen. However, other chemicals which remain in the stripped water are used to moisturize the processed shale. These components are depicted in Appendix D.

An ammonia separation unit processes the sour water from the naphtha and gas oil hydrotreaters. Liquid anhydrous ammonia is produced as a marketable byproduct. Gaseous hydrogen sulfide is removed and sent to sulfur recovery and the stripped water is recycled to the hydrotreaters.

The water used for pollution control is condensed by the process and routed back into the steam generating facility.

References

1. U. S. Department of the Interior, Final Environmental Impact Statement, Proposed Development of Oil Shale Resources, Vol. I and II, by The Colony Development Corporation for Bureau of Land Management (DOI), 1977, pp. II-49, II-71 to 73, II-75.

IV. PHYSICAL REQUIREMENTS

Water

Water use by the Colony shale oil plant is briefly described in the following paragraphs and is depicted in Figure 2. The primary source of water for the Colony plant is the Colorado River at a daily rate of

Makeup water from the Colorado River

$$\begin{aligned} &= (6500 \text{ gal/min})(60 \text{ min/hr})(24 \text{ hrs/day}) \\ &= 9.36 \times 10^6 \text{ gal/day} \end{aligned}$$

On an annual basis,

Makeup water from the Colorado River

$$\begin{aligned} &= (9.36 \times 10^6 \text{ gal/day})(365 \text{ days/yr})(0.9 \text{ capacity factor}) \\ &= 3.07 \times 10^9 \text{ gal/yr} \end{aligned}$$

This water use is lower than that of the ANG coal gasification plant.

Comparison of Water Requirements

	ANG ²	Colony
Annual Energy Production	90.6 x 10 ¹² Btu (SNG)	92.9 x 10 ¹² Btu (Syncrude)
Raw Water Intake	11,670 x 10 ³ gpd	9,360 x 10 ³ gpd

A portion of this water is used at the product storage and shipping facilities in Parachute, some is stored behind the Middle Fork Dam for use by the mining operations, and still more is used for dust control in the primary crusher and coarse ore storage area prior to reaching the main facilities.

Once at the retort and oil upgrading facility, a small portion of the water is diverted to the pyrolysis unit for make-up water, while the majority of the water is treated in a clarifier prior to all further uses within the plant.

	<u>Quantity</u>
Zeolite Softener and Gravity Filters → Clarifier	50 gpm
Cooling Tower Blowdown → Pyrolysis Water Storage	370 gpm
Steam Users and Process Machinery Condensate → Steam Generators	1580 gpm
Steam Users and Process Machinery Steam → Pyrolysis Unit	390 gpm
Hydrotreater Process Condensate → Hydrotreater	45 gpm
Pyrolysis Unit Foul Water → Foul Water Stripper → Pyrolysis Water Storage	450 gpm
Pyrolysis Unit Moisturized Processed Shale → Processed Shale Pile	1500 gpm
Coker → Foul Water Stripper → Pyrolysis Water Storage	30 gpm
Oily Water Sewer Process Drains → Oil/Water Separator → Pyrolysis Water Storage	275 gpm
Sanitary Waste Liquid Effluent → Pyrolysis Water Storage	-
Sanitary Waste Sludge → Processed Shale Pile	-
Revegetation Water → Processed Shale Pile	70-700 gpm
Processed Shale Pile Rainwater Runoff → Davis Gulch Reservoir → Pyrolysis Water Storage	1200 gpm (May/June)

Figure 2. MAJOR RECYCLING/REUSE LOOPS FOR COLONY SHALE OIL MINING AND PRODUCTION FACILITIES

During normal operations, about half of the clarified water is used in the cooling tower for process water cooling, a small quantity is used for the potable water system, a portion goes into the utility water distribution system, and the rest is treated further in gravity filters and with zeolite softeners. During fires, all of the clarified water can be used for fire fighting.

The water undergoing further treatment is divided again. The major portion of this water is used for steam generation and by the hydrotreater, with the remainder being sent to the water storage system for the pyrolysis unit.

Water storage for the pyrolysis unit receives water from many sources within the plant, i.e., treated plant drainage water and sanitary wastewater, condensate from the steam generators, recycled foul water from the pyrolysis unit, cooling tower blowdown and, as indicated previously, water from the zeolite softener and the Colorado River.* The total amount of water flowing into the storage system is routed to the pyrolysis unit where it is joined by water from the steam-using processes and process machinery, water from the utility water distribution system, and moisture present in the shale. A large portion of the water present after pyrolysis is used to cool the processed shale and to moisturize the shale to 14 weight percent water.

The foul water exiting the pyrolysis unit is combined with water from the coker and is treated in the foul water stripper. Stripped water is then recycled to the pyrolysis water storage system.

Additional water input is water from sewer process drains, raw shale surface moisture and moisture from retorting, and water from combustion. This totals, on a daily basis,

Miscellaneous Water Input¹

$$\begin{aligned} &= (995 \text{ gal/min})(60 \text{ min/hr})(24 \text{ hr/day}) \\ &= 1.43 \times 10^6 \text{ gal/day} \end{aligned}$$

On an annual basis,

Miscellaneous Water Input

$$\begin{aligned} &= (1.43 \times 10^6 \text{ gal/day})(365 \text{ days/yr})(0.9 \text{ capacity factor}) \\ &= 471 \times 10^6 \text{ gal/yr} \end{aligned}$$

* River water make-up to pyrolysis will decrease when other water sources, such as precipitation runoff, are available.

The natural flow water rights held by the Colony Development Operation for the diversion of water from the Colorado River has a low priority because they were so recently acquired. According to the western system of allocating water rights, "Prior Appropriation," old water rights have priority over new ones in times of reduced river flow. Thus, to ensure continuous plant operation, an additional source of water is necessary. It has been proposed that additional water be contracted from the Green Mountain Reservoir (a part of the Colorado-Big Thompson project), and that wells drilled to satisfy construction needs continue production during operation. Procuring water rights in the west is a potential problem for many oil shale developments.

Land

The land required for oil shale development is very dependent on the local physiography and the level of development currently existing in the area. For example, physiography dictates the types and size of spent shale disposal requirements, the necessity for and size of water catchment and diversion facilities, and access road, pipeline and utility routes. The level of existing development dictates length of access roads, pipelines, and utility lines, and the necessity to construct additional power generation plants, water facilities, and administration buildings. The land requirements of the Colony project typify the land requirements of oil shale development in mountainous, sparsely populated areas. The primary oil shale facilities occupying land are the shale retorting and oil upgrading complex, processed shale disposal area, catchment dams, water diversion structures, mine bench, access roads, service corridor, staging area, railroad spurs and terminal, powerline corridor, administration buildings and pipeline corridor. The land required for these facilities is presented in Table 3.

Land Disturbed by Mining

Over 67,000 tons of shale will be mined per day using room and pillar mining. The shale seam is 60 feet thick and the average shale will produce 35 gallons of shale oil per ton. Sixty percent of the shale seam can be extracted. After 20 years of mining, the underground workings will occupy 4,100 acres.

Thus 75,300 bbl of shale oil are produced from each acre:

Shale oil per acre mined

$$= (47 \times 10^3 \text{ bbl/day})(365 \text{ days/yr})(0.9 \text{ capacity factor})(20 \text{ yr}) / (4.1 \times 10^3 \text{ acres})$$

$$= (309 \times 10^6 \text{ bbl}) / (4.1 \times 10^3 \text{ acres})$$

$$= 75.3 \times 10^3 \text{ bbl/acre}$$

Table 3. LAND REQUIREMENTS¹

<u>Roads and Conveyor Route</u>	<u>Acreage</u>
Valley Access Road	95
Mine Access Road	50
Plant Access Road	100
Conveyor Routes	70 to 80
Administration Building Access Road	5
Colorado River Pump Station Access Road	10
In-Plant Roads	15
	<hr/> 355
<u>Mine (surface land)</u>	
Bench	6
Flood Control Dam	36
	<hr/> 42
<u>Plant Site</u>	
Retorting and Upgrading Facility	160
Ore Storage	15
	<hr/> 175
<u>Processed Shale</u>	
Embankment (disposal site)	800
Dam and Diversion Structures	72
	<hr/> 872
<u>Off-Site Facilities</u>	
Terminal	75
Railroad Spur	5
Colorado River Pump Stations	10
Administration Building	5
194-mile Pipeline	1,175
Terminal	10
Utility Corridor	5
Powerline Construction	950
	<hr/> 2,261

References

1. U. S. Department of the Interior, Final Environmental Impact Statement, Proposed Development of Oil Shale Resources, Vol. I and II, by The Colony Development Operation for Bureau of Land Management (DOI), 1977, pp. II-10, II-49, II-71 to II-73.
2. U. S. Department of Energy, Draft Environmental Impact Statement for the ANG Coal Gasification Company, North Dakota Project, prepared by Upper Missouri Region, Bureau of Reclamation for the U. S. Department of the Interior, INT DES 77-11, March 17, 1977.

V. PERSONNEL

Peak construction employment will occur between 1.5 and 2 years after project initiation. The number of employees that will be required during peak construction was estimated at 2,400 by Colony in 1974 but has been increased to 2,500 to 2,700 more recently (1979).^{1,2} The number of employees required for plant operation is estimated to be 1,040 and will be working after 3.5 years of project initiation. The indirect employment generated by the operation of the Colony plant is estimated to be 1,012.

The overall population increase due to the Colony project has been estimated at 4,100. The population of the two primary impact towns was under 300 in 1970 and thus this level of growth will require the expansion of many city services, will create pressure on the housing market, and will alter the general character of existing communities.

References

1. U. S. Department of the Interior, Final Environmental Impact Statement, Proposed Development of Oil Shale Resources, Vol. I and II, by The Colony Development Operation for Bureau of Land Management (DOI), 1977, p. IV-194.
2. U. S. Environmental Protection Agency, Environmental Perspective on the Emerging Oil Shale Industry, by EPA Oil Shale Research Group, edited by Edward R. Bates (Industrial Environmental Research Laboratory) and Terry L. Thoem (Office of Energy Policy Coordination -- Region VIII), EPA-600/2-80-205a.

VI. OCCUPATIONAL SAFETY AND HEALTH

The work force at the Colony oil shale plant during the 20 year operation is projected to be 1,040. It is estimated that approximately 660 of these employees will be miners and 380 will work in the retort facility. The morbidity/mortality rates for the emerging oil shale industry per worker per year are:

	<u>Deaths</u>	<u>Injuries</u>
Underground Mining	0.0014	0.062
Surface Retorting	0.0004	0.045

At these rates, the Colony oil shale development will experience the following morbidity/mortality per year:

	<u>Deaths</u>	<u>Injuries</u>
Underground Mining	0.92	40.8
Surface Retorting	0.15	17.1

The morbidity/mortality rates cited above are based on data from other similar industries because the oil shale industry in the United States has not reached the level of maturity required to produce meaningful health statistics. Statistics from similar industries are representative of the oil shale industry because many of the most hazardous procedures in oil shale production are performed routinely in other industries and are well documented. The most hazardous aspects of oil shale production are underground shale mining, the operation of heavy equipment, and exposure to high temperature processes and equipment under high pressures. In these aspects, oil shale production is similar to underground coal mining and mineral mining, oil refining, and copper smelting.

A significant occupational hazard in coal mining is the inhalation of coal dust. Over a period of many years coal dust inhalation results in debilitating and fatal respiratory disease. Oil shale mining will also expose workers to inhalable dust. However, the properties (particle size, constituents) of oil shale dust may be significantly different from coal dust and may pose a greater (or lesser) degree of health hazard. Similarly, the materials present during oil shale retorting may be more (or less) hazardous than those which workers in oil refineries are exposed to because of the differences between oil and shale oil.

The primary concern regarding materials present in oil shale is their carcinogenicity. The most recent research on oil shale worker morbidity/mortality concludes that:^{3,4}

- 1) Oil shale workers are generally healthier than control population groups (selected on the basis of race, sex and location) regarding circulatory system diseases and respiratory system diseases, but exhibit a slightly higher propensity for accidents.
- 2) Oil shale workers exhibit higher rates of malignant neoplasms, particularly for the colon, but also for the trachea, bronchus and lung. However, the oil shale workers studied also smoked and had experience in mining in which there was a high exposure to radioactivity. Smoking and exposure to radioactivity was more closely associated with these malignancies than was oil shale production.
- 3) Workers employed in maintenance activities at the oil shale plant had the highest disease incidence and miners had the lowest. Workers employed in the retorting facility fell in between.
- 4) Nonsmoking oil shale workers had considerably fewer people reporting chest symptoms than the miners, while smokers had nearly identical levels of cough and phlegm, but fewer cases of wheeze and breathlessness. Ex-miners' results were intermediate between smokers and nonsmokers. No significant associations of prevalence with exposure to oil shale production work was seen.
- 5) Possibly malignant skin tumors were suspected in 16 men in each study group. After biopsy, the malignant nature of the tumors was confirmed in eight controls and four oil shale workers. Similar numbers or slight excesses of nevi, telangiectasiae, possible pitch warts, pigment changes and papillomata were seen in the control group, while actinic keratoses were slightly more frequent in the oil shale workers. The prevalence of actinic keratoses was associated significantly and positively with oil shale work exposure after allowing for age, sunlight exposure, and other exposures.
- 6) A few cases of leukoplakia occurred mainly in the control group. No clear pattern was evident when pulmonary cytology results for the two groups were compared. The prevalence of metaplasia was positively associated with years of production work in oil shale. More of the oil shale workers had atypical cells in their urine but the excess was mostly found among ex-smokers. No trend with exposure was seen in the oil shale group.
- 7) Surveillance of oil shale workers for health effects should be a high priority for future research.

References

1. U. S. Environmental Protection Agency, Energy from the West, Energy Resource Development Systems Report, Vol. III: Oil Shale, EPA-600/7-79-060c, March 1979, pp. 51, 191.
2. U. S. Environmental Protection Agency, Energy from the West, Energy Resource Development Systems Report, Vol. I: Introduction and Summary, EPA-600/7-79-082a, March 1979, p. 140.
3. "Morbidity Study of Oil Shale Workers Employed at Anvil Points, Colorado, During 1948-1969," by M. D. Attfield, J. Costello, NIOSH, Morgantown, West Virginia; J. Burkart, Ph.D., UBTL, Salt Lake City, Utah; and J. Krueger, M.D., W. Rom, M.D., J. Zone, M.D., University of Utah, Salt Lake City, Utah.
4. "Retrospective Mortality Study of Oil Shale Workers, 1948-1977," J. Costello, National Institute for Occupational Safety and Health, Division of Respiratory Disease Studies, presented at the 13th Annual Oil Shale Symposium, Colorado School of Mines, Golden, Colorado, April 16-18, 1980.

APPENDIX A

THE TOSCO II RETORTING PROCESS (INDIRECT MODE)

The TOSCO II retorting process employs a solid-to-solid heat exchange between crushed shale and heated ceramic balls. The retorting system can be divided into three distinct sub-systems: 1) Pre-heating System, 2) Elutriation System, and 3) Shale Wetting System.

Preheating System

Raw shale of -1.25 cm (-0.5 inch) is first preheated to about 260°C (500°F) with flue gases from the ball heater. Residual hydrocarbons in the flue gases are simultaneously burned and the cooled gases are separated from the preheated shale. The preheated shale is fed to a horizontal rotating drum and mixed with approximately 1.5 times its weight in hot ceramic balls to raise the shale to pyrolysis temperature, 480°C (900°F). Pyrolysis vapors are drawn out of the retort and taken to a fractionator located above the retort. These hydrocarbon vapors are fractionated into water, gas, naphtha, gas oil and bottoms oil. The water is subsequently stripped of ammonia and hydrogen sulfide and used to wet the processed shale. The other products are taken to treatment or upgrading units.

Elutriator System

The mixture of ceramic balls and pyrolyzed shale is collected in an accumulator and discharged by a rotating trommel screen, separating the balls from the processed shale. Dust is removed from the balls with flue gases from a steam superheater. The dust-free warm balls are returned to the ball heater by bucket elevator, reheated to approximately 700°C (1300°F) using in-plant fuel, and returned to the pyrolysis drum.

Shale Wetting System

The hot retorted shale is cooled to approximately 150°C (300°F) in a rotating drum cooler (where steam is produced for process use), and moisturized to 11 to 15 weight percent water content for disposal. At 93°C (200°F) or less, the wet shale is transported by conveyor to the disposal site.

TOSCO II RETORTING PROCESS*

* Source: EPA, Environmental Perspective on the Emerging Oil Shale Industry, by EPA Oil Shale Research Group, EPA-600/2-80-205a, 1980, p. 287.

APPENDIX B FACILITY AND ENVIRONMENTAL CONTROL COSTS

Although detailed facility and control costs for the Colony TOSCO II oil shale production process are beyond the scope of this report, the following presents estimates of total capital investment and annualized environmental control costs.

Total facility costs have been reported to be \$960 million (September 1975 dollars) or \$1050 million (1977 dollars).² Net annual operating costs are estimated at \$80.4 million (1977 dollars).² Assuming a 10 percent discounted cash flow return on an all-equity investment, the syncrude selling price would need to be \$14.20 per barrel (1975).

Estimates show that environmental control costs range from 10 to 20 percent of total facility costs.³ Control costs can be based on relaxed or stringent control requirements. A DOE document⁴ reports cost results for both cases, one supplied by Denver Research Institute (DRI) and the other by MITRE Corporation. DRI analyzed the control costs under the relaxed approach and estimated the cost to be \$1.90 per barrel syncrude production (1979 dollars). The estimate reported by MITRE has been prepared based on the stringent requirements, in addition to a more conservative approach to the selection of basic technological and economic assumptions. It is believed that this approach may be a more realistic method to be used by developers.⁴ The resulting estimate of \$3.70 per barrel syncrude production (1979 dollars) is based on the following economic assumptions:

- Depreciable life -- 8 to 13 years
- Straight-line depreciation
- 15% discounted cash flow, rate of return financing
- 0/100% debt/equity ratio
- 0% investment tax credit
- Non-linear investment profile

Within the same document, DOE has adjusted MITRE's estimates to \$3.30 per barrel syncrude production by employing the DOE standardized costing methodology.⁴ This methodology includes the following key economic assumptions.

- Depreciable life -- 80% of project operating life
- Sum-of-years digits depreciation
- 15% rate of return
- 0/100% debt/equity ratio
- 10% investment tax credit
- Linear investment profile

The less conservative estimate is \$1.90 per barrel syncrude production.

The environmental control costs presented above include direct operating costs, capital recovery costs, other indirect costs, and all appropriate byproduct credits. The environmental items which are controlled fall into the following categories.

Water Management

- Ammonia Recovery
- Organic Removal
- Miscellaneous Water Management

Air Pollution Control

- Sulfur Dioxide
- Hydrocarbons
- Particulates
- Fugitive Dust

Solid Waste Management

- Pollution Control Sludge Disposal and Site Closure

Although both environmental cost estimates assume that a Stretford unit will be employed for sulfur control as opposed to a Claus unit as has been identified within this ECIR (stream 29), the overall control costs are not expected to be significantly affected.

Also, note that the environmental control cost estimates do not include consideration of new regulations, such as Resource Conservation and Recovery Act and anticipated industrial hygiene regulations.

References

1. U. S. Environmental Protection Agency, A Preliminary Assessment of the Environmental Impacts from Oil Shale Developments, by TRW, Inc., for EPA/IERL, EPA-600/7-77-069, July 1977, p. 26.
2. Vawter, R. G., "The TOSCO II Process Ready for Commercialization," 1978.
3. U. S. Department of Energy, Environmental Analysis of Synthetic Liquid Fuels, Assistant Secretary for Environment, Office of Technology Impacts, July 12, 1979.
4. U. S. Department of Energy, Environmental Control Costs for Oil Shale Processes, Office of Technology Impacts, DOE/EV-0055, October 1979, Overview/pp.4-10, Attachment 2/p. C-2.

APPENDIX C

METHODS FOR MINING OIL SHALE

Green River formation oil shale deposits are amenable to either surface mining (open pit or strip) or to underground mining methods (such as room and pillar), depending on various factors such as accessibility, overburden thickness, and presence of groundwater in the mining zone. Surface mining is economically attractive for large, low-grade ore deposits because it permits high recovery of the resource and allows sufficient space for very large and efficient mining equipment. An open pit mine could recover almost 90 percent of the oil shale in a very thick deposit. Strip mining could provide even higher recoveries. In contrast, underground mining would recover less than 70 percent.²

Open pit mining involves excavation of the overlying waste rock to expose the oil shale resource below. The oil shale and waste rock are "benched" down to a depth dictated by the economic limits or cutoff grade of the pit.² In strip mining, overburden is removed with a dragline -- a massive type of scraper shovel. When the dragline has filled its scoop, it pivots and dumps the burden into an adjacent mined-out area. One difference between open pit and strip mines is that in strip mining the burden is simply cast into a nearby area; in open pit, it must be moved far from the mine site to prevent interference with the development of the pit.²

In the Piceance Creek basin, nearly 80 percent of the oil shale resource is confined to the deposits in the deep central part of the basin. For this reason, underground mining systems with high volume and low cost will probably be used to efficiently mine the thick oil shale resource, unless the entire basin were to be mined as one grand-scale open pit.

The methods available are the room and pillar system, and bulk mining methods such as sublevel stoping and block coring using slushers. Room and pillar methods appear to be the more attractive method because the technique has been proved for use in deposits no thicker than 100 to 150 feet on a large scale. The oil shale mine on the Dow West property feeding the plant described in this ECIR is a room and pillar mine.

For any commercial facility, whatever method of mining is used, either surface or underground, the system must be capable of excavating large quantities of oil shale at a very low cost. The mine design must not only be cost effective, but also a strict concern must be directed toward health and safety and the effects on the physical, biological, human, and mining environments.²

References

1. U. S. Environmental Protection Agency, Environmental Perspective on the Emerging Oil Shale Industry, by EPA Oil Shale Research Group, edited by Edward R. Bates (Industrial Environmental Research Laboratory) and Terry L. Thoem (Office of Energy Policy Coordination -- Region VIII), EPA-600/2-80-205a, pp. 277-279.
2. Cameron Engineers, Inc., Synthetic Fuels Data Handbook, 2nd ed., Denver Colorado, 1978, pp. 6, 51-53.

APPENDIX D

COMPONENTS OF MAJOR PROCESS STREAMS

Raw Oil Shale^{1,2,3}

<u>Component</u>	<u>wt % (dry)</u>
Kerogen:	14
Carbon	80.5
Hydrogen	10.3
Nitrogen	2.4
Sulfur	1.0
Oxygen	5.8
Inorganic Minerals:	86
Dolomite	32
Calcite	16
Quartz	15
Illite	19
Albite	10
K Feldspar	6
Pyrite	1
Analclime	1

Raw Shale Oil²

<u>Property</u>	
Carbon, wt %	85.1
Hydrogen, wt %	11.6
Oxygen, wt %	0.8
Nitrogen, wt %	1.9
Sulfur, wt %	0.9
Gravity, ° API	21.2
Specific Gravity	0.928
Arsenic, ppm	-
Nickel, ppm	6
Iron, ppm	100
Vanadium, ppm	3
C/H Ratio	7.34
Pour Point, °F	80
Heating Value, Btu/lb	-

Spent Shale^{2,3}

Property

Component, wt %

SiO ₂	33.0
CaO	15.8
MgO	5.31
Al ₂ O ₃	6.80
Fe ₂ O ₃	2.52
Na ₂ O	8.68
K ₂ O	3.28
SO ₃	-
P ₂ O ₅	-
Mineral CO ₂	5.71
Organic C ²	4.49
Inorganic C	5.71

pH

7.5-9.0

Inorganic Ions³ (leachable from freshly retorted (spent) shale)

<u>Leachable Ion</u>	<u>kgm/tonne</u>	<u>lbs/ton*</u>	<u>tons/yr leachable*</u>
K ⁺	0.32	0.64	5.60 x 10 ³
Na ⁺	1.65	3.30	2.89 x 10 ⁴
Ca ⁺⁺	1.15	2.30	2.01 x 10 ⁴
Mg ⁺⁺	0.27	0.54	4.72 x 10 ³
HCO ₃ ⁻	0.20	0.40	3.50 x 10 ³
Cl ⁻	0.08	0.16	1.40 x 10 ³
SO ₄ ⁼	7.30	14.60	1.28 x 10 ⁵

• 17.5 x 10⁶ tons spent shale per year.

Stripped Foul Water^{1,2,4} (from foul water stripper to spent shale moisturizer)

<u>Component*</u>	<u>Concentration (ppm)</u>
Ca ⁺²	280
Mg ⁺²	100
Na ⁺¹	670
NH ₄ ⁺¹	15
Zn ⁺²	5
As ⁺⁵	(15 to 300 ppb)
Cr ⁺⁶	2
CO ⁻²	360
HCO ₃ ⁻¹	100
SO ₄ ⁻²	850
S ₂ O ₃ ⁻²	90
PO ₄ ⁻³	5
Cl ⁻¹	570
CN ⁻¹	5
Phenols	315
Amines	410
Organic acids	1,330
Neutral oils	960
Chelate	5

* Elements present in trace amounts include Pb, Ce, Ag, Mo, Zr, Sr, Rb, Br, Se, Cu, Ni, Co, Fe, Mn, V, Ti, K, P, Al, F, B, and Li.

References

1. U. S. Department of the Interior, Final Environmental Impact Statement, Proposed Development of Oil Shale Resosurces, Vol. I and II, by the Colony Development Operation for the Bureau of Land Management (DOI), 1977.
2. U. S. Environmental Protection Agency, Environmental Perspective on the Emerging Oil Shale Industry, by EPA Oil Shale Research Group, edited by Edward R. Bates (Industrial Environmental Research Laboratory) and Terry L. Thoem (Office of Energy Policy Coordination -- Region VIII) EPA-600/2-80-205a.
3. U. S. Environmental Protection Agency, A Preliminary Assessment of the Environmental Impacts from Oil Shale Developments, by TRW Environmental Engineering Division for EPA, EPA-600/7-77-069, July 1977.
4. U. S. Department of Energy, Western Oil Shale Development: A Technology Assessment, Vol. 2: Technology Characterization and Production Scenarios (Draft), by Battelle for DOE, Contract No. DE-AC06-76RLO 1830, June 1981.

APPENDIX E

POLLUTANTS EXITING ON-SITE STEAM BOILER

Treated fuel gas will be burned by two on-site (auxiliary) utility boilers used for the generation of steam. Emissions associated with these boilers are:

<u>Potential Pollutant Emitted</u>	<u>kgr/hr</u>	<u>tons/hr</u>
SO ₂	3.24	3.56×10^{-3}
NO _x	9.80	1.08×10^{-2}
HC	0.18	1.98×10^{-4}
CO	1.15	1.27×10^{-3}
Particulates	1.30	1.43×10^{-3}
<u>Normal Firing Duty</u>		144×10^6 Btu/hr

Reference

U. S. Department of the Interior, Final Environmental Impact Statement, Proposed Development of Oil Shale Resources, Vol. I and II, by the Colony Development Operation for Bureau of Land Management (DOI), 1977.

GLOSSARY

absorbent	Material capable of absorbing another material out of a third material and into it.
accumulator	A device which collects and separates solid material from gas, liquid, or fine solids.
acid gas	Gas containing sulfur compounds (mainly in the form H_2S).
adit	An approach or entrance; an almost horizontal passageway into a mine.
baghouse filter	A particulate control device which uses a filter to extract particles out of an air stream.
blowdown	Water that is periodically removed from either the cooling towers or the coal-fired boiler to prevent concentration of total dissolved solids.
bottoms oil (bottoms)	Generally, the heaviest oil exiting a fractionating unit.
capacity factor	The actual plant output in a year divided by the output that would be achieved if the plant were to operate at 100 percent power for 365 days/year.
catalyst	Material which initiates or stimulates (promotes) the occurrence of a chemical reaction without itself being altered in form or consumed.
clarifiers	A system used to remove total suspended solids in the river makeup water.
cooling tower drift loss	Aerosols of water that are lost to the atmosphere from the cooling towers.
cooling tower evaporation loss	Circulating water that is evaporated as a result of heat transferred from the circulating water system and lost in the atmosphere via the cooling towers.
cracking	The process of breaking down heavier hydrocarbons by heat and pressure or by catalysts into lighter hydrocarbons.
day	Consists of 24 hours.
dead storage	Generally, long-term, open-pile storage.

GLOSSARY (Cont'd)

elutriator	A device which allows dust, etc., to be washed with gas from solid material.
flue gas	Gases generated from the combustion of fossil fuel in the boiler.
negative emissions	Unintentional emissions, such as blowing dust from a shale pile.
indirect mode	Heat from retorting is supplied by hot retorting gases from an outside furnace, thereby eliminating combustion in the retort.
leaching	The separation or dissolving of soluble minerals or metals out of an ore by contact with water.
pyrolysis	Chemical decomposition of a substance by heat -- in the absence of air.
raw shale	Oil shale that has not been retorted.
recycle water	Water that is collected, treated, and reused at the facility.
reforming	To heat under pressure (with or without catalyst) to produce cracking.
retort	A closed refractory chamber in which kerogen in the shale is thermally decomposed into crude shale oil.
retort gas	Gas that is one of the products resulting from the retorting of oil shale, being high-Btu (TOSCO II) or low-Btu quality depending on the process.
retorted shale	Shale that has had the oil values extracted and still contains carbon.
revegetation	The act or process of vegetating a parcel of stripped land or a landfill area..
rubblize	The process of breaking up the oil shale deposits, usually with the help of explosives, into rough, angular, fragments.
runoff	Excess precipitation or snowmelt not absorbed by the ore storage pile or waste material.

GLOSSARY (Cont'd)

run-of-mine shale	Shale as it comes from the mine prior to sizing or other preparation.
shale oil	Oil that is the dominant liquid product resulting from the retorting of oil shale; it is the liquid multi-component hydrocarbon mixture resulting from the molecular rearrangement of kerogen in the oil shale.
sludge	Solid particles entrained in a liquid.
sour water	Highly contaminated water (i.e., high H_2S content).
spent shale	See retorted shale.
surface retorting	Extracting oil from shale in an aboveground retort.
syncrude	Shale oil which has been upgraded to remove nitrogen, sulfur, and metals, and which has little to no bottoms remaining.
wet scrubber	Particulate control device which uses water to capture particles in air.

ACRONYMS AND ABBREVIATIONS

ANFO	ammonium nitrate fuel oil mixture (explosive)
ANG	American Natural Gas Coal Gasification Company
bbl	barrel
CO	carbon monoxide
CO ₂	carbon dioxide
Cr	chromium
Cu	copper
ECIR	Environmental Characterization Information Report
Fe	iron
HC	hydrocarbons
HDN	hydrodenitrogenation
HDS	hydrodesulfurization
H ₂ S	hydrogen sulfide
kgm	kilogram (weight)
LPG	liquid petroleum gas
NH ₃	ammonia
NO _x	nitrogen oxides
NSPS	New Source Performance Standards
SO ₂	sulfur dioxide

Solvent Refined Coal II (SRC-II) Plant

Environmental Characterization Information Report

August 1982

**U.S. Department of Energy
Assistant Secretary for Environmental
Protection, Safety, and
Emergency Preparedness
Office of Environmental Analysis**

CONTENTS

	<u>Page</u>
I. SUMMARY	A.6-4
II. PROCESS DESCRIPTION AND ENVIRONMENTAL POINTS OF INTEREST	A.6-8
A. Coal Handling	A.6-12
1. Run-Of-Mine Coal To Coal Pretreatment	A.6-12
2. Controlled Runoff From Onsite Coal Storage.	A.6-14
3. Fugitive Dust From Onsite Coal Storage.	A.6-16
4. Coal Dust From Coal Sizing.	A.6-17
5. Coal Dryer Stack Gas.	A.6-18
6. Coal Cleaning Refuse.	A.6-19
7. Flue Gas From Slurry Preheater.	A.6-20
B. SRC-II Liquefaction.	A.6-21
8. Dissolver Air Emissions	A.6-22
C. Product Refining	A.6-24
9. Gas Separation Vapors	A.6-25
10. Gases To Acid Gas Removal	A.6-26
D. Byproduct Recovery	A.6-27
11. Tar Acid Recovery Solvent	A.6-28
12. Tar Acid Recovery Acid.	A.6-30
13. Ammonia Recovery Chemicals.	A.6-31
14. Tail Gas From SCOT Process.	A.6-32
15. Amines For Acid Gas Removal	A.6-34
16. Wastewater From Acid Gas Removal.	A.6-36
E. Plant Support.	A.6-37
17. Oxygen Generation Waste Gases	A.6-38
18. Vacuum Flash Bottoms To Hydrogen Generation	A.6-39
19. Amine For Hydrogen Generation	A.6-40
20. Hydrogen Generation Flue Gas.	A.6-41
21. Hydrogen Generation Wastewater.	A.6-42
22. Slag Handling System.	A.6-43
23. Raw Water Supply.	A.6-44
24. Raw Water Treatment Chemicals	A.6-45
25. Raw Water Treatment Sludge.	A.6-46
26. Steam Generation Makeup Water	A.6-47
27. Steam Generation Flue Gases.	A.6-48
28. Steam Generation Boiler Blowdown.	A.6-49
29. Cooling Tower Chemicals	A.6-50
30. Cooling Tower Makeup Water.	A.6-51
31. Cooling Tower Drift and Evaporation Losses.	A.6-53
32. Cooling Tower Blowdown.	A.6-55
33. Wastewater Treatment Effluent	A.6-56
34. Wastewater Treatment Sludge	A.6-60
35. Flare System.	A.6-62

CONTENTS (continued)

	<u>Page</u>
III. PHYSICAL REQUIREMENTS.	A.6-63
IV. PERSONNEL.	A.6-65
V. OCCUPATIONAL SAFETY AND HEALTH	A.6-66
APPENDIX A. SOLID, LIQUID, AND GASEOUS WASTE STREAMS	A.6-68
APPENDIX B. COST INFORMATION	A.6-72
APPENDIX C. SRC-II PRODUCTS.	A.6-76
GLOSSARY.	A.6-81
ABBREVIATIONS & ACRONYMS.	A.6-83

I. SUMMARY

This Environmental Characterization Information Report (ECIR) for a Solvent Refined Coal II (SRC-II) plant utilizing Illinois No. 6 bituminous coal has been prepared from the latest available environmental and technical information collected from several sources. Although this report is process-specific with respect to the coal handling and liquefaction steps, other portions of the assumed design are treated in a generic manner and will vary as a function of site-specific characteristics or conditions.

The "commercially-sized" plant chosen to typify Solvent Refined Coal II (SRC-II) processing utilizes 30,000 tons/day of coal to deliver nearly 100,000 barrels/day of liquid and liquefied gaseous products. As input to the plant, any grade of coal below anthracite (from lignite to low-volatile bituminous) can be used in the SRC-II process. The outputs of the plant are a series of usable liquid products but full upgrading (final hydrotreating) to refinery-type outputs is not included in this characterization. The process also produces marketable byproducts such as sulfur, anhydrous ammonia and phenols. Hydrogen and oxygen are assumed to be generated within the plant for process use, but electricity is purchased from a utility. This off-site electricity also will account for another emission source. All wastewaters are treated onsite.

The process, plant operating parameters, resources needed, environmental residuals, and products associated with the plant are shown in this section in the summary sheet (Table 1). Annual resource usage and pollutant discharges are shown in English and Metric units assuming an annual plant capacity factor of 92 percent or 336 days per year of operation. In addition to annual quantities, the summary table gives quantities in terms of 10^{12} Btu of energy produced. These figures are provided to allow comparison between different energy processes and to facilitate application of the information in computer models.

Section II describes each step of the plant's process flow with sample data for various quantities associated with these steps. Among the quantities are environmental residuals and amounts of resources used.

The remaining sections include information on physical requirements, personnel, and occupational safety and health. The appendices describe solid/liquid/gaseous waste streams, costs, and SRC-II products. Also included are a glossary, a list of abbreviations.

TABLE 1. SUMMARY SHEET

SOLVENT REFINED COAL II (SRC-II) PLANT

ENERGY SYSTEM DESCRIPTION

Pretreated Coal Is Mixed With a Coal-Derived Solvent and Then Hydrogenated in the Dissolver. The Resulting Slurry Is Then Gas Separated for Separation of Gases, Slurry, and Hydrocarbons. Acid Gases Are Sent to Sulfur Recovery. Purified Gas Is Cryogenically Processed Into LPG, SNG, and Recycle H_2 . Some Slurry Is Recycled to Coal Pretreatment While the Remainder Is Vacuum Flashed and the Light Fraction From the Flash Is Sent to the Fractionator. These Light Fractions Plus the Light Hydrocarbons Are Fractionated Into Naphtha and Fuel Oil.

FACILITY OPERATING PARAMETERS

Size: 30,000 ton/d of coal
 Annual Capacity Factor: 92% (to produce 100×10^3 bbl/d of products on an equivalent petroleum refinery basis)
 Annual Energy Production: 181×10^{12} Btu
 Efficiency: 71.1%
 Lifetime: 20 to 25 yr

PROCESS FLOW

TABLE 1. (Continued)

SOLVENT REFINED COAL II (SRC-II) PLANT

RESOURCES USED				
Code No.	Resource	Quantities Used		
		Reference Energy System Annual Usage*		Per 10 ¹² Btu Energy Produced
		English Units	Metric Units	
<u>Feed Materials</u>				
①	Coal	10.1 × 10 ⁶ tons	9.16 × 10 ⁶ tonnes	55.8 × 10 ³ tons
<u>Energy</u>				
	Electricity (overall)	330 × 10 ⁶ kWh	330 × 10 ⁶ kWh	1.82 × 10 ⁶ kWh
<u>Processing Materials</u>				
⑪	Tar acid recovery solvent	1.02 × 10 ³ tons	925 tonnes	5.64 tons
⑫	Tar acid recovery acid	10.8 × 10 ³ tons	9.79 × 10 ³ tonnes	59.7 tons
⑬	Ammonia recovery chemicals	2.44 tons	2.21 tonnes	13.5 × 10 ⁻³ tons
⑮	Acid gas removal amine	271 tons	246 tonnes	1.5 tons
⑰	Hydrogen generation amine	313 tons	284 tonnes	1.73 tons
⑲	Raw water treatment chemicals	4.88 × 10 ³ tons	4.43 × 10 ³ tonnes	27.0 tons
⑳	Cooling tower chemicals	Not Determined		
<u>Water</u>				
㉓	Raw water	11.1 × 10 ⁶ tons	10.1 × 10 ⁶ tonnes	61.3 × 10 ³ tons
㉔	Steam generation makeup water	1.63 × 10 ⁶ tons	1.48 × 10 ⁶ tonnes	9.01 × 10 ³ tons
㉕	Cooling tower makeup water	9.70 × 10 ⁶ tons	8.80 × 10 ⁶ tonnes	53.6 × 10 ³ tons
<u>Construction Materials**</u>				
	Concrete	20.3 × 10 ⁶ ft ³	575 × 10 ³ m ³	112 × 10 ³ ft ³
	Steel	100 × 10 ³ tons	90.7 × 10 ³ tonnes	552 tons
	Paving	4.35 × 10 ⁶ ft ²	404 × 10 ³ m ²	24.0 × 10 ³ ft ²
	Railroad trackage	75.0 × 10 ³ ft	22.9 × 10 ³ m	414 ft
	Pipe	5.00 × 10 ⁶ ft	1.52 × 10 ⁶ m	27.6 × 10 ³ ft
	Glass	25.5 × 10 ³ ft ²	2.37 × 10 ³ m ²	141 ft ²
	Wood	10.0 × 10 ⁶ bd ft	23.6 × 10 ³ m ³	55.2 × 10 ³ bd ft
	Water	1.00 × 10 ⁹ gal	3.79 × 10 ⁹ litre	5.52 × 10 ⁶ gal
	Land**			
	Total	305-2600 acres	124-1050 ha	1.69-14.4 acres
<u>Personnel</u>				
	Construction (3.5 yr)	3100 workers (average) 5400 workers (peak)		17.1 workers 29.8 workers
<u>Operation and Maintenance</u>				
	General and administrative	170-200 workers		0.94-1.10 workers
	Operators	150-200 workers		0.83-1.10 workers
	Maintenance	110-130 workers		0.61-0.71 workers

*Based on assumed 92% capacity factor.
**One-time acquisition; not an annual requirement.

*Based on assumed 92% capacity factor.

**One-time acquisition; not an annual requirement.

COSTS			
Facility	Reference Energy System	Per 10 ¹² Btu Energy Reduced	Remarks
	(1981 \$)		
<u>Facility</u>			
Construction (3.5 yr)	\$6.26 × 10 ⁹ total	\$34.6 × 10 ⁶ total	
Operation and maintenance	\$486 × 10 ⁶ /yr	\$2.69 × 10 ⁶ /yr	
	\$608 × 10 ⁶ /yr	\$3.36 × 10 ⁶ /yr	
<u>Environmental Controls</u>			
	Not Determined		

TABLE 1 (Continued)

SOLVENT REFINED COAL II (SRC-II) PLANT

ENVIRONMENTAL RESIDUALS

ENVIRONMENTAL RESIDUALS		Quantities Released		
		Reference Energy System Annual Levels*		Per 10 ¹² Btu Energy Produced
Code No.	Residual or Product	English Units	Metric Units	
<u>Air Pollutants</u>				
(3)	Coal storage fugitive dust	Not Determined	2.45 tonnes	14.9 × 10 ⁻³ tons
(4)	Coal sizing dust	2.70 tons		56.4 tons
(5)	Coal dryer stack particulates	10.2 × 10 ³ tons	9.25 × 10 ³ tonnes	25.8 × 10 ³ tons
(7)	Flue gas (total)	4.67 × 10 ⁶ tons	4.24 × 10 ⁶ tonnes	
(8)	Hydrocarbon vapors	Not Determined		
(9)	Hydrocarbon vapors	Not Determined		
(14)	Sulfur dioxide	3.95 × 10 ³ tons	3.58 × 10 ³ tonnes	21.8 tons
	Nitrogen oxides	259 tons	235 tonnes	1.43 tons
	Carbon monoxide	6.95 tons	6.30 tonnes	38.4 × 10 ⁻³ tons
	Total suspended particulates	31.3 tons	28.4 tonnes	0.173 tons
	Nonmethane hydrocarbons	6.95 tons	6.3 tonnes	38.4 × 10 ⁻³ tons
(17)	Waste gases	3.16 × 10 ⁶ tons	2.87 × 10 ⁶ tonnes	17.5 × 10 ³ tons
(20)	Flue gases	354 × 10 ³ tons	321 × 10 ³ tonnes	1.96 × 10 ³ tons
(27)	Sulfur dioxide	960 tons	870 tonnes	5.30 tons
	Nitrogen oxides	4.35 × 10 ³ tons	3.95 × 10 ³ tonnes	24.0 tons
	Carbon monoxide	555 tons	505 tonnes	3.07 tons
	Total suspended particulates	525 tons	475 tonnes	2.90 tons
	Nonmethane hydrocarbons	130 tons	120 tonnes	0.718 tons
(31)	Cooling tower evaporation and drift	7.79 × 10 ⁶ tons	7.07 × 10 ⁶ tonnes	43.0 × 10 ³ tons
(35)	Flare system emissions	Not Determined		
<u>Water Pollutants</u>				
(2)	Runoff from coal storage	Not Determined		
(16)	Wastewater	2.09 × 10 ³ tons	1.90 × 10 ³ tonnes	11.5 tons
(21)	Wastewater	280 × 10 ³ tons	254 × 10 ³ tonnes	1.55 × 10 ³ tons
(28)	Boiler blowdown	Not Determined		
(32)	Cooling tower blowdown	1.96 × 10 ⁶ tons	1.78 × 10 ⁶ tonnes	10.8 × 10 ³ tons
(33)	Wastewater effluent	3.26 × 10 ⁶ tons	2.96 × 10 ⁶ tonnes	18.0 × 10 ³ tons
<u>Solid Wastes</u>				
(6)	Coal cleaning refuse	2.68 × 10 ⁶ tons	2.43 × 10 ⁶ tonnes	14.8 tons
(18)	Vacuum flash bottom	474 × 10 ³ tons	430 × 10 ³ tonnes	2.62 × 10 ³ tons
(22)	Slag	430 × 10 ³ tons	390 × 10 ³ tonnes	2.38 × 10 ³ tons
(25)	Sludge	16.9 × 10 ³ tons	15.3 × 10 ³ tonnes	93.3 tons
(34)	Sludge	71.9 × 10 ³ tons	66.1 × 10 ³ tonnes	397 tons

PRODUCTS

PRODUCTS	Quantities Used		
	Reference Energy System Annual Production*		
	English Units	Metric Units	Per 10 ¹² Btu Energy Produced
Primary			
Fuel oil	20.6 × 10 ⁶ bbl	3.27 × 10 ⁶ m ³	114 × 10 ³ bbl
Distillate and Naphtha	5.04 × 10 ⁶ bbl	80 × 10 ³ m ³	27.8 × 10 ³ bbl
SNG	11.4 × 10 ⁶ SCF	323 × 10 ⁶ m ³	63.0 × 10 ⁶ SCF
LPG	2.50 × 10 ⁶ bbl	397 × 10 ³ m ³	13.8 × 10 ³ bbl

By-Products

Sulfur	2.1 × 10 ³ tons	396 × 10 ³ tonnes	2.41 × 10 ³ tons
Ammonia	2.1 × 10 ³ tons	18.2 × 10 ³ tonnes	111 tons
Tar acids (phenols)	806 × 10 ³ bbl	128 × 10 ³ m ³	4.45 × 10 ³ tons

Recoverables/Recyclables

None

*Based on assumed 92% capacity factor.

OCCUPATIONAL SAFETY AND HEALTH

Not Determined

II. PROCESS DESCRIPTION AND ENVIRONMENTAL POINTS OF INTEREST

The Solvent Refined Coal II (SRC-II) process is a direct liquefaction process in which coal is converted into a range of liquid and gaseous products. This type of conversion is needed because 75% of the primary energy of the United States comes from liquid and gaseous fuels rather than from solid fuels.

To help describe the complete SRC-II process, the overall facility has been divided into five functional areas: coal handling, SRC-II liquefaction product refining, byproduct recovery and plant support. This functional down of the conversion of coal into liquid and gaseous products is shown in Figure 1. The SRC-II products are fuel oil, naphtha, SNG and LPG and the by-products are sulfur, tar acids (phenols) and ammonia.

The facility characterized processes 30,000 tons/day of coal. Coal pretreatment is the largest single source of solid waste, followed by hydrogen generation. The slag production during hydrogen generation is concentrated in a clarifier prior to landfill disposal with coal pretreatment wastes.

Final effluent from wastewater treatment is the largest source of liquid wastes to the environment. The plant siting will greatly influence the level of treatment necessary for those wastes. If the present wastewater treatment processes do not adequately treat the final effluent, then either the design will be modified or a zero discharge design will be considered.

Air emissions generally consist of coal dust, flue gas (i.e., from pre-heaters), cooling tower evaporative losses, SCOT tail gas, flare system vapors and fugitive hydrocarbon vapors from leaks in the facility. Coal dust is the largest source of particulates and SCOT tail gas is the major source of sulfur dioxide (SO_2).

Concern has been expressed over the emissions from an SRC-II plant since the conversion process produces carcinogenic polynuclear aromatics and other substances of concern such as trace metals. The polynuclear aromatics result from the conversion process, with little contribution from auxiliary processes. Care should be taken to minimize the release of contaminants to the environment.

Thirty-five points of environmental interest are identified on the flow diagram and are discussed in this section. Items (1) through (6) concern the

Figure 1. Process Flowchart with Environmental Points of Interest -- Solvent Refined Coal-II (SRC-II) Plant

storage, handling, pretreatment and mixing of the coal prior to hydrogenation. The liquefaction reaction is discussed in items (7) and (8). Items (9) and (10) concern the refining of products from the liquefaction process. The treatment of gases is discussed in items (11) through (16). The remaining items, (17) through (35), address the support operations for the SRC-II processes such as hydrogen and oxygen generation, steam generation, cooling systems, and other treatment processes.

It should be noted that many of the quantities calculated in this section are based on values estimated in Reference 1. However, the values in Reference 1 have been normalized by a factor to reflect differences in plant size and coal moisture.

The emission estimates presented in this report are calculated on the basis of steady state operation of the pollution control equipment of design capacity. The actual release of contaminants will deviate due to actual vs. design operating conditions, process swings, system upsets, and downrating of equipment and catalysts due to aging (e.g., erosion and contamination). Fugitive dust emissions can be anticipated to be high in early stages of the facility shakedown, taper off as a more normalized operation is achieved, and then gradually increase as equipment wears out and is replaced.

Reference

- (1) Hittman Associates, Inc., "Environmental Assessment Report: Solvent Refined Coal (SRC) Systems," EPA-600/7-79-146, prepared for U.S. Environmental Protection Agency, June 1979.

A. COAL HANDLING

Coal would be stored at a distance of 1700 ft (519 m) from the SRC-II plant as a fire precaution and to minimize potential problems of blowing dust affecting the operation of the facility. Approximately one month's supply of coal, 900×10^3 tons (816×10^3 tonnes), would be stockpiled in an area covering approximately 55 acres (22.3 ha).⁽¹⁾

The coal is pulverized to approximately 74 μ m and dried to a moisture content of 1-3%. For coal drying, fuel gas and air are required.^(2,3)

References

- (1) U.S. Department of Energy, "Solvent Refined Coal-II Demonstration Project, Fort Martin, West Virginia, Final Environmental Impact Statement, "DOE/EIS-0069/V1 and V2, January 1981.
- (2) Hittman Associates, Inc., "Environmental Assessment Report: Solvent Refined Coal (SRC) Systems," EPA-600/7-79-146, prepared for U.S. Environmental Protection Agency, June 1979.
- (3) U.S. Environmental Protection Agency, "System for 14 Liquefaction Processes, Volume 1, Environmental Assessment Data Base for Coal Liquefaction Technology, "EPA-600/7-78-184a, 1978.

1 Run-Of-Mine (ROM) Coal To Coal Pretreatment

The amount of run-of-mine (ROM) coal to the coal pretreatment plant is 10.1×10^6 tons/yr.

The ROM coal for this facility is assumed to be Illinois No. 6 bituminous. Coal is sized 2 x 0 in. and washed to about 12% ash level before delivery. From the off-loading site, it will be transported by conveyor to the coal storage area where it will be stacked in layered or chevron type piles with an automatic luffing stacker. Coal is retrieved from the storage area by an automatic reclaimer and transported to the coal pulverizing - drying system on conveyors. (1) Pneumatic ducts convey the pulverized coal (74 μ m) to silos from which it is slurried and fed into the process. (2)

The amount of coal entering the pretreatment plant needed to produce a desired energy output of the resulting product mix can be determined from the coal conversion thermal efficiency of the process. This is defined as the energy content of the output products divided by the coal energy input to the plant (does not include electricity input). This factor along with the electricity input requirement factor are calculated as follows for a 30,000-ton/day plant using dried Illinois No. 6 bituminous coal.

<u>Input Energy Sources</u>		10^{12} Btu/Day
Coal (30,000 tons/day at 12,662 Btu/lb)		760×10^{-3}
Electrical power (41 MW _e)		10×10^{-3}
<u>Output Products</u>		
SNG		44.8×10^{-3}
LPG		29.1×10^{-3}
Naphtha		82.9×10^{-3}
Fuel oil		383×10^{-3}
Total		540×10^{-3}
Coal conversion thermal efficiency = $\frac{\text{output energy}}{\text{coal input energy}} = \frac{540 \times 10^{-3}}{760 \times 10^{-3}} = 0.711$		
Electricity input requirement factor = $\frac{\text{output energy}}{\text{electrical input energy}} = \frac{540 \times 10^{-3}}{10 \times 10^{-3}} = 54.0$		
*Based upon power plant thermal efficiency of 33%.		

Using the characteristics of Illinois No. 6 bituminous coal assumed for the subject SRC-II plant, the amount of ROM coal required for daily plant operation can be calculated as follows:

ROM coal to pretreatment plant =

$$\frac{(\text{energy content of desired product mix})}{(\text{coal conversion thermal efficiency})(\text{coal heat content})(2000 \text{ lb/ton})}$$

$$= \frac{(540 \times 10^9 \text{ Btu/day})}{(0.711)(12,622 \text{ Btu/lb})(2000 \text{ lb/ton})}$$

$$= 30.0 \times 10^3 \text{ tons/day (27.2 tonnes/day)}$$

On an annual basis,

$$\begin{aligned} \text{ROM coal to pretreatment plant} &= (\text{daily ROM coal to pretreatment plant}) \\ &\quad \times (365 \text{ days/yr})(\text{capacity factor}) \\ &= (30.0 \times 10^3 \text{ tons/day})(365 \text{ days/yr})(0.92) \\ &= 10.1 \times 10^6 \text{ tons/yr (9.16} \times 10^6 \text{ tonnes/yr)} \end{aligned}$$

While the amount of ROM coal required by the pretreatment plant is generally proportional to the energy content of the output product mix, this ratio may not hold true for other types of input coal (e.g., lignite or subbituminous) or changes in throughput. Different coal feedstocks may change the proportions of various products in the output mix. Further, changing the processing plant size may affect economics of scale.

References

- (1) U.S. Department of Energy, "Solvent Refined Coal-II Demonstration Project, Fort Martin, West Virginia, Final Environmental Impact Statement," DOE/EIS-0069/V1 and V2, January 1981.
- (2) Hittman, Associates, Inc., "Environmental Assessment Report: Solvent Refined Coal (SRC) Systems," EPA-600/7-79-146; prepared for U.S. Environmental Protection Agency, June 1979.

2 Controlled Runoff From Onsite Coal Storage

The quantity of water runoff from the coal storage area is equal to the combined product of the surface area of the coal storage piles, the precipitation rate, the duration of the storm, and a runoff coefficient.

Rainfall that comes in contact with coal storage piles will cause the leaching of organic and inorganic components of the coal.⁽¹⁾ The resulting runoff is likely to be high in iron, acidity and sulfate content and will have significant levels of many minor and trace elements.⁽²⁾ Leaching can be mitigated via an application of a polymer coating to the pile.⁽³⁾ Coal pile runoff will be collected and sent to the wastewater treatment plant.⁽¹⁾

The quantity and composition of coal pile runoff is variable since they depend on factors such as local meteorological conditions and coal type.⁽¹⁾ The quantity of runoff for a given storm can be calculated as the product of the area of the coal pile, the intensity and duration of the rainfall, and the runoff coefficient. Runoff coefficients of 0.7 for the coal storage pile and 0.2 for the exposed land can be used in this formula.^(4,5)

The concentration of a large number of the typical chemical constituents in coal pile runoff are presented in Table 2. The large range of values is indicative of the numerous variables involved in this process.

Constituents	Number of Samples	Arithmetic Mean	Geometric Mean	Unbiased Standard Deviation	Range
Acidity (total), as CaCO ₃	7	7400.	300.	12000.	8.68-27,810
Alkalinity	8	20.	0.0	28.	0.0-36.41
Biological Oxygen Demand	4	3.3	0.0	4.7	0.0-10.
Chemical Oxygen Demand	6	680	300	510.	9-1,099.
Conductance (µmhos/cm)	2	2250	2240	210	2,100-2,400
pH	13	4.2	3.8	2.0	2.8-7.8
Total dissolved solids	9	10,000	3200.	15,000	247-44,050
Total hardness (as CaCO ₃)	6	800.	520.	660.	130-1850
Total solids	8	4200.	4400.	15000.	1330-45,000
Total suspended solids	9	800.	390.	990	22-3302
Turbidity, JTU	6	220	46.	240.	2.8-505
Aluminum	3	730	570.	500.	190-1200
Ammonia	5	0.69	0.00	0.82	0.00-1.77
Arsenic	2	0.01	0.01	0.00	0.009-0.001
Barium	1	0.1			
Beryllium	1	0.01			

					0.01-0.01
Cadmium	2	0.004	0.002	0.004	0.001-0.006
Calcium	2	300.	290.	80.	240-350
Chloride	5	100.	0	220	0-481
Chromium	8	2.	0.	6	0.0-15.7
Copper	6	1.5	1.1	1.1	0.18-3.4
Iron	11	9000	10.	28000	0.06-93,000
Lead	2	0.016	0.015	0.009	510-830
Magnesium	4	65	4.5	82.	0.023-174
Manganese	2	68.	54.	58	2.7-110.
Mercury	2	0.014	0.002	0.019	0.0002-0.027
Nickel	2	1.0	0.73	1.0	0.32-1.7
Nitrate	5	1.31	0.93	0.94	0.3-2.25
Phosphorus	2	0.72	0.53	0.69	0.23-1.2
Selenium	2	0.02	0.009	0.02	0.003-0.03
Silicon (dissolved)	1	91.			
Sodium	4	670.	180.	680.	4.1-1260.
Sulfate	1	2600.	2600.	-	2600-2600.
Titanium	1	1.	1.	-	1.-1.
Zinc	9	5.1	1.1	7.9	0.006-23

References

- (1) Hittman Associates, Inc. "Environmental Assessment Report: Solvent Refined Coal (SRC) Systems," EPA-600/7-79-146, prepared for U.S. Environmental Protection Agency, Washington, D.C., June 1979.
- (2) U.S. Department of Energy, "Solvent Refined Coal-II Demonstration Project, Fort Martin, West Virginia, Final Environmental Impact Statement," DOE/EIS-0069/V1 & V2, January 1981.
- (3) Hittman Associates, Inc. "SRC Site Specific Pollutant Evaluation, Volume 1, Discussion," EPA-600/7-78-223a, prepared for the U.S. Environmental Protection Agency, 1978.
- (4) Cox, D.B., T.Y.J. Chu, and R.J. Ruane, "Characterization of Coal Pile Drainage," EPA-600/7-79-051, prepared by the Tennessee Valley Authority for the U.S. Environmental Protection Agency, February 1979.
- (5) Clar, J.W., W.W. Viseman, and M.J. Hammer, Water Supply and Pollution Control, Harper and Row, 1977.

3 Fugitive Dust From Onsite Coal Storage

It is not possible to accurately quantify the fugitive dust emissions from the coal storage area. Wind erosion resulting in airborne dust should not be a significant air pollution source for active piles if dust control measures are maintained.

Coal fines are an inevitable result of coal and handling operations. Dust emissions from the storage areas, especially active storage, can be effectively controlled through the use of surface compaction and, if necessary, water sprays. In addition, oil, asphalt, or latex coatings can be applied to long-term storage piles to control dust emissions. It should also be noted that the surface of a properly compacted long-term storage pile will quickly lose fines, which can become airborne through wind erosion or by settling in the pile, and the dust emissions will drop to a relatively low level unless the pile is physically disturbed.⁽¹⁾

The dust emissions from an open coal storage pile are not, in general, quantifiable. They are, however, proportional to the exposed surface of the coal pile and generally will increase with increases in surface wind velocity.⁽¹⁾

Reference

- (1) U.S. Department of Energy, "Indirect Coal Liquefaction Plant (Lurgi Fischer-Tropsch Process), Environmental Characterization Information Report (Draft)," October 1981.

6 Coal Cleaning Refuse

The annual quantity of refuse generated from coal pretreatment is estimated to be 2.68×10^6 tons.

Solid waste discharged from the pretreatment plant consists of shale, plastic material, tramp iron, coal and water. The refuse has a moisture content of approximately 24% and ultimate disposal will probably occur in a strip mine.⁽¹⁾ The refuse generation rate for the proposed facility is estimated to be 7.25×10^3 tonnes/day. The annual quantity of refuse is calculated as follows:

$$\begin{aligned}\text{Annual quantity of refuse} &= (\text{refuse generation/day}) (365 \text{ days/yr}) \\ &\quad \times (\text{capacity factor}) \\ &= (7.25 \times 10^3 \text{ tonnes/day}) (365 \text{ days/yr}) (0.92) \\ &= 2.43 \times 10^6 \text{ tonnes/yr} \\ &= 2.68 \times 10^6 \text{ tons/yr}\end{aligned}$$

Reference

- (1) Hittman Associates, Inc., "Environmental Assessment Report: Solvent Refined Coal (SRC) Systems," EPA-600/7-79-146, prepared for U.S. Environmental Protection Agency, June 1979.

7 Flue Gas From Slurry Preheater

The annual flue gas released to the atmosphere from the preheater is estimated to be 4.67×10^6 tons.

Fuel gas is used to fire the preheater to raise the temperature of the dissolver to approximately 454°C (850°F).⁽¹⁾ Approximately 650 tonnes/day (717 tons/day) of fuel gas and 11,962 tonnes/day (13,188 tons/day) of air are required.⁽¹⁾ The resultant quantity of flue gas is estimated to be 12,612 tonnes/day (13,905 tons/day). Annual flue gas quantities are calculated as follows:

Annual flue gas = (flue gas/day) (365 days/yr) (capacity factor)
= (12,612 tonnes/day) (365 days/yr) (0.92)
= 4.24×10^6 tonnes/yr
= 4.67×10^6 tons/yr

The preheater flue gas, consisting of nitrogen, oxygen, carbon dioxide, and water vapor, is emitted to the atmosphere. Hydrocarbon vapors may be emitted also but are not expected to be environmentally significant if plant fuel such as liquefied petroleum gas (LPG) or substitute natural gas (SNG) is used to fire the preheaters.

Reference

- (1) Hittman Associates, Inc., "Environmental Assessment Report: Solvent Refined Coal (SRC) Systems," EPA-600/7-79-146, prepared for U.S. Environmental Protection Agency, June 1979.

4 Coal Dust From Coal Sizing

The annual release of coal dust from coal sizing using a cyclone and baghouse control equipment is estimated to be 2.70 tons.

Coal dust will be released during the pretreatment process (handling, ing and drying). The dust will have approximately the same composition as coal itself as discussed in Appendix A. ⁽¹⁾

The uncontrolled air emissions from the coal sizing operation can be estimated as follows: ⁽¹⁾

$$\begin{aligned}\text{Uncontrolled coal dust} &= (\text{no. of sizing units}) \\ &\quad \times (\text{throughput of units}) \\ &\quad \times (\text{unit loading}) \\ &= (4 \text{ sizing units}) (1.9 \text{ m}^3/\text{sec}) (11.12 \text{ gm/m}^3) \\ &= 84.5 \text{ gm/sec} (0.186 \text{ lb/sec})\end{aligned}$$

The alternative systems for controlling these emissions are: 1) a cyclone and baghouse and 2) a wet scrubber. Representative removal efficiencies for these systems are 99.9% and 98.5% respectively. For the proposed plant employing a cyclone and baghouse, the annual release of emissions can be calculated as follows:

$$\begin{aligned}\text{Annual coal dust} &= (\text{uncontrolled coal dust}) (31.5 \times 10^6 \text{ sec/yr}) \\ &\quad \times (\text{annual capacity factor}) \\ &\quad \times (1 - \text{removal efficiency}) \\ &= (84.5 \text{ gm/sec}) (31.5 \times 10^6 \text{ sec/yr}) (0.92) (1 - 0.999) \\ &= 2.45 \times 10^6 \text{ gm/yr} \\ &= 2.45 \text{ tonnes/yr} \\ &= 2.70 \text{ tons/yr}\end{aligned}$$

Reference

- (1) Hittman Associates, Inc., "Environmental Assessment Report: Solvent Refined Coal (SRC) Systems," EPA-600/7-79-146, prepared for U.S. Environmental Protection Agency, June 1979.

5 Coal Dryer Stack Gas

The annual release of particulate emissions from the coal dryer stack gas is estimated to be 10.2 tons.

It is estimated that the gas flow through the coal dryer will be $355 \text{ m}^3/\text{sec}$ with a particulate loading of $0.9 \text{ gm}/\text{m}^3$.⁽¹⁾ This is based upon a cyclone collector being installed inside the gas dryer unit. The annual uncontrolled particulates are calculated as follows:

$$\begin{aligned}\text{Uncontrolled particulates} &= (\text{dryer gas flow}) (\text{particulate loading}) \\ &\quad \times (31.5 \times 10^6 \text{ sec/yr}) (\text{capacity factor}) \\ &= (355 \text{ m}^3/\text{sec}) (0.9 \text{ gm}/\text{m}^3) \\ &\quad (31.5 \times 10^6 \text{ sec/yr}) (0.92) \\ &= 9.26 \times 10^9 \text{ gm/yr} \\ &= 9.26 \times 10^3 \text{ tonnes/yr} \\ &= 10.2 \times 10^3 \text{ tons/yr}\end{aligned}$$

The alternative control strategies with their respective removal efficiencies are:

<u>Control Technique</u>	<u>Nominal Removal Efficiency</u>
Cyclone	80.0%
Baghouse	99.9%
Wet Scrubber	98.5%

For the proposed plant employing a baghouse, the annual particulate emissions are calculated as follows:

$$\begin{aligned}\text{Annual particulates} &= (\text{uncontrolled particulates/yr}) \\ &\quad \times (1 - \text{removal efficiency}) \\ &= (10.2 \times 10^3 \text{ tons/yr}) (1 - 0.999) \\ &= 10.2 \text{ tons/yr}\end{aligned}$$

Reference

- (1) Hittman Associates, Inc., "Environmental Assessment Report; Solvent Refined Coal (SRC) Systems," EPA-600/7-79-146, prepared for U.S. Environmental Protection Agency, June 1979.

B. SRC-II LIQUEFACTION

In the liquefaction operation, coal from the pretreatment process is mixed with a recycled slurry stream from the process and the resultant slurry mixture is pumped to a preheater where it is first injected with hydrogen. The hydrogen gas is a mixture of recycled hydrogen and synthesis gas from the hydrogen production module. The preheater increases both the pressure and temperature of the gas/slurry stream. (1)

The heated mixture is then introduced into a dissolver where the coal is depolymerized and hydrogenated. The solvent is hydrocracked to form hydrocarbons of lower molecular weight, ranging from light oil to methane. Much of the sulfur, oxygen and nitrogen in the original coal is hydrogenated to H_2S , H_2O , and NH_3 respectively. The resultant product stream contains gases, liquids, and solids. It is removed from the dissolver reactor and transferred to a series of vessels to separate various products. (1)

Reference

- (1) Hittman Associates, Inc., "Environmental Assessment Report: Solvent Refined Coal (SRC) Systems," EPA-600/7-79-146, prepared for U.S. Environmental Protection Agency, June 1979.

8 Dissolver Air Emissions

Fugitive hydrocarbon vapors may be emitted from the dissolver through leaks in seals and flanges.

The preheated coal/solvent slurry enters the dissolver with an excess of hydrogen.⁽¹⁻⁹⁾ Under these conditions, 90% of the moisture and ash-free coal is dissolved.^(2,5) Since the heat generated by this exothermic hydrogenation reaction quickly raises the temperature of the reactants, hydrogen quench is added to control the reaction temperature, to maintain adequate gas distribution, and to help maintain the hydrogen partial pressure.^(7,9)

Through this reaction, coal is depolymerized and hydrogenated, which causes a decrease in the individual constituent product weight. Light hydrocarbons (light oil to methane) are produced via the hydrocracking of the solvent.^(1,4,8) Hydrogen sulfide (H_2S), ammonia (NH_3), and water (H_2O) are formed via the hydrogenation of molecularly bound sulfur, nitrogen, and oxygen in the original coal.^(1,3,4,8)

The degree to which the dissolution reaction occurs depends on the nature of the coal and on the coal sulfur content.^(6,8) The reaction can also be affected by the dissolver temperature, hydrogen partial pressure, slurry residence time, and by other factors. In general, an increased "severity" of the reaction (i.e., higher dissolver temperature, longer residence time in the dissolver) results in a more complete hydrogenation and thus a greater tendency of the overall process to lighter products.⁽⁵⁾ This subject is discussed further in Appendix C.

Fugitive hydrocarbon vapors may be emitted from the dissolver through leaks in pump joints, seals, and flanges.⁽¹⁾ However, these have not been quantified.

References

- (1) Hittman Associates, Inc., "Environmental Assessment Report: Solvent Refined Coal (SRC) Systems," EPA-600/7-79-146, prepared for U.S. Environmental Protection Agency, June 1979.
- (2) Gulf Mineral Resources Company, "The SRC-II Process," presented at the Third Annual International Conference on Coal Gasification and Liquefaction, University of Pittsburgh, August 3-5, 1976.
- (3) The Pittsburgh and Midway Mining Company, "Conceptual Commercial Plant: Plant Description," (Vol. 2 of 5), SRC-II Demonstration Project, Phase Zero, Task Number 3, Deliverable Number 8, prepared for U.S. Department of Energy, July 31, 1979.
- (4) Noyes Data Corporation, Coal Conversion Technology, SRC - PAMCO, Chemical Technology Review No. 66, Park Ridge, N.J., 1976.
- (5) The Pittsburgh and Midway Coal Mining Company, "Operation of the Ft. Lewis, Washington Solvent Refined Coal (SRC) Pilot Plant in the SRC I and SRC II Modes," presented at the Thirteenth Intersociety Energy Conversion and Engineering Conference, San Diego, California, August 20-25, 1978.
- (6) U.S. Environmental Protection Agency, "Systems for 14 Liquefaction Processes, Vol. 1, Environmental Assessment Data Base for Coal Liquefaction Technology," EPA-600-7-78-184a, 1978.
- (7) Chemical Engineering Progress, "Coal Processing Technology, Volume VI," American Institute of Chemical Engineers, New York, N.Y., 1980.
- (8) The Southwest Research Institute, "Identification of Probable Automotive Fuels Composition: 1985-2000," HCP/W3684-01/1, prepared for U.S. Department of Energy, 1978.
- (9) SRC International, Inc., "The SRC-II Demonstration Project," Chemical Engineering, Vol. 77, No. 5, pp. 86-91, 1981.

C. PRODUCT REFINING

The effluent from the dissolver is separated into gas, light hydrocarbon liquids, and slurry stream using conventional flashing techniques. A portion of the liquid hydrocarbon and residue slurry is recycled to blend with the feed coal in the coal slurry preparation plant noted earlier. The balance of the residue slurry is vacuum flashed to recover additional fuel oil product. Gases from the gas separation stage are treated in an absorption system to remove acid gases. The resultant gas stream is then treated cryogenically to produce product gases. The fractionation section separates the coal liquids into naphtha, distillate oil and fuel oil products. (1)

Reference

- (1) The Pittsburg & Midway Coal Mining Co., "Conceptual Commercial Plant: Plant Description," SRC-II Demonstration Project, Phase Zero, Task Number 8, Vol. 2 of 5, prepared for U.S. Department of Energy, July 31, 1979.

9 Gas Separation Vapors

Fugitive hydrocarbon vapors may escape from the gas separation process, but they have not been quantified.

Dissolver effluent containing a mixture of vapors, liquids and solids goes to the gasification process.⁽¹⁻⁴⁾ The effluent first goes to a hot, high-pressure flash drum where vapors are separated from the slurry. This mixture is then cooled and the remaining vapors are separated from the liquids and solids in a series of pressure reductions.⁽¹⁻⁴⁾ The vapors containing unreacted hydrogen, methane and other light hydrocarbons, plus phenols, cresols, CO₂, water, and H₂S are also condensed during this process.^(1,3,4) Non-condensed vapors are directed to the acid gas removal process.⁽¹⁻⁴⁾ Liquid hydrocarbons go the fractionation process and "sour" water goes to the tar acid removal process.

The slurry remaining from the gas separation process consists mainly of original solvent, dissolved coal and undissolved coal solids.⁽¹⁾ This mixture is split into two streams, one of which is recycled to the slurry mix tank while the other stream goes to the fractionation process.^(1,2,4)

Fugitive hydrocarbon vapors may escape from the gas separation process through leaks in seals and flanges or from material spills.⁽¹⁾ However, these have not been quantified.

References

- (1) Hittman Associates, Inc., "Environmental Assessment Report: Solvent Refined Coal (SRC) Systems," EPA-600/7-79-146, prepared for U.S. Environmental Protection Agency, June 1979.
- (2) Gulf Mineral Resources Company, "The SRC-II Process," presented at the Third Annual International Conference on Coal Gasification and Liquefaction, University of Pittsburgh, August 3-5, 1976.
- (3) Ralph M. Parsons Company, "Coal Liquefaction Process Research Process Survey," R&D Interim Report No. 2, ORNL/Sub-7186/13, prepared for U.S. Department of Energy, 1977.
- (4) U.S. Environmental Protection Agency, "Systems for 14 Liquefaction Processes, Vol. 1, Environmental Assessment Data Base for Coal Liquefaction Technology," EPA-600/7-78-184a, 1978.

10 Gases To Acid Gas Removal

The total quantity of gases delivered to the acid gas removal process is approximately 1.67×10^6 tons/yr.

Acid gas from the gas separation process is sent to the acid gas removal process for removal of hydrogen sulfide (H_2S) and carbon dioxide (CO_2). These gases are formed during the hydrogenation of substances in the feed coal (i.e., sulfur) and include hydrogen, methane and other hydrocarbons, phenols, cresols, and water in addition to small amounts of carbon disulfide and carbonyl sulfide.⁽¹⁻⁴⁾ Approximately 4511 tonnes/day (4974 tons/day) are sent to the acid gas removal process. Annual quantities are calculated as follows:

$$\begin{aligned}\text{Annual gases delivered} &= (\text{total gas/day}) (365 \text{ days/yr}) (\text{capacity factor}) \\ &= (4511 \text{ tonnes/day}) (365 \text{ days/yr}) (0.92) \\ &= 1.52 \times 10^6 \text{ tonnes/yr} \\ &= 1.67 \times 10^6 \text{ tons/yr}\end{aligned}$$

References

- (1) Hittman Associates, Inc., "Environmental Assessment Report: Solvent Refined Coal Systems," EPA-600/7-79-146, prepared for U.S. Environmental Protection Agency, June 1979.
- (2) Gulf Mineral Resources Company, "The SRC-II Process," presented at the Third Annual International Conference on Coal Gasification and Liquefaction, University of Pittsburgh, August 3-5, 1976.
- (3) The Pittsburgh and Midway Coal Mining Company, "Conceptual Commercial Plant: Plant Description," SRC-II Demonstration Project, Phase Zero, Task No. 3, Deliverable No. 8, Vol. 2, prepared for U.S. Department of Energy, July 31, 1979.
- (4) U.S. Environmental Protection Agency, "Systems for 14 Liquefaction Processes, Vol. 1, Environmental Assessment Data Base for Coal Liquefaction Technology," EPA-600/7-78-184a.

D. BYPRODUCT RECOVERY

Secondary recovery plants are provided to control emissions by recovering tar acids, ammonia, and sulfur. The tar acid recovery process removes phenols from sour water delivered from the cryogenic and gas separation processes. Solvent extraction processes employing counter-current solvent stream contact are proven techniques for the removal of phenols.

Several sour water streams contain ammonia which can be recovered as a byproduct. After lime is added to raise the pH of these streams, steam or air can be used to strip the ammonia from the water. In addition to the byproduct ammonia, wastewater is generated and is delivered to the wastewater treatment plant.

The acid gas stream from the acid gas removal process contains significant quantities of sulfide. It is feasible to convert this hydrogen sulfide to elemental sulfur using the Claus sulfur recovery process. Tail gas from this process is then delivered to the SCOT process where an amine solvent selectively absorbs most of the remaining H_2S . Heating the amine solvent releases the H_2S which is returned to the Claus plant. This process increases the overall sulfur recovery efficiency to greater than 99%.

11 Tar Acid Recovery Solvent

The annual solvent requirement is estimated to be 1.02×10^3 tons/yr.

Sour water is supplied to the tar acid recovery process principally from cryogenic separation, gas separation, and acid gas removal.⁽¹⁻⁵⁾ The purpose of the tar acid recovery process is to remove phenols, cresols, xylenols and other phenols from the water fed to the process.⁽⁴⁾ Solvent extraction processes such as the Phenosolvan process are commercial, proven techniques for the removal of tar acids.⁽⁴⁾ Basically, these processes introduce sour water into an extraction column where the water is contacted by a counter-flowing stream of solvent^(1,3) such as diisopropyl ether and proprietary additives.⁽⁶⁾ In the case of Phenosolvan tar acids are recovered from the solvent via distillation and sent to product storage. Solvent is recovered and recycled to the extraction column.^(1,3,6) Sour water from which tar acids have been removed are sent to the ammonia recovery process.^(5,6)

The daily solvent makeup requirement for solvent dissolved in the wastewater has been estimated to be 2.75 tonnes/day (3.03 tons/day).⁽¹⁾ The annual solvent requirement is calculated as:

Annual solvent requirement = (daily solvent requirement) (365 days/yr)
x (capacity factor)
= (2.75 tonnes/day) (365 days/yr) (0.92)
= 923 tonnes/yr
= 1.02×10^3 tons/yr

References

- (1) Hittman Associates, "Environmental Assessment Report: Solvent Refined Coal (SRC) Systems," EPA-600/7-79-146, prepared for U.S. Environmental Protection Agency, June 1979.
- (2) The Pittsburg and Midway Coal Mining Company, "Conceptual Commercial Plant: Plant Description," SRC-II Demonstration Project, Phase Zero, Task No. 3, Deliverable No. 8, Vol. 2, prepared for U.S. Department of Energy, July 31, 1979.
- (3) U.S. Department of Energy and the Federal Minister for Research and Technology of the Federal Republic of Germany, "International Agreements for Cooperation in Coal Liquefaction Using the SRC-II Process," 1980.
- (4) U.S. Department of Energy, "Final Environmental Impact Statement, Solvent Refined Coal-II Demonstration Project, Fort Martin, West Virginia," DOE/EIS-0069, Volumes 1 & 2, January 1981.
- (5) Universal Oil Products, "SRC-II Demonstration Plant, Simplified Process Flow Diagram," 1981.
- (6) Oak Ridge National Laboratory, "Liquefaction Technology Assessment - Phase 1," ORNL-5664, U.S. Department of Energy, 1981.

12 Tar Acid Recovery Acid

The annual acid requirement for the tar acid recovery process is estimated to be 10.8×10^3 tons.

Acid is fed to the tar acid recovery process discussed in (11) to control the pH of the incoming wastewater. The acid requirement, primarily hydrochloric acid, has been estimated to be 29.1 tonnes/day (32.1 tons/day).⁽¹⁾ The annual acid requirement is calculated as follows:

$$\begin{aligned}\text{Annual acid requirement} &= (\text{daily acid requirement}) (365 \text{ days/yr}) \\ &\quad \times (\text{capacity factor}) \\ &= (29.1 \text{ tonnes/day}) (365 \text{ days/yr}) (0.92) \\ &= 9.79 \times 10^3 \text{ tonnes/yr} \\ &= 10.8 \times 10^3 \text{ tons/yr}\end{aligned}$$

Reference

- (1) Hittman Associates, Inc., "Environmental Assessment Report: Solvent Refined Coal (SRC) Systems," EPA-600/7-79-146, prepared for U.S. Environmental Protection Agency, June 1979.

13 Ammonia Recovery Chemicals

The annual calcium oxide (CaO) requirement is estimated to be 2.44×10^3 tons/yr.

Sour water from the tar acid recovery and slag treatment processes is sent to ammonia recovery.⁽¹⁾ Steam or air stripping are common methods of removing ammonia from wastewater due to the simplicity of their operation.⁽²⁾ The water is first made alkaline by addition of lime (calcium oxide)^(2,3,4) and then passes through a clarifier for removal of any excess lime.⁽³⁾ It then enters a stripping column where it is contacted with air or steam which strips the ammonia from the water.^(2,3,4,5) An ammonia/air mixture is produced and is sent to a fractionator. Water removed from the bottom of the fractionator is sent to wastewater treatment and the anhydrous ammonia product is removed from the top of the fractionator and is sent to product storage. The calcium oxide requirement is estimated to be 6.58 tonnes/day (7.25 tons/day).⁽³⁾ The annual requirement is calculated as follows:

$$\begin{aligned}\text{Calcium oxide} &= (\text{daily CaO requirement}) (365 \text{ days/yr}) \\ &\quad \times (\text{capacity factor}) \\ &= (6.58 \text{ tonnes/day}) (365 \text{ days/yr}) (0.92) \\ &= 2.21 \times 10^3 \text{ tonnes/yr} \\ &= 2.44 \times 10^3 \text{ tons/yr}\end{aligned}$$

References

- (1) Universal Oil Products, "SRC-II Demonstration Plant, Simplified Process Flow Diagram," 1981.
- (2) Clark, J.W., W. Viessman, Jr., and M.J. Hammer, Water Supply and Pollution Control, Harper & Row Publishers, Hagerstown, Md., 1977.
- (3) Hittman Associates, Inc., "Environmental Assessment Report: Solvent Refined Coal (SRC) Systems," EPA-600/7-79-146, prepared for U.S. Environmental Protection Agency, June 1979.
- (4) U.S. Environmental Protection Agency, "Process Design Manual for Nitrogen Control," October 1975.
- (5) U.S. Department of Energy, "Final Environmental Impact Statement, Solvent Refined Coal-II Demonstration Project, Fort Martin, West Virginia," DOE/EIS-0069, Volumes 1 and 2, January 1981.

14 Tail Gas From SCOT Process

The maximum annual emissions from the SCOT process are estimated to be:

SO_2	3.95×10^3 tons/yr
NO_x	259 tons/yr
CO	6.95 tons/yr
TSP	31.3 tons/yr
NMHC	6.95 tons/yr

Tail gas from the Claus sulfur recovery process is combined with hydrogen prior to hydrogenation. The hydrogenation reaction converts sulfur and sulfur compounds to H_2S ^(1,2,3) via the following reactions:

The resulting gases are cooled in several steps and the vapors are contacted with an amine solvent (i.e., alkanolamine⁽⁴⁾) that selectively absorbs H_2S in the presence of CO_2 . Nearly all of the H_2S is absorbed along with some of the CO_2 . The H_2S and CO_2 are released as the amine solvent is heated and are then returned to the Claus recovery process.^(1,2,3)

Vapors that are not absorbed by the amine solvent are incinerated, converting residual H_2S and sulfur compounds into sulfur dioxide (SO_2).^(2,3) SO_2 is neither as malodorous nor as toxic as H_2S .⁽²⁾ The flue gas from the SCOT tail-gas incinerator will comprise most of the SO_2 emissions from the SRC-II plant.⁽²⁾ This process increases the sulfur recovery efficiency to 99.8%.⁽³⁾

Estimated maximum emissions from the tail-gas incinerator of a demonstration plant are given in Table 3. It is not likely that the emissions from a commercial plant would be as much as a factor of 5 greater (commercial plant feedstock input $\div$ demonstration plant input) than the demonstration plant emissions although this is the assumption behind the quantities for the commercial plant. Actual values would fall between the values given for a demonstration and commercial plant.

Table 3. Estimated Maximum SCOT Tail-Gas Emissions for an SRC-II Demonstration and Commercial Plant

Components	Quantities			
	Demonstration Plant ⁽²⁾		Commercial Plant	
	tonnes/yr	tons/yr	tonnes/yr	tons/yr
Sulfur dioxide (SO ₂)	717	790	3585	3950
Nitrogen oxides (NO _x)	46.9	51.7	234.5	259
Carbon monoxide (CO)	1.26	1.39	6.3	6.95
Total suspended particulates (TSP)	5.67	6.25	28.4	31.3
Non-methane hydrocarbon (NMHC)	1.26	1.39	6.3	6.95

References

- (1) U.S. Department of Energy and the Federal Minister for Research and Technology of the Federal Republic of Germany, "International Agreements for Cooperation in Coal Liquefaction Using the SRC-II Process," 1980.
- (2) U.S. Department of Energy, "Final Environmental Impact Statement, Solvent Refined Coal-II Demonstration Project, Fort Martin, West Virginia," DOE/EIS-0069, January 1981.
- (3) "Gas Process Handbook," Hydrocarbon Processing, Gulf Publishing Company, Houston, Texas, April 1979.
- (4) Hittman Associates, Inc. "Environmental Assessment Report: Solvent Refined Coal (SRC) Systems," EPA-600/7-79-146, prepared for U.S. Environmental Protection Agency, June 1979.

15 Amines For Acid Gas Removal

The annual amine requirement is estimated to be 278 tons.

Acid gas from the gas separation and fractionation processes is sent to the acid gas removal process for removal of hydrogen sulfide (H_2S) and carbon dioxide (CO_2). These gases are formed during the hydrogenation of substance in the feed coal (i.e., sulfur) and include hydrogen, methane and other hydrocarbons, phenols, cresols, and water in addition to small amounts of carbon disulfide and carbonyl sulfide.⁽¹⁻⁷⁾

A variety of acid gas removal processes are available for use in an SRC-II plant.^(1,8) The basic design of an acid removal process includes an amine absorber and an amine regenerator. In the amine absorber, an amine such as MEA (monoethanolamine)⁽¹⁾ or DEA (diethanolamine)^(3,6) forms complexes with CO_2 , H_2S , carbon disulfide and carbonyl sulfide.⁽¹⁾ Upon regeneration of the amine, H_2S and CO_2 off-gases are directed to the sulfur recovery process and the purified gas goes to the cryogenic separation process.^(1,2) Removal efficiencies of the MEA absorption process are approximately 99.6% for H_2S and 88% for CO_2 .⁽¹⁾

The makeup amine requirement has been estimated to be 0.8 tonnes/day by one source for a 32,800 ton/day plant.⁽¹⁾ Adjusting this estimate for the proposed 30,000 ton/day plant would cause the projected makeup amine requirement to be 733×10^{-3} tonnes/day (807×10^{-3} tons/day) and the anticipated annual requirement is calculated as follows:

Annual amine requirement = (daily amine requirement) (365 days/yr)
x (capacity factor)
= (733×10^{-3} tonnes/day) (365 days/yr) (0.92)
= 246 tonnes/yr
= 271 tons/yr

References

- (1) Hittman Associates, Inc., "Environmental Assessment Report: Solvent Refined Coal (SRC) Systems," EPA-600/7-79-146, prepared for U.S. Environmental Protection Agency, June 1979.
- (2) Gulf Mineral Resources Company, "The SRC-II Process," presented at the Third Annual International Conference on Coal Gasification and Liquefaction, University of Pittsburgh, August 3-5, 1976.
- (3) The Pittsburg and Midway Coal Mining Company, "Conceptual Commercial Plant: Plant Description," SRC-II Demonstration Project, Phase Zero, Task No. 3, Deliverable No. 8, Vol. 2, prepared for U.S. Department of Energy, 1979.
- (4) U.S. Environmental Protection Agency, "Systems for 14 Liquefaction Processes, Vol. 1, Environmental Assessment Data Base for Coal Liquefaction Technology," EPA-600/7/78-184a, 1978.
- (5) Battelle Columbus Laboratories, "Liquefaction and Chemical Refining of Coal," Columbus, Ohio, 1974.
- (6) Chemical Engineering Progress, "Coal Processing Technology, Volume VI," American Institute of Chemical Engineers, New York, N.Y., 1980.
- (7) SRC International, Inc., "The SRC-II Demonstration Project," Chemical Engineering, Vol. 77, No. 5, pp. 86-91, 1981.
- (8) U.S. Department of Energy and the Federal Minister for Research and Technology of the Federal Republic of Germany, "International Agreements for Cooperation in Coal Liquefaction Using the SRC-II Process," 1980.

16 Wastewater From Acid Gas Removal

The annual wastewater from acid gas removal is estimated to be 2.09×10^3 tons/yr.

The compounds formed by carbon disulfide and carbonyl sulfide cannot be regenerated and are purged from the regenerator. Nonvolatile salts formed the reaction of caustic and amine complexes are also removed as blowdown wastewater.

The estimated quantity of wastewater, including blowdown and purges, is 5.64 tonnes/day (6.22 tons/day).⁽¹⁾ The annual quantity of wastewater is calculated as follows:

$$\begin{aligned}\text{Annual wastewater} &= (\text{daily wastewater}) (365 \text{ days/yr}) \times (\text{capacity factor}) \\ &= (5.64 \text{ tonnes/day}) (365 \text{ days/yr}) (0.92) \\ &= 1.89 \times 10^3 \text{ tonnes/yr} \\ &= 2.09 \times 10^3 \text{ tons/yr}\end{aligned}$$

Reference

- (1) Hittman Associates, Inc., "Environmental Assessment Report: Solvent Refined Coal (SRC) Systems," EPA-600/7-79-146, prepared for U.S. Environmental Protection Agency, June 1979.

E. PLANT SUPPORT

Conventional plant support facilities include:

- Oxygen generation
- Hydrogen generation
- Raw water treatment
- Steam generation
- Cooling tower system
- Wastewater treatment

The conceptual plant envisions that air, water and solid waste residuals from these processes will be controlled using conventional techniques to meet all applicable environmental standards prior to final discharge.

17 Oxygen Generation Waste Gases

Annual waste gases discharged from the oxygen generation process are estimated to be 3.16×10^6 tons.

A cryogenic air separation system with a series of compression stages is used to produce oxygen for the hydrogen generation process. The oxygen is about 99.5% pure and is produced at an estimated rate of 2.40×10^3 tonnes/day (2.65×10^3 tons/day).⁽¹⁾ The waste gases remaining after oxygen is separated from input air consist primarily of nitrogen (95%). The daily discharge of waste gases is estimated to be 8.54×10^3 tonnes (9.42×10^3 tons).⁽¹⁾ The annual discharge is calculated as follows:

$\begin{aligned}\text{Annual waste gases} &= (\text{daily waste gases}) (365 \text{ days/yr}) (\text{capacity factor}) \\ &= (8.54 \times 10^3 \text{ tonnes/day}) (365 \text{ days/yr}) (0.92) \\ &= 2.87 \times 10^6 \text{ tonnes/yr} \\ &= 3.16 \times 10^6 \text{ tons/yr}\end{aligned}$

The waste gas stream also contains small amounts of oxygen, argon, water vapor, CO_2 , hydrogen, neon, krypton, and xenon. An unknown portion of this waste gas stream will probably be utilized as an inert gas blanket in bulk storage tanks containing volatile or explosive liquids.

Reference

- (1) Hittman Associates, Inc., "Environmental Assessment Report: Solvent Refined Coal (SRC) Systems," EPA-600/7-79-146, prepared for U.S. Environmental Protection Agency, June 1979.

18 Vacuum Flash Bottoms To Hydrogen Generation

The annual quantity of vacuum flash bottoms delivered to the hydrogen generation process is estimated to be 474×10^3 tons.

Coal and the bottoms from the vacuum flash process are used in the production of hydrogen for the SRC-II process. An oxygen-blown high-pressure gasifier operating at 3300-3500°F (1815-1930°C) converts the vacuum bottoms and coal into a mixture of gaseous hydrogen, carbon monoxide, carbon dioxide, hydrogen sulfide, water and other trace gases. This synthesis gas goes through a shift converter in which the steam and carbon monoxide are converted to hydrogen and carbon dioxide. Upon removal of carbon dioxide and hydrogen sulfide, the hydrogen-rich synthesis gas is available for use in the dissolver.⁽¹⁾

The quantity of vacuum flash bottoms and coal delivered to the hydrogen generation process is estimated to be 2.59×10^3 tonnes/day (2.85 tons/day).⁽¹⁾ The vacuum flash bottoms account for 1.28×10^3 tonnes/day (1.41×10^3 tons/day) of this quantity. The annual quantity of vacuum flash bottoms is calculated as follows:

$$\begin{aligned}\text{Annual vacuum flash bottoms} &= (\text{daily vacuum flash bottoms}) \\ &\quad \times (365 \text{ days/yr}) (\text{capacity factor}) \\ &= (1.28 \times 10^3 \text{ tonnes/day}) (365 \text{ days/yr}) (0.92) \\ &= 430 \times 10^3 \text{ tonnes/yr} \\ &= 474 \times 10^3 \text{ tons/yr}\end{aligned}$$

Reference

- (1) Hittman Associates, Inc., "Environmental Assessment Report: Solvent Refined Coal (SRC) Systems," EPA-600/7-79-146, prepared for U.S. Environmental Protection Agency, June 1979.

19 Amine For Hydrogen Generation

The annual amine consumption for the hydrogen generation process is estimated to be 313 tons.

An amine scrubbing unit is used to remove hydrogen sulfide and carbon dioxide from the hydrogen product gas stream. The quantity of amine used in the hydrogen generation process is estimated to be 0.846 tonnes/day (0.933 tons/day).⁽¹⁾ The annual consumption is calculated as follows:

$$\begin{aligned}\text{Annual amine consumption} &= (\text{daily amine consumption}) (365 \text{ days/yr}) \\ &\quad \times (\text{capacity factor}) \\ &= (846 \times 10^{-3} \text{ tonnes/day}) (365 \text{ days/yr}) (0.92) \\ &= 284 \text{ tonnes/yr} \\ &= 313 \text{ tons/yr}\end{aligned}$$

Reference

- (1) Hittman Associates, Inc., "Environmental Assessment Report: Solvent Refined Coal (SRC) Systems," EPA-600/7-79-146, prepared for U.S. Environmental Protection Agency, June 1979.

20 Hydrogen Generation Flue Gas

The annual quantity of flue gas discharged from the hydrogen generation unit to the atmosphere is estimated to be 354×10^3 tons.

Input fuel gas and air are combusted to preheat the reaction mixture to the desired gasifier inlet temperature. The quantity of flue gas discharged to the atmosphere has been estimated to be 956 tonnes/day (1.05×10^3 tons/day).⁽¹⁾ The annual quantity of flue gas is calculated as follows:

Annual flue gases = (daily flue gas discharged) (365 days/yr)
x (capacity factor)
= (956 tonnes/day) (365 days/yr) (0.92)
= 321×10^3 tonnes/yr
= 354×10^3 tons/yr

Reference

- (1) Hittman Associates, Inc., "Environmental Assessment Report: Solvent Refined Coal (SRC) Systems," EPA-600/7-79-146, prepared for U.S. Environmental Protection Agency, June 1979.

21 Hydrogen Generation Wastewater

The annual wastewater discharged from the hydrogen generation process is estimated to be 280×10^3 tons.

Wastewater streams are continuously discharged from the hydrogen generation process to the wastewater treatment facilities. These streams may possibly contain ammonia, tars, and oils. The daily quantity of wastewater is estimated to be 755 tonnes/day (832 tons/day).⁽¹⁾ The annual wastewater generation is calculated as follows:

$$\begin{aligned}\text{Annual wastewater generation} &= (\text{daily wastewater generation}) \times (365 \text{ days/yr}) \\ &\quad (0.92) \\ &= (755 \text{ tonnes/day}) (365 \text{ days/yr}) (0.92) \\ &= 254 \times 10^3 \text{ tonnes/yr} \\ &= 280 \times 10^3 \text{ tons/yr}\end{aligned}$$

Reference

- (1) Hittman Associates, Inc., "Environmental Assessment Report: Solvent Refined Coal (SRC) Systems," EPA-600/7-79-146, prepared for U.S. Environmental Protection Agency, June 1979.

22 Slag Handling System

The annual quantity of material leaving the slag handling system is estimated to be 429×10^3 tons.

The gasification of vacuum bottoms and coal during hydrogen production is a major source of solid waste. This slag is concentrated in a clarifier upon entering the slag handling system. Components of the slag most likely will be unreacted coal ash with minor amounts of sulfur and spent amine solution from the hydrogen gas purification. An estimated 1.45×10^3 tonnes/day (1.60×10^3 tons/day) of slag/water mixture (60 wt. % slag) leave the hydrogen generation process.⁽¹⁾ The amount of slag leaving the system depends on the degree of water removal. Assuming that one-half of the water (20% of mixture) is removed, the annual quantity of material leaving the slag handling system is calculated as follows:

$$\begin{aligned}\text{Annual slag generation} &= (\text{daily slag/water mixture generation}) \\ &\quad \times (1 - 0.2) \times (365 \text{ days/yr}) \\ &\quad \times (\text{capacity factor}) \\ &= (1.45 \times 10^3 \text{ tonnes/day}) (0.8) (365 \text{ days/yr}) (0.92) \\ &= 390 \times 10^3 \text{ tonnes/yr} \\ &= 430 \times 10^3 \text{ tons/yr}\end{aligned}$$

Reference

- (1) Hittman Associates, Inc., "Environmental Assessment Report: Solvent Refined Coal (SRC) Systems," EPA-600/7-79-146, prepared for U.S. Environmental Protection Agency, June 1979.

23 Raw Water Supply

The annual raw water supply is estimated to be 2.67×10^9 gal/yr.

A continuous supply of water is needed for cooling tower makeup water, boiler feedwater and other process operations. In addition, it is needed for the waste disposal treatment facilities as well as for potable, fire and domestic water uses. The total raw water supply is estimated to be 30.1×10^3 tonnes/day (33.2×10^3 tons/day)⁽¹⁾ and the annual supply is calculated as follows:

$$\begin{aligned}\text{Annual water supply} &= (\text{daily water supply}) (365 \text{ days/yr}) \times (\text{capacity factor}) \\ &= (30.1 \times 10^3 \text{ tonnes/day}) (365 \text{ days/yr}) (0.92) \\ &= 10.1 \times 10^6 \text{ tonnes/yr} \\ &= 11.1 \times 10^6 \text{ tons/yr} \\ &= 2.67 \times 10^9 \text{ gal/yr}\end{aligned}$$

Reference

- (1) Hittman Associates, Inc., "Environmental Assessment Report: Solvent Refined Coal (SRC) Systems," EPA-600/7-79-146, prepared for U.S. Environmental Protection Agency, June 1979.

24 Raw Water Treatment Chemicals

The annual water treatment chemical requirement is estimated to be 4.88×10^3 tons/yr.

Chemicals are added to the raw water as flocculation and coagulation aids in settling out suspended matter. Softening agents are also added. A combined estimated 13.2 tonnes/day of lime and sodium chloride are used per day. ⁽¹⁾ The annual consumption of these chemicals is calculated as follows:

$$\begin{aligned}\text{Annual chemical consumption} &= (\text{daily chemical consumption}) \times (365 \text{ days/yr}) \times \\ &\quad (\text{capacity factor}) \\ &= (13.2 \text{ tonnes/day}) (365 \text{ days/yr}) (0.92) \\ &= 4.43 \times 10^3 \text{ tonnes/yr} \\ &= 4.88 \times 10^3 \text{ tons/yr}\end{aligned}$$

Reference

- (1) Hittman Associates, Inc., "Environmental Assessment Report: Solvent Refined Coal (SRC) Systems," EPA-600/7-79-146, prepared for U.S. Environmental Protection Agency, June 1979.

25 Raw Water Treatment Sludge

The annual raw water treatment sludge required to be landfilled is estimated to be 16.9×10^3 tons.

The use of chemicals in the raw water treatment facility results in sludge which is composed of water, suspended solids, CaCO_3 , $\text{Mg}(\text{OH})_2$, $\text{Ca}_5(\text{OH})_3$ and detergent. The daily quantity of sludge generated is estimated to be 348 tonnes/day (384 tons/day) with a solids content of 5 percent.⁽¹⁾ Recovery of chemicals from the sludge can also drastically reduce the water content. Assuming this is done, the sludge remaining to be landfilled amounts to 45.6 tonnes/day (50.3 tons/day).⁽¹⁾ The annual quantity generated is calculated as follows:

$$\begin{aligned}\text{Annual sludge} &= (\text{daily sludge}) \times (365 \text{ days/yr}) \times (\text{capacity factor}) \\ &= (45.6 \text{ tonnes/day}) (365 \text{ days/yr}) (0.92) \\ &= 15.3 \times 10^3 \text{ tonnes/yr} \\ &= 16.9 \times 10^3 \text{ tons/yr}\end{aligned}$$

Reference

- (1) Hittman Associates, Inc., "Environmental Assessment Report: Solvent Refined Coal (SRC) Systems," EPA-600/7-79-146, prepared for U.S. Environmental Protection Agency, June 1979.

26 Steam Generation Makeup Water

The annual makeup water requirement for steam generation is estimated to be 1.63×10^6 tons/yr or 391×10^6 gal/yr.

Steam is produced in part by naphtha and/or gas fired boilers.⁽¹⁾ The steam is recycled to the boilers except that steam which is required for direct use in a process.⁽²⁾ Since not all the steam is recycled, makeup water is required. This has been estimated to be 4.40×10^3 tonnes/day (4.85×10^3 tons/day) or 1.16×10^6 gal/day.⁽²⁾ The annual makeup water requirement is calculated as follows:

$$\begin{aligned}\text{Annual makeup water} &= (\text{daily makeup water}) \times (365 \text{ days/yr}) \\ &\quad \times (\text{capacity factor}) \\ &= (4.40 \times 10^3 \text{ tonnes/day}) (365 \text{ days/yr}) (0.92) \\ &= 1.48 \times 10^6 \text{ tonnes/yr} \\ &= 1.63 \times 10^6 \text{ tons/yr} \\ &= 391 \times 10^6 \text{ gal/yr}\end{aligned}$$

Steam can also be produced indirectly in waste heat boilers that recover heat from process streams.

References

- (1) U.S. Department of Energy, "Final Environmental Impact Statement, Solvent Refined Coal-II Demonstration Project, Fort Martin, West Virginia," DOE/EIS-0069, January 1981.
- (2) Hittman Associates, Inc., "Environmental Assessment Report: Solvent Refined Coal (SRC) Systems," EPA-600/7-79-146, prepared for U.S. Environmental Protection Agency, June 1979.

27 Steam Generation Flue Gases

The maximum annual emissions from steam generation are estimated to be:

SO ₂	960 tons/yr
NO _x	4.35 x 10 ³ tons/yr
CO	555 tons/yr
TSP	505 tons/yr
NMHC	130 tons/yr

If naphtha or gas is used, the flue gas emissions produced during steam generation are not expected to be environmentally significant.⁽¹⁾ Estimated emissions for steam generation for an SRC-II demonstration plant are given in Table 4. Actual emissions for a commercial plant would probably be less than those calculated in Table 4 since the calculations assumed that the commercial plant emissions would be five times greater (commercial plant feedstock input ÷ demonstration plant input) than those of the demonstration plant.

Table 4. Estimated Emissions from Steam Generation for the SRC-II Demonstration and Commercial Plant

Component	Quantities			
	Demonstration Plant ⁽¹⁾		Commercial Plant (x5)	
	tonnes/yr	tons/yr	tonnes/yr	tons/yr
Sulfur dioxide (SO ₂)	174	192	870	960
Oxides of nitrogen (NO _x)	789	870	3.95x10 ³	4.35x10 ³
Carbon monoxide (CO)	101	111	505	555
Total suspended particulates (TSP)	95	105	475	525
Non-methane hydrocarbons (NMHC)	24	26	120	130

References

- (1) U.S. Department of Energy, "Final Environmental Impact Statement, Solvent Refined Coal-II Demonstration Project, Fort Martin, West Virginia," DOE/EIS-0060, January 1981.

28 Steam Generation Boiler Blowdown

The annual quantity of blowdown is the product of the prescribed blowdown percentage and the annual quantity of boiler feedwater.

Boiler feedwater, regardless of the type of treatment used to process the makeup water, contains measurable concentrations of impurities. When steam, essentially pure H_2O vapor, is discharged, the solids introduced in the feedwater remain in the boilerwater. An increase in the level of dissolved solids in the boiler water results in impurities being continuously added and pure water being withdrawn. To prevent the concentration of solids from exceeding a predetermined limit, boiler water is withdrawn as blowdown and discharged.⁽¹⁾ This limit is prescribed to minimize potential for scale, corrosion, carryover and other specific problems. The percent blowdown can range from less than one percent of the feedwater when an extremely high quality feedwater is available to greater than 20 percent in a critical system with poor quality feedwater.⁽²⁾ When the percentage of blowdown is determined, the quantity of blowdown is calculated as follows:

$$\begin{aligned}\text{Annual blowdown} &= (\text{blowdown percentage}) (\text{annual boiler feedwater}) \\ &= (\% \text{ blowdown}) (\text{annual boiler makeup water} \\ &\quad + \text{recycled condensate})\end{aligned}$$

The annual boiler makeup water was calculated in (26) ; the recycled condensate is estimated to be 1.12×10^9 gal/yr.⁽³⁾

References

- (1) Kemmer, F.N., ed., The NALCO Water Handbook, Nalco Chemical Company, McGraw-Hill Book Company.
- (2) Betz Handbook of Industrial Water Conditioning, Eighth Edition, Betz Laboratories, Inc., Trevose, Pa., 1980.
- (3) Hittman Associates, Inc., "Environmental Assessment Report: Solvent Refined Coal (SRC) Systems," EPA-600/7-79-146, prepared for U.S. Environmental Protection Agency, June 1979.

29 Cooling Tower Chemicals

Chemicals added to the cooling tower have not been quantified.

Chemicals such as chromates and chlorine are used as corrosion and scale inhibitors, pH controllers (sulfuric acid), biocides, and anti-fouling agents. However, these have not been quantified.

30 Cooling Tower Makeup Water

The annual cooling tower makeup water requirement is estimated to be 9.70×10^6 tons or 2.33×10^9 gal.

The cooling tower system is designed to provide a 1.19×10^6 tons/day $\times 10^3$ (gpm) circulation rate⁽¹⁾ for an 18.5°F drop in temperature across the tower.⁽²⁾ The number of cycles of concentration that the tower feedwater would undergo as a result of evaporation to attain this temperature drop would be a function of its chemical composition and the type of chemical treatment used in the tower. Assuming approximately five cycles of concentration⁽²⁾ of the solids in the makeup water before the tower is blown down and diluted with fresh makeup water, the resulting makeup stream would be 2.44% of the recirculation rate.⁽¹⁾

The breakdown of sources of this makeup water are noted in Table 5.

Table 5. Cooling Tower Makeup Water Sources⁽¹⁾

Source	Quantity
Raw Water	23.9×10^3 tons/day
Hydrogen Generation Facility	254 tons/day
Wastewater Treatment Plant	4.70×10^3 tons/day
Total	28.9×10^3 tons/day

Therefore, on an annual basis:

$$\begin{aligned}
 \text{Annual makeup water} &= (\text{daily makeup water}) \times (365 \text{ days/yr}) \\
 &\quad \times (\text{capacity factor}) \\
 &= (28.9 \times 10^3 \text{ tons/day}) (365 \text{ days/yr}) (0.92) \\
 &= 9.70 \times 10^6 \text{ tons/yr} \quad (8.80 \times 10^6 \text{ tonnes/yr}) \\
 &= 2.33 \times 10^9 \text{ gal/yr}
 \end{aligned}$$

The makeup water requirement replaces three types of losses from the cooling tower: 1) drift or windage loss, 2) evaporation loss, and 3) blowdown

loss. These are calculated in (31) and (32). However, they do not add exactly to the makeup water rate due to roundoff in individual calculations.

References

- (1) Hittman Associates, Inc., "Environmental Assessment Report: Solvent Refined Coal (SRC) Systems," EPA-600/7-79-146, prepared for U.S. Environmental Protection Agency, June 1979.
- (2) Betz Laboratories, Inc., Betz Handbook of Industrial Water Conditioning, 7th ed., Trevese, Pa., 1976.

31 Cooling Tower Evaporation and Drift Losses

The annual cooling tower evaporation and drift losses are estimated to be 7.79×10^6 tons or 1.87×10^9 gal.

These losses are the major consumers of water for the SRC-II process. Drift or windage losses are fine droplets of water that are entrained in the circulating air and tower carry over. While these losses vary with the type of tower, they typically comprise 0.1 to 0.3 percent of the recirculation rate through the tower. For this particular application, an average drift loss of 0.1 percent of recirculation is assumed. The recirculation rate is estimated to be 1.19×10^6 tons/day.⁽¹⁾ Therefore, the annual drift loss is calculated as follows:

$$\begin{aligned}
 \text{Annual drift loss} &= (\text{daily recirculation rate}) (0.001) (365 \text{ days/yr}) \\
 &\quad \times (\text{capacity factor}) \\
 &= (1.19 \times 10^6 \text{ tons/day}) (0.001) (365 \text{ days/yr}) (0.92) \\
 &= 400 \times 10^3 \text{ tons/yr} \\
 &= 96.0 \times 10^6 \text{ gal/yr}
 \end{aligned}$$

The blowdown and evaporation loss rates are very closely related to the cycles of concentration. This relationship is defined in the following formula:

$$\text{Cycles of concentration} = \frac{\text{evaporation rate (E)} + \text{blowdown rate (B)}}{\text{blowdown rate (B)}}$$

For 4.8 cycles of concentration,⁽²⁾ the above equation becomes:

$$4.8 = \frac{(E) + (B)}{(B)}$$

In addition,

Makeup rate = drift loss rate + evaporation rate (E) + blowdown rate (B).

Substituting for the makeup rate noted in (30) and the drift loss rate, this equation becomes:

$$0.0244 = 0.001 + E + B$$

By solving for the two unknowns from the above two equations, the evaporation

rate (E) and the blowdown rate (B) are determined to be 1.85 percent and 0.49 percent of the recirculation rate, respectively. Therefore, the annual evaporation loss is calculated as follows:

$$\begin{aligned}\text{Annual evaporation loss} &= (\text{daily recirculation rate}) (0.0185) \\ &\quad \times (365 \text{ days/yr}) (\text{capacity factor}) \\ &= (1.19 \times 10^6 \text{ tons/day}) (0.0185) \\ &\quad \times (365 \text{ days/yr}) (0.92) \\ &= 7.39 \times 10^6 \text{ tons/yr} \\ &= 1.77 \times 10^9 \text{ gal/yr}\end{aligned}$$

The annual drift and evaporation losses are noted to be:

$$\begin{aligned}\text{Annual drift and evaporation losses} &= (\text{annual drift loss}) \\ &\quad + (\text{annual evaporation loss}) \\ &= (400 \times 10^3 \text{ tons/yr}) + (7.39 \times 10^6 \text{ tons/yr}) \\ &= 7.79 \times 10^6 \text{ tons/yr} \\ &= 1.87 \times 10^9 \text{ gal/yr}\end{aligned}$$

The evaporative losses contain insignificant quantities of solids since they are in a gaseous (evaporated) state. The drift losses, however, are a mist and the droplets may contain solids, corrosion inhibitors and other chemicals that are added to the recirculated cooling water.

References

- (1) Hittman Associates, Inc., "Environmental Assessment Report: Solvent Refined Coal (SRC) Systems," EPA-600/7-79-146, prepared for U.S. Environmental Protection Agency, June 1979.
- (2) Betz Laboratories, Inc., Betz Handbook of Industrial Water Conditioning, 7th Ed., Trevese, Pa., 1976.

32 Cooling Tower Blowdown

The annual cooling tower blowdown loss is estimated to be 1.96×10^6 tons or 471×10^6 gal.

The cooling tower blowdown rate was calculated in (31) to be 0.49 percent the recirculation rate. Since the recirculation rate is estimated to be 1.19×10^6 tons/day, ⁽¹⁾ the annual blowdown quantity is calculated as follows:

$$\begin{aligned}\text{Annual blowdown} &= (\text{daily recirculation rate}) (0.0049) \\ &\quad \times (365 \text{ days/yr}) (\text{capacity factor}) \\ &= (1.19 \times 10^6 \text{ tons/day}) (0.0049) (365 \text{ days/yr}) (0.92) \\ &= 1.96 \times 10^6 \text{ tons/yr} (1.78 \times 10^6 \text{ tonnes/yr}) \\ &= 471 \times 10^6 \text{ gal/yr}\end{aligned}$$

The composition of this stream varies widely depending on the makeup water source, the materials of construction used in the cooling water system, and the condensates which are added to the system. It will generally contain significant amounts of solids with a very low BOD₅ loading and chemicals used as corrosion and scale inhibitors, pH controllers, biocides and anti-fouling agents.

Reference

- (1) Hittman Associates, Inc. "Environmental Assessment Report: Solvent Refined Coal (SRC) Systems," EPA-600/7-79-146, prepared for U.S. Environmental Protection Agency, June 1979.

33 Wastewater Treatment Effluent

The total liquid discharge from the wastewater treatment plant is estimated to be 3.26×10^6 tons/yr or 783×10^6 gal/yr.

A variety of wastewater streams will flow to the wastewater treatment plant. Table 6 lists the major sources of this wastewater and their estimated quantities.

Table 6. Sources and Types of Wastewater			
Source	Description	Estimated Quantity	
		tons/day	tonnes/day
Coal Preparation	Gland Water	not quantifiable	
Coal Receiving and Storage	Coal Pile Runoff	6.7	6.0
Cooling Towers	Blowdown	6,423.	5,831.
Hydrogen Generation	Process Wastewater	832.	755.
Acid Gas Removal	Blowdown and Purges	6.6	5.6
Ammonia Recovery	Process Wastewater	4,013.	3,643.
Phenol Recovery	Process Wastewater	<u>3,214.</u>	<u>2,918.</u>
Total		14,495	13,159

Gland water is leakage from pumps and valves in the piping system of the coal preparation facilities. This leakage cannot be quantified although it may contain substantial concentrations of particulate and organic matter.

When falling rain and snow infiltrate into the coal storage pile, the resulting leachate contains both organic and inorganic constituents of the raw coal. This runoff water is collected for treatment.

Cooling tower blowdown results from the evaporation of water in the cooling tower increasing the concentration of dissolved and suspended solids in the process cooling water. This condition must be controlled by bleeding away some of this stream and diluting the remaining water with low solids content makeup water. This high solids content bleed water is referred to as blowdown.

Process wastewater from the hydrogen generation facility may contain tars, oils, and ammonia.

A purge stream is removed from the amine-based acid gas removal process. This is done to maintain the concentration of amine and remove non-regenerable compounds.

The input to the ammonia recovery process consists of the wastewater streams from hydrotreating, hydrogen generation, and hydrogen/hydrocarbon recovery. The effluent wastewater exiting ammonia recovery contains hydrogen sulfide, phenols, hydrocarbons, and traces of ammonia.

The phenol recovery unit processes condensate from the gas separation operation. The resulting wastewater stream contains hydrocarbons, ammonia, hydrogen sulfide, and traces of phenol.⁽¹⁾

Treatment of the SRC-II wastewater is indicated in Figure 2 (from the Final Environmental Impact Statement prepared for the SRC-II demonstration plant). All of the prescribed wastewater treatment processes are conventional and commercially proven.⁽²⁾

A significant portion of the final effluent from the wastewater treatment plant will be recycled to the cooling tower. It is estimated that this portion will consist of 4.79×10^3 tons/day (4.35×10^3 tonnes/day).⁽¹⁾ Discounting the losses of water to the moisture in sludge, this recycling would reduce the final effluent discharge stream to only 9.71×10^3 tons/day (8.81×10^3 tonnes/day).

$$\begin{aligned}\text{Annual effluent discharge} &= (\text{final daily effluent discharge rate}) \times \\ &\quad (\text{days/yr}) (\text{capacity factor}) \\ &= (9.71 \times 10^3 \text{ tons/day}) (365 \text{ days/yr}) (0.92) \\ &= 3.26 \times 10^6 \text{ tons/yr} \\ &= 2.96 \times 10^6 \text{ tonnes/yr}\end{aligned}$$

The final SRC-II wastewater stream will contain essentially all of the organic and inorganic pollutants generated in the system or added to it.

Although the types and quantities of the materials in the wastewater stream are not known, Table 7 provides estimates of several contaminants and their concentrations for treated wastewater from an SRC-II plant.⁽²⁾

Table 7. Estimated Average Concentration of Contaminants in Treated Wastewater Discharge⁽²⁾

Parameter	Average Concentration (mg/l)
BOD ₅	10
TSS	10
COD	100
Oil and Grease	5
Phenol	0.1
Ammonia	5
Sulfide	0.0
Cyanide (free)	0.15
Iron	1.0
Total Chromium	0.2
TDS	3000
Sulfate	1000
pH	6-9

A zero discharge system is under consideration for the wastewater treatment facilities of an SRC-II commercial plant. However, monitoring of the water effluents will have to be conducted before a decision on such a design could be made.

WASTEWATER STREAMS	TREATMENT PROCESSES								
	1	2	3	4	5	6	7	8	9
PROCESS STREAMS	X	X	X	X	X	X	X	X	
COOLING TOWER BLOWDOWN				X	X				X
BOILER BLOWDOWN						X	X	X	
SANITARY WASTE					X	X	X		
PROCESS AREA RUNOFF	X				X	X	X	X	
COAL PILE RUNOFF				X	X		X	X	
SLAG LEACHATE					X				

1 OIL/WATER SEPARATION

2 TAR ACID RECOVERY

3 AMMONIA RECOVERY (STRIPPING)

4 pH CONTROL

5 PRIMARY SETTLING

6 SECONDARY (i.e., BIOLOGICAL) TREATMENT

7 TERTIARY TREATMENT (ACTIVATED CARBON, DEEP SAND
BED FILTRATION, AND OZONATION AS REQUIRED)

8 DESALINATION (TO PRODUCE BOILER FEED WATER)

9 CHROMIUM REMOVAL

Figure 2. Applicability Matrix for Wastewater Treatment
Process Used in SRC-II Demonstration Plant⁽²⁾

References

- (1) Hittman Associates, Inc., "Environmental Assessment Report: Solvent Refined Coal (SRC) Systems," EPA-600/7-79-146, prepared for U.S. Environmental Protection Agency, June 1979.
- (2) U.S. Department of Energy, "Final Environmental Impact Statement, Solvent Refined Coal-II Demonstration Project, Fort Martin, West Virginia," DOE/EIS-0069, January 1981.

34 Wastewater Treatment Sludge

The total sludge discharge from the wastewater treatment plant is estimated to be 71.9×10^3 ton/yr.

Sludge results from several phases of wastewater treatment including: 1) settlings from primary, secondary, and tertiary treatment, 2) pH control, and 3) chromium reduction. These sludges will consist primarily of metal hydroxides, calcium sulfate, and polymers. Estimates of the approximate quantities of sludge generated in the 6,000 ton/day demonstration plant have been increased by a factor of five to reflect the approximate conditions at the 30,000 ton/day commercial-sized plant. This information is presented in Table 8. ⁽¹⁾

Table 8. Approximate Quantities of Wastewater Sludge from a Commercial Plant⁽¹⁾

<u>Process</u>	<u>Sludge (dry tons/day)</u>
Liming Sludge	160.
Biological Sludge	10.
Cooling Tower Blowdown Treatment Sludge	40.
Sanitary Sludge	0.5
Rainwater-Runoff Treatment Sludge	3.5
Total	214.

The annual quantity of sludge from these major sources of solid wastes is as follows:

$$\begin{aligned}\text{Annual quantity of sludge} &= (214 \text{ tons/day dry}) (365 \text{ days/yr}) \times \\ &\quad (\text{capacity factor}) \\ &= (214 \text{ tons/day}) (365) (0.92) \\ &= 71.9 \times 10^3 \text{ ton/yr dry } (66.1 \times 10^3 \text{ tonnes/yr})\end{aligned}$$

It is planned that all of the above processed sludge will be disposed of in a common secured landfill.

Reference

- (1) U.S. Department of Energy, "Final Environmental Impact Statement, Solvent Refined Coal-II Demonstration Plant, Fort Martin, West Virginia," DOE/EIS-0069, January 1979.

35 Flare System

Sulfur oxide, carbon dioxide, and other emissions from the flare system have not been quantified.

Flare systems may be used to incinerate hydrocarbon vapors that may escape or are vented during start-up and shut-down, emergency, or normal operations from many of the processes of SRC-II.⁽¹⁾ These systems include a controlled combustor, a vent purge combustor, and an elevated flare system. Elevated flare systems are used in conventional chemical and petrochemical processing facilities and may be used in the SRC-II facility to expedite rapid venting of process vapors during emergency situations and to handle vapor streams that do not contain significant hydrocarbons. In a flare system, the vapors are ignited and burned in the atmosphere with no further controls.

Emissions from the flare system will consist mainly of carbon dioxide, sulfur oxide, carbon monoxide, and small amounts of hydrocarbons. However, these emissions have not been quantified.

Reference

- (1) U.S. Department of Energy, "Final Environmental Impact Statement, Solvent Refined Coal-II Demonstration Project, Fort Martin, West Virginia," DOE/EIS-0069, January 1981.

III. PHYSICAL REQUIREMENTS

Land

The land acquired for an SRC-II facility must encompass:

- the plant facility,
- coal storage,
- access roads, and
- product storage.

The acreage required for the plant facility depends largely on the arrangement of the processes and the potential expansion of these processes. Estimates range from 250 acres (101 ha) to 640 acres (259 ha).^(1,2,3) Storage of a month's supply of coal (about 900,000 tons) occupies on the order of 55 acres (22 ha).⁽¹⁾ The size of the product storage area varies with the expected retention time of the products, but can be expected to be approximately 35 acres (14 ha).⁽¹⁾

For annual solid waste disposal, approximately 40 acres were allotted in the design of the Morgantown, West Virginia, plant including expansion to 30,000-ton-per-day capacity.⁽³⁾

Estimates of total on-site land requirements range from 305 to 2600 acres (123-1050 ha).^(1,2,3)

Water

The amount of water required for the operation of an SRC-II facility is a function of the size of the plant and of the mechanics of the process operations.⁽⁴⁾ Of the approximately 5,500 gpm of water withdrawn by a 30,000-ton-per-day plant, a portion is recovered and recycled to the raw water source leaving a net consumption rate of about 4,000 gpm. A high percentage of this water is consumed by the cooling system via evaporation.^(1,4) For start-up and operation, roughly 210,000 gpm are required for circulation between the cooling tower and the processes that require cooling water.

Steam generation accounts for about 20% of the 4,000 gpm consumption. The remaining water goes to other uses including waste disposal treatment, domestic use, potable requirements, and fire prevention systems.⁽⁴⁾

References

- (1) The Pittsburgh and Midway Coal Mining Company, "Conceptual Commercial Plant: Plant Description," SRC-II Demonstration Project, Phase Zero, Task No. 3, Deliverable No. 8, Vol. 2, prepared for U.S. Department of Energy, 1979.
- (2) Hittman Associates, Inc., "SRC Site-Specific Pollutant Evaluation, Volume 1, Discussion," EPA-600/7-78-223a, prepared for U.S. Department of Energy, 1978.
- (3) U.S. Department of Energy, "Final Environmental Impact Statement, Refined Coal-II Demonstration Project, Fort Martin, West Virginia," DOE/EIS-0069, January 1981.
- (4) Hittman Associates, Inc., "Environmental Assessment Report: Solvent Refined Coal (SRC) Systems," EPA-600/7-79-146, prepared for U.S. Environmental Protection Agency, June 1979.

IV. PERSONNEL

The amount of manpower required for plant operation may vary as a function of the complexity of each plant, but reasonable estimates of these requirements can be made. ⁽¹⁾ The total number of operators necessary to control the processes of a 30,000 ton/day SRC-II plant range from 150 to 200 persons. ^(1,2,3) Maintenance of the facility requires roughly 110 to 130 persons (i.e., electricians, carpenters, etc.). ^(1,3) Approximately 170 to 200 persons are required for general and administrative (G&A) positions. ^(1,3)

Construction of an SRC-II facility would require an average of 3,100 persons, with a peak labor force of approximately 5,400 persons. ⁽⁴⁾

Table 7 summarizes the personnel requirements.

Table 7. Personnel Requirements	
<u>Plant Phase</u>	<u>Approximate Manpower</u> ^(1,2,3,4)
CONSTRUCTION	
Average	3100
Peak	5400
OPERATION	
General & Administrative	170-200
Operators	150-200
Maintenance	110-130

References

- (1) The Pittsburg and Midway Coal Mining Company, "Conceptual Commercial Plant: Plant Description," SRC-II Demonstration Project, Phase Zero, Task No. 3, Deliverable No. 8, Vol. 2, U.S. Department of Energy, Washington, D.C., July 31, 1979.
- (2) U.S. Department of Energy, "SRC-II Program," Washington, D.C., 1980.
- (3) U.S. Department of Energy, "Solvent Refined Coal-II Demonstration Project, Final Environmental Impact Statement, Fort Martin, West Virginia," DOE/EIS-0069, Washington, D.C., January 1981.
- (4) The Pittsburg and Midway Coal Mining Company, "Conceptual Commercial Plant, Summary," SRC-II Demonstration Project, Phase Zero, Task No. 3, Deliverable No. 8, Vol. 1, U.S. Department of Energy, Washington, D.C., 1979.

V. OCCUPATIONAL SAFETY AND HEALTH

Liquid and Vapor Exposure

Occupational exposure to coal liquefaction products and wastes by dermal and inhalation routes is one of the main health concerns of the SRC-II process.^(1,2) Chemical composition of both the products and the wastestreams is a function of the type of coal used as a feedstock and process operating conditions such as temperature and pressure. At this time, detailed chemical characterization studies on SRC-II products and wastestreams are very limited. However, some data on samples from a pilot plant facility have been reported.

A recent health assessment summarized health effects testing for three product fractions distinguished by boiling points: light distillate (160-350°F), middle distillate (350-485°F), and heavy distillate (485-850°F).⁽¹⁾ The majority of the executive summary of that assessment is presented below:

"Within the limits of the available data, SRC-II heavy distillate shows much higher mutagenic and teratogenic activities than middle or light distillates or crude petroleum, and much higher carcinogenic activities than SRC-II light distillate or crude petroleum. The carcinogenicity of SRC-II middle distillate remains undefined, although it possesses very little mutagenic activity. All three distillates possess several times higher acute toxicity than crude petroleum, but roughly the same acute toxicity as tannic acid found in tea and coffee. Of all four materials, SRC-II light distillate may possess the highest maternal toxicity. The meaningfulness of some of these studies are limited by methodological problems. However, these tests do indicate that SRC-II products may pose a significant carcinogenic and fetal toxicity risk.

. . . Information about ambient air quality at an SRC-II site is based on monitoring data from the Fort Lewis, Washington pilot plant. The monitoring program is limited, but evaluation of the workplace environment thus far seems to indicate that occupational exposures to airborne organic vapors such as benzene, toluene, and xylene are very low. Phenols also do not seem to present an inhalation hazard, although they may be a significant hazard via the dermal route.

. . . During start-ups, shut-downs and changes in process conditions, some worker categories will be exposed to even higher levels. These levels may exceed safe levels needed to protect worker health. The upper limit of lung cancer risk for coal liquefaction workers will be comparable to the lower limit of risk for coke oven workers (13-63 percent excess risk).

There are many unknowns related to the potential severity of dermal exposure of SRC-II coal liquefaction workers to hazardous materials. Spills, leaks, and handling of contaminated piping and equipment may cause a significant excess skin cancer risk if proper precautions are not taken. . . . Current data suggest that coal liquefaction workers are exposed to a skin cancer risk six times greater than average. The maintenance workers, in particular, are projected to be the highest risk group for dermal carcinogenesis. Coal liquefaction ranks within the same range of cancer risk as asphalt and pitch (4 times the national average), benzene workers (5), coke oven workers (3-10) and roofers (2-5)."

As noted earlier, the above information is based on product and wastestream testing from a pilot plant facility and, therefore, should not be considered representative of a commercial-scale operation. Process adjustments, changes in operating conditions and differences in plant scale can substantially affect the composition of product streams.

Coal Dust Exposure

Coal dust from the pretreatment of the coal represents another occupational hazard of the SRC-II process. Extended exposure to crystalline free silica in coal dust can lead to pneumoconiosis, a disabling and sometimes fatal disease.⁽²⁾ Other constituents of the coal dust such as trace metals and partially oxidized hydrocarbons may cause lung cancer upon long-term exposure.⁽¹⁾

Safety

Accidents resulting in worker injuries or fatalities during SRC-II plant construction and operation have not been determined. In general, some analogy may be made with the general construction industry and accident rates at petroleum refineries and coal-fired power plants. However, there is no historical base for accident rates at commercial SRC-II plants.

References

- (1) Energy and Environmental Analysis, Inc., "Qualitative Health Assessment of SRC-II Coal Liquefaction," Arlington, Va., 1981.
- (2) MITRE Corporation, "Health and Environmental Effects of Coal Gasification and Liquefaction Technologies, A Workshop Summary and Panel Reports," DOE/HEW/EPA-03, 1979.
- (3) The Pittsburgh and Midway Coal Mining Company, "Environmental Control Systems for the SRC-II Demonstration Plant," presented at the Second U.S. Department of Energy Environmental Control Symposium, Reston, Va., March 17-19, 1980.

APPENDIX A. SOLID, LIQUID, AND GASEOUS WASTE STREAMS

Solid Wastes

Disposal of solid wastes is a major environmental concern of the SRC-II process.⁽¹⁾ A commercial facility that processes 30,000 tons of coal per day will produce between 7,000 and 13,000 tons of residue per day with the expected value being closer to the lower end of this range.^(1,2,3,4) Approximately half of the solid wastes consists of ash residue (i.e., reactor slag, bottom and fly ash) with the rest being wastes from air and water pollution control systems.⁽³⁾ Due to the presence of metallic, organic and radioactive contaminants, some solid wastes may be classified as hazardous under current regulations. Metals are of concern since they may leach into groundwater and drinking water supplies and may be subsequently bioaccumulated and passed on to human food sources.⁽²⁾

Many of the organic polynuclear aromatics present in coal conversion wastes are either known or suspected carcinogens and should be disposed of in a controlled manner.^(1,2,3)

Radionuclides have been found in U.S. coal mainly in the form of Uranium²³⁸, Thorium²³² and their isotopes, and Potassium⁴⁰.⁽²⁾ The radioactive elements generally adhere to the fly ash resulting from coal combustion and follow the same pathways as the ash.⁽²⁾

The sources of solid waste from the SRC-II process are shown in the process flow diagram and are described in the text of Section II. Among the most significant (with respect to size) solid waste streams are:

- (a) coal preparation refuse,
- (b) reactor slag/ash,
- (c) residue from solid/liquid separation,
- (d) tar/oil phenol by-products, and
- (e) hydrogen production slag.^(2,3)

A recent report⁽²⁾ stated that several solid waste streams of synfuel facilities will probably be classified as hazardous. The waste streams named were:

- (1) cooling tower and demineralizer blowdown solids,
- (2) waste gas liquor sludge,
- (3) tar/phenol/oil by-products,

- (4) spent catalyst, and
- (5) sulfur recovery blowdown

The legislation that will have the most impact on solid waste disposal is the Solid Waste Disposal Act (SWDA) as amended by the Resource Conservation and Recovery Act (RCRA) of 1976.

Liquid Effluents

The most significant wastewaters from an SRC-II facility are process wastewaters and runoff waters.

Process wastewaters will normally contain cyanides, phenols, ammonia, sulfides, and dissolved solids. ^(3,4) The organic pollutants will largely be formed within the process itself with little contribution from auxiliary processes. ^(3,4) These wastewaters pass through the secondary recovery processes and wastewater treatment prior to release to the environment.

In addition to process wastewaters, there are several sources of contaminated runoff:

- coal storage pile,
- coal handling area,
- process area, and
- product storage area. ^(3,5)

For example, precipitation causes the leaching of organic and inorganic components of coal, ⁽³⁾ and runoff from the coal storage pile is likely to be high in iron, acidity and sulfate content and will have significant levels of many minor and trace elements. ⁽⁵⁾ Leaching can be mitigated via the application of a polymer coating to the coal pile. ^(3,4) Runoff from the coal handling area will contain solid coal particles and coal leachate, and runoff from the process area and the product storage area will be contaminated with process fluids and with SRC-II products, respectively. These two runoff streams will be diked and routed to wastewater treatment. ⁽⁵⁾

The two Federal laws that could have the most bearing on disposal of SRC-II liquid wastes are the Federal Water Pollution Control Act (commonly known as the Clean Water Act) and the Safe Drinking Water Act. ^(1,3) Section 402 of the Clean Water Act, the National Pollutant Discharge Elimination System (NPDES), may impact SRC-II power plants by imposing stricter state and site specific permitting limits. ⁽¹⁾ The NPDES permit is required for the discharge of point source pollutants into navigable waters.

Air Emissions

Air emissions from an SRC-II facility generally contain oxides of sulfur, oxides of nitrogen, carbon monoxide, hydrocarbons and particulates.⁽¹⁾ Particular concern is given to (1) coal dust emissions from coal receiving, storage, and preparation; (2) low-sulfur effluent gas from sulfur recovery; (3) boiler gas from steam generation; and (4) emissions from the flare system.⁽³⁾ Prolonged exposure to coal dust can be harmful, as described in Section V, Occupational Safety and Health. The composition of coal dust is the same as that of raw coal with the trace elements of concern in the dust being aluminum, arsenic, chromium, iron, lithium, and silicon.⁽³⁾

Boiler gas from steam production contains particulates, oxides of sulfur, polynuclear aromatic hydrocarbons that become absorbed by the fly ash during combustion.^(3,6) Oxides of sulfur may also be released from the sulfur recovery system. The oxygen generation process is the primary source of oxides of nitrogen. Carbon monoxide and carbon dioxide are emitted from the flare system.⁽³⁾

Preheater flue gases are not expected to be environmentally significant if SNG or LPG is used. The stack gas produced during coal drying operations will contain coal particulates and possibly volatilized hydrocarbons. The most likely fuel for the coal dryer is fuel gas. The same type of emissions may result from the drying of the mineral residue from solid/liquid separation. Nitrogen-rich gas may escape from the oxygen generation process and carbon dioxide-rich gas will be emitted from the hydrogen production process.⁽³⁾

Hydrocarbon vapors will be emitted through leaks in pump seals, joints, flanges, compressors, and from handling of vent operations. These vapors may also escape from the product/by-product storage areas, but these emissions can be minimized by proper storage techniques.^(3,4,7) More information on air emissions can be found in Section II.

Air emissions from an SRC-II facility will be regulated by the U.S. EPA under the Clean Air Act (CAA) and its amendments. Five sections of the CAA are of particular interest with respect to the SRC-II development: (1) New Source Performance Standards (NSPS); (2) Prevention of Significant Deterioration (PSD); (3) Non-attainment; (4) Visibility; and (5) Hazardous Pollutant Emission Standards.^(1,3,4)

References

- (1) U.S. Department of Energy, "Environmental Analysis of Synthetic Liquid Fuels," DOE/EV-0044, 1979.
- (2) Ohio River Basin Commission, "Assessment of the Potential Risk to Public Health, Safety and the Environment from Synfuel Solid Waste," Cincinnati, Ohio, 1980.
- (3) Hittman Associates, Inc., "Environmental Assessment Report: Solvent Refined Coal (SRC) Systems," EPA-600/7-79-146, prepared for U.S. Environmental Protection Agency, 1979.
- (4) Hittman Associates, Inc., "SRC Site-Specific Pollutant Evaluation, Discussion," Vol. 1, EPA-600/7-78-223a, prepared for U.S. Environmental Protection Agency, 1978.
- (5) U.S. Department of Energy, "Final Environmental Impact Statement, Solvent Refined Coal-II Demonstration Project, Fort Martin, West Virginia, DOE/EIS-0069, January 1981.
- (6) Morris, S.C., et al., "Coal Conversion Technologies: Some Environmental and Health Effects," Science, Vol. 206, November 9, 1979.
- (7) The Pittsburgh and Midway Coal Mining Company, "Conceptual Commercial Plant: Plant Description," SRC-II Demonstration Project, Phase Zero, Task No. 3, Deliverable No. 8, Vol. 2, prepared for U.S. Department of Energy, July 31, 1979.

APPENDIX B. COST INFORMATION

Capital Costs

Cost estimates for the SRC-II process were made in February 1981 for a proposed demonstration plant (6,000 tons/day of coal).^(1,2) These estimates placed capital (design, construction, startup) costs at \$1.993 billion (1981 dollars).⁽²⁾ For a commercial plant (30,000 tons/day of coal), older estimates (1975-1978) of capital costs range from \$1.7 to \$2.2 billion (1981 dollars).^(4,5) These estimates are low considering that the previous \$1.993 billion estimate is based on a pilot plant that is one fifth the size of the commercial plant.

The demonstration plant 1981 cost estimates can be used to update estimates for the commercial plant since the primary process of an SRC-II plant can be constructed as multiple process trains of the demonstration-size modules.⁽³⁾ Therefore, a 30,000 ton/day commercial plant consists of five 6,000 ton/day modules. Costs for auxiliary processes such as coal pretreatment and wastewater treatment will not expand linearly because of the scale-up of individual modules. The costs of waste gas and wastewater treatment facilities were estimated by one source to be approximately five percent of the total plant facility investment.⁽⁶⁾

The modular concept provides an estimate of the commercial plant cost using the February 1981 estimates. Since only the primary processes expand modularly, only their cost will be multiplied by a factor of five. The approximate distribution of the capital cost over various portions of the plant is shown in Table B-1. In most cases, the non-primary costs will double.⁽⁷⁾

TABLE B-1	
Capital Cost Distribution ^(3,4,5)	
Primary processes	38%
Coal pretreatment	7%
Hydrogen production	20%
Secondary recovery and oxygen production	20%
Utility system and general facilities	15%

These assumptions result in the following calculation:

$$\begin{aligned} \$1.993 \times 10^9 \times 38\% \times 5 &= \$3.787 \times 10^9 \quad (\text{primary processes}) \\ \$1.993 \times 10^9 \times 62\% \times 2 &= \$2.471 \times 10^9 \quad (\text{remaining cost}) \\ \$6.258 \times 10^9 &\quad \text{Total} \end{aligned}$$

While a thorough cost analysis would be required to accurately predict capital costs of a commercial plant, this estimate of approximately \$6 million will be closer to the actual cost than the older (1975-78) estimates.

Operating Costs

Estimates of annual operating cost range from \$125 million to \$247 million (1981 dollars) not including coal costs. (2,5,6) Table B-2 lists an approximate distribution of operating costs.

Coal costs are roughly \$43-\$45 per ton including freight charges. (8) Assuming \$44/ton for a 30,000 ton/day plant at 75% capacity, an SRC-II plant will need to spend about \$361 million per year on coal. Adding the annual coal cost to the operating cost estimates results in an annual operating expense of \$486 million to \$608 million (1981 dollars).

TABLE B-2
Operating Cost Distribution (7)

MATERIALS (not including coal cost)		11.0%
LABOR		
Operating labor	10.0%	
Operating supervision	1.6%	
Maintenance labor	10.3%	
Administration and support	4.4%	
Payroll burden	9.2%	
Total	35.5%	35.5%
UTILITIES		49.8%
GENERAL ADMINISTRATION		3.7%
		100.0%

Product Commercialization

The SRC-II plant characterized in this ECIR does not include final fractionation/hydrotreating necessary to convert SRC products to products essentially equivalent to those derived from petroleum. Therefore, the SRC products from the characterized plant have a different composition.

Due to differences in composition, raw SRC-II products are not completely interchangeable with petroleum products⁽⁹⁾; however, SRC-II fuel oil is similar to, and may be marketable as a substitute for No. 4 and No. 6 fuel oils. Their properties are compared in Table B-3.

TABLE B-3
SRC-II Fuel Oil Properties⁽⁹⁾

	SRC Fuel Oil	Typical Petroleum Fuel	
		No. 4	No. 6
Gravity (°API)	8.3	23	12
Viscosity (cS, 100°F)	4	14-20	900
Flash Point (°F)	>150	>150	>150
Pour Point (°F)	-23	<-20	<+60
Sediment (%)	<0.03	0.05	0.25
Carbon Residue (%)	<0.3	5.5	6-16
Ash (%)	0.015	0.01	0.05
Sulfur (%)	0.25	1.00	0.3-2.2
Nitrogen (%)	0.9	0.2	0.4
Net Heating Value (Btu/gal)	148,000	135,000	141,000

As of July 1981, the costs of No. 4 and No. 6 fuel oil were \$40.1/barrel and \$37.5/barrel, respectively.⁽¹⁰⁾ The cost of raw SRC-II coal liquids is projected to be \$40 to \$60 per barrel depending on capital costs and coal costs.⁽¹¹⁾ The projected capital costs of upgrading the fuel oil have been estimated at \$267 to \$433 million (1981 dollars) for a commercial plant with an added cost to the products of \$9 to \$15 per barrel.⁽¹¹⁾ This being the case, SRC-II fuel oil could become economically competitive if petroleum-derived fuel oil prices increase or if capital expenditures for future SRC-II processes decrease as the process evolves.

References

- (1) "Chementator," Chemical Engineering, July 13, 1981, p. 33.
- (2) "Policy Changes Torpedo SRC-II," Chemical Engineering, July 27, 1981, p. 25.
- (3) Gulf Mineral Resources Company, "The SRC-II Process," presented at the Third Annual International Conference on Coal Gasification and Liquefaction, University of Pittsburgh, August 3-5, 1976.
- (4) The Pittsburg and Midway Coal Mining Company, "Conceptual Commercial Plant: Plant Description," SRC-II Demonstration Project, Phase Zero, Task No. 3, Deliverable No. 8, Vol. 2., prepared for U.S. Department of Energy, July 31, 1979.
- (5) Hittman Associates, Inc., "Environmental Assessment Report: Solvent Refined Coal (SRC) Systems," EPA-600/7-79-146, prepared for U.S. Environmental Protection Agency, 1979.
- (6) Southern Company Services, The Economics of Solvent Refined Coal, Birmingham, Ala., 1977.
- (7) U.S. Department of Energy, "Final Environmental Impact Statement, Solvent Refined Coal-II Demonstration Project," Fort Martin, West Virginia, DOE/EIS-0069, January 1981.
- (8) Fox, George, Autex Fibers, Inc., Personal Communication, July 29, 1981.
- (9) SRC International, Inc., "The SRC-II Demonstration Project," Chemical Engineering Progress, Vol. 77, No. 5, May 1981, pp. 86-91.
- (10) Busler, Dean, Amerada Hess Company, Personal Communication, July 28, 1981.
- (11) Simbeck, D.R., et al., "Coal Liquefaction: Direct versus Indirect - Making a Choice," Oil & Gas Journal, May 4, 1981.

APPENDIX C. SRC-II PRODUCTS

This section discusses the physical properties and end-uses of SRC-II products including fuel oil, distillates, naphtha, substitute natural gas (SNG), and liquified petroleum gas (LPG). In addition, a discussion of the regulatory concerns of the marketing of these products is included.

A range of products is available from the SRC-II process^(1,2), the amounts of which vary with process characteristics such as dissolver temperature, solvent residence time and coal type.

Product slates from different plants may differ not only because of variations in process conditions, but also because of differences in definitions of the products.⁽³⁾ There are no standard definitions of SRC-II products, so what one plant may list as light hydrocarbon gases, another may list as LPG and SNG, and still another may list as propane, butane, methane and ethane. This and other differences in nomenclature can make project slates very difficult to compare accurately.

This product slate for the SRC-II process described in this characterization will be assumed to be the slate listed in Table C-1. This is a representative distribution of products for the process. Ranges of amounts of products are given in the following discussion when adequate data are available.⁽⁴⁾

Table C-1. Product Slate⁽⁴⁾

<u>Products</u>	<u>Quantity</u>
Fuel Oil	61,200 barrels/day
SNG	34 million SCF/day
LPG	7,440 barrels/day
Distillates and Naphtha	15,000 barrels/day
<u>By-Products</u>	
Sulfur	1,300 tons/day
Ammonia	60 tons/day
Phenol	tons/day

Fuel Oil

The major product of the SRC-II process is an ashless, low-sulfur distillate fuel oil (<0.4% sulfur).^(5,6,7,8,9) Approximately 60,000 barrels per day of fuel oil, which is a mixture of middle and heavy distillates, are produced by a commercial-size plant.^(4,7,8) At a heating value of the order of 17,284 Btu/lb^(5,6,7), this amount of fuel oil is enough to meet the electricity generation needs of a city of 3 million.⁽⁸⁾ Table C-2 lists various physical properties of SRC-II fuel oil.

Table C-2. Physical Properties of SRC-II Fuel Oil

Boiling range	400-900°F ^(4,6,10,11)
Viscosity	4cS at 100°F ⁽¹²⁾
Molecular weight	230 ⁽⁶⁾
Flash point	168°F ⁽⁶⁾
Composition ⁽⁶⁾	<div style="display: inline-block; vertical-align: middle;"><div style="display: inline-block; vertical-align: middle; font-size: 3em; line-height: 1;">{</div><div style="display: inline-block; vertical-align: middle;"><div>C 87 % (wt)</div><div>H 7.9%</div><div>O 3.9%</div><div>N 0.9%</div><div>S 0.3%</div></div></div>

SRC-II fuel oil can be used by electric utility and industrial markets that traditionally use petroleum fuels.^(6,8,9) This fuel oil can be upgraded for use as jet aircraft fuel, diesel fuel, and home heating oil.^(8,9) Its use in boilers has been investigated with respect to two criteria: transportation and combustion. SRC-II fuel oil has a low viscosity that enables it to be transported by pipeline.^(7,12) It also has a low pour point, a high flash point, and is sufficiently stable. Metal corrosion is unlikely to be a problem.⁽¹²⁾

SRC-II fuel oil has a lower hydrogen and sulfur content, and a higher aromatic and nitrogen content than most petroleum fuel oils.^(3,7,10,12) The higher aromatics cause SRC-II fuel oil to have a more radiant flame and a greater tendency to smoke. A redder flame may be advantageous in some situations, but it can cause combustor liner overheating and reduce the combustor life. This problem may be resolved through design modification, to the applicable burner, boiler or engine.⁽¹²⁾ The higher nitrogen content

of SRC-II fuel oil causes higher NO_x , but it has been shown that both the NO_x and the smoke can be controlled with conventional combustion technology.⁽¹⁰⁾
Due to its lower sulfur content, SRC-II fuel oil produces less SO_x than do many petroleum fuel oils.^(7,10)

Distillates and Naphtha

Another important product of the SRC-II process is a light distillate. There is also a naphtha portion of this stream. The distillate product has a low boiling range of 100°F to 400°F,^(4,6) is produced at a rate of 13,000 to 17,000 barrels per day^(4,6,7) and has a heating value of approximately 18,000 Btu/lb.⁽⁷⁾ The approximate composition of this product stream is listed below.

<u>Distillate Composition</u> ⁽⁶⁾	
C	84% (wt)
H	11.5
O	3.9
N	0.4
S	0.2

Naphtha can be burned within the SRC-II plant or can be used in a petroleum refinery.⁽⁶⁾ If the naphtha is upgraded, it can be used as high-octane unleaded gasoline blending stock which can supplement gasoline supplies derived from petroleum.^(4,8) It can also be a feedstock for chemicals used in manufacturing; for example, naphtha can be a valuable source of aromatics used in the production of nylon.⁽⁸⁾

Substitute Natural Gas

Substitute natural gas (SNG) is composed mainly of methane and ethane with minor amounts of propane, nitrogen, and hydrogen.^(6,7) SNG is produced at a rate of approximately 30 to 50 million SCF per day^(6,7,8) and has a heating value of 940 to 1200 Btu/SCF.^(6,7) This gas can be used as a plant fuel gas with the SRC-II plant or as a home heating fuel.^(4,8,9,11) Ethane can be converted to ethylene and used in production of polyester fabrics and hard plastics.⁽⁸⁾

Liquified Petroleum Gas

Liquified petroleum gas (LPG) is composed mainly of propane and butane with minor portions of ethane.^(6,7) The approximately 7400 barrels per day

of LPG that are produced during the cryogenic separation process^(3,6) can be used within the SRC-II process or as a domestic and industrial fuel. Butane can be used in gasoline production or converted into butylene for use in the manufacture of rubber tires, hoses, and belts.⁽⁸⁾

Regulatory Issues

An EPA program may impact the marketing of SRC-II products. Regulations promulgated under the Toxic Substances Control Act (TSCA) require a firm to submit new substances to EPA for review of their toxicity if the substance was not "in commerce," that is, manufactured, imported or processed for a commercial purpose in the United States, before January 1, 1980. Under the provisions of the TSCA premanufacture notice (PMN) requirements, EPA has the authority, based on certain test data, to ban the substance or to place restrictions on its use. Although some SRC products are listed on the "TSCA Chemical Substance Inventory" (a compilation of chemicals "in commerce"), the EPA may decide that certain synfuel products were not in commerce because they had not been sold or for some other reason. In any case, any forthcoming EPA policy is likely to be applied consistently to all synfuel processes, resulting in varying impacts on developers.⁽¹³⁾

References

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GLOSSARY

Butane	A hydrocarbon that is a component of LPG.
Carcinogen	A substance that causes cancer.
Catalyst	A substance that modifies, especially increases, the rate of a chemical reaction without being consumed in the reaction.
Cooling tower	A structure used to cool water by evaporation.
Cooling tower blowdown	Water discharged from the cooling tower to control concentrations of salts and other impurities in the circulating water.
Cryogenic	A term used to describe a process that occurs at very low temperatures.
Dissolver	The vessel in which the hydrogenation reaction of coal takes place, also called "hydrogenation reactor" in some sources.
Ethane	An odorless, colorless hydrocarbon gas (C_2H_6) that is a component of SNG.
Fractionation	The process of separating a substance into components. Distillation is the fractionation process used in SRC-II.
Fuel oil	See SRC-II fuel oil.
Gasification	The process of converting a solid or liquid into a gas.
Heavy distillate	The component of SRC-II fuel oil that has higher range boiling points of the distillates from the fractionator.
Hydrocarbon	An organic compound composed only of hydrogen and carbon.
Hydrogenation	The process of adding hydrogen to an element or compound.
Light distillate	See Naphtha.
Liquefaction	The process of converting a substance into a liquid. The SRC-II process converts coal into a liquid via hydrogenation.
Liquefied petroleum gas	An industrial and residential fuel composed primarily of propane and butane; LPG.
Methane	An odorless, colorless hydrocarbon gas (CH_4) that is the main component of SNG.
Middle distillate	The component of SRC-II fuel oil that has the middle range boiling point of distillates from the fractionator.
Mutagen	Any substance that causes biological mutation.
Naphtha	The lightest of the oils distilled from the fractionator (lowest boiling range). Naphtha is one of the products of the SRC-II process.
Pipeline gas	Substitute natural gas (SNG).
Propane	A colorless hydrocarbon gas (C_3H_8) that is the main component of LPG.

Solvent refined coal	Coal that has been converted into liquid and gaseous products through a hydrogenation reaction with coal-derived solvent.
SRC-II	A process developed by the Pittsburgh and Midway Coal Mining Company that converts coal into a series of liquid and gaseous products.
SRC-II fuel oil	The major product of the SRC-II process; an ashless, low-sulfur distillate fuel oil that can be used as an industrial fuel. If refined further, SRC-II fuel oil can be used as a home heating, diesel, or jet fuel.
SRC-II liquid	A liquid composed of pyridine soluble organics that boil at temperatures above 850°F. SRC-II liquid is removed from the bottom of the vacuum flash unit and the fractionator and is then gasified for hydrogen production.

ABBREVIATIONS & ACRONYMS

BACT	best available control technology
BAT	best available technology
bbl	barrel (42 gallons)
ft	board feet
BOD ₅	biochemical oxygen demand (5-day)
Btu	British thermal unit
CAA	Clean Air Act
CO	carbon monoxide
CO ₂	carbon dioxide
COD	chemical oxygen demand
cS	centiStoke
CWA	Clean Water Act
d	day
dB(A)	A-weighted decibels
DOE	Department of Energy
ft	foot (ft ² = square feet, ft ³ = cubic feet)
g	gram
gal	gallon
gpm	gallons per minute
h	hour
ha	hectare
H ₂ O	water
H ₂ S	hydrogen sulfide
JTU	Jackson Turbidity Unit
kg	kilogram

l	liter
LAER	lowest achievable emission rate
LPG	liquefied petroleum gas
m	meter (m^2 = square meters, m^3 = cubic meters)
mg	milligram
Mg	megagram = metric tonne
NA	non-attainment
NAAQS	National Ambient Air Quality Standards
NMHC	non-methane hydrocarbons
NO _x	oxides of nitrogen
NSPS	New Source Performance Standards
ppm	parts per million
PSD	Prevention of Significant Deterioration
RCRA	Resource Conservation and Recovery Act
SDWA	Safe Drinking Water Act
sec	second
SNG	substitute natural gas
SO ₂	sulfur dioxide
SO _x	oxides of sulfur
SRC	solvent refined coal
TDS	total dissolved solids
TSP	total suspended particulates
TSS	total suspended solids
µg	microgram
wt	weight
yr	year

Lurgi High-Btu Coal Gasification

Environmental Characterization Information Report

October 1982

U.S. Department of Energy
Assistant Secretary for Environmental
Protection, Safety, and
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Office of Environmental Analysis

CONTENTS

	<u>Page</u>
I. SUMMARY	A.7
II. INTRODUCTION.	A.7-8
1. Run of Mine Coal.	A.7-10
2. Fugitive Dust from Crushing and Screening	A.7-12
3. Fugitive Dust from On-Site Coal Storage	A.7-14
4. Runoff from On-Site Coal Storage.	A.7-15
5,6. Sized Coal and Coal Fines from Secondary Screening.	A.7-17
7,8. Byproducts Recycled to Steam Production Facilities.	A.7-19
9. Flue Gas Released by Steam Production Facilities.	A.7-20
10. Ash Generated by Steam Production Facilities.	A.7-21
11. Boiler Blowdown	A.7-22
12. Emissions from Oxygen Plant	A.7-23
13. Coal Gasification	A.7-25
14. Ash Quench Water and Quench Off-gases	A.7-27
15. Ash to Waste Disposal	A.7-29
16. Shift Conversion Catalyst Regeneration Off-gas.	A.7-30
17. Gas Liquor Stream from Gas Cooling.	A.7-31
18. Rectisol Process Acid Gas Removal	A.7-32
19. Acid Gas Stream from Rectisol to Sulfur Recovery.	A.7-33
20. Methanation	A.7-34
21,22. SNG Compression and Dehydration	A.7-36
23. Flash Gases from Gas Liquor Separation.	A.7-37
24. Phenosolvan Unit and Byproduct Phenols.	A.7-39
25. Phenolic Water from Ammonia Recovery Unit	A.7-41
26. Acid Gases from Ammonia Recovery to Sulfur Recovery	A.7-42
27. Ammonia Recovery/Byproduct Production	A.7-43
28,29. Air Emissions and Byproduct Sulfur Recovery--Stretford Unit	A.7-44
III. PHYSICAL REQUIRMENTS.	A.7-45
IV. PERSONNEL	A.7-49
V. OCCUPATIONAL SAFETY AND HEALTH.	A.7-50
APPENDIX A: HEAT AND MASS BALANCE	A.7-52
APPENDIX B: SULFUR BALANCE.	A.7-56
APPENDIX C: TRACE ELEMENT ANALYSIS.	A.7-57
APPENDIX D: GAS STREAM COMPOSITION.	A.7-58
APPENDIX E: GASIFIER ASH COMPOSITION.	A.7-59
APPENDIX F: ANG GASEOUS EMISSIONS COMPARED TO FEDERAL STANDARDS	A.7-60
GLOSSARY	A.7-64
ACRONYMS AND ABBREVIATIONS	A.7-66

I. SUMMARY

This Environmental Characterization Information Report (ECIR) on Lurgi high-Btu coal gasification utilizes an established first-generation commercial-scale process design as a basis for estimating the quantities of emissions produced. The selected prototype plant design is the Great Plains Coal Gasification Project which is a mine mouth facility located in Mercer County, North Dakota. This plant design is based on the use of the "Lurgi Dry-Ash Gasifier" which can only process non-caking coals; lignite and subbituminous coals. The facility is designed to produce 275×10^6 scf/day SNG with a heating value of 977 Btu/scf. Power is not produced by the plant but is purchased from an adjacent coal-fired power plant.

The process, operating parameters, resources, environmental emissions, and the products produced are presented in the Summary Table. Annual resource requirements and emission discharges are shown in English and metric units, assuming an annual plant capacity factor of 91 percent. The Summary Table also gives quantities in terms of 10^{12} Btu of SNG produced. These figures are provided to allow comparison between different energy processes and to facilitate use of the information in computer models. Information supporting the Summary Table and the methods used to derive the data are given in Section II. Twenty-nine environmental points of interest are discussed. These discussions give a brief description of the pollutants or resources involved, standards to be met, scaling laws, extrapolation methods, and a bibliography of cited references.

The ANG coal gasification plant produces pollutants similar to those of other commercial-scale plants; for example, coal-fired electric power plants and oil and gas refineries. A typical Lurgi-type coal gasification plant will produce:

- o Ash from the gasifier
- o SO_x , NO_x , and TSP from a supporting steam plant
- o Ammonia byproducts
- o Phenolic water from gas quenching and sludge from the sulfur plant
- o COS and H_2S tail gases from the sulfur plant.

Section III discusses the overall physical requirements of the plant, Section IV gives the approximate number of personnel involved in constructing and operating a commercial-scale coal gasification facility, and Section V briefly describes the occupational safety and health hazards associated with coal gasification plants.

The heat and mass balance of the plant, the sulfur balance, a trace element analysis, the composition of gas streams at various points in the process, the composition of ash exiting the gasifiers and a comparison of air emissions from the ANG plant and the Basin Electric Power Plant with Federal air standards are included as appendices to this report. A glossary and a list of acronyms and abbreviations are also included.

TABLE 1. SUMMARY SHEET

LURGI HIGH-BTU COAL GASIFICATION PLANT

ENERGY SYSTEM DESCRIPTION

The "SNG From Coal Process Using the Lurgi Dry Ash Gasifier" is Based On the Great Plains Coal Gasification Project To Be Located in Mercer County, North Dakota. The Gasifier, Located at the Mine Mouth, Is To Generate Raw Gases From the Lignite Coal of the Beulah-Hazen Coal Field, Clean and Shift the Raw Gases To Enrich the Hydrogen Content, Remove the Acid Gases From the Stream Prior to Methanation and, Thereby, Produce a Pipeline Quality Synthetic Natural Gas as Its Primary Energy Products. An Onsite Boiler Fueled by Tars, Tar Oils, Naphtha, Phenol, and Tail Gases From the Process Provides the Necessary Process Steam. A Sulfur Recovery Unit, Extracts More Than 99 Percent of the Elemental Sulfur From the Acid Gases. This Sulfur and Some Ammonia Are the Marketable By-Products of the Process. Coal Fines From the Coal Preparation Process Are Sent to an Associated But Offsite Basin Power Plant Which Will Also Be Located Near the Mine Mouth and Will Be the Source of Electric Power for the SNG From Coal Plant. Other Onsite Supporting Processes Include an Oxygen Plant, a Wastewater Treatment Plant, and a Gas Liquor Separation Plant.

FACILITY OPERATING PARAMETERS

Facility Size:	2.75×10^6 scf/day SNG
	977 Btu/scf SNG
Annual Capacity Factor:	91%
Annual Energy Production:	90.6×10^{12} Btu
Process Thermal Conversion Efficiency:	68.1%
Lifetime:	25 yr

PROCESS FLOW

TABLE 1. (Continued)

LURGI HIGH-BTU COAL GASIFICATION PLANT

RESOURCES USED

		Quantities Used			
		Reference Energy System Annual Usage			
Code No.	Resource	English Units	Metric Units	Per 10 ¹² Btu Energy Produced	Remarks
①	Run of mine coal	14.2 × 10 ⁶ tons	12.91 × 10 ⁶ tonnes	157 × 10 ³ tons	
⑤	Coal to basin electric power plant	5.15 × 10 ⁶ tons	4.68 × 10 ⁶ tonnes	56.8 × 10 ³ tons	
⑥	Coal to gasifier	9.06 × 10 ⁶ tons	8.23 × 10 ⁶ tonnes	100 × 10 ³ tons	
	Water to ANG plant	2.3 × 10 ⁹ gal	8.7 × 10 ⁹ tonnes	25.4 × 10 ⁶ gal	
	Water consumed in process	300 × 10 ⁶ gal	1.1 × 10 ⁶ liters	3.3 × 10 ⁶ gal	
⑬	Methanol to rectisol (gal × 10 ⁶)	1.32 × 10 ⁶ gal	5.0 × 10 ⁶ liters	14.6 × 10 ³ gal	
	Oxygen to gasifier	1.80 × 10 ⁶ tons	1.64 × 10 ⁶ tonnes	19.9 × 10 ³ tons	
	<u>Land</u>				
	• Plantsite	535 acres	217 ha	6.0 acres	
	• Mining operations	12.5 × 10 ³ acres	5.1 × 10 ³ ha	138 acres	
	• Construction and overburden deposit	905 acres	366 ha	10 acres	
	• Pipeline	2.19 × 10 ³ acres	887 ha	24.2 acres	
	• Water intake, pipeline, railroad spurs and roads	440 acres	178 ha	4.9 acres	
	Total	16.57 × 10 ³ acres	6.71 ha	182.9 acres	
	<u>Personnel</u>				
	Construction (10 yr)	—	1,046 workers	11.5 workers	Peak work force in 10-yr period
	Operation and maintenance	—	527 workers	5.8 workers	Average work force clearing operation

COSTS

	Reference Energy System	(1979 \$)	Per 10 ¹² Btu Energy Produced	Remarks
<u>Facility</u>				
Construction (10 yr)	\$2 × 10 ⁶ total		22.1 × 10 ⁶	
Operation and maintenance		Not Determined		
<u>Environmental Controls</u>		Not Determined		

ENVIRONMENTAL RESIDUALS

		Quantities Released			
		Reference Energy System			
Code No.	Residual or Product	Annual Levels		Per 10 ¹² Btu Energy Produced	Remarks
		English Units ¹	Metric Units		
	<u>Gaseous Wastes</u>				
9	Steam Boilers				
	SO ₂	4,065 tons	3,697.6 tonnes	44.8 tons	
	NO _x	3,109 tons	2,820.4 tonnes	34.3 tons	
	HC	239 tons	216.8 tonnes	2.63 tons	
	TSP	518 tons	469.9 tonnes	5.71 tons	
	CO	438 tons	397.3 tonnes	4.83 tons	

TABLE 1. (Continued)

LURGI HIGH-BTU COAL GASIFICATION PLANT

ENVIRONMENTAL RESIDUALS (Continued)

		Quantities Released		
		Reference Energy System		
		Annual Levels		
Code No.	Residual or Product	English Units	Metric Units	Per 10 ¹² Btu Energy Produced
	Steam superheaters			
	SO ₂	5,102 tons	4,628.4 tonnes	56.3 tons
	NO _x	1,275 tons	1,156.6 tonnes	14.0 tons
	HC	120 tons	108.8 tonnes	1.32 ton
	TSP	159 tons	144.2 tonnes	1.75 ton
	CO	996 tons	903.5 tonnes	10.9 tons
13	Gasifier start-up incinerators, intermittent*	—	—	—
	Main plant flares, intermittent*	—	—	—
	Particulates from gasifier building	110 tons	99.7 tonnes	1.90 ton
	Basin Electric Power Plant			
	SO ₂	45.4 × 10 ³ tons	41.2 × 10 ³ tonnes	501.4 tons
	NO _x	18.9 × 10 ³ tons	17.2 × 10 ³ tonnes	208.9 tons
	TSP	3.8 × 10 ³ tons	3.4 × 10 ³ tonnes	41.8 tons
	CO	Negligible	Negligible	
	HC	Negligible	Negligible	
2	Fugitive dust from coal crushing and screening	173 tons	156.9 tonnes	1.90 ton
5	Fugitive dust from fines storage silo and transport	35 tons	31.7 tonnes	0.38 ton
3	Fugitive dust from coal storage	Not Determined		
16	Shift catalyst removal — SO ₂	164 tons	148.7 tonnes	1.81 ton
25	Process water cooling tower evaporation and drift	7.6 × 10 ⁶ tons	6.9 × 10 ⁶ tonnes	83,885.2 tons
23	Gas liquor separator flare — SO ₂	2.3 × 10 ³ tons	2.1 × 10 ³ tonnes	25.4 tons
21	Steam in SNG drying vent gas	Negligible	Negligible	Negligible
22	Oxygen plant evaporation and drift	1.43 × 10 ⁶ tons	1.30 × 10 ⁶ tonnes	15,783.6 tons
28	Stratford plant emission incinerator — SO ₂	3.0 × 10 ³ tons	2.7 × 10 ³ tonnes	33.1 tons
	Stratford plant evaporation	10.0 × 10 ³ tons	9.1 × 10 ³ tonnes	110.3 tons
14	Evaporation from ash handling	60 × 10 ³ tons	54.4 × 10 ³ tonnes	66.22 tons
	Liquid Wastes			
25	Multieffect evaporator waste water	140 × 10 ³ tons	127 × 10 ³ tonnes	1.54 × 10 ³ tons
4	Runoff from coal storage	Not Determined		
11	Boiler blowdown	430 × 10 ³ tons	390 × 10 ³ tonnes	4.7 × 10 ³ tons
	Runoff from water ponds	Not Determined		
14	Water to mine disposal with ash	140 × 10 ³ tons	127 × 10 ³ tonnes	1.54 × 10 ³ tons
	Miscellaneous plant waste water	1.0 × 10 ⁶ tons	0.91 × 10 ⁶ tonnes	11.0 × 10 ³ tons

*The emissions from these sources are primarily SO₂ and are released with undetermined frequency. The rates of release respectively are: 1.15 × 10³ lb/hr and 13.33 × 10³ lb/hr.

TABLE 1. (Continued)

LURGI HIGH-BTU COAL GASIFICATION PLANT

ENVIRONMENTAL RESIDUALS (Continued)

Code No.	Residual or Product	Quantities Released			Regulatory Compliance Levels
		Reference Energy System		Per 10 ¹² Btu Energy Produced	
		Annual Levels			
		English Units	Metric Units		
	<u>Solid Wastes</u>				
	Miscellaneous plant refuse		Not Determined		
15	Gasifier ash	586 × 10 ³ tons	532 × 10 ³ tonnes	6,468 tons	
10	Fly ash from steam production	500 tons	453.5 tonnes	5.51 tons	
10	Bottom ash from steam production		Not Determined		
16	Spent catalyst from shift conversion		Not Determined		
	Sanitary sewage treatment sludge		Not Determined		
20	Spent catalyst from methanation		Not Determined		
25	Evaporator residue		Not Determined		
	Raw water treatment sludge and silt		Not Determined		

PRODUCTS

PRODUCTS

		Quantities Produced			
		Reference Energy System			
		Annual Production			
Code No.		English Units	Metric Units	Per 10 ¹² Btu Energy Produced	Remarks
	Primary				
(22)	SNG	189 × 10 ³ tons	1.7 × 10 ⁶ tonnes	20.9 × 10 ³ tons	
(27)	Ammonia	70.9 × 10 ³ tons	64.3 × 10 ³ tonnes	782 tons	
(29)	Sulfur	53.4 × 10 ³ tons	48.4 × 10 ³ tonnes	589 tons	
(5)	Coal fines	515 × 10 ³ tons	4.7 × 10 ⁶ tonnes	56.8 × 10 ³ tons	
	Byproducts*				
(7) (8)	Tar	279 × 10 ³ tons	253 × 10 ³ tonnes	30.9 × 10 ³ tons	*Recycled
	Tar oil	93 × 10 ³ tons	84.4 × 10 ³ tonnes	10.3 × 10 ³ tons	
	Naphtha	46 × 10 ³ tons	41.7 × 10 ³ tonnes	5.1 × 10 ³ tons	
	Phenol	55 × 10 ³ tons	49.9 × 10 ³ tonnes	6.1 × 10 ³ tons	
	Stratford tail gas (scf/yr)	133 × 10 ⁹ scf	3.77 × 10 ⁶ m ³	14.7 × 10 ⁹ scf	
	Coal lockhopper off-gas (scf/yr)	0.25 × 10 ⁹ scf	7.10 × 10 ⁶ m ³	27.6 × 10 ⁹ scf	

OCCUPATIONAL SAFETY AND HEALTH

	Coal Strip Mine		Plant Operations	
	Annual	Per 10 ¹² Btu	Annual	Per 10 ¹² Btu
Deaths	0.34	0.0037	0.42	0.0046
Accidental Injuries	10.6	0.1169	1.0	0.0110

II. INTRODUCTION

Lurgi high-Btu gasification produces methane (CH_4) from coal by increasing the hydrogen fraction of coal. The Lurgi gasifier accomplishes this by reacting coal with steam and oxygen in a slowly moving bed. The crude gas produced in this reaction must then be cleaned of impurities and upgraded through methanation to attain pipeline quality.

The gasification process, including gas clean-up and upgrading, is complex and produces liquid, solid, and gaseous wastes. There are a variety of plant configurations and subsystems available to handle these wastes. The plant configuration presented in this ECIR is considered to be representative of Lurgi high-Btu coal gasification plants; however, the emissions identified should be viewed with several qualifications.

The coal gasification plant this ECIR is based on is the first commercial-scale plant to be built in the United States. Therefore, no actual operating experience exists and the emission levels are based on best engineering analysis alone. Although commercial-scale plants have been operating in other countries, these facilities are not designed with the level of pollution control equipment coal gasification plants in the U. S. will be required to incorporate and they do not use American coals. These factors greatly influence the nature of the emissions produced. In addition, emission standards for coal gasification facilities have not been developed and thus it is unclear whether the ANG facility has incorporated adequate pollution control measures or if future standards will require less stringent measures.

Although the primary function of this ECIR is to identify, quantify, and discuss the emissions released to the environment from Lurgi high-Btu coal gasification facilities, the uncertainty associated with actual operation and design has made it necessary to include quite detailed descriptions of the plant subsystems. The inclusion of this detail will allow this ECIR to be useful in assessing emission characteristics of coal gasification plants with different designs and subsystems. By providing adequate information on the design and function of the ANG plant and the emissions produced, it will be possible to estimate the change in emissions caused by a change in plant design.

In spite of the lack of a coal gasification industry in the United States and the resulting lack of operating experience, this ECIR presents first order approximations of the resources used and emissions released by coal gasification plants. The best information available has been used to prepare this ECIR and once the ANG facility is completed and operating, the new data generated should be incorporated in updates.

FIGURE 1. SIMPLIFIED ANG LURGI COAL GASIFICATION PROCESS

1 Run of Mine Coal

To produce 275 MMscf/day SNG requires 27×10^3 tons/day of coal. Losses in coal preparation require the amount of run-of-mine (ROM) coal to be 56.8×10^3 or 14.2×10^6 tons/yr.

The Lurgi dry-ash gasifier can accept either lignite or subbituminous coals. The ANG gasification project is a mine mouth facility which uses lignite from the Beulah-Hazen field. The proximate analysis of the coal is as follows:

Moisture, wt %	35.98
Ash, wt %	7.42
Fixed carbon, wt %	23.39
Volatiles, wt %	27.21
HHV	7230 Btu/lb

A more detailed analysis is presented in Appendix A.

The quantity of coal mined for the ANG coal gasification plant, or run-of-mine coal, is 14.2×10^6 tons/yr. In the coal preparation facilities, the run-of-mine coal is crushed until it is small enough for gasification. During coal preparation, coal fines are produced which are too small for gasification. The fines are collected and used to produce power for the gasification plant and mine, 160 MW. At the ANG plant, the coal fines are transferred to an adjacent power plant, the Basin Electric Power Plant, which generates 880 MW. The properly sized coal is fed to the gasifier. The run-of-mine coal equals the sum of the coal daily fed to the Basin Electric Power Plant and the gasification process:

Coal fines to Basin Electric Power Plant

$$\begin{aligned}
 &= 15,496 \text{ tons/day}^1 \\
 &= (15,496 \text{ tons/day})(365 \text{ days/yr})(0.91 \text{ capacity factor}) \\
 &= 5,147,000 \text{ tons/yr}
 \end{aligned}$$

Sized coal to gasifier

$$\begin{aligned}
 &= 27,272 \text{ tons/day}^1 \\
 &= (27,272 \text{ tons/day})(365 \text{ days/yr})(0.91 \text{ capacity factor}) \\
 &= 9,058,400 \text{ tons/yr}
 \end{aligned}$$

Run-of-mine coal

$$\begin{aligned} &= 5,147,000 \text{ tons/yr} + 9,058,400 \text{ tons/yr} \\ &= 14,205,400 \text{ tons/yr} \\ &= (14,205,400 \text{ tons/yr}) / (250 \text{ days/yr}) * \\ &= 56,822 \text{ tons/day} \end{aligned}$$

The coal preparation plant prior to fines separation operates 18 hours per day, 250 days per year.

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1. U. S. Department of Energy, Final Environmental Impact Statement for the ANG Coal Gasification Company, North Dakota Project, August 1980, update of Draft Environmental Impact Statement for the ANG Coal Gasification Company, North Dakota Project, prepared by Upper Missouri Region, Bureau of Reclamation for U. S. Department of the Interior, INT DES 77-11, March 17, 1977.

2 Fugitive Dust from Crushing and Screening

The total amount of particulates generated by coal crushing and screening is approximately 173.4 tons/yr.

Dump trucks deliver coal from the mine to storage bins near the coal preparation facilities. The transfer of coal from trucks to receiving hoppers is conducted in an enclosure equipped with inertial and bag-type filters. From the bins, the raw coal is transferred to primary crushing facilities where the coal size is reduced to approximately 8 inches. The crushed coal is then screened to separate the oversized coal from the undersize product coal. The preferred size ranges from 0.135 to 1.38 inches. The oversized coal is sent to secondary crushing facilities and returned to the crushed coal product stream.

A minimum quantity of particulates are produced by coal crushing and screening operations. These emissions are reduced at the ANG facility by enclosing the screening and crushing facilities and employing baghouse filters to collect a majority of the dust.

Table 2 presents the quantities of particulates generated at the crushing and screening facilities, at the sampling stations, and at transfer stations within the coal preparation train. These operations are enclosed and equipped with bag-type filters; however, the removal efficiency of these filters has not been determined to date. An additional method for controlling the fugitive dust would be to use water sprays for dust suppression at all transfer, screening, and crushing points.

Table 2. PARTICULATES GENERATED BY COAL HANDLING OPERATIONS²

	<u>Tons per day</u>	<u>Tons per year</u>
Primary Crushing Station*	0.08	20.0
Secondary Crushing Station*	0.12	30.0
Belt Conveyor Transfer and Sampling Station*	0.09	22.5
Fine Screening and Crushing Station*	0.11	27.5
Belt Conveyor Transfer Station*	0.02	5.0
Belt Conveyor Transfer and Sampling Station**	0.16	58.4
Live Storage Reclaim Tunnel Ventilation**	0.03	10.0
Total	0.61	173.4

* Coal handling operations operate 18 hours/day, 250 days/year

** Storage reclaim and associated coal conveyor operate 24 hours/day, 365 days/year.

The above figures were calculated using these equations:

$(\text{lbs/hr} \times 18 \text{ hrs/day}) / (2000 \text{ lbs/ton}) = \text{tons per day}$
 $\text{Tons per day} \times 250 \text{ days} = \text{tons per year}$

$(\text{lbs/hr} \times 24 \text{ hrs/day}) / (2000 \text{ lbs/ton}) = \text{tons per day}$
 $\text{tons per day} \times 365 \text{ days} = \text{tons per year}$

References

1. Environmental Protection Agency/Industrial Environmental Research Lab, Environmental Assessment Report: Lurgi Coal Gasification Systems for SNG, prepared by TRW Environmental Engineering Division, EPA-600/7-79-120, May 1979.
2. U. S. Department of Energy, Final Environmental Impact Statement for the ANG Coal Gasification Company, North Dakota Project, August 1980, update of Draft Environmental Impact Statement for the ANG Coal Gasification Company, North Dakota Project, prepared by Upper Missouri Region, Bureau of Reclamation for U. S. Department of the Interior, INT DES 77-11, March 17, 1977.

3

Fugitive Dust from On-site Coal Storage

The fugitive dust emissions from coal storage piles are controlled by compacting the coal, maintaining a 20 percent grade on the sides of the piles and spraying with latex.

A quality analysis is conducted on the crushed product before it is sent to live storage. Live storage consists of one 300,000 ton pile, part of which would be above and part below grade (a 7-day feed supply to gasifier). Alternate routes (after analysis) are to send it to dead storage (with a 30-day feed supply capacity) or directly to secondary screening.

Dead storage consists of a 1,200,000 ton pile. It is laid down and compacted in 1-foot layers. The pile is approximately 1,200 feet square and 30 feet high. The storage piles have the potential of producing fugitive dust emissions. The wind-caused fugitive dust is reduced on the dead storage pile by maintaining a maximum 20 percent grade around the perimeter of the piles and by coating the piles with latex. Data for particulate quantities generated at this location are not available.

4

Runoff from On-site Coal Storage

Runoff from coal storage piles may contain fines, other suspended particulates and dissolved organics.

The live and dead coal storage piles are exposed to precipitation. Water percolating through these piles can leach trace elements and organic compounds from the coal contaminating the runoff. If it is assumed that 10 percent of the average annual precipitation results in runoff, the runoff from the dead storage pile can be calculated:

Dead storage pile runoff

$$= (1200 \text{ ft}^2)(15.15 \text{ inches/yr})(0.1 \text{ runoff factor}) \\ (7.48 \text{ gal/ft}^3)/(12 \text{ in/ft}) \\ = 1133.2 \text{ gal/yr}$$

If the dimensions of the live storage pile are assumed to be proportionate to those of the dead storage pile, the live storage pile would require 300 ft² and thus the runoff can be calculated as:

Live storage pile runoff

$$= (300 \text{ ft}^2)(15.15 \text{ inches/yr})(0.1 \text{ runoff factor})(7.48 \text{ gal/ft}^3) / \\ (12 \text{ in/ft}) \\ = 283.3 \text{ gal/yr}$$

Approximately 77 percent of the precipitation in Bismark, North Dakota (a site near the plant site where precipitation data are collected) occurs in the months from April to September.

Possible control measures for coal pile runoff include collecting pile runoff for treatment and process use, and minimizing runoff generation by detouring any storm runoff from adjacent areas away from the coal piles.² At the ANG plant, plant site runoff containing coal fines, other suspended particulates, and dissolved organics resulting from oxidation and solubilization of coal impurities is collected in contaminated water sewers and transported to a 5 million cubic foot (20 acre) retention pond. Water not evaporated from this pond is clarified and the resources are recovered. The sludge is combined with waste ash and buried in the mine. The clarifier overflow is sent to deep well disposal.

References

1. U. S. Department of Energy, Final Environmental Impact Statement for the ANG Coal Gasification Company, North Dakota Project, August 1980, update of Draft Environmental Impact Statement for the ANG Coal Gasification Company, North Dakota Project, prepared by Upper Missouri Region, Bureau of Reclamation for U. S. Department of the Interior, INT DES 77-11, March 17, 1977.
2. Environmental Protection Agency/Industrial Environmental Research Lab, Environmental Assessment Report: Lurgi Coal Gasification Systems for SNG, prepared by TRW Environmental Engineering Division, EPA-600/7-79-120, May 1979.

5 & 6 Sized Coal and Coal Fines from Secondary Screening

The amount of coal required by the Lurgi gasifiers is 9.06×10^6 tons/yr. The amount of coal fines produced for transfer to the power plant is 5.15×10^6 tons/yr. The total particulates released by coal transport and storage at the ANG plant will be approximately 35 tons/yr.

Crushed coal from the live storage pile is conveyed to the secondary screening facility where coal fines are separated from the properly sized coal and sent to storage.

The quantity of coal fines collected total:

$$\begin{aligned}\text{Coal fines} &= 15,496 \text{ tons/day} \\ &= (15,496 \text{ tons/day})(365 \text{ days/yr})(0.91 \text{ capacity factor}) \\ &= 5,147,000 \text{ tons/yr}\end{aligned}$$

The sized coal is then conveyed to the storage bins (coal bunkers) located above each gasifier in the gasifier building. This quantity totals:

$$\begin{aligned}\text{Pre-sized coal to gasifier} &= 27,272 \text{ tons/day} \\ &= (27,272 \text{ tons/day})(365 \text{ days/year})(0.91 \text{ capacity factor}) \\ &= 9,058,400 \text{ tons/yr}\end{aligned}$$

Controlled particulates released to the atmosphere by the fines storage silo and the coal transport system are listed below. These relatively small quantities of particulates are included in the figures representing the quantities coal fed to the power plant and the gasifiers, respectively.

Fines Storage Silo and Belt Conveyor Transfer Station

= 0.14 tons/day*

= (0.14 tons/day)(250 days/yr)

= 35.0 tons/yr

• 24 hrs/day

The coal fines collected during secondary screening are sent to an adjacent power plant as supplemental fuel. As an alternative, the coal fines could be burned in an on-site power plant. This would produce additional air emissions at the gasification plant site.

Byproducts Recycled to Steam Production Facilities

On-site steam production is fueled with process byproducts and therefore involves no additional coal combustion or waste disposal.

Both the utility boilers and the superheaters are fired with a combination of solid byproduct fuels and gaseous waste streams recovered from the gasification process.

Alternative designs include on-site power production, the use of coal or coal fines as fuel for the boilers or superheaters, and/or the use of low-Btu gas from the gasifier as fuel for gas turbine generators to produce electric power.

For the ANG process, the utility boilers are fired with the tar and tar oil byproducts recovered from the gas liquor separation unit. Fuel for the superheater furnaces includes byproduct tar oil, naphtha and phenols, tail gas from the Stretford sulfur recovery unit, and gasifier coal-lock chamber off-gases. Consumption rates associated with these facilities (250 MMscf/d SNG production at 91 percent operating capacity) are listed in Table 3. The emissions produced during the combustion of these byproducts are detailed in stream 9.

Table 3. BREAKDOWN OF STEAM BOILER AND SUPERHEATER FUEL CONSUMPTION*²

Area	Fuel Type	Consumption Rate (10 ³ ton/yr)	Wt. % Ash	% Sulfur
Steam Boilers	Tar	279	0.45	0.65 (wt.)
	Tar Oil	37	-	0.52 (wt.)
Superheaters	Tar Oil	55	-	0.52 (wt.)
	Naphtha	46	-	1.60 (wt.)
	Phenol	55	-	-
	Stretford Tail Gas**	133 x 10 ⁹	-	0.029 (vol.)
	Coal Lock Off Gas**	0.25 x 10 ⁹	-	0.320 (vol.)

* ANG coal gasification facility -- 250 MMscf/d SNG production at 91 per cent operating capacity (7972 hr/yr).

** (scf/yr)

References

1. Environmental Protection Agency/Industrial Environmental Research Lab, Environmental Assessment Report: Lurgi Coal Gasification Systems for SNG, prepared by TRW Environmental Engineering Division, EPA-600/7-79-120, May 1979.
2. U. S. Department of Energy, Final Environmental Impact Statement for the ANG Coal Gasification Company, North Dakota Project, August 1980, update of Draft Environmental Impact Statement for the ANG Coal Gasification Company, North Dakota Project, prepared by Upper Missouri Region, Bureau of Reclamation for U. S. Department of the Interior, INT DES 77-11, March 17, 1977.

9 Flue Gas Released by Steam Production Facilities

The amount of SO_x produced by the steam plant and superheaters is estimated to be less than 0.0091×10^6 tons/yr. The amount of NO_x , HC, particulates and CO produced annually is expected to be smaller than the SO_x produced.

The steam production facilities emit gaseous and some liquid and solid waste streams which resemble those associated with liquid fuel-fired steam boilers.

The flue gas streams from the steam boilers and superheaters contain sulfur dioxide, nitrogen oxides, and particulates. The boiler flue gas streams pass through electrostatic precipitators (ESP) with 99 percent removal efficiency for fly ash (particulate) removal. (The ash originally in the coal is entrained in the gasifier gases, attaches to the tar in the gas liquor, and remains with the tar during byproduct extraction and combustion.) The emissions from the superheater are released uncontrolled to the atmosphere through the plant's main stack. The quantities of the pollutants emitted to the atmosphere are presented in Table 4.

Table 4. POLLUTANTS IN ESP CONTROLLED FLUE GAS STREAMS FROM BOILERS AND SUPERHEATERS

	Units	SO_2	NO_x	HC	Particulates	CO
Boilers	(tons/day)	12.24	9.36	0.72	1.56	1.32
	(tons/yr*)	4065	3109	239	518	438
Superheaters	(tons/day)	15.36	3.84	0.36	0.48	3.00
	(tons/yr*)	5102	1275	120	159	996
TOTALS	(tons/day)	27.6	13.2	1.08	2.04	4.32
	(tons/yr*)	9167	4384	359	677	1434

- Steam production is assumed to operate at the same capacity factor as the gasification facilities (91 percent)

$$\text{tons/day} = (\text{lb/hr})(24 \text{ hrs/day})/(2000 \text{ lbs/ton})$$

$$\text{tons/yr} = (\text{tons/day})(365 \text{ days/yr})(0.91 \text{ capacity factor})$$

Reference

1. U. S. Department of Energy, Final Environmental Impact Statement for the ANG Coal Gasification Company, North Dakota Project, August 1980, update of Draft Environmental Impact Statement for the ANG Coal Gasification Company, North Dakota Project, prepared by Upper Missouri Region, Bureau of Reclamation for U. S. Department of the Interior, INT DES 77-11, March 17, 1977.

10

Ash Generated by Steam Production Facilities

512.97 tons of fly ash are generated by the steam boilers per year.

The flyash captured in the electrostatic precipitator (ESP) is removed and sent to the mine for disposal. Assuming a 99 percent particulate removal efficiency for the boiler ESP, the captured flyash totals:

$$\begin{aligned}\text{Flyash} &= (1.56 \text{ tons/day})(0.99/(1-0.99)) \\ &= 1.54 \text{ tons/day} \\ &= (1.54 \text{ tons/day})(365 \text{ days/yr})(0.91 \text{ capacity factor}) \\ &= 512.97 \text{ tons/yr}\end{aligned}$$

Combustion of gasification byproducts produces an undetermined quantity of bottom ash. This ash is also disposed of in the mine.

11

Boiler Blowdown

0.43 x 10⁶ tons/yr of water exit the low pressure steam boiler and are disposed of by deep well injection.

The boilers used to generate steam for gasification are periodically flushed of material which deposits on internal surfaces due to water impurities. The process is called "blowdown." The ANG facility utilizes both a high pressure and a low pressure boiler. Nine hundred gpm of demineralized water enter the high pressure boiler as feedwater. Of the feedwater, 108 gpm are used as blowdown and the majority is converted to steam. The 108 gpm used as blowdown is fed to the low pressure boiler along with 3804 gpm from the water softening system and 375 gpm from the multi-effect evaporator. Two hundred fifteen gpm of the feedwater is used as blowdown while the majority is converted to steam. Once used, the blowdown is disposed of through deep well injection. A complete description of the water use within the ANG plant is presented in the Resources Section of this report.

Blowdown to deep well disposal

$$= (215 \text{ gpm})(8.345 \text{ lbs/gal})(60 \text{ min/hr})(24 \text{ hr/day})(365 \text{ days/yr}) \\ (0.91 \text{ capacity factor})/(2000 \text{ lb/ton})$$

$$= 0.43 \times 10^6 \text{ tons/yr}$$

Prior to disposal, blowdown from the low pressure boiler is combined with regeneration wastes for the softened and demineralized water streams and overflow from the contaminated rainwater clarifier. The estimated chemical composition of the total stream is given in Table 5. These miscellaneous waste waters are generated at the rate of 0.10 x 10⁶ tons/yr.

Table 5. WASTE STREAM TO DEEP WELL DISPOSAL

Parameter	Concentration mg/l	Parameter	Concentration mg/l
CaSO ₄	540	NaHCO ₃	110
MgSO ₄	460	CaCl ₂	860
Na ₂ SO ₄	6460	MgCl ₂	730
NaCl	2770		

12

Emissions from Oxygen Plant

The oxygen used for gasification is produced by separating air into oxygen, nitrogen and noble gases. 1.80×10^6 tons of oxygen are used by the gasifiers annually. The nitrogen and noble gases are released to the atmosphere. The oxygen plant uses its own cooling tower which requires 1.5×10^6 tons/yr of water; 1.12×10^6 tons/yr are used as blowdown and then cycled to the process water cooling tower. The majority is evaporated (1.40×10^6 tons/yr) and lost as drift, 0.03×10^6 tons/yr.

Oxygen is used instead of air for gasification because the nitrogen in air would dilute the raw product gas which would prevent the successful production of high Rtu SNG. The oxygen is produced from air using standard air separation units. The oxygen plant cryogenically separates oxygen (at 99.5 percent purity) from the nitrogen and noble gas constituents in clean air.

The clean air enters the air compressors where it is compressed and becomes hot. The hot air is cooled using a water cooling system. As the cooled air is decompressed, the resulting temperature is lower than its initial temperature. This cycle is continued until a temperature is reached which allows the air to liquify. This liquid air is then sent to the air separation unit and is fractionated into nitrogen gas, noble gases, and liquid oxygen. The liquid oxygen stream is extracted, vaporized, and sent to the gasifiers for consumption (5,432 tons/day, 1.80×10^6 tons/yr).

The only discharge streams from this process are nitrogen and noble gases (released to the atmosphere). The cooling water used in the oxygen production process is sent to a cooling tower where a major portion of it evaporates to the atmosphere. These streams are quantified below.

Water to oxygen plant cooling tower

$$\begin{aligned}
 &= 1.1 \times 10^6 \text{ gals/day} \\
 &= (1.1 \times 10^6 \text{ gals/day})(365 \text{ days/yr})(0.91 \text{ capacity factor}) \\
 &= 365 \times 10^6 \text{ gals/yr} \\
 &= (365 \times 10^6 \text{ gals/yr})(8.345 \text{ lbs/gal})/(2000 \text{ lbs/ton}) \\
 &= 1.5 \times 10^6 \text{ tons/yr}
 \end{aligned}$$

Cooling tower evaporation losses

$$\begin{aligned} &= 1.0 \times 10^6 \text{ gals/day} \\ &= (1.0 \times 10^6 \text{ gals/day})(365 \text{ days/yr})(0.91 \text{ capacity factor}) \\ &= 332 \times 10^6 \text{ gals/yr} \\ &= (332 \times 10^6 \text{ gal/yr})(8.345 \text{ lbs/gal})/(2000 \text{ lbs/ton}) \\ &= 1.4 \times 10^6 \text{ tons/yr} \end{aligned}$$

Cooling tower drift losses

$$\begin{aligned} &= 21.6 \times 10^3 \text{ gals/day} \\ &= (21.6 \times 10^3 \text{ gals/day})(365 \text{ days/yr})(0.91 \text{ capacity factor}) \\ &= 7.1 \times 10^6 \text{ gals/yr} \\ &= (7.1 \times 10^6 \text{ gals/yr})(8.345 \text{ lbs/gal})/(2000 \text{ lbs/ton}) \\ &= 0.03 \times 10^6 \text{ tons/yr} \end{aligned}$$

Blowdown from the oxygen plant cooling tower is filtered and recycled to the process water cooling tower.

Water recycled to process water cooling tower

$$\begin{aligned} &= 8.9 \times 10^4 \text{ gals/day} \\ &= (8.9 \times 10^4 \text{ gals/day})(365 \text{ days/yr})(0.91 \text{ capacity factor}) \\ &= 29 \times 10^6 \text{ gals/yr} \\ &= (29 \times 10^6 \text{ gals/yr})(8.345 \text{ lbs/gal})/(2000 \text{ lbs/ton}) \\ &= 0.12 \times 10^6 \text{ tons/yr} \end{aligned}$$

Reference

1. U. S. Department of Energy, Final Environmental Impact Statement for the ANG Coal Gasification Company, North Dakota Project, August 1980, update of Draft Environmental Impact Statement for the ANG Coal Gasification Company, North Dakota Project, prepared by Upper Missouri Region, Bureau of Reclamation for U. S. Department of the Interior, INT DES 77-11, March 17, 1977.

13

Coal Gasification

Twenty-six gasifiers are employed in the ANG facility, 23 gasifiers are required to produce 250 MMcf/day of SNG. The raw gas produced is processed to attain pipeline quality and the ash is cooled and disposed of in plant subsystems discussed in the following sections. 1,150 lbs/hr of SO_2 are released from the gasifier start-up incinerators intermittently. 13,330 lbs/hr of SO_2 are released intermittently by the plant flares. 0.00011×10^6 tons/yr of particulates are released from the gasifier building.

The gasifier building releases particulates from coal handling at the rate of 28.5 lbs/hr.

Particulate release from gasifier building

$$\begin{aligned}
 &= 28.5 \text{ lbs/hr} \\
 &= (28.5 \text{ lbs/hr})(24 \text{ hrs/day})(365 \text{ days/yr})(0.91 \text{ capacity factor}) / \\
 &\quad (2000 \text{ lbs/ton}) \\
 &= 113.5 \text{ tons/yr}
 \end{aligned}$$

Steam (1300 psig) and oxygen (99.5 percent purity) flow vertically up (countercurrent to the coal flow) through the gasifier where it contacts the coal flowing down at different stages or zones within the gasifier. The four active zones within the gasifier, from top to bottom, include drying, devolatilization, gasification, and combustion. In the drying and devolatilization zones, heat from the gasification (product gas) and combustion zones strips the coal of its moisture and volatile matter in preparation for the gasification zone. The coal proceeds by gravity to the gasification zone where sufficient heat is available from the combustion zone to react the input steam and the carbon from the coal, thereby producing a product gas consisting of CO , H_2 , CO_2 , CH_4 , sulfur compounds (COS , H_2S), entrained particles, and smaller quantities (less than 2 percent dry total) of various other compounds. Finally, within the combustion zone, a portion of the coal is burned to provide the heat for the devolatilization and gasification zones.

The raw product gas exits the top of each gasifier at approximately $850^\circ F$ and 27 psig. The composition of the raw gas exiting the gasifier is indicated in Appendix D.

Under normal operating condition, the gasifier units do not release any gaseous pollutants. Only during start-up, shut-down (for maintenance) or accidental failure conditions are gaseous materials released. Even then, the gas streams will be flared³ to convert organics, carbon monoxide, and reduced sulfur and nitrogen compounds to less hazardous forms (e.g., O_2 , SO_2 , NO_x).

Gasifier start-up incinerator emissions (start-up of 5 gasifiers,
3 on air, 2 on oxygen) = 1150 lbs/hr SO_2

Two flares incinerate emergency hydrocarbon vapors from safety valves and overriding pressure controllers intermittently. Each flare is capable of flaring 25 percent of the total plant gas production. Steam is injected into these flares to achieve smokeless flaring; however, in a plant-wide emergency (anticipated to last for less than 1 hour), smokeless conditions would be exceeded.

Plant flares = 13,330 lbs/hr of SO_2

Ash Quench Water and Quench Off-gases

Ash quenching uses 0.48×10^6 tons/yr of recycled process water. 0.06×10^6 tons/yr of this water are evaporated, 0.10×10^6 tons/yr are disposed of with the ash.

The ash in the bottom of each gasifier is transferred via a rotating grate to an ash lockhopper. The ash is then cooled using recycled process water. Approximately 10 to 15 percent of the water evaporates and is vented. The quench water is recycled phenolic water (cleaned and treated gas liquor) from phenosolvan filter backwash. Because process water is used for ash quench, the water vapor may contain trace amounts of volatile substances originally present in the waste water. The quantity of ash lockhopper vent gas released is negligible. The trace particulates emitted from the ash lockhopper are controlled by a low energy scrubber. The amounts of process water utilized by the ash handling system are quantified below.

Process water to ash handling system

$$\begin{aligned}
 &= 347 \times 10^3 \text{ gals/day} \\
 &= (347 \times 10^3 \text{ gals/day})(365 \text{ days/yr})(0.91 \text{ capacity factor}) \\
 &= 115 \times 10^6 \text{ gals/yr} \\
 &= 115 \times 10^6 \text{ gals/yr} (8.345 \text{ lbs/gal}) / (2000 \text{ lbs/ton}) \\
 &= 0.48 \times 10^6 \text{ tons/yr}
 \end{aligned}$$

Evaporation rate at ash handling system

$$\begin{aligned}
 &= 46 \times 10^3 \text{ gals/day} \\
 &= (46 \times 10^3 \text{ gals/day})(365 \text{ days/yr})(0.91 \text{ capacity factor}) \\
 &= 15.3 \times 10^6 \text{ gals/yr} \\
 &= (15.3 \times 10^6 \text{ gal/yr})(8.345 \text{ lbs/gal}) / (2000 \text{ lbs/ton}) \\
 &= 0.06 \times 10^6 \text{ tons/yr}
 \end{aligned}$$

The remaining water is used to form an ash slurry to facilitate ash handling. The ash slurry is processed to separate the ash solids from the slurry water. The separated slurry water is clarified and reused in the hydraulic ash handling system. Some water remains with the ash and is disposed of with it.

Quench water in ash stream to mine disposal

$$\begin{aligned} &= 76 \times 10^3 \text{ gals/day} \\ &= (76 \times 10^3 \text{ gals/day})(365 \text{ days/yr})(0.91 \text{ capacity factor}) \\ &= 25.3 \times 10^6 \text{ gals/yr} \\ &= (25.3 \times 10^6 \text{ gals/yr})(8.345 \text{ lbs/gal})/(2000 \text{ lbs/ton}) \\ &= 0.10 \times 10^6 \text{ tons/yr} \end{aligned}$$

15 Ash to Waste Disposal

The amount of ash produced in the coal ash lockhopper is 0.586×10^6 tons/yr which is disposed of in the mine.

The solids are separated by a series of screens, settling ponds, and filters and are ultimately placed on a conveyor and disposed of in the mine. Gasifier ash composition is included as Appendix E.

The slurry water is clarified and reused in the hydraulic ash handling system. The quantity of ash produced and disposed of is presented below.

Ash from gasifiers to mine disposal

$$\begin{aligned} &= 1,763 \text{ tons/day} \\ &= (1,763 \text{ tons/day})(365 \text{ days/yr})(0.91 \text{ capacity factor}) \\ &= 586 \times 10^3 \text{ tons/yr} \end{aligned}$$

16 Shift Conversion Catalyst Regeneration Off-gas

164 tons/yr of SO₂ are produced during catalyst regeneration.

Cobalt molybdate-based catalysts are employed by the ANG facility. This catalyst can operate at high temperatures (550°F) which reduces gas cooling requirements prior to shift conversion, and can withstand intrusion by sour gas components (i.e., H₂S and COS) which permits acid gas cleanup to occur after, instead of before, shift conversion. It also has the capability to promote the conversion of some potentially hazardous components in the gas stream to manageable pollutants (i.e., organic sulfur and HCN converted to H₂S and NH₃, respectively).

The catalyst is regenerated (using controlled air oxidation of deposited carbon) every few months which prolongs useful life to 2 to 5 years. During regeneration, off-gas is produced and vented to the atmosphere. The major pollutant being emitted with this off-gas is SO₂ at a rate of 2750 lb/hr. This, however, is an intermittent occurrence equivalent to 1.5 percent of the total operating time, or 164 tons SO₂/yr. The spent catalyst is replaced every 2 to 5 years and will be disposed of in the mines along with the ash, if it meets the criteria for non-hazardous waste.

Shift catalyst regeneration emissions

$$\begin{aligned} &= 2750 \text{ lb/hr} \\ &= (2750 \text{ lb/hr})(131.4 \text{ hrs/yr})(0.91 \text{ capacity factor}) / \\ &\quad (2000 \text{ lbs/ton}) \\ &= 164 \text{ tons/yr of SO}_2 \end{aligned}$$

17 Gas Liquor Stream from Gas Cooling

8.88 x 10⁶ tons/yr of gas liquor are produced which is treated for byproduct recovery and recycled.

The primary gas cooling process consists of a washer cooler and a waste heat boiler. Cooled recycled gas liquor enters the washer cooler and partially cools and condenses some of the gas liquor from the gas stream. Both streams proceed to the waste heat boiler in which additional heat is removed from the gas stream and more gas liquor condenses. A portion of the separated gas liquor is recycled to the washer cooler unit while the remaining liquor is sent to the gas liquor separation unit for byproduct recovery. (This is discussed in a subsequent section.)

Meanwhile, the cooled gas (approximately 500°F) is split into two streams (as has been described in the shift conversion section). Prior to remixing the converted and bypass gas streams, both streams are sent through parallel secondary gas cooling units. The bypass stream passes through waste heat boilers where more gas liquor is condensed out of the gas stream and additional process heat is recovered. The same products result when the converted stream is directed through a water cooler and waste boiler sequence. Finally, this converted stream is compressed, recombined with the cleaned and cooled bypass stream (360°F combined temperature), and sent to the acid gas removal unit. The gas liquor condensed from this cooling stage is combined with that of the primary gas cooling unit and sent to the gas liquor separation unit.

Gas liquor stream to byproduct recovery

$$\begin{aligned} &= (4,460 \text{ gals/min})(60 \text{ min/hr})(24 \text{ hrs/day}) \\ &= 6.42 \times 10^6 \text{ gals/day} \\ &= (6.42 \times 10^6 \text{ gals/day})(365 \text{ days/yr})(0.91 \text{ capacity factor}) \\ &= 2.13 \times 10^9 \text{ gals/yr} \\ &= (2.13 \times 10^9 \text{ gals/yr})(8.345 \text{ lb/gal})/(2000 \text{ lb/ton}) \\ &= 8.88 \times 10^6 \text{ tons/yr} \end{aligned}$$

The gas liquor stream,¹ which consists of moisture, tars, tar oils, phenols, ammonia, sulfur compounds, and other minor constituents, is sent to the gas liquor separation unit and on to the water treatment unit for byproduct recovery (tars and tar oils, phenols and ammonia, respectively). This byproduct recovery approach eliminates any requirements to dispose of the gas liquor, an action which could result in a serious environmental concern.

18

Rectisol Process Acid Gas Removal

Gaseous, liquid and solid wastes produced are recycled or sent to treatment units. 1.32×10^6 gal/yr of methanol are required as make-up. 0.25×10^6 tons of water per year are required.

The combined shifted and bypass gases exiting the secondary gas cooling facilities contain acid gas (H_2S and trace sulfur compounds) and CO_2 which must be removed prior to methanation in order to obtain a product gas with a high heating value (comparable to natural gas). The Lurgi proprietary Rectisol process is employed to remove the CO_2 and acid gas components from the gas stream. The process is based on the physical absorption of these components in cold methanol. The solid, liquid and gaseous wastes exiting this process are recycled for reuse or treated in subsequent processes discussed in later sections of this report.

The Rectisol process consists of a prewash column, a prewash flash vessel, a naphtha separator, azeotrope and methanol wash columns, a hot methanol regenerator, an H_2S absorber, and a flash regenerator.

The CO_2 and H_2S -rich methanol stream which has absorbed the acid gases and CO_2 from the raw gas enters the flash generator where H_2S and CO_2 are flashed off. The resulting gas (expansion gas) is sent to the gasifiers where it is consumed as supplementary fuel. H_2S - and CO_2 -rich offgases are sent to the sulfur recovery unit. The liquid wastes are combined with other liquid wastes and treated in the gas liquor separator. Naphtha is produced and sent to storage.

One thousand to 4000 gallons of methanol are required as make-up per day, even though a substantial portion is recycled.

Methanol make-up

$$\begin{aligned} &= 4000 \text{ gal/day} \\ &= (4000 \text{ gal/day})(365 \text{ days/yr})(0.91 \text{ capacity factor}) \\ &= 1.32 \times 10^6 \text{ gal/yr} \end{aligned}$$

The water used by the Rectisol unit is from the water treatment facility. It consists of both recycled water and fresh make-up water.

Water to Rectisol

$$\begin{aligned} &= 0.18 \times 10^6 \text{ gal/day} \\ &= (0.18 \times 10^6 \text{ gal/day})(365 \text{ days/yr})(0.91 \text{ capacity factor}) \\ &\quad (8.345 \text{ lbs/gal})/(2000 \text{ lbs/ton}) \\ &= 0.25 \times 10^6 \text{ tons/yr} \end{aligned}$$

19

Acid Gas Stream from Rectisol to Sulfur Recovery

7.25 x 10⁶ tons/yr of acid gases from the Rectisol unit are treated.

If the three types of gaseous effluents (expansion gas, acid gas, and product gas) produced within the rectisol unit, only the acid gas streams must pass through a sulfur recovery unit.

The acid gas streams from the Rectisol unit originate in three processes -- prewash gas flashing, hot methanol regeneration, and flash regeneration. These streams, which are sent to the sulfur recovery unit for cleanup prior to exiting through the stack, are quantified below.

Acid gas from rectisol unit to sulfur recovery unit

= 21,837 tons/day

= (21,837 tons/day)(365 days/yr)(0.91 capacity factor)

= 7.25 x 10⁶ tons/yr

Methanation produces condensate, 1.18×10^6 tons/yr, which is added to boiler feedwater and methanation catalysts periodically require disposal. Spent catalysts are disposed of with the ash in the mine.

Feed gas entering the methanation reactors is composed of the preheated synthesis gas and a portion of the methanated gas which has been recycled. A nickel-type catalyst is present within each reactor to enhance the methanation process. The wet methanated gas exits the reactors and passes through waste heat boilers where the accumulated reaction heat is extracted to produce 1300 psig steam.

The cooled methanated gas (except for the portion recycled to the feed stream) proceeds to a clean-up reactor which removes any remaining CO , CO_2 , and H_2 via a nickel catalyzed methanation reaction. The wet product gas is cooled by successive heat exchange with fresh synthesis gas, air, and cooling water before it enters a condensate separator. The water, which is condensed and separated from the product gas, is recycled within the plant while the methanated product gas (SNG) is sent to a glycol dehydration unit for residual moisture removal.

The condensate from the methanation unit is relatively free of dissolved solids but must undergo dissolved gas removal via depressurization prior to being added to boiler feedwater.

Condensate from methanation

$$\begin{aligned} &= 3568.7 \text{ tons/day} \\ &= (3568.7 \text{ tons/day})(365 \text{ days/yr})(0.91 \text{ capacity factor}) \\ &= 1.18 \times 10^6 \text{ tons/yr} \end{aligned}$$

The resulting depressurization offgas is added to the SNG product stream.

The spent nickel catalyst used in each reactor is periodically decommissioned and sent for disposal. A common catalyst decommissioning procedure involves catalyst cooling and slow oxidation using an air or oxygen stream. During decommissioning, the possibility exists for the production of an offgas which may contain particulate matter, sulfur compounds, organo-metallic compounds, and carbon monoxide. Also, the stable, decommissioned catalyst is potentially toxic due to its nickel content and must be disposed of carefully. One

possible use of the oxidized catalyst may be as a methanation guard for sulfur removal. Even though the frequency for decommissioning is not known, it is expected to be low. As a result, the associated emissions should be infrequent and small in quantity.

Reference

1. Environmental Protection Agency/Industrial Environmental Research Lab. Environmental Assessment Report: Lurgi Coal Gasification Systems for SNG, prepared by TRW Environmental Engineering Division, EPA-600/7-79-120, May 1979.

21 & 22 SNG Compression and Dehydration

The amount of SNG product is 1.89×10^6 tons/yr. Dehydration condensate is also produced but is negligible.

The SNG is then sent to a gas compression unit where it is compressed to pressure of 1440 psig and is ready for metering and discharge to the pipeline for distribution. The resulting SNG production is presented below.

Synthetic natural gas (SNG) production

$$\begin{aligned} &= 275 \times 10^6 \text{ scf/day} \\ &= 5,681 \text{ tons/day} \\ &= (275 \times 10^6 \text{ scf/day})(365 \text{ days/yr})(0.91 \text{ capacity factor}) \\ &= 91.34 \times 10^9 \text{ scf/yr} \\ &= 1.89 \times 10^6 \text{ tons/yr} \end{aligned}$$

Ethylene glycol is used in the dehydration unit for the ANG process. Since this material can be regenerated and reused, the input requirements are negligible. Another method available for removing residual moisture from a gas involves the use of molecular sieves. These, too, are capable of regeneration and reuse. The composition of the product SNG is indicated in Appendix D.

The only emission associated with SNG compression² and dehydration is CO₂. Dehydration condensate may contain traces of glycol.

References

1. U. S. Department of Energy, Final Environmental Impact Statement for the ANG Coal Gasification Company, North Dakota Project, August 1980, update of Draft Environmental Impact Statement for the ANG Coal Gasification Company, North Dakota Project, prepared by Upper Missouri Region, Bureau of Reclamation for U. S. Department of the Interior, INT DES 77-11, March 17, 1977.
2. Environmental Protection Agency/Industrial Environmental Research Lab, Environmental Assessment Report: Lurgi Coal Gasification Systems for SNG, prepared by TRW Environmental Engineering Division, EPA-600/7-79-120, May 1979.

Flash Gases from Gas Liquor Separation

Expansion gas comprised of CO_2 , CH_4 , CO , NH_3 and H_2S is produced from gas liquor separation. This gas is incinerated in a low-pressure flare. The emissions from the flare are 2.31×10^3 tons/yr of SO_2 .

Gas liquor from the primary and secondary gas cooling units within the main gasification train consists mainly of tar, tar oil, naphtha, and dissolved compounds such as phenols, ammonia, carbon dioxide, and hydrogen sulfide. The main function of the gas liquor separation unit is to extract the tar and tar oil components from the gas liquor.

The raw gas liquor streams from the gas cooling units are cooled, combined, and sent through expansion vessels where the liquor undergoes a reduction in pressure. This pressure reduction causes dissolved gases to be flashed off. The bubbling action associated with this floats the oil to the surface and enhances tar and tar oil separation via flotation.

The gas liquor then flows through primary separators where a majority of the tar is removed, and on to the secondary separators where a watery tar stream, a tar oil stream, and a stripped gas liquor stream result. A majority of the stripped gas liquor is recycled to the primary gas cooler while the remainder is sent for final tar oil/gas liquor separation. The tar- and oil-free liquor stream is sent to the water treatment area for phenol and ammonia recovery, and the tar and tar oil byproducts are sent to storage for combustion in steam boilers and superheaters. A 99 percent tar and tar oil removal efficiency may be achieved with this separation method.

Tar production

$$\begin{aligned} &= 70,120 \text{ lbs/hr} \\ &= (70,120 \text{ lbs/hr})(24 \text{ hrs/day})(365 \text{ days/yr}) \\ &\quad (0.91 \text{ capacity factor})/(2000 \text{ lb/ton}) \\ &= 0.279 \times 10^6 \text{ tons/yr} \end{aligned}$$

Tar oil production

$$\begin{aligned} &= 23,390 \text{ lbs/hr} \\ &= (23,390 \text{ lb/hr})(24 \text{ hrs/day})(365 \text{ days/yr}) \\ &\quad (0.91 \text{ capacity factor})/(2000 \text{ lbs/ton}) \\ &= 0.09 \times 10^6 \text{ tons/yr} \end{aligned}$$

Consequently, the only emission from this process area is the gas (primarily CO_2 with traces of CH_4 , CO , NH_3 , and H_2S) released from the expansion vessel. However, prior to release to the atmosphere, this expansion gas is passed through a water scrubber for ammonia removal and then incinerated in a low-pressure flare. The resulting emission rate is as follows:

Expansion gas from gas liquor separator flare to atmosphere

$$\begin{aligned} &= 7.0 \text{ tons/day} \\ &= (7.0 \text{ tons/day})(365 \text{ days/yr})(0.91 \text{ capacity factor}) \\ &= 2.3 \times 10^3 \text{ tons/yr} \end{aligned}$$

Phenosolvan Unit and Byproduct Phenols

The amount of phenol byproduct is 0.055×10^6 tons/yr. Most of this phenol byproduct is consumed by process operations. 0.48×10^6 tons/yr of filter backwash water are produced which go to ash quench as make-up water.

The portion of the gas liquor exiting the gas liquor separation unit which is not recycled to the main gasification train is contaminated with phenols, ammonia, H_2S , and CO_2 . These contaminants are extracted via a wastewater treatment facility. The wastewater treatment facility actually consists of two separate processes, the Phenosolvan process and the Phosam-W (ammonium removal) process. The first process removes the phenols from the gas liquor stream while the latter extracts the ammonia and some of the CO_2 and H_2S .

The gas liquor feed is passed through a filter and on to extractors where an organic solvent is used to remove the phenols from the liquor. The phenol entrained solvent is then sent to a distillation column where the phenols and solvent are separated. The solvent is recycled to the extractors for reuse while the phenols are stripped of excess solvent, recovered, and transferred to storage for combustion in the superheater. This byproduct is quantified below.

Phenol byproduct production rate

$$\begin{aligned} &= 165 \text{ tons/day} \\ &= (165 \text{ tons/day})(365 \text{ days/yr})(0.91 \text{ capacity factor}) \\ &= 54.8 \times 10^3 \text{ tons/yr} \end{aligned}$$

Input material to the Phenosolvan process includes make-up organic solvent used to extract the phenols from the gas liquor stream. Two commonly used solvents are butyl acetate or isopropyl ether.

The filter medium used in the Phenosolvan process to capture tarry materials and other suspended solids in the gas liquor has not been identified for the ANG process but will require disposal periodically. Backwash water is expected to periodically clean the filter medium. This water may contain tarry/oily substances and coal ash fines. Filter backwash constitutes make-up water for ash quenching.

Filter backwash

$$= 241 \text{ gpm}$$

$$= (241 \text{ gpm})(60 \text{ min/hr})(24 \text{ hr/day})(365 \text{ days/yr}) \\ (0.91 \text{ capacity factor})(8.345 \text{ lbs/gal})/(2000 \text{ lbs/ton})$$

$$= 0.48 \times 10^6 \text{ tons/yr}$$

Reference

1. Environmental Protection Agency/Industrial Environmental Research Lab
Environmental Assessment Report: Lurgi Coal Gasification Systems for
SNG, prepared by TRW Environmental Engineering Division, EPA-600/7-79-
120, May 1979.

25

Phenolic Water from Ammonia Recovery Unit

The amount of treated phenolic water produced is 8.82×10^6 tons/yr which is used as process cooling water. 7.6×10^6 tons of water are lost as evaporation and drift from the process water cooling tower and 1×10^6 tons of water are disposed of with sludge from the multieffect evaporators.

The dephenolized gas liquor exits the solvent recovery scrubber in the Phenol-solvan process and enters a superstill (stripper) where the ammonia, H_2S , CO_2 , and other steam volatiles (i.e., phenols, HCN)³ are evaporated out of the gas liquor while the stripped liquor (phenolic water) exits the bottom of the stripper. The rate of cleaned phenolic water produced is presented below.

Cleaned phenolic water

$$\begin{aligned} &= 26,557 \text{ tons/day} \\ &= (26,557 \text{ tons/day})(365 \text{ days/yr})(0.91 \text{ capacity factor}) \\ &= 8.82 \times 10^6 \text{ tons/yr} \end{aligned}$$

The phenolic water which exits the superstill is used as make-up process cooling water to replace the cooling water which evaporates from the cooling tower. Since the phenolic water may contain small quantities of phenols and a number of other organics, it is treated via biological oxidation in the cooling tower. The water which evaporates (3852 gpm) from the cooling tower carries with it only a small percent of the phenol contained in the phenolic water. A majority of the impurities are captured in the cooling tower blow-down and concentrated in the multieffect evaporators. The sludge from the evaporators which contain 70 gpm of water is disposed of in the mine.

26

Acid Gases from Ammonia Recovery to Sulfur Recovery

Acid gases produced from ammonia recovery are processed by the sulfur recovery plant.

Before the acid gas stream exits the ammonia recovery unit, it contacts a circulating ammonium phosphate solution which absorbs the ammonia out of the gas.

The ammonia-free acid gas stream (containing H_2S and CO_2) is sent to the sulfur recovery unit for cleanup. This gas stream is quantified below.

Acid gas from ammonia recovery unit to Stretford unit

$$\begin{aligned} &= 571 \text{ tons/day} \\ &= (571 \text{ tons/day})(365 \text{ days/yr})(0.91 \text{ capacity factor}) \\ &= 190 \times 10^3 \text{ tons/yr} \end{aligned}$$

27

Ammonia Recovery/Byproduct Production

The amount of marketable byproduct is 70.9×10^3 tons/yr.

The ammonia/ammonium phosphate stream is sent to a steam stripper where an ammonia-rich stream is produced and the ammonium phosphate solution is recovered. The recovered phosphate solution is recycled to the stripper (superstill) while the ammonia-rich stream is fractionated (with the aid of a caustic stream) to produce anhydrous ammonia.

The recovered ammonia byproduct is sent to storage and is quantified below.

Ammonia byproduct production

$$\begin{aligned} &= (17,800 \text{ lbs/hr})(24 \text{ hrs/day})/(2,000 \text{ lbs/ton}) \\ &= 213.6 \text{ tons/day} \\ &= (213.6 \text{ tons/day})(365 \text{ days/yr})(0.91 \text{ capacity factor}) \\ &= 70.9 \times 10^3 \text{ tons/yr} \end{aligned}$$

Both may be sold but the ANG facility plans to use the phenols to supplement the fuel for the superheaters. It must be made known that impurities may also exist in this byproduct stream.

Input material to the ammonia recovery unit includes phosphoric acid to the superstill (to adjust the pH of the system) caustic to the ammonia fractionator (to enhance stripping efficiency), and approximately 215 gpm of recycled water. Specific quantities for the ANG process are not reported.

28 & 29 Air Emissions and Byproduct Sulfur Recovery—Stretford Unit

The amount of marketable sulfur byproduct is 53.4×10^3 tons/yr. 3×10^3 tons/yr of SO_2 are released from the incineration of CO_2 . 10×10^3 tons of water/yr are released as evaporation.

Acid gas streams (H_2S and CO_2) exiting the rectisol and ammonia recovery units are combined and sent to the sulfur recovery unit for clean-up. The Stretford process can be used on streams with low H_2S (1 to 10 percent). The Stretford process has a potential H_2S removal efficiency in excess of 99 percent. The sulfur balance of the ANG facility is included as Appendix B.

The hydrogen sulfide in the acid gas stream is dissolved in a mixture of sodium carbonate and sodium bicarbonate where sodium hydrosulfide ions are formed. The sulfide is then oxidized by metavanadate to free the sulfur, which is captured and can be sold. The liquid sulfur byproduct is quantified below.

Liquid sulfur byproduct

$$\begin{aligned} &= (321,262 \text{ lbs/day}) / (2,000 \text{ lbs/ton}) \\ &= 161 \text{ tons/day} \\ &= (161 \text{ tons/day})(365 \text{ days/yr})(0.91 \text{ capacity factor}) \\ &= 53.4 \times 10^3 \text{ tons/yr} \end{aligned}$$

The metavanadate solution is regenerated by spraying it with air in the presence of an ADA catalyst. Excess air from this step contains CO_2 , which is incinerated, and water vapor, which is released to the atmosphere.

Incinerator emissions

$$\begin{aligned} &= 9.24 \text{ tons/day} \\ &= (9.24 \text{ tons/day})(365 \text{ days/yr})(0.91 \text{ capacity factor}) \\ &= 0.003 \times 10^6 \text{ tons/yr} \end{aligned}$$

III. PHYSICAL REQUIREMENTS

Water

The ANG coal gasification plant is designed to recycle much of the water used. However, process water consumption, evaporative losses and untreatable waste waters require the plant to demand a significant quantity of make-up water per day. The source of this water is Lake Sakakawea, from which 28×10^6 gal/day of water are withdrawn; 19×10^6 gal/day of this water are sent to the Basin Electric Power Plant for cooling tower make-up and for potable water. Therefore, the water required by the ANG facility itself is 9.0×10^6 gal/day.

Facility	Quantities (10^6 gpd)
Raw water from Lake Sakakawea	28.0
Water for Basin Electric Power Plant	19.0
Water for ANG Coal Gasification Plant	9.0

Figure III-1 illustrates the water circulation system of the ANG plant. All flows are in average GPM and are based on summer weather conditions. As indicated on this figure, the majority of the water lost from the ANG plant is due to evaporation. Table III-1 specifies these water losses. No process water streams are released to surface water bodies.

Process areas which handle contaminated liquids are paved and any water due to spillage or natural precipitation and drainage is collected and transported to a 5 million ft³ (20 acre) retention pond. Water not evaporated is treated, the oil recovered and incinerated, the sludge disposed of with the ash and the overflow disposed of through deepwell injection. Precipitation water from clean areas is diverted around the plant.

Figure III-1. WATER CIRCULATION SYSTEM

A.7.46

Table III-1
ANG Plant Water Use¹

<u>Facility</u>	<u>Water Losses</u>		
	GPM	GPD (10 ⁶)	TPY (10 ⁶)
Basin Electric Power Plant Cooling Tower Make-up and Potable Water	13,530	19.4	27
Process Water Cooling Tower Evaporation and Drift	3,852	5.5	7.6
Oxygen Plant Cooling Tower Evaporation and Drift	705	1.01	1.40
Stretford Unit Evaporation	56	0.08	0.1
Ash Handling System Evaporation	32	0.04	0.06
Multieffect Evaporator Waste Water to Mine Disposal	70	0.1	0.14
Ash Handling System Waste Water to Mine Disposal	53	0.07	0.10
Miscellaneous Plant Waste Water to Deepwell Injection (29 GPM of this water originates as rain water)	508	0.7	1.0
Water contained in S and Na ₂ SO ₄ -10 H ₂ O byproducts	6	0.008	0.01
Water consumed by process	<u>659</u>	<u>0.9</u>	<u>1.3</u>
	19,471	28	39

Land Requirements

16,510 acres are required for the ANG coal gasification plant and supporting facilities (excluding power generation).

The ANG plant buildings, process equipment and coal storage will occupy 535 acres. The construction laydown, area to deposit overburden from the initial mining cuts, and unused land not occupied by plant buildings but part of ANG's property comprises 905 acres. A railroad spur extending from the Burlington Northern Railroad spur 9 miles away, 6.2 miles of new roads, and 7.6 miles of underground water pipeline will require 440 acres. The product pipeline will be 365 miles long to connect the plant to Thief River Falls, Minnesota, where the SNG produced will be comingled with natural gas for transmission to the Michigan-Wisconsin market. This pipeline will require 2,190 acres. The proposed mine consists of four areas in close proximity to the plant.

Approximately 500 acres per year would be mined involving 12,500 acres over a 25-year period. The acreage disturbed by mining could vary as much as 10 percent depending on the actual depth and thickness of the coal seams.

Air

The ANG Lurgi gasification process requires 5,432 TPD of oxygen. The oxygen is produced by separating the oxygen, nitrogen, and noble gases from air. The nitrogen and noble gases are subsequently released to the atmosphere.

Reference

1. U. S. Department of Energy, Final Environmental Impact Statement for the ANG Coal Gasification Company, North Dakota Project, August 1980, update of Draft Environmental Impact Statement for the ANG Coal Gasification Company, North Dakota Project, prepared by Upper Missouri Region, Bureau of Reclamation for U. S. Department of the Interior, INT DES 77-11, March 17, 1977.

IV. PERSONNEL

Plant construction will require 1046 temporary employees in the peak year. Plant operation will require 414 permanent employees for the first 6 years, increasing to 640 thereafter.

Peak construction will occur 3 years after project initiation. The number of temporary employees that will be necessary during peak construction is 1046. The number of permanent employees required for plant operation will be 414 after the construction phase is completed. This number will remain constant for the first 6 years of operation; however, from the seventh year until plant decommissioning or refurbishing, 640 employees will be required.

Construction of the mine will commence simultaneously to plant construction but will only continue for 8 years and employ 320 in the peak year. The number of employees needed to operate the mine will increase from 47 in the first year to 360 by the ninth year.

Reference

1. U. S. Department of Energy, Final Environmental Impact Statement for the ANG Coal Gasification Company, North Dakota Project, August 1980, update of Draft Environmental Impact Statement for the ANG Coal Gasification Company, North Dakota Project, prepared by Upper Missouri Region, Bureau of Reclamation for U. S. Department of the Interior, INT DES 77-11, March 17, 1977.

V. OCCUPATIONAL SAFETY AND HEALTH

The work force at the coal gasification plant responsible for daily operations and maintenance is projected to be 527 employees.* There will also be an average of 312 employees who will be working at the surface mine.¹ The morbidity/ mortality rates per worker per year are:²

	<u>Deaths</u>	<u>Injuries</u>
Surface strip mining	0.0011	0.034
Coal gasification	0.0008	0.002

At these rates, the Great Plains Gasification Plant will experience the following morbidity/mortality per year.

	<u>Deaths</u>	<u>Injuries</u>
Surface strip mining	0.34	10.6
Coal Gasification	0.42	1.0

Coal handling and blasting, the presence of flammable materials, large equipment use, and heavy truck traffic pose the most significant safety hazards to coal miners. In addition, significant amounts of coal dust produced during blasting, loading, hauling, coal stacking, and reclaiming operations are generated which could cause or exacerbate respiratory ailments.

Potential leaks or spills of liquids and gases may be the most significant health hazard associated with the coal gasification plant. Although the probability of accidents from handling gasification byproducts and chemicals such as tar, oil, naphtha, methanol and phenols is quite low, there is a potential hazard due to their flammability. Additional safety hazards are associated with the possible leakage at the plant site of toxic materials such as hydrogen sulfide or ammonia which can be lethal in high concentrations.

* This is an average figure.

References

1. U. S. Department of Energy, Final Environmental Impact Statement for the ANG Coal Gasification Company, North Dakota Project, August 1980, update of Draft Environmental Impact Statement for the ANG Coal Gasification Company, North Dakota Project, prepared by Upper Missouri Region, Bureau of Reclamation for U. S. Department of the Interior, INT DES 77-11, March 17, 1977.
2. U. S. Environmental Protection Agency, Energy from the West: Impact Analysis Report, Vol. 1, Introduction and Summary, EPA-600/7-79-082a, March 1979.

APPENDIX A. HEAT AND MASS BALANCE

An overall heat balance for this SNG from coal process is given in Table A-1.¹ As indicated in that energy balance, SNG is the primary product with a small quantity of ammonia as a marketable by-product. Other energy by-products such as tars, phenols, and off-gases are recovered to generate steam for process operation. As can be seen by the fuel requirements for the plant, supporting electric power must be purchased from a central utility. Other process designs have been based on on-site electric power generation.² The overall process thermal efficiency for the ANG plant is 66 percent to 69 percent which conforms with other similar process efficiency estimates cited in the general technical literature.

The overall mass balance for the gasification train for this process is broken down in Table A-2 under the column labeled "ANG". The mass balance for an alternative design, the WESCO project,³ is also broken down in Table A-2 to illustrate how widely the mass flow rates can vary for an alternative design which would produce essentially the same amount of SNG (within 5 percent of the tons/day of the ANG project). The WESCO project would use a subbituminous coal (versus the lignite to be used by ANG) and is designed for a much lower water consumption rate (as indicated by the lower amounts of wastewater produced which could be used for cooling) than the ANG design. Also note that the ANG design would use more coal yet vent more CO₂ than the WESCO design because of the corresponding coal characteristics which are given in Table A-3. The ash produced by the ANG design is 6.5 percent of the weight of the input coal or within a percentage point of the ash constituent indicated in the proximate analysis of Table A-3. The ash produced by the WESCO design is 24.3 percent of the weight of the input coal or within 7 percentage points of the ash constituent indicated in the proximate analysis of Table A-3.

The tars, oils, phenols, and other byproducts of the process capture the balance of the ash. The ash that may remain in the product SNG would be in the order of a few parts per million (ppm) at most. Consequently, most of the unreactive ash in the feed coal to the gasifier is separated as ash in the gasifier lock hopper. Most of the remaining ash captured by the tars, oils, and phenols from the process is eventually incinerated again as a boiler fuel. Consequently, only a very small fraction of the ash in the source coal is emitted into the air as a pollutant after boiler emission controls. Any hazardous trace metals in the ash are therefore essentially captured with ash by-products from the gasifier and supporting boiler. The ash produced by each of the designs in Table A-2 illustrates that, despite a wide range in the proportion of ash constituents in the feed coals, most of the ash is separated in solid or sludge form.

Table A-1. SNG FROM COAL ENERGY BALANCE^a

<u>Input</u>	<u>Million Btu/day</u>
1. Coal to Gasifier	394,353
o 27,272 tons/day	
o 2,000 lbs/ton	
o 7,230 Btu/lb	
2. Fuel to Electric Power Station ^b	11,700
o Supporting power	
o Power at 3410 MWh/day	
3. Fuel for on-site vehicles	<u>2,900</u>
4. Total Input Energy	408,953

<u>Output</u>	
1. SNG	268,691
o $275 \times 10^6 \text{ ft}^3/\text{day}$	
o 977 Btu/ft^3	
2. Ammonia	<u>4,200</u>
3. Total Output Energy	272,891

Overall Process Efficiency

1. Efficiency = $\frac{\text{Total Output Energy}}{\text{Total Input Energy}} = 66.7\%$

(without recovery of waste energy to generate steam for the electric power station)

2. Efficiency with waste heat recovery, $E' = 68.7\%$.
(deduct fuel to electric power station from total input energy).

Other Energy Byproducts^c

o Tar, oils, and naphtha	41,900
o Phenols	4,500
o Stretford off-gas	<u>14,500</u>
o Total intermediate energy	60,900
o Electric energy potential = 6000 MWh/day or 250MW capacity (plant efficiency = 33% assumed)	

Notes:

- From Ref. 1, page B-6 (Appendix B) and page 1-50.
- Fuel for the Electric Power Station is the fuel required by a remote source of electrical energy (no on-site electrical energy is produced).
- Most of these other energy by-products are used to generate steam for plant operations (Ref. 1, page 1-50).

Table A-2. GASIFICATION TRAIN MATERIAL BALANCES

Source	ANG	WESCO	
Year	1974	1976	Supporting
Ref.	(Ref. 1)	(Ref. 4)	Processes
	tons/day	tons/day	
I. Inputs			
Coal to Lurgi Gasifiers	26,842	24,820	
Steam to Lurgi Gasifiers	28,365	22,570	Steam Plant
Oxygen to Lurgi Gasifiers	5,432	5,800	Oxygen Plant
Water and Steam to Rectisol Plant	746	1,080	Steam Plant
I. Totals (rounded)	61,385	54,270	
II. Outputs			
Ash from Gasifier to Disposal	1,763	6,534	
Ammonia from Phenosolvan Plant to Sales	214	204	
Offgas from Rectisol Plant to Stretford Unit	21,838	19,438	
Naphtha from Rectisol Plant to Plant Fuel	136	315	
Dry Gas SNG from Methanator to Sales	5,681	5,960	
III. Intermediate Products			
CO ₂ and H ₂ S Expansion Gas	68	266	Sulfur Plant
CO ₂ and H ₂ S from Phenosolvan to Sulfur Plant	570	516	Sulfur Plant
Tar from Gas Liquor Separation to Plant Fuel	841	743	
Tar Oil and Naphtha to Sales or Plant Fuel	142	755	
Crude Phenols from Phenosolvan to Plant Fuel	163	102	
Phenolic Water to Treating and Reuse (cooling)	26,399	14,551	Wastewater Treatment
Water from Rectisol to Reuse	-	1,125	Wastewater Treatment
Water from Methanator to Reuse	3,570	3,760	Wastewater Treatment
III Totals (rounded)	61,385	54,270	

Table A-3. THE CHARACTERISTICS OF COALS FOR TWO COAL GASIFICATION PROJECTS

1. Proximate Analysis

<u>Constituent</u>	<u>Percent by Weight</u>	
	<u>ANG^a</u>	<u>WESCO^b</u>
Moisture	35.98	12.4
Ash	7.42	30.8
Fixed Carbon	23.39	-
Volatiles	27.21	-
<u>Heat Content, Btu/lb</u>	7,230	8,500

2. Ultimate Analysis

<u>Element</u>	<u>Percent by Weight</u>	
	<u>ANG^a</u>	<u>WESCO^b</u>
Carbon	71.45	37.2
Hydrogen	4.81	3.7
Oxygen	21.01	11.1
Nitrogen	1.44	1.01
Sulfur	1.26	1.09
Chloride	0.02	-

a) ANG coal is based on the results of 107 samples of run-of-mine lignite from the Beulah-Hazen Coalfield (Ref. 1, page 1-20).

b) WESCO coal is taken from subbituminous coal mines in New Mexico (Ref. 3, page 82).

Table A-3 also indicates that western coals tend to have a low sulfur content (generally less than 2 percent). Most of the sulfur in the gas stream must be reduced to less than 0.1 ppm to avoid poisoning the methanation catalyst. The product SNG therefore will contain essentially no sulfur and will not produce measurable sulfur oxides upon combustion. Over 90 percent of the sulfur in the fuel gases from the gasifier is separated as elemental sulfur. Some of the balance sulfur is captured by ash, tar, and oil by-products. The fraction that may be vented as H_2S , SO_2 , COS , and CS_2 into the air can be reduced to much less than 1 ppm through tail gas treatment.

References

1. U. S. Department of Energy, Final Environmental Impact Statement for the ANG Coal Gasification Company, North Dakota Project, August 1980, update of Draft Environmental Impact Statement for the ANG Coal Gasification Company, North Dakota Project, prepared by Upper Missouri Region, Bureau of Reclamation for U. S. Department of the Interior, INT DES 77-11, March 17, 1977.
2. Environmental Protection Agency/Industrial Environmental Research Lab, Environmental Assessment Report: Lurgi Coal Gasification System for SNG, prepared by TRW Environmental Engineering Division, EPA-600/7-79-120, May 1979.
3. U. S. Department of the Interior, Western Coal Gasification Company (WESCO) Coal Gasification Project and Expansion of Navajo Mine by Utah International, Inc., San Juan, New Mexico: Final Environmental Statement, prepared by Bureau of Reclamation, INT FES 76-2, January 14, 1976.

APPENDIX B. SULFUR BALANCE

*Ref. 1, Appendix A.

APPENDIX C. TRACE ELEMENT ANALYSIS

ELEMENT	COAL		ASH			GAS LIQUOR			TAR			OIL			BALANCE
	2/ ppm	g/t 1/ coal	ppm	mg/t coal	distr	ppm	mg/t coal	distr	ppm	mg/t coal	distr	ppm	mg/t coal	distr	
Lithium	20	13.1	60	4.35	33	0.02	0.02	0.2	5	0.18	1.4	0.5	0.004	-	35
Beryllium	2.0	1.3	5	0.36	28	0.008	0.008	0.6	0.1	0.003	0.2	0.05	0.0004	-	29
Boron	300	197	>1500	109	55	3	3.0	1.5	20	0.73	0.4	30	0.24	0.1	57
Fluorine	24	15.8	230	16.7	106	0.5	0.5	3.2	12	0.44	2.8	0.06	0.0005	-	112
Vanadium	10	6.6	70	5.1	77	0.003	0.003	-	0.05	0.002	-	0.15	0.001	-	77
Chromium	6	3.9	40	2.9	74	<0.03	0.03	0.8	1	0.04	0.9	0.6	0.005	0.1	76
Cobalt	2	1.3	10	0.73	56	<0.03	0.03	2	0.05	0.002	0.2	0.02	0.0002	-	59
Nickel	3	2.0	25	1.8	91	<0.2	0.2	10	10	0.37	18	1.5	0.01	0.6	120
Copper	5	3.3	50	3.6	109	0.3	0.3	9	0.1	0.004	-	2	0.01	0.3	118
Zinc	0.6	0.4	0.5	0.04	10	0.4	0.4	100	6	0.2	50	0.4	0.003	0.8	161
Arsenic	30	19.7	60	4.3	22	3	3	15	2	0.07	0.4	1.7	0.01	-	39
Selenium	1	0.66	1.5	0.11	16	2	2	303	0.2	0.007	1	<0.01	-	-	320
Molybdenum	0.5	0.33	4	0.29	88	<0.2	0.2	61	0.02	0.0007	0.2	0.02	0.0001	-	149
Silver	0.1	0.066	0.7	0.05	77	<0.2	0.2	303	<0.2	0.007	11	<1	0.008	12	403
Cadmium	<0.1	0.066	<1	0.07	106	<0.03	0.03	45	<0.1	0.004	5	<0.1	-	-	156
Tin	4	2.63	12	0.87	33	<0.03	0.03	1	0.2	0.007	0.3	<0.05	-	-	34
Antimony	0.1	0.066	1	0.07	110	<0.03	0.03	45	<0.05	0.002	3	<0.02	-	-	158
Barium	2500	1642	1.2% 870	53	-	-	-	-	15	0.55	-	0.5	0.004	-	53
Mercury	0.05	0.033	<0.1	0.007	22	<0.03	0.03	91	<0.1	0.003	11	<0.1	0.0008	2.4	126
Lead	20	13.1	200	14.5	111	0.2	0.2	1.5	1.5	0.055	0.4	0.15	0.001	-	113
Thorium	1	0.66	6	0.43	66	-	-	-	2	0.07	11	<1	0.008	1	78
Uranium	1	0.66	6	0.43	66	<0.2	0.2	30	5	0.18	28	<1	0.008	1	125

1/ Grams/metric ton (wet)

2/ Parts per million (dry)

Source: Ref. 1, **APPENDIX A.**

APPENDIX D. GAS STREAM COMPOSITION

Stream	General Components	Percent by Weight
Raw Gas (from gasifier)	Dry Gas	51.7
	Water	45.4
	Hydrogen Cyanide	0.0002
	Chlorides	0.0016
	Tar	1.6
	Oil	0.37
	Naphtha	0.18
	Phenols	0.31
	Fatty Acids	0.09
	Dust	0.30

Stream	Constituents	Molecular Percent
Dry Gas (from gasifier)	H ₂	38.8
	CO	15.6
	CO ₂	32.5
	CH ₄	10.8
	C ₂ H ₆	0.5
	C ₂ H ₄	0.07
	C ₃ H ₈	0.08
	C ₃ H ₆	0.07
	C ₄ H ₁₀	0.04
	C ₄ H ₈	0.07
	N ₂	0.07
	Ar	0.05
	H ₂ S	0.35
	COS	0.01
	Organic Sulfur	0.01
	NH ₃	1.0

Product Stream	Constituents	Percent by Volume
SNG Product	CH ₄	95.9
	H ₂	3.0
	CO	0.05
	CO ₂	0.40
	N ₂	0.60
	Heating Value	970 Btu/scf (minimum)

* From Ref. 1, APPENDIX A.

APPENDIX E. GASIFIER ASH COMPOSITION

<u>Major Elements</u>	<u>Percent</u>
Al_2O_3	24
CaO	26
Fe_2O_3	11
K_2O	0.6
MgO	7
Na_2O	8
SiO_2	25
TiO_2	0.6
SO_3	3.1
C	-
N	-
Cl	0.007

• From Ref. 1, pg. APPENDIX A.

APPENDIX F. ANG GASEOUS EMISSIONS COMPARED TO FEDERAL STANDARDS

The primary pollutants released from the gasification plant, assuming full operation of all pollution control equipment at design levels, are listed below in lbs/hr. A 400-foot stack will release emissions from sulfur recovery and a 200-foot stack will release emissions from plant flares.

<u>Emission</u>	<u>lbs/hr</u>
NO ₂	1,100
SO ₂	2,880*
TSP	265
CO	360
HC	130

- Assumes a maximum of 1.7 percent sulfur in the coal.

These figures exclude emissions from start-up, shut-down and upset flares and they do not include emissions from the Basin Electric power plant. The maximum predicted ground-level concentrations of these pollutants due to these levels of releases and the national ambient air quality standards are presented in Table F-1. The predicted levels of ground-level pollutant concentrations due to the gasification plant are well below the Federal and state standards.

The emissions from the Basin Electric Power Plant, which supplies the power for the ANG plant, together with emissions from steam generation for the gasifier exceed current Federal emission standards for SO₂ and particulates (see Table F-2). However, the gasification plant and the supporting mine only require 160 MW of the 880 MW generated by Basin Electric. Therefore, not all these emissions can be attributed to coal gasification. However, these two plants in combination may require additional pollution control measures to meet these standards. Treatment of flue gases in an FGD unit and control of superheater emissions would probably allow the SO₂ and particulate standards to be met. If the ANG plant were designed to generate its own power, the emission levels may be significantly lower.

Table F-1. MAXIMUM GROUND-LEVEL CONCENTRATIONS FROM ANG GASIFICATION PLANT (Ref. 1) ($\mu\text{g}/\text{m}^3$)

Pollutant	Averaging Time	ANG	Federal National Ambient Air Quality Standards		PSD		
			Primary	Secondary	Class I	Class II	Class III
NO _x	Annual	0.5	100	Same			
	24-hour	-					
	3-hr	-					
	1-hr	32.5					
SO ₂	Annual	2.4	80	1,300	2	20	40
	24-hr	24.3	365		8	91	182
	3-hr	61.8			25	512	700
	1-hr	152.8					
Particulates	Annual	0.1	75	60	5	19	37
	24-hr	0.8	260	150	10	37	75
	3-hr	-					
	1-hr	-					
CO	Annual	-	10	40			
	24-hr	-					
	8-hr	-					
	1-hr	-					

A.7-61

Table F-2. COMPARISON OF STEAM AND POWER GENERATION WITH FEDERAL STANDARDS (Ref. 1) g/million cal (lb/million Btu)

	<u>ANG</u>	<u>Federal Standards</u>
NO _x	1.0 (0.25)	1.1 (0.6)
SO ₂	1.3 (0.72)	0.94 (0.52)
Particulates	0.13 (0.072)	0.054 (0.030)

Site-Specific Considerations

The composition and quantities of gaseous emissions from Lurgi coal gasification plants differ according to coal sulfur content, plant size, design of the Rectisol acid gas removal unit, the fuel used for onsite steam and power generation, and the specific air pollution control processes employed. The composition and quantities of emissions identified in this report are based on the use of 1.7 percent sulfur coal with 7230 Btu/lb HHV. Coals with higher heat content but the same percentage of sulfur should produce acid gases from the Rectisol unit which have a higher ratio of CO₂ to H₂S and COS. Coals with higher sulfur produce acid gases in which H₂S and COS₂ are increased in proportion to sulfur content. The air pollution control energy requirements should increase as sulfur content in the coal increases because of the additional energy demands of FGD and sulfur recovery systems. Increased heat content increases the volume of acid gases and therefore increases the use of acid gas/tail gas pollution control equipment for sulfur, CO, and HC.

The air emission standards Lurgi gasification plants must meet include site-specific requirements. To facilitate regulation and plant permitting under these regulatory conditions, EPA may not promulgate new source performance standards for Lurgi coal gasification plants but instead is preparing a Pollution Control Guidance Document (PCGD) which will present several acceptable pollution control options. In a preliminary guidance document, "Control of Emissions from Lurgi Coal Gasification Plants," published in March 1978, the Rectisol process is identified as the major emission source. Two alternative emission control systems are analyzed in this document. Alternative I consists of a Stretford sulfur recovery plant and an H₂S concentration plant (ADIP) type followed by Claus sulfur recovery and represents the minimal level of emission control. Alternative II consists of two options, Option II-1 includes a Stretford sulfur recovery plant on the combined lean and rich H₂S gas streams. Option II-2 includes a Stretford plant on the lean H₂S stream and an ADIP-H₂S plant followed by a Claus plant and Claus tail gas treatment on the rich H₂S stream. The emissions produced by these options for three types of coal (a western subbituminous coal of low sulfur content, a low sulfur western lignite, and a high sulfur midwest bituminous coal) are presented in Table F-3. The final PCGD will allow permit writers in all levels of government to determine the appropriate level of control required on coal

gasification plants given varying meteorological, climatological and topographic conditions.

The pollution control option used by the ANG plant most closely resembles EPA Option II-1. This option achieves the highest percentage of sulfur recovery and the lowest pollutant emissions of the three EPA options.

Table F-3. EMISSIONS FROM A 250-MILLION BTU PER DAY LURGI SNG COAL GASIFICATION PLANT WITH ALTERNATIVE EMISSION CONTROLS (Ref. 1)

Pollutant	Uncontrolled			Alternative I			Alternative II (Options 1 and 2)					
	(a) [†]	(b) [†]	(c) [†]	(a)	(b)	(c)	1(a)	1(b)	1(c)	2(a)	2(b)	2(c)
SO ₂	--	--	--	418 (922)	1,012 (2,134)	2,777 (6,131)	209 (461)	426 (941)	1,035 (2,285)	215 (474)	441 (973)	1,067 (2,355)
H ₂ S	2,563 (5,658)	8,847 (19,530)	26,541 (58,589)	--	--	--	--	--	--	--	--	--
HC [‡]	7,954 (17,559)	7,954 (17,559)	7,954 (17,559)	113 (250)	113 (250)	113 (250)	113 (250)	113 (250)	113 (250)	113 (250)	113 (250)	113 (250)
Total Sulfur, as S	2,424 (5,325)	8,327 (18,381)	24,980 (55,143)	209 (461)	506 (1,117)	1,389 (3,066)	104 (230)	213 (470)	517 (1,142)	107 (237)	220 (406)	534 (1,178)
Sulfur Recovery, %	0	0	0	91.3	93.9	94.5	95.7	97.4	97.9	95.6	97.4	97.9

*All numbers in kg/hr (lb/hr) except where noted

[†]Sulfur/heating value ratios of 0.72, 2.2 and 6.5 kg/sulfur/10⁶ kcal (0.4, 1.2 and 3.6 lb sulfur/10⁶ Btu), respectively

[‡]Non-methane hydrocarbons, average molecular weight = 29

Reference

1. U. S. Environmental Protection Agency, Control of Emissions from Lurgi Coal Gasification Plants, prepared by the EPA Office of Air and Waste Management, Office of Air Quality Planning and Standards, Research Triangle Park, North Carolina, March 1978.

GLOSSARY

Blowdown	Water that is periodically removed from either the cooling towers or the coal-fired boiler to prevent concentration of total dissolved solids.
Bottom ash	Noncombustible residues of coal combustion that are collected and removed from the boiler.
Capacity factor	The actual plant output in a year divided by the output that would be achieved if the plant were to operate at 100-percent power for 365 days/year.
Catalyst	A substance used to increase the rate of a chemical reaction which does not undergo permanent chemical change itself.
Clarifiers	System used to remove the majority of total suspended solids in the river makeup water.
Coal fines	Coal crushed into particles smaller than 0.64 cm.
Cooling tower drift loss	Aerosols of water that are lost in the atmosphere from the cooling towers.
Cooling tower evaporation loss	Circulating water that is evaporated as a result of heat transferred from the circulating water system and lost in the atmosphere via the cooling towers.
Dead storage	Long-term storage in which the coal is typically compacted and sealed.
Electrostatic precipitator	Environmental control device used to remove a high percentage of the fly ash in the flue gas.
Flue gas	Gases generated from the combustion of fossil fuel in the boiler.
Flue gas desulfurization scrubbers	Environmental control device used to remove a high percentage of the sulfur dioxide in flue gases.
Fly ash	Noncombustible residues of coal combustion that are carried out of the boiler in the flue gas.
Fugitive emissions	Unintentional emissions, such as blowing dust from a coal pile.
Leaching	The separation or dissolving of soluble minerals or metals out of an ore by percolation of water.

GLOSSARY (Cont'd)

Lignite	The lowest rank of coal regarding fixed carbon content, heat content, moisture and volatile matter.
Lurgi gasification	A high Btu coal gasifier developed in Germany.
Recycle water	Water that is collected, treated, and reused at the power plant.
Run-of-mine coal	Coal as it comes from the mine prior to sizing or other preparation.
Sludge	Wet residue of lime/limestone and sulfur that is generated in the flue gas desulfurization unit or ash from gasifier and steam plant combined with phenolic water.
Synthetic natural gas	A low, medium, or high Btu methane gas synthetically produced from carbonaceous material (i.e., coal, biomass) composed of hydrogen, carbon monoxide, carbon dioxide, and methane.

ACRONYMS AND ABBREVIATIONS

ANG	American Natural Gas Coal Gasification Company	MMscf/d	million standard cubic feet per day
bbl	barrel	N ₂	nitrogen
Btu	British thermal unit	NH ₃	ammonia
C	carbon	NO _x	nitrogen oxides
CH ₄	methane gas	NSPS	New Source Performance Standards
CO	carbon monoxide	O ₂	oxygen
CO ₂	carbon dioxide	ppm	parts per million
ECIR	Environmental Character- ization Information Report	ROM	run-of-mine
ESP	electrostatic precipitator	S	sulfur
gal	gallon	scf	standard cubic foot
H	hydrogen	SNG	synthetic natural gas
HC	hydrocarbons	SO ₂	sulfur dioxide
H ₂ O	water	TSP	total suspended particles
H ₂ S	hydrocarbons	g	microgram
lb	pound	WESCO	Western Gasification Company (New Mexico)
m ³	cubic meter	yr	year

Eastern Underground Coal Mining

Environmental Characterization Information Report

October 1982

U.S. Department of Energy
Assistant Secretary for Environmental
Protection, Safety, and
Emergency Preparedness
Office of Environmental Analysis

CONTENTS

	<u>Page</u>
I. SUMMARY	A.8-3
II. PROCESS DESCRIPTION AND ENVIRONMENTAL POINTS OF INTEREST.	A.8-7
1. Exploration and Construction Resources.	A.8-8
2. Air Emissions During Exploration.	A.8-8
3. Solid Waste From Portal (Shaft) Construction.	A.8-13
4. Runoff From Spoils of Construction and Mining Operations.	A.8-14
5. Emissions During Construction of Portal Shaft	A.8-15
6. Construction of Mains	A.8-17
7. Roof Support During Construction of Mains	A.8-18
8. Suppression of Underground Coal Dust During Construction of Mains	A.8-19
9. Air Emissions From Installation of Electricity, Belts, and Track	A.8-21
10. Release and Treatment of Ground Water	A.8-22
11. Solid Waste From Ventilation of Shaft Construction.	A.8-23
12. Water Used for Dust Suppression During Longwall Extraction.	A.8-25
13. Dust Emissions From Belt Transfer Operations.	A.8-27
14. Water Used for Dust Control During Continuous Extraction Operations.	A.8-28
15. Noise Emissions From the Underground Mining Equipment	A.8-30
16. Power Requirements for the Underground Mine	A.8-31
17. Subsidence of Land.	A.8-33
18. Emissions From Coal Storage at the Preparation Plant.	A.8-34
19. Energy Requirements for Coal Preparation Plant.	A.8-34
20. Fugitive Dust Emissions From Crushing and Screening Operations.	A.8-35
21. Coal Washing.	A.8-36
22. Noise Emissions From the Coal Preparation Plant	A.8-37
23. Liquid Waste From the Coal Mine and Preparation Plant	A.8-38
24. Solid Waste From the Coal Preparation Plant	A.8-39
III. PHYSICAL REQUIREMENTS	A.8-40
IV. PERSONNEL	A.8-43
V. OCCUPATIONAL SAFETY AND HEALTH.	A.8-44
APPENDIX A: WASTEWATER EFFLUENT LIMITATIONS.	A.8-45
APPENDIX B: COST ESTIMATES	A.8-46
GLOSSARY	A.8-49
ACRONYMS AND ABBREVIATIONS	A.8-51

I. SUMMARY

This Environmental Characterization Information Report (ECIR) for Eastern Underground Coal Mining has been prepared from the latest available environmental and technical information collected from a number of sources. The mine selected for characterization produces some 1.5 million tons of bituminous coal annually and has an on-site coal preparation plant.

The assumed coal production process, mine operating parameters, input resources required, and the environmental residuals and products associated with the mine are summarized in this section in Table 1. Annual resource usage and pollutant discharges are shown in English and metric units on an operating basis of three shifts per day for 300 days each year.

In addition to annual quantities, Table 1 presents quantities on the basis of 10^{12} Btu of energy (coal) produced. These figures are provided to allow comparisons among different energy processes and to facilitate application of the information in computer models.

The supporting information and calculation procedures for the data are given in Section II. Twenty-four environmental points of interest are discussed individually. For each of these, a brief description is given of the pollutants or resources involved and standards to be met. Example calculations are provided to show the derivation of quantities, scaling laws and extrapolation methods to adjust to other conditions.

Section III discusses the overall physical requirements of the mine for land and water; Section IV gives the approximate number of personnel involved in constructing and operating the mine and coal preparation plants; and Section V presents a brief description of the occupational health and safety hazards associated with underground coal mining and processing. A glossary and a listing of acronyms and abbreviations used appear at the end of the document.

TABLE 1. SUMMARY SHEET

EASTERN UNDERGROUND COAL MINING

ENERGY SYSTEM DESCRIPTION

Underground Bituminous Coal Mine Located in Appalachia; Coal Preparation Plant Onsite; Rock Dusting and Water Spray Inside Mine for Dust Control; Water Spray in Coal Preparation Plant, on Mine Roads, and on Coal and Waste Storage Piles; Drainage Ditches and Catchment Ponds; Onsite Solid Waste Disposal; Onsite Water Treatment and Recycling To Minimize Discharge and Makeup Water Requirements. Facilities Are Subject to Federal and State Regulations.

FACILITY OPERATING PARAMETERS

Size	• Mine:	1.5×10^6 ton/yr
	• Preparation Plant:	1.125×10^6 ton/yr
Annual Capacity Factor	• Preparation Plant:	60% to 85%
Annual Energy Production	• Preparation Plant:	30.2×10^{12} Btu
Efficiency	• Preparation Plant:	75%
Lifetime	• Mine:	23 yr

PROCESS FLOW

RESOURCES USED

Code No.	Resource	Quantities Used		
		Reference Energy System Annual Usage		Per 10 ¹² Btu Energy Produced
		English Units	Metric Units	
	<u>Diesel Fuel</u>			
(1)	Exploration and reserve assessment	3.2 × 10 ³ gal	12 × 10 ³ liters	106 gal
(1) (5)	Portal and facility construction	54 × 10 ³ gal	204 × 10 ³ liters	1.79 × 10 ³ gal
	<u>Electricity</u>			
(16)	Mine equipment requirements	52.5 × 10 ⁶ kWh	—	1.74 × 10 ⁶ kWh
	Coal preparation plant	6.4 × 10 ⁶ kWh	—	212 × 10 ³ kWh

TABLE 1. (Continued)

EASTERN UNDERGROUND COAL MINING

RESOURCES USED (Continued)

		Quantities Used			Remarks
		Reference Energy System Annual Usage		Per 10 ¹² Btu Energy Produced	
Resource	English Units	Metric Units			
<u>Land</u>					
Surface construction (fixed land)	6 acres	2.4 ha	—		
Coal preparation waste storage	1.5 acres	0.6 ha	0.05 acres		
<u>Water</u>					
<u>Dust Control (total)</u>	110 × 10 ⁶ gal	416 × 10 ⁶ liters	3.6 × 10 ⁶ gal		
(8) Mains	8.6 × 10 ⁶ gal	33 × 10 ⁶ liters	0.3 × 10 ⁶ gal		
(12) Longwalls	24.3 × 10 ⁶ gal	92 × 10 ⁶ liters	0.8 × 10 ⁶ gal		
(14) Continuous extraction	78 × 10 ⁶ gal	295 × 10 ⁶ liters	2.6 × 10 ⁶ gal		
<u>Makeup Water (total)</u>	41 × 10 ⁶ gal	155 × 10 ⁶ liters	1.4 × 10 ⁶ gal		
Mining/construction	11 × 10 ⁶ gal	42 × 10 ⁶ liters	0.4 × 10 ⁶ gal		
(21) Preparation plant	30 × 10 ⁶ gal	114 × 10 ⁶ liters	1.0 × 10 ⁶ gal		
(10) Ground water		Unquantifiable			
<u>Personnel</u>					
Coal mine	425 workers		14.07 workers	Operation and maintenance personnel	
Preparation plant	12 workers		0.397 workers		

COSTS				
Facility	Reference Energy System	(1978 \$)	Per 10 ¹² Btu Energy Produced	Remarks
<u>Capital</u>				
• Mine	\$65 × 10 ⁶ total		\$2.2 × 10 ⁶ total	See Appendix B for details and data sources
• Preparation plant	(\$1.4-\$13.4) × 10 ⁶ total		(\$0.05-\$0.44) × 10 ⁶ total	
<u>Operation and maintenance</u>				
• Mine	\$24 × 10 ⁶ /yr		\$0.79 × 10 ⁶ /yr	
• Preparation plant	(\$0.8-\$10.0) × 10 ⁶ /yr		(\$0.03-\$0.33) × 10 ⁶ /yr	
<u>Environmental Controls</u>	Included in above costs			

ENVIRONMENTAL RESIDUALS AND PRODUCTS				
Code	Residual or Product	Quantities Used		
		Reference Energy System Annual Levels		Remarks
		English Units	Metric Units	
(6) (7)	Fugitive Dust (unquantifiable)			
(2)	Construction of mains		Negligible	
(9)	Exploration		Unquantifiable	
(13)	Installations		Unquantifiable	
(18)	Belt transfer of coal		Unquantifiable	
(20) (21)	Coal storage		No emissions	
	Crushing, screening and washing		Negligible	

TABLE 1. (Continued)

EASTERN UNDERGROUND COAL MINING

ENVIRONMENTAL RESIDUALS AND PRODUCTS
(Continued)

(Continued)		Quantities Released			Remarks
Code No.	Residual or Product	Reference Energy System		Per 10 ¹² Btu Energy Produced	
		Annual Levels			
		English Units	Metric Units		
25	<u>Diesel Fuel Emissions</u>				
	Particulates	0.72 ton	0.65 tonne	0.02 ton	
	HC	0.72 ton	0.65 tonne	0.02 ton	
	SO ₂	0.89 ton	0.81 tonne	0.03 ton	
	CO	2.5 tons	2.3 tonnes	0.08 ton	
	NO ₂	9.4 tons	8.5 tonnes	0.31 ton	
23	<u>Water Pollutants</u>		Unquantifiable		
4	<u>Liquid Waste/Runoff</u>		Unquantifiable		
	<u>Solid Wastes</u>				
3	Portal construction	58 × 10 ³ tons	52.7 × 10 ³ tonnes	1.92 × 10 ³ tons	One time
11	Waste from mine ventilation	12 × 10 ³ tons	10.9 × 10 ³ tonnes	397 tons	
24	Waste from preparation plant	375 × 10 ³ tons	340 × 10 ³ tonnes	12.4 × 10 ³ tons	
17	<u>Land Subsidence</u>		Not Determined		Unlikely for a 90-in. coal seam at a depth greater than 375 feet
	<u>Noise Emissions</u>				
15	Underground coal mine equipment	85-99 dBA			
22	Coal preparation plant	75-105 dBA			

PRODUCTS

Primary	Quantities Produced			Remarks
	Reference Energy System		Per 10 ¹² Btu Energy Produced	
	System			
	Annual Production			
	English Units	Metric Units		
Beneficiated Coal	1.125 × 10 ⁶ tons	1.02 × 10 ⁶ tonnes	37.3 × 10 ³ tons	Heating value of beneficiated coal = 13,400 Btu/lb

OCCUPATIONAL SAFETY AND HEALTH

	Preparation Plant		Underground Mine	
	Annual	Per 10 ¹² Btu	Annual	Per 10 ¹² Btu
Deaths	0.008	0.26 × 10 ⁻³	0.45	0.01
Injuries	1.1	0.036	71.0	2.35

II. PROCESS DESCRIPTION AND ENVIRONMENTAL POINTS OF INTEREST

The coal mining operation described in this report is typical of a deep underground coal mine in the eastern U. S. with production of approximately 1.5 million tons per year. The coal is sized and cleaned at an on-site preparation plant. The mine operates three shifts daily and has a remaining life expectancy of 23 years at current production rates. The mine uses continuous and longwall mining methods. Underground, coal is hauled in shuttle cars and is transported to the surface by conveyor. All underground equipment used during the mining process is electrically powered. The mine specifications are from Reference 1.

The process of coal mine development, from exploration to transport loading, is shown in flow diagram form in Figure 1. The environmental points of interest have been identified in this figure and are discussed in the following sections along with the resource requirements for specific parts of the mining process.

Reference

1. Mining Informational Services of McGraw-Hill Publishing Co., Keystone Coal Industry Manual, George F. Nielsen, Editor-in-Chief, 1979.

FIGURE 1. PROCESS FLOWCHART WITH ENVIRONMENTAL POINTS OF INTEREST QUANTIFIED — EASTERN UNDERGROUND MINE WITH PREPARATION PLANT

1

Exploration and Construction Resources

Reserve assessment requires 2 years of drilling which results in consumption of approximately 3×10^3 gallons of diesel fuel each year. Diesel fuel equipment used during exploration and construction activities is estimated to require 57×10^3 gallons each year.

The mine is assumed to have a life expectancy of approximately 23 years. In order to provide a production of 1.5×10^6 tons/yr, reserves averaging 90 inches thick and extending for 13,440 acres (21 square miles) must be available. To verify this quantity of coal reserves, extensive drilling and geologic investigations are necessary.

The initial drilling plan is based on a grid pattern designed to identify any gross changes in coal continuity, quality, and structural dip. In areas where initial drilling indicates a uniform coal thickness, dip, and quality, the spacing of additional exploration holes is dictated by mining methods to be used and physical features in the overburden and on the surface. When initial drilling indicates changes in coal quality, thickness, or dip, a more closely spaced drill pattern is required to determine if a section is mineable and the best mining method to employ.

The major resource used in the exploration phase is diesel fuel. Drilling one 750-ft hole takes approximately 8 hours. This includes set-up, drilling, and tear-down time. Actual drilling time is approximately 4 hours. While drilling, the rig uses approximately 8.2 gallons of fuel per hour. Under non-load conditions (i.e., pulling steel, idle time, etc.) the drill rig will consume approximately 5 gallons of fuel per hour.

Quantity of diesel fuel required per 750 ft exploration hole

$$\begin{aligned}
 &= [(\text{time required for drilling}) (\text{fuel consumption rate})] \\
 &\quad + [(\text{non-load fuel requirement}) (\text{non-load drill time})] \\
 &= [(4 \text{ hours}) (8.2 \text{ gal/hr})] + [(5.0 \text{ gal/hr}) (4 \text{ hours})] \\
 &= 52.8 \text{ gal/750 ft hole}
 \end{aligned}$$

The exploration and reserve assessment for a mine of this size entails the drilling of 80 to 120 test holes having an average depth of 750 feet.

Maximum drilling effort for exploration and reserve assessment is calculated to average 3×10^3 gallons of diesel fuel each year.

$$\begin{aligned}\text{Fuel consumed} &= (52.8 \text{ gal diesel/hole})(120 \text{ holes})/(2 \text{ years}) \\ &= 6,300 \text{ gal}/(2 \text{ years}) \\ &= 3,150 \text{ gal/year (avg.)}\end{aligned}$$

Portal and facility construction activities are discussed in Section 5. It is assumed that diesel fueled equipment operates 12 hours per day and requires 54,000 gallons of fuel each year for surface preparation, overburden movement, and drill rig operation.

$$\begin{aligned}\text{Fuel consumed} &= (\text{diesel fuel consumption rate})(\text{operating time}) \\ &= (15 \text{ gal/hr})(12 \text{ hr/day} \times 300 \text{ days/yr}) \\ &= 54,000 \text{ gal/yr}\end{aligned}$$

$$\begin{aligned}\text{Diesel fuel requirements (total)} &= (\text{fuel consumed for exploration}) + (\text{fuel consumed for construction activities}) \\ &= (3,150 \text{ gal/yr}) + (54,000 \text{ gal/yr}) \\ &= 57 \times 10^3 \text{ gal/yr}\end{aligned}$$

Reference

1. Ingersoll-Rand, Personal Communication, 600 Greentree Road, Pittsburgh, Pennsylvania, May 1981.

2

Air Emissions During Exploration

Emissions from diesel equipment used during exploration and reserve assessment are negligible, amounting to less than one ton per year.

Particulates	HC	SO ₂	CO	NO ₂
0.04	0.04	0.05	0.14	0.52

During the exploration and reserve evaluation phase of underground coal mine development, emissions are limited to diesel engine emissions, and noise and dust from drill equipment. These emissions are short lived and have a minimal impact on isolated or remote environments. However, when a drill site is near public or private facilities, although still short lived, the impact of exploration activities becomes more important. Dust and noise can be a temporary problem for residents adjacent to drill sites. The quantification of these factors is virtually impossible due to the extreme variability of drilling conditions, media being drilled, topography, and weather conditions encountered during drilling.

The pollutants emitted to the atmosphere during exploration and reserve assessment are from the combustion of diesel fuel used in the drilling operations. Using given emission factors,¹ the quantities of pollutants are calculated directly from the quantity of diesel fuel consumed. The emissions for each pollutant are given by:

Quantity of pollutant = (fuel consumption rate) (emission factor)

Particulates	= (3,150 gal/yr)	(25.3 x 10 ⁻³ lb/gal)
	= 80 lb/yr	
Hydrocarbons	= (3,150 gal/yr)	(25.1 x 10 ⁻³ lb/gal)
	= 79 lb/yr	
Sulfur dioxide	= (3,150 gal/yr)	(31.1 x 10 ⁻³ lb/gal)
	= 98 lb/yr	
Carbon monoxide	= (3,150 gal/yr)	(87.5 x 10 ⁻³ lb/gal)
	= 276 lb/yr	
Nitrogen oxides	= (3,150 gal/yr)	(332 x 10 ⁻³ lb/gal)
	= 1,046 lb/yr	

The combined emission from all these pollutants into the atmosphere, on a yearly basis, is:

Emissions from exploration and reserve assessment

$$\begin{aligned} &= (80 \text{ lb} + 79 \text{ lb} + 98 \text{ lb} + 276 \text{ lb} + 1,046 \text{ lb}) \\ &= (1,579 \text{ lb/yr}) / (2,000 \text{ lb/ton}) \\ &= 0.79 \text{ ton/yr (avg.)} \end{aligned}$$

Reference

1. U. S. Environmental Protection Agency, Compilation of Air Pollutant Emission Factors, PB 275 525, Third Edition, Table 3.2.7-1.

3

Solid Waste From Portal (Shaft) Construction

Volume of spoil material generated during shaft construction is 50×10^3 cubic yards, which is equal to about 58×10^3 tons of solid waste.

The initial entry into an underground mine consists of two shafts, one shaft for service and personnel and the other is for production. During shaft construction overburden removed will be stockpiled and/or used in the construction of surface facilities associated with the mine. Usually the amount of overburden removed from the shafts is in excess of surface needs. The excess material is placed in the waste or coal refuse pile associated with the preparation plant. All marketable coal encountered during the shaft construction is removed, transported to the preparation plant, crushed, and washed.

The size of each shaft is 35 x 20 ft; shaft depth from surface to coal is 750 ft. Due to the inability of unconsolidated material to be recompact, the consolidated material removed from the shaft will increase in volume by an average of 30 percent. Considering the aforementioned conditions and dimensions, 50,500 cu yds of material will be displaced during construction of the service and production shafts.

Volume of overburden

$$\begin{aligned}
 &= (\text{shaft length})(\text{shaft width})(\text{shaft depth})(\text{swell factor}) \\
 &\quad (\text{number of shafts}) \\
 &= (35 \text{ ft})(20 \text{ ft})(750 \text{ ft})(1.30/\text{shaft})(2 \text{ shafts})/(27 \text{ cu ft/cu yd}) \\
 &= 50,500 \text{ cu yd}
 \end{aligned}$$

The average density of the overburden material is approximately 1.5 tons/cu yd. Therefore, the shafts yield 58×10^3 tons of spoil.

Tons of overburden

$$\begin{aligned}
 &= (\text{Volume of consolidated material removed from shaft}) \\
 &\quad (\text{overburden density})(\text{number of shafts}) \\
 &= [(35 \text{ ft})(20 \text{ ft})(750 \text{ ft})/(27 \text{ cu ft/cu yd})](1.5 \text{ tons/cu yd}) \\
 &\quad (2 \text{ shafts}) \\
 &= 58 \times 10^3 \text{ tons}
 \end{aligned}$$

4

Runoff From Spoils of Construction and Mining Operations

Spoils runoff from construction and mining operations is diverted to wastewater treatment and is not quantifiable.

Depending on how this material is distributed and stored, the surface exposed to runoff will vary considerably. However, all runoff and leachate are diverted into a treatment facility associated with the portal shaft and coal preparation plant. In relation to the quality and quantity of leachate originating from the coal waste storage, the leachate originating from the spoil material is insignificant.

5

Emissions During Construction of Portal Shaft

Emissions from diesel fuel equipment used during construction total 13.5 tons/yr.

Particulates	HC	SO ₂	CO	NO ₂
0.68	0.68	0.84	2.4	8.9

Equipment used to construct the shaft is diesel powered and consists of a bulldozer and large-capacity construction equipment. The bulldozer (D-9 size) is used in the surface preparation and movement of overburden. The drill rig is powered by a diesel engine comparable in size to one used in a large bulldozer.

The construction crews work on a 24-hour schedule for the life of the operation. The bulldozer is used intermittently, only when volumes of overburden accumulate and must be moved. The construction process takes about 24 months.

Assuming that the combined operation of diesel equipment results in one machine operating 12 hours per day, the emissions from the diesel fuel combustion are calculated by using diesel emission factors:

$$\begin{aligned}
 \text{Emissions} &= (\text{Diesel fuel consumption rate})(\text{operating time}) \\
 &\quad (\text{emission factor}) \\
 &= (15 \text{ gal/hr})(12 \text{ hr/day} \times 300 \text{ days/yr})(\text{emission factor}) \\
 &= (54,000 \text{ gal/yr})(\text{emission factor})
 \end{aligned}$$

$$\begin{aligned}
 \text{Particulates} &= (54,000 \text{ gal/yr})(25.3 \times 10^{-3} \text{ lb/gal}) \\
 &= 1,366 \text{ lb/yr} \\
 &= 0.68 \text{ ton/yr}
 \end{aligned}$$

$$\begin{aligned}
 \text{Hydrocarbons} &= (54,000 \text{ gal/yr})(25.1 \times 10^{-3} \text{ lb/gal}) \\
 &= 1,355 \text{ lb/yr} \\
 &= 0.68 \text{ ton/yr}
 \end{aligned}$$

$$\begin{aligned}
 \text{Sulfur dioxide} &= (54,000 \text{ gal/yr})(31.1 \times 10^{-3} \text{ lb/gal}) \\
 &= 1,679 \text{ lb/yr} \\
 &= 0.84 \text{ ton/yr}
 \end{aligned}$$

Carbon monoxide = (54,000 gal/yr)(87.5 x 10⁻³ lb/gal)
= 4,725 lb/yr
= 2.4 tons/yr

Nitrogen oxides = (54,000 gal/yr)(332 x 10⁻³ lb/gal)
= 17,928 lb/yr
= 8.9 tons/yr

The combined annual emissions of pollutants from diesel fuel combustion during the construction of facilities is:

Combined emissions

= (0.68 + 0.68 + 0.84 + 2.4 + 8.9) tons/yr
= 13.5 tons/yr

During construction of the shaft, water is used to aid drilling and suppress dust. This reduces dust emissions to a negligible level. The water employed in dust control is also cycled through the treatment facility prior to discharge. Dust control is discussed in Section (8).

Reference

1. U. S. Environmental Protection Agency, Compilation of Air Pollutant Emission Factors, PB 275 525, Third Edition, Table 3.2.7-1.

6 Construction of Mains

Underground sections are developed for the use of continuous miners and a longwall unit.

After the initial portal construction is complete, actual mine development begins. This operation consists of cutting entries into the main reserve areas. Eight parallel entries are cut to allow adequate room for personnel transport, coal haulage, ventilation, electrical supply lines, and equipment movement. The size of the entry varies depending on the physical condition of the roof and floor. These cross cuts connect the parallel entries to allow for adequate ventilation and movement of equipment. The main entries range in size from 18 to 20 feet with approximately 50 by 100 foot pillars of coal left between entries and cross cuts. The development of the main entries is accomplished by continuous miner units which have a cutting width of between 10 and 12 feet.

Sub-mains are initiated when the main entries have been advanced far enough to allow for additional lateral development. These sub-mains are cut perpendicular to the main entry and usually consist of three or four entries the same size as the mains. Cross cuts are also constructed to allow for ventilation and equipment movement. The sub-mains and cross cuts also result in 50 by 100 foot pillars of coal left in place to provide adequate roof support.

If the section is being developed for continuous miner use, a room-and-pillar plan is employed. The sub-mains are usually cut to a length that allows for the construction of four to six "rooms" with appropriate cross cuts. These rooms are 500 to 600 feet long.

When a section is planned for longwall operations the sub-mains are cut to an appropriate length to allow for economical longwall development. Perpendicular to the mains, sub-mains are then cut with continuous mining equipment. These sub-mains usually consist of three sets of entries with cross cuts and remaining pillars. These sub-mains are between 2,300 and 2,500 feet long and spaced 500 to 600 feet apart. Two of the sub-mains are connected across the farthest extent of the section and the longwall unit is installed.

Reference

1. Cassidy, Samuel M., Elements of Practical Coal Mining, The American Institute of Mining Metallurgical and Petroleum Engineers, Inc., Port City Press, Inc., Baltimore, Maryland, 1973.

7 Roof Support During Construction of Mains

Equipment operators cannot be exposed to an unsupported roof.

During the construction of the mains, adequate and semi-permanent roof support is essential. In addition to the pillars of coal left during development, roof bolting is employed. In the main haulage ways the bolts are spaced according to conditions of the roof. Where poor roof material exists, close spacing of bolts is essential, with the addition of full headers across the entry. The bolt spacing is commonly 4 feet. In some cases, it is necessary to employ safety posts at the ends of the headers. If the roof material is satisfactory, bolts are spaced on 4-foot centers but only 1/2 headers are used.

Bolting is accomplished in conjunction with the cutting of entries and cross cuts. Safety dictates that the equipment operator not be exposed to unsupported roof. The operator of a continuous miner is approximately 16 to 18 feet from the face. As the miner advances, it will only cut about 16 feet before pulling back so roof support can be accomplished. The miner usually retreats and moves to an adjacent entry to cut while the roof is being bolted. This process allows for continuous production of coal while minimizing the waiting time of the roof bolters.

In association with this operation, rock dusting (to prevent explosions) and ventilation advancement is accomplished in other entries which have been cut and bolted. Regulations require that rock dust must always be within 40 feet of the working face.² With this process in mind, at least three entries are always being worked. That is, when the miner cuts as far as safety allows, it moves to another entry while that one is being bolted. By the time the first entry is bolted adequately, the miner has moved to a third entry and the bolters take its place. The dusting unit will move into the first entry and apply the rock dust and advance the ventilation duct. By the time the first entry is bolted and dusted, the miner is ready to re-enter the initial entry.

Development mining is less productive than the completion mining associated with retreat work. Therefore, the mine is sectioned with mains dividing the reserve area into smaller units, so that when a section is advanced, retreat work can begin in that section while advancement is taking place in another section.

Mine planning is such that enough development work is being done to utilize the available equipment. In addition to roof support, ventilation and electrical supplies are installed as the mains are advanced.

References

1. Cassidy, Samuel M., Elements of Practical Coal Mining, The American Institute of Mining Metallurgical and Petroleum Engineers, Inc., Port City Press, Inc., Baltimore, Maryland, 1973.
2. Mine Safety and Health Administration, Title 30, Federal Register, Part 70.100-A, March 1977.

8

Suppression of Underground Coal Dust During Construction of Mains

For the construction of mains, dust is controlled by spraying 8.6×10^6 gallons of water each year.

The ripping type of mining equipment used creates large quantities of dust. The primary method of dust suppression is water. This serves two purposes, it reduces dust and cools cutting teeth. Depending on the condition of the coal, various quantities of water are used. Each continuous miner has between 12 and 28 spray nozzles for dust suppression. While actually cutting, each unit uses between 10 and 40 gallons of spray water per minute. This results in usage of between 24,000 and 96,000 gallons of water per mine per shift.

$$\begin{aligned}
 \text{Spray water used} &= (\text{gpm/unit})(\text{cutting min/shift})(\text{number of units}) \\
 &= (10 \text{ gpm/unit})(240 \text{ min/shift})(10 \text{ units}) \\
 &= 24,000 \text{ gal/shift} \\
 &\text{or} \\
 &= (40 \text{ gpm/unit})(240 \text{ min/shift})(10 \text{ units}) \\
 &= 96,000 \text{ gal/shift}
 \end{aligned}$$

$$\begin{aligned}
 \text{Maximum spray water used} \\
 &= (96,000 \text{ gal/shift})(3 \text{ shifts/day})(300 \text{ days/yr}) \\
 &= 86,400,000 \text{ gal/yr}
 \end{aligned}$$

Construction of mains represents approximately 10 percent of the continuous miner equipment use; therefore, the spray water used annually for the construction of mains is:

$$\begin{aligned}
 \text{Spray water used for construction of mains} \\
 &= (0.1)(86.4 \times 10^6 \text{ gal/yr}) \\
 &= 8.6 \times 10^6 \text{ gal/yr}
 \end{aligned}$$

Most of the spray water used is recycled. Water lost in the recycle process is absorbed into the loaded coal. This quantity will vary with the moisture content and other physical conditions of the coal.

In addition to the spray water, ventilation is employed to reduce the dust and natural gas hazard in the mine. Federal regulations allow no more than 2.0 mg/cu m of dust in the air of the working mine employee. Ventilation rates for a continuous miner range between 32 and 60 cu ft/min. This variation is due to the physical condition of the coal and spray pattern of each miner.

References

1. Mine Safety and Health Administration, Title 30, Federal Register, Part 70.100-A, March 1977.
2. Dower, John, Personal Communication, MSHA Health Section, Morgantown, West Virginia.

9

Air Emissions From Installation of Electricity, Belts, and Track

The pollutants and emissions generated during the installation of track, belts, and electricity are minimal and unquantifiable.

As the mains are advanced through the reserve areas of the mine, it is necessary to install electrical supplies for equipment power and belt and track for coal movement. The equipment in the mine is all electric. The power utilization of each piece is discussed under Item 16.

The main haulage system in the mine is locomotive. This system travels from the loading areas along the main haulage system to the production portal where the coal is transported to the surface by conveyors. As the mine is developed, the track for the trains is advanced on an as-needed basis. Usually one 3- to 5-man crew is responsible for the electrical advancement and men are assigned on an as-needed basis for the installation of new track. Belt transfer of coal is used in conjunction with the longwall mining units. Belts are installed concurrently with the mining unit.

Emissions created during this phase of the mine development are minimal and unquantifiable.

10 Release and Treatment of Ground Water

The flow of ground water must be controlled and then treated before discharge into surface streams. Water removed from the underground mine is not quantifiable.

Prior to initiation of shaft construction, the proposed site is evaluated for potential hydrologic problems. This is accomplished by test drilling the overburden material and evaluating local residential water supplies. If during test drilling no significant quantities of water are encountered, construction can begin. However, if large quantities (50 to 200 gpm flow) of water are encountered in regional aquifers, steps must be taken to prevent this water from entering the shaft or mine. Water control of this magnitude is accomplished by pregrouting the construction site at stratigraphic locations consistent with zones of water production. Small flows of water are controlled by the construction of "water rings" at key stratigraphic locations with a dewatering well connecting them to a sump in the mine floor. The water collected in this sump is then pumped to the surface for treatment, discharge, or for use in dust control.

Controls are designed and employed to ensure that no deleterious material or water is introduced into the local stream or groundwater regime. These controls consist of diversion and collection ditches which divert water into treatment and/or settlement ponds. This water is monitored periodically and treatment is employed to ensure that state and Federal water quality standards are met prior to discharge from the site. Actual quantity and quality of water entering the facility vary with the geochemistry and physical condition of the spoil material. The principal treatment method for toxic material is the addition of soda ash briquettes or other basic substances to raise the pH of the water to a point where toxic elements precipitate in the settlement pond prior to discharge. All coal encountered during shaft construction is trucked to the preparation plant and prepared for sale. This eliminates a primary source of potentially toxic material which may contribute to acid mine drainage.

11

Solid Waste From Ventilation Shaft Construction

Volume of spoil material removed from each ventilation shaft ranges between 23,000 and 30,000 cubic yards or an average of 12,000 tons per year.

Order to maintain adequate ventilation and ensure safety for mining operations, additional air shafts are installed as mining advances farther from the initial portal. Shafts are designed to intercept proposed mains and provide ventilation to the section in their area. Depending on the needs of the mine, these air shafts are spaced between 4,500 and 7,500 ft apart. In a mine producing 1.5 million tons of coal per year, seven to eight air shafts are necessary to adequately ventilate the entire mine workings. One or more of the air shafts are used for personnel entry as mining progresses farther from the initial portal and production shaft. This reduces the trip time for miners from the surface to the working face. Coal haulage is maintained to the initial production shaft since track and belts are in place and cost prohibits the relocation of the preparation plant.

Air shaft dimensions are 35 by 20 feet and shaft depths range between 700 and 900 feet due to the varying overburden thickness. Consolidated material removed from the shaft increases in volume by approximately 30 percent. This is due to the inability of extracted material to be compacted to the original volume. Considering these factors, the quantity of extracted material to be handled and distributed on the surface varies between 2.3×10^4 cu yd and 3.0×10^4 cu yd.

Volume of spoil generated during shaft construction

$$\begin{aligned} &= (\text{width})(\text{length})(\text{depth})(\text{swell factor}) \\ &= (35 \text{ ft})(20 \text{ ft})(700 \text{ ft})(1.30 \text{ swell factor})/(27 \text{ cu ft/cu yd}) \\ &= 23 \times 10^3 \text{ cu yd} \\ &\text{or} \\ &= (35 \text{ ft})(20 \text{ ft})(900 \text{ ft})(1.30 \text{ swell factor})/(27 \text{ cu ft/cu yd}) \\ &= 30 \times 10^3 \text{ cu yd} \end{aligned}$$

The average density of the spoil material is 1.5 tons/cu yd in this area.² Therefore, airshaft construction produces between 27×10^3 and 35×10^3 tons of material.

Spoil production:

$$\begin{aligned} &= (\text{volume of consolidated material in shaft})(1.5 \text{ tons/cu yd}) \\ &= (18 \times 10^3 \text{ cu yd})(1.5 \text{ tons/cu yd})/\text{air shaft} \\ &= 27 \times 10^3 \text{ tons/air shaft} \\ &\quad \text{or} \\ &= (23 \times 10^3 \text{ cu yd})(1.5 \text{ tons/cu yd})/\text{air shaft} \\ &= 35 \times 10^3 \text{ tons/air shaft} \end{aligned}$$

Eight shafts over a 23-year period annually generate an average of 12×10^3 tons of spoil.

Spoil production

$$\begin{aligned} &= (35 \times 10^3 \text{ tons/shaft})(8 \text{ shafts/23 yr}) \\ &= 12 \times 10^3 \text{ tons/yr (avg.)} \end{aligned}$$

References

1. Consolidated Coal Corporation, Personal Communication, May 1981.
2. Cassidy, Samuel M., Elements of Practical Coal Mining, The American Institute of Mining Metallurgical and Petroleum Engineers, Inc., Port City Press, Inc., Baltimore, Maryland, 1973.

12 Water Used for Dust Suppression During Longwall Extraction

Water used in dust suppression by the longwall unit is 2.43×10^7 gallons per year.

Longwall mining begins with cutting parallel sub-mains approximately 600 feet apart perpendicular to the main haulage ways. These sub-mains are between 2,300 and 2,500 feet long and consist of three entries to allow for ventilation and equipment movement.¹ These sub-mains are connected across their furthest extent by two entries. These sub-mains are cut using continuous miners and associated equipment. Once the entries have been cut, adequately supported, and ventilation advanced, the longwall unit is installed. Retreat mining is practiced when longwall equipment is used (that is, mining out of the reserve area toward the main haulage ways). The longwall mining system offers recovery rates almost equal to those attainable by continuous methods. However, efficiency of this method is extremely good under deep cover and weak roof material. Cost of unrecoverable roof supports are minimized since the primary roof supports move with the unit.

Dust suppression is accomplished by spray water and adequate ventilation. Rock dusting is not necessary, thus eliminating time and material necessary for this operation. Each longwall shearer has between 36 and 80 spray heads which use between 25 and 60 gallons of water per minute depending on the moisture status of the coal.² This results in the use of between 11,250 and 27,000 gallons of water per shift. Spray water is recycled through the treatment facility and, therefore, the only water loss is that which is absorbed in the loaded out coal.

Spray water used

$$= (\text{gpm/unit})(\text{cutting min/shift})(\text{number of units})$$

$$= (25 \text{ gpm/unit})(450 \text{ min/shift})(1 \text{ unit})$$

$$= 11,250 \text{ gallons/shift}$$

or

$$= (60 \text{ gpm/unit})(450 \text{ min/shift})(1 \text{ unit})$$

$$= 27,000 \text{ gallons/shift}$$

On an annual basis, this quantity becomes 2.43×10^7 gallons.

Spray water used

$$= (27,000 \text{ gal/shift})(3 \text{ shifts/day})(300 \text{ days/yr})$$

$$= 2.43 \times 10^7 \text{ gal/yr}$$

Air ventilation also aids in meeting the Federal requirement of no more than 2.0 mg/cu m dust in the air above the longwall operator. Air movement maintained between 225 and 350 cu ft/min is maintained at the operator.

References

1. Cassidy, Samuel M., Elements of Practical Coal Mining, The American Institute of Mining Metallurgical and Petroleum Engineers, Inc., Port City Press, Inc., Baltimore, Maryland, 1973.
2. Dower, John, Personal Communication, MSHA Health Section, Morgantown, West Virginia.
3. Mine Safety and Health Administration, Title 30, Federal Register, Part 70.100-A, March 1977.

13 Dust Emissions From Belt Transfer Operations

Dust emissions for underground conveyors are unregulated and unquantifiable.

movement from the longwall unit to the main track haulage system is accomplished by conveyor belt. The conveyor is installed in conjunction with section development and ranges in length from 2,300 to 2,500 feet. Coal is moved from the cutting face of the longwall unit by a conveyor integrated with the unit. From there, it is transferred to a conveyor system designed to move the coal to the main haulage system.

Dust is a serious problem on the conveyor systems, especially at the transfer points. Therefore, spray nozzles are employed periodically along the conveyor and at the transfer points. Rock dusting apparatus is used to control float dust (airborne coal dust). If it is not controlled, the float dust presents a serious risk of explosion.

No regulations or requirements have been established for the quantities of water or rock dust necessary to control the dust hazard. Spray water and rock dust are employed on an as-needed basis and application is governed by the section boss charged with maintaining the conveyor systems.

Reference

1. Cassidy, Samuel M., Elements of Practical Coal Mining, The American Institute of Mining Metallurgical and Petroleum Engineers, Inc., Port City Press, Inc., Baltimore, Maryland, 1973.

14

Water Used for Dust Control During Continuous Extraction Operations

Water used for dust control is 7.8×10^7 gallons per year.

After mains and sub-mains have been constructed in a section of the mine rooms are developed and, finally, pillaring or retreat work begins. This is the process of removing the pillars left as roof support during the advancement phase. Full recovery is practiced and production rates are higher than in development work. When continuous mining equipment is used, the "pocket-and-wing" method of block extraction is employed.

In this method, the pillar lift is mined by outlining an opening through the block parallel to the gob (see Glossary), but leaving a slab of solid coal between the opening and gob. The opening is called the "pocket" and the slab of coal termed the "wing." The roof in the pocket is supported in the same manner as mains and entries. Roof bolts, full and/or half headers and additional posts as needed are the typical roof support systems used. Once the pocket is cut the full length of the pillar and the roof is adequately supported, the miner retreats taking successive angled cuts from the wing. The thickness of the wing is designed such that the continuous miner operator need never go beyond the protection of supported roof while mining the complete wing. The removal of the wing allows the roof to safely collapse and remove load from the remaining pillar. Cuts are taken from alternate sides of the block until only a small stump remains which is then "pushed out" thus completing the pillar removal. As with development mining, several pillars are mined by the same unit to reduce equipment down time and maximize production.

Dust control is a major problem in pillaring operations as it is in development mining. As with development operations, spray water is the primary method of dust control. Natural water and physical conditions of the coal dictate the amount of spray water necessary for adequate dust suppression. Each continuous mining unit has between 12 and 28 spray nozzles for dust suppression.² Each unit, while cutting, will use between 10 and 40 gallons of water per minute. This results in 24,000 to 96,000 gallons of water being used each shift.

Spray water used (total)

$$\begin{aligned} &= (\text{gpm/unit})(\text{cutting min/shift})(\text{number of units}) \\ &= (10 \text{ gpm/unit})(240 \text{ min/shift})(10 \text{ units}) \\ &= 24,000 \text{ gallons/shift} \\ &\text{or} \\ &= (40 \text{ gpm/unit})(240 \text{ min/shift})(10 \text{ units}) \\ &= 96,000 \text{ gallons/shift} \end{aligned}$$

For one year, this quantity of spray water used becomes 86.4×10^6 gallons.

Spray water used (total)

$$= (96,000 \text{ gal/shift})(3 \text{ shifts/day})(300 \text{ days/yr})$$

$$= 86,400,000 \text{ gal/yr}$$

Since room and pillar operations comprise 90 percent of the continuous miner equipment use, the spray water used during these operations equals 78×10^6 gal/yr.

Spray water used for room and pillar operations

$$= (0.9)(86.4 \times 10^6 \text{ gal/yr})$$

$$= 78 \times 10^6 \text{ gal/yr}$$

Pillaring operations also require adequate ventilation to maintain necessary fresh air at the working face. Ventilation in the pocket is advanced as cutting advances.

The equipment necessary for pillaring work is essentially the same as for advancement work. The sequence of operation is also similar. The continuous miner advances into the pocket only to a depth that the operator is always under supported roof. The miner then pulls back and moves to another pillar while the roof in the pocket is bolted and rock dusted. The shuttle cars, conveyors, and mechanical loaders follow the continuous miner to transport the coal to the main haulage ways. After the initial cut is bolted and dusted, the miner, loaders, conveyors, and shuttle cars return to make a second cut. Cuts are between 16 and 20 feet wide to allow for easy equipment access, ventilation ducts, and to maintain adequate roof support.

References

1. Cassidy, Samuel M., Elements of Practical Coal Mining, The American Institute of Mining Metallurgical and Petroleum Engineers, Inc., Port City Press, Inc., Baltimore, Maryland, 1973.
2. Dower, John, Personal Communication, 600 Greentree Road, Pittsburgh, Pennsylvania, May 1981.

15

Noise Emissions From the Underground Mining Equipment

Noise levels can exceed 90 decibels at the working face.

The noisiest location in the underground coal mine is at the working face. The activity at the face is the extraction of coal by brute force ripping and shearing into coal seams. A byproduct of the activity is the generation of excessive noise. Noise level ranges for various machines used in the underground are shown in Table 2. The range of noise levels for individual machines is due to the noise associated with different operating modes of the equipment.

Hearing damage is generally thought to occur when workers are repeatedly exposed to noise levels (A-weighted sound pressure levels) in excess of 90 dB for 8 hours per day. This requires worker protection in accordance with mine safety and health administration regulations.² Noise exposure can be reduced by limiting the time that a mine employee works in the noisiest areas and by the wearing of ear protective equipment.

Table 2. NOISE LEVELS OF UNDERGROUND COAL MINING EQUIPMENT

<u>Machine Type</u>	<u>Noise Level Range (dB)</u>
Continuous Miner	87-97
Loading Machine	92-99
Shuttle Car	86-99
Roof Bolter	85-91
Longwall Shear	89

Note: Noise level data from Reference 1.

References

1. Bobrick, T. G., and D. A. Giardino, The Noise Environment of the Underground Mine, U. S. Department of the Interior, Information Report 1034, 1976.
2. Code of Federal Regulations (CFR) Title 30, Part 70, Subpart f, pp. 427-432, 1981.

16 Power Requirements for the Underground Mine

The underground coal mining operations consume 5.25×10^7 kWh of electrical energy each year.

All equipment in the underground coal mine is powered by electricity. The power requirements for individual pieces of equipment are determined by the voltage at which the equipment operates and the current drawn during operation. For many pieces of equipment the actual current drawn varies depending on whether the equipment is operating under load or non-load conditions. An average power requirement is determined by assuming a load factor of 50 percent for those pieces of equipment.

For the continuous miner, the operating voltage is 0.55 kilovolt and the average current drawn is 340 amps.

$$\begin{aligned}\text{Power (continuous miner)} &= (0.55 \text{ kilovolt})(340 \text{ amps}) \\ &= 187 \text{ kilowatts}\end{aligned}$$

Total electrical energy consumption per year for a single piece of equipment is equal to the power required for the unit multiplied by the number of operating hours per year.

The yearly electrical energy consumption for the ten continuous miners needed in this underground mine is

$$\begin{aligned}E (\text{continuous miners}) &= (\text{average power/machine})(\text{number of machines}) \\ &\quad (\text{hours of operation/yr/machine}) \\ &= (187 \text{ kW/machine})(10 \text{ machines})(6,750 \text{ hr/yr}) \\ &= 1.26 \times 10^7 \text{ kWh/yr}\end{aligned}$$

The power requirements and yearly electrical energy consumption are calculated in the same manner for all the underground coal mining equipment. The electrical energy consumption is shown by equipment type in Table 3. For the entire mine the electrical energy required to operate the equipment is 5.25×10^7 kWh/yr.^{1,2,3}

Table 3. ELECTRICAL ENERGY CONSUMPTION OF UNDERGROUND
COAL MINING EQUIPMENT

Equipment	Average Power Required Per Unit in Kilowatts	Number of Units*	Hours Per Year Per Unit	kWh/year x 10 ⁷
Continuous miners	187	10	6750	1.26
Longwall miners	220	1	6750	0.15
Mechanical loaders	37.4	13	6750	0.33
Roof bolter	19.1	15	6750	0.19
Rock dusters	1.9	13	6750	0.02
Conveyors	35.2	12	6750	0.29
Shuttle cars	44.7	22	6750	0.66
Ventilation fans	448	4	8640	1.55
Locomotives	149	15	3600	0.80
Total kWh				5.25 x 10 ⁷

- Equipment needed to produce the rated output of the mine.

References

1. Abbs Valley Electric Corporation, Personal Communication, Bluefield, West Virginia, May 1981.
2. Joy Equipment Manufacturing Company, Personal Communication, Meadowlark, Pittsburgh, Pennsylvania.
3. U. S. Department of the Interior, Basic Estimated Capital Investment and Operating Costs for Underground Bituminous Coal Mines, PB 252 567, April 1976.

17 Subsidence of Land

Subsidence is unlikely for a 90 inch coal seam located at a surface depth greater than 375 feet.

When large quantities of coal are removed from the earth it is possible that the surface land will subside. The likelihood of subsidence occurring depends on the stratigraphy above the mine and the relation of the mine depth to the coal seam thickness. Recent studies indicate that subsidence is unlikely to occur when mining is at surface depths greater than 50 times the mine height (thickness of coal seam). The mine characterized in this report has a seam of 90 inches (7.5 feet) located 400 to 600 feet below the surface.

Depth (subsidence unlikely)

= 50 x 7.5 ft

= 375 ft

Reference

1. von Schonfeldt, F. D. Wright, K. F. Unizug, "Subsidence and Its Effect on Longwall Mine Design," Mining Congress Journal, Vol. 66, 5, 1980.

18 Emissions From Coal Storage at the Preparation Plant

Coal is stored in silos before and after coal preparation. There are fugitive dust emissions during storage. Liquid waste is unquantifiable.

There is no open storage of either raw or cleaned coal at the on-site coal preparation plant. Wet coal is transported directly by the underground conveyor to the surface storage silo where it is temporarily held before being fed into the crusher. Any leachate from the coal is treated by liming and settling before the water is recycled or discharged. The quantity of lime required varies with coal conditions and is not quantified for this operation.

19 Energy Requirements for Coal Preparation Plant

The coal preparation equipment consumes 6.4×10^6 kWh of electrical energy per year.

ROM coal is processed in an aboveground coal preparation plant where it is fed into a crusher and reduced in size to a nominal 3 inches. Coal is then separated with sizing screens into coarse and fine coal and moved to the cleaning operation. A flow diagram indicating the coal preparation process after silo storage is shown in Figure 2.

For the crushing, screening, washing, and conveying equipment used in the coal preparation plant, electrical energy consumption is estimated to be 6.4×10^6 kWh per year.

20

Fugitive Dust Emissions From Crushing and Screening Operations

Fugitive dust from the crushing operations is negligible because the operations are enclosed and the coal is processed in a wet mode.

Crushing

The crushing operation is completely enclosed and is operated in a wet mode; therefore, there is little opportunity for fugitive dust emissions from this phase of the cleaning operation. Coal stored prior to initial size reduction is in enclosed silos and adds little to dust emissions.

Crushing operations are accomplished using roller mills with a total capacity of 250 standard tons per hour. The wet coal passes from the crushers to the screening operation and excess water is recycled for reuse. Run-of-mine coal is reduced to a nominal 3-inch size in the initial crushing operation.

Screening

The entire screening operation is enclosed and is operated in the wet mode so fugitive dust emissions from the process are minimal. The cleaning operation cleans both coarse and fine coal once the sizing screens separate the coal into two size ranges. The coarse coal has dimensions of 3 inches by 3/8 inch and the fine coal 3/8 inch by zero. Excess water is recycled for reuse and there is no discharge of water from this process. All coal material that is sized moves to the cleaning operation.

21 Coal Washing

Fugitive coal dust emissions are negligible from the washing phase of the coal preparation cycle as the system is enclosed and no thermal drying is used. Makeup water is estimated at 30×10^6 gallons each year.

The coarse coal fraction, 3 inches by 3/8 inch, is cleaned by heavy media separation, magnetite suspension. Pretreatment includes crushing and sizing to remove fine coal. Wetting is not required as the spray process screens the coal while wet. The sized, wet coal moves to the dense media vessel which uses magnetite suspension. From the heavy media vessel the coal/magnetite/water slurry moves to stationary screens, vibrating screens, and finally to vibrating screens with water spray to remove the magnetite. The coal is dried mechanically by shaker screens, and the water is recycled to the rinsing screens. Thermal drying, if used, would create 15 to 25 pounds of dust per ton of coal dried.

The underflow from the screens, consisting of magnetite and water, is passed by a magnet and then to a thickener. The overflow water from the thickener is recycled to the screen spray once the concentrated magnetite is recycled to the dense media vessel. Magnetite recovery is approximately 85 to 90 percent.

The fine coal fraction of 3/8 inch by zero is cleaned by wet concentrating tables. Pretreatment includes crushing and sizing to remove the coarse coal fraction. Wetting is not required although the sizing process is wet mode. The crushed, sized coal moves to concentrating tables where the underflow consists of coal fines (less than 28 mesh), pyrite, and shale in a water slurry which is dewatered by drain screens and passes out of the plant as a wet solid waste. The overflow consists of coal and water and passes to drain tables and then to centrifuges for dewatering. The water is recycled back to the concentrating table.

The water requirement (make up) for the cleaning plant is estimated at 20 gallons per ton of ROM coal.¹

Cleaning Water

$$\begin{aligned} &= (20 \text{ gal/ton})(1.5 \times 10^6 \text{ tons/yr}) \\ &= 30 \times 10^6 \text{ gal/yr} \end{aligned}$$

Reference

1. U. S. Department of Energy, Coal-Fired Power Plant (Eastern Coal) ECIR, January 1981.

22 Noise Emissions From the Coal Preparation Plant

Uncontrolled noise levels at the coal preparation plant reach 105 decibels.

Noise produced by the coal cleaning plant can be a problem, both for the plant personnel (hearing damage) and for the nearby community. The noise at the coal preparation plant is generated by the crushing, screening, heavy media washing and coal conveying procedures. Since the preparation plant described in this report is located at the mine site, coal arrives at the plant by a belted conveyor. If the preparation plant was remotely located, the coal would be transported by rail car and extremely high noise levels (110 to 120 dB) would be generated during car shakeout.

The predominant in-plant noise is from the screens. The noise levels at the worker position for screening range from 95 to 105 dB. Other high levels of noise are found at the crusher, where the levels are 90 to 105 dB; and near belted conveyors, where levels are 75 to 85 dB (noise level data from Ref. 1).

When noise exceeds noise regulation levels established by the Mine Safety and Health Administration, it must be restricted to comply with Federal regulations² for worker hearing protection and general safety in mines. In-plant noise levels are controlled by machine enclosures and/or worker enclosures. Where these measures do not sufficiently reduce noise exposure, workers must be provided with protective hearing devices.

References

1. U. S. Bureau of Mines, Coal Cleaning Plant Noise, PB-235-852, May 1974.
2. Code of Federal Regulations (CFR) Title 30, Part 71, Subpart i, pp. 445-446, 1981.

23 Liquid Waste From the Coal Mine and Preparation Plant

Acid wastewater is treated with lime to settle out iron and magnesium in the water.

No liquid waste is discharged directly from the cleaning operation at the coal preparation plant. However, liquid runoff does occur from the solid waste storage areas and must be treated along with mine water before it is discharged (Figure 3).

The wastewater generated by eastern underground coal is generally acidic (pH 2.5 to 4.0), and contains residual heavy metal concentrations of Fe, Mn, As, Cr, Pb, Hg, Ni, Se, and Zn. The concentration of these metals in the wastewater depends on the coal seam being mined, the area geology, rainfall and other local conditions. The effluent characteristics of greatest concern are the concentration of iron, manganese, total suspended solids (TSS) and the range of pH values (see Appendix A for effluent limitations). To control iron and manganese discharges, the pH of the wastewater is raised with soda ash or lime causing the iron and manganese compounds to precipitate and the waste water to become less acid. For the mine type characterized in this report, typical values (or ranges of values) before and after discharge treatment are shown in Table 4.

Table 4. EFFLUENT CHARACTERISTICS BEFORE AND AFTER TREATMENT
(milligrams per liter)

Characteristic	Before Treatment	After Treatment
Iron	42	2.8 - 3.0
Manganese	30	1.8
TSS	130	15 - 20
pH	2.9 - 3.4	6.5 - 7.0

References

1. U. S. Environmental Protection Agency, Development Document for Proposed Effluent Limitation Guidelines, New Source Performance Standards for the Coal Mining Point Source Category, January 1980.
2. Maryland Department of Natural Resources, Mine Drainage and Abatement Investigation, Allegany and Garrett Counties, Maryland, November 1972.

24 Solid Waste From the Coal Preparation Plant

Solid wastes from cleaning the coal amount to 25 percent of the coal mined; 375,000 tons of solid waste are generated each year.

Solid waste is stored on-site in open storage and consists of shale, pyrites, and coal fines. Fugitive dust from the storage occurs primarily during periods of drought and will increase with surface wind velocity. Dust emissions from storage areas are not, in general, quantifiable. When they occur, emissions are controlled by surface compaction and water sprays.

An average of 25 percent of the coal that is cleaned results in solid waste which is stored at the plant site.

Solid Waste

$$\begin{aligned} &= (\text{coal mined})(0.25) \\ &= (1.5 \times 10^6 \text{ tons/yr})(0.25) \\ &= 375,000 \text{ tons/yr} \end{aligned}$$

Reference

1. Leonard, Joseph W., Coal Preparation, 4th Edition, The American Institute of Mining Metallurgical and Petroleum Engineers, Port City Press, Inc., Baltimore, Maryland, 1979.

III. PHYSICAL REQUIREMENTS

The major resource requirements for underground mining are water, land, and electricity. The discussion on water contains both consumptive and non-consumptive requirements. The discussion on land requirements includes surface land needs that are necessary to support the mining operation and the coal preparation plant as well as land needed for waste disposal. The electricity consumption is estimated for both the coal mine and preparation plant operation.

Water

The principal use of water used during the deep mining operation is for dust control. Approximately 90 percent of the water is recycled; the remainder is absorbed by the coal or lost to evaporation. Spraying for dust control (see Items 8, 12, and 14) can require 1.1×10^8 gallons of water per year. Makeup water for the operation will therefore require 1.1×10^7 gallons/year.

Net water for dust control

$$\begin{aligned} &= (\text{total water requirement}) - (\text{water recycled}) \\ &= (1.1 \times 10^8 \text{ gal}) - (0.90)(1.1 \times 10^8 \text{ gal}) \\ &= 1.1 \times 10^7 \text{ gal/yr} \end{aligned}$$

An additional net 3.0×10^7 gallons of water per year are required to run the coal preparation plant. Therefore, the total net water consumption for the coal mine and preparation plant is:

Total water consumption

$$\begin{aligned} &= (\text{dust control water}) + (\text{coal cleaning water}) \\ &= 1.1 \times 10^7 \text{ gal/yr} + 3.0 \times 10^7 \text{ gal/yr} \\ &= 4.1 \times 10^7 \text{ gal/yr} \end{aligned}$$

The water required per ton of coal mined and cleaned is:

Water/ton coal

$$\begin{aligned} &= (4.1 \times 10^7 \text{ gal/yr}) / (1.5 \times 10^6 \text{ tons coal/yr}) \\ &= 27 \text{ gal water per ton coal} \end{aligned}$$

During the course of a year large quantities of water may need to be drained from aquifers in the mine or above the mine. For a deep mine and coal preparation plant processing operation of 1.5 million tons per year, treatment (liming) of acid water could typically cost \$750,000 per year.

However, yearly costs for water treatment can vary considerably since many factors affect these costs. These factors include the quantity and quality of water encountered, and the amount of rainfall upstream of the water discharge location.

Land

The land required to support the underground coal mine and surface coal preparation plant consists of a fixed area of 6 acres for facilities and parking, and 1.5 acres per year needed for waste storage.

Facilities include water treatment plant, buildings for ventilation equipment, power substations, bathhouse, maintenance buildings, and the coal preparation plant. Over the remaining 23-year life of the mine, waste storage will require 34.5 acres.

Waste storage land

$$\begin{aligned} &= (1.5 \text{ acres/yr})(23 \text{ yr}) \\ &= 34.5 \text{ acres} \end{aligned}$$

Electrical Power

The electrical power required to produce 1.5 million tons of coal from a deep mine is estimated from the electrical equipment used during the mining operation. Total power consumed in 1 year for the mining operation is 5.25×10^7 kWh. On a per-ton basis, the required electrical energy to produce a ton of coal is

kWh/ton coal

$$\begin{aligned} &= (5.25 \times 10^7 \text{ kWh/yr}) / (1.5 \times 10^6 \text{ tons coal/yr}) \\ &= 3.5 \text{ kWh per ton coal} \end{aligned}$$

For the coal preparation plant electrical energy consumption is estimated to be 6.4×10^6 kWh per year. On a per-ton basis, the required electrical energy to clean a ton of coal is

kWh/ton coal

$$= (6.4 \times 10^6 \text{ kWh/yr}) / (1.5 \times 10^6 \text{ tons coal/yr})$$

$$= 4.3 \text{ kWh per ton coal}$$

IV. PERSONNEL

The number of personnel required to operate a 1.5 million ton/yr Eastern underground mine will vary depending on factors such as the type of equipment used at the mine, as well as the operating philosophy of the owners.

For the mining methods and equipment described in this report the mine would employ 425 workers and would operate three shifts per day.

The coal preparation plant would require 12 workers and would run two shifts per day.

V. OCCUPATIONAL SAFETY AND HEALTH

Data on the incidence of injuries and deaths due to accidents in underground coal mines are collected and published by the U. S. Department of Labor.

For an eastern underground coal mine (1.5 million tons/yr and 425 workers), the expected fatality rate is 0.45 deaths and the injury rate (including fatalities) is 71 per year.

For the coal preparation plant (12 workers) the expected fatality rate is 0.0086 per year. The injury rate (including fatalities) is 1.1 per year.

<u>Deep Coal Mine</u>		<u>Coal Preparation Plant</u>
Deaths	0.45 per year	0.0086 per year
Injuries	71 per year	1.1 per year

The Federal Mine Safety & Health Act of 1977

The Act was established to provide more effective means for improving the working conditions in the nation's coal mines in order to prevent death and serious physical harm and in order to prevent occupational diseases. The Act established safety and health standards for both surface and underground mines, and designated the mine operators to be responsible for safe and healthful conditions in the mines.

Since coal dust emissions in underground mines have long been recognized as the most important physical hazard to the miner's health, this Act set forth a maximum exposure of 1 mg/cu m of respirable dust for the miner averaged over an 8-hour shift.

Monitoring is required during each shift on each working section, for the presence of methane and/or oxygen deficiency.

Rib, roof and face fall are the most important causes of mine fatalities, therefore the roof and ribs of underground working areas and roadways must be supported adequately to prevent falling material.

Other provisions of the Act require that the mine be equipped with suitable fire fighting equipment and that the underground storage of oil and grease be in fireproof containers; that rock dust be applied to within 40 feet of all working faces to control explosions; and that the equipment noise levels which workers are exposed be controlled to prevent hearing damage.

Reference

1. U. S. Department of Labor Mine Safety and Health Administration, Injury Experience in Coal Mining, 1979, Information Report IR 1122 (1980).

APPENDIX A

WASTEWATER EFFLUENT LIMITATIONS

Regulations under the Federal Water Pollution Control Act (PL 92-500) require a permit to discharge pollutants into navigable waters. The EPA, acting under the authority of this legislation, has promulgated best practicable control technology (BPT) standards that were implemented in 1977. The EPA has set BPT water pollution standards that specifically apply to coal beneficiation. These standards are detailed in Table A-1.

Table A-1. EFFLUENT LIMITATIONS PERTAINING TO COAL BENEFICIATION
(milligrams per liter)

For sources with discharges normally acidic prior to treatment

<u>Effluent Characteristic</u>	<u>Maximum for Any One Day</u>	<u>Effluent Limitations Average of Daily Values for 30 Consecutive Days Shall Not Exceed</u>
Iron, total	7.0	3.5
Manganese, total	4.0	2.0
TSS	70.0	35.0
pH	within the range 6.0 to 9.0	

For sources with discharges normally alkaline prior to treatment

Iron, total	7.0	3.5
TSS	70.0	35.0
pH	within the range 6.0 to 9.0	

Note: In general, discharges are acidic in the eastern U. S. and alkaline in the western U. S.

Reference

1. U. S. Environmental Protection Agency, "Coal Mining Point Source Category -- Effluent Limitations for Existing Sources," Federal Register, September 19, 1977, p. 46932.

APPENDIX B COST ESTIMATES

Mining Cost Estimates

Estimates of capital investment and operating and maintenance (O&M) costs indicated in Table 1, Summary Sheet (Section 1), were derived from one of a series of cost analysis reports prepared by the DOE Process Evaluation Office for hypothetical coal mines using various mining methods.¹ The basic intent of the reported cited is to provide an indication of the approximate economics of underground coal mining under average conditions using a continuous mining system.

Table B-1 summarizes the basic capital investment and O&M costs for two hypothetical underground bituminous coal mines with annual production capacities of 1.188 and 2.376 million tons. The corresponding cost estimates for a 1.5×10^6 ton/yr facility, characterized environmentally in Reference 1, are also indicated and were derived by linear interpolation of the range of cost estimates developed for the two hypothetical mines. The operating parameters of the mining systems hypothesized in the cost report and in Reference 1 compare favorably, although there is no complete one-to-one correspondence between the sets of data. Environmental control costs (capital and O&M) are included in the total and per-unit costs are presented.

Table B-1. Summary of Cost Estimates for Eastern Underground Coal Mines

Cost Item	Capacity (ton/yr) (1978\$)		
	1.188×10^6	1.5×10^6	2.376×10^6
Total Capital Cost	$\$56 \times 10^6$	$\$65 \times 10^6$	$\$87 \times 10^6$
Capital Cost Per Ton	\$47.10	\$43.33	\$35.58
O&M Cost			
Per Year	$\$19.9 \times 10^6$	$\$24 \times 10^6$	$\$36 \times 10^6$
Per Ton Produced	\$16.73	\$16.00	\$15.27
Environmental Control	Included in the above cost estimates		

Preparation Plant Cost Estimates

As indicated in the available literature on coal preparation costs, the degree of beneficiation and, therefore, the cost is determined largely by the product specifications of the intended market and the prospective rate of return to the investor. Current coal

beneficiation processes encompass a broad spectrum of treatment, ranging from simple breaking to elaborate systems that include flotation circuits and thermal drying (Reference 2 defines seven levels of coal beneficiation). According to the literature, even bidding to identical and carefully drawn specifications, different contracting engineers might quote prices in a ratio of 2:1 between high and low bidder. Because of this uncertainty, a range of costs indicative of various levels of coal beneficiation are presented in the Table 1, Summary Sheet, rather than point estimates.

Two ranges of cost estimates (References 1 and 2) are shown in Table B-2, one expressed in terms of mine capacity and the other in terms of beneficiated coal. The per-unit cost ranges for the latter were used to estimate the total capital and O&M cost per year for the coal preparation plant in Reference 1. Reference 2 provides the methodology developed for determining the relative costs of coal preparation. This methodology was used to compute the cost estimates for the 2×10^6 ton/yr preparation plant depicted in Table B-2.

Table B-2. Summary of Cost Estimates for Coal Preparation Plants

Cost Item	Capacity (ton/yr)		
	3×10^6 (ROM coal) (1978\$)	2×10^6 (beneficiated coal) (1975\$)	1.125×10^6 (beneficiated coal) (1975\$)
Total Capital Cost	(\$6.8-\$50) $\times 10^6$	(\$2.5-23.8) $\times 10^6$	(\$1.4-\$13.4) $\times 10^6$
Capital Cost Per Ton	\$2.3-\$17	\$1.25-\$11.91	\$1.25-\$11.91
O&M Cost			
Per Year	(\$0.24-\$11) $\times 10^6$	(\$1.42-\$17.64) $\times 10^6$	(\$0.8-\$10.0) $\times 10^6$
Per Ton Produced	\$0.08-\$3.66	\$0.71-\$8.82	\$0.71-\$8.82
Environmental Control	Included in the above cost estimates		

Environmental Control Costs

Environmental control for coal mining and preparation plants is limited primarily to treatment of mine water and discharges, treatment of preparation plant water discharges, and reclamation of mined land. Environmental control cost consideration was included in the cost analyses produced in References 1. There is mention that items of capital equipment are interchanged between operating and environmental

requirements functions. It has been assumed that environmental control costs are included in the overall cost estimates for the hypothetical cost preparation plants.

References

1. U.S. Department of Energy, Basic Estimated Capital Investment and Operating Costs for Underground Bituminous Coal Mines Utilizing a Continous Mining System--Mining with Annual Production of 1.188 and 2.376 MMtpy. ROM from a 72-Inch Coal-Bed, FE/EES-79/1, DOE Process Evaluation Office, Morgantown, West Virginia, November 1978.
2. Schmidt, R.A., Coal In America--An Encyclopedia of Reserves, Production and Use, McGraw, Hill Publications Company, 1979.

GLOSSARY

A-weighted Sound Level	The ear does not respond equally to frequencies, but is less efficient at low and high frequencies than it is at medium or speech range frequencies. Thus, to obtain a single number representing the sound level of a noise containing a wide range of frequencies in a manner representative of the ear's response, it is necessary to reduce the effects of the low and high frequencies with respect to the medium frequencies. The resultant sound level is said to be A-weighted, and the units are decibels (dB).
bituminous coal	A broad class of coals containing 46 to 86 percent fixed carbon and 20 to 40 percent volatile matter.
British thermal unit (Btu)	The quantity of heat required to raise the temperature of one pound of water one degree Fahrenheit at or near 39.2° F.
coal preparation	A process for upgrading raw coal by physical means.
continuous miner	A mining machine which mechanically breaks the coal, then loads and transports it to a shuttle car.
decibel	A unit of measure, on a logarithmic scale, of the magnitude of sound with respect to a standard reference value.
face	The surface in the mine where coal is being extracted.
fugitive dust emissions	Unintentional emissions such as blowing dust from a coal storage pile.
gob	Material left after the mining operation is completed. The collapsed roof material.
jig	A device in which coal is cleaned by agitation.
heavy media separation	A process in which coal is washed in a heavy medium bath in a mixture of water and magnetite. Refuse sinks to the bottom while the clean coal floats and is skimmed off the surface.

GLOSSARY (Cont'd)

leaching	The separation or dissolving of soluble minerals or metals into the water.
longwall mining	Mining in which large blocks of coal are mined in a single continuous operation. The longwall equipment carries its own roof support system which moves with the machine as it advances.
overburden	Material overlying a coal deposit.
pH	The negative logarithm of the effective hydrogen ion concentration used in expressing both acidity and alkalinity on a scale with values ranging from 0 to 14 (values less than 7 indicate increasing acidity; values greater than 7 indicate increasing alkalinity).
retreat work	The process of removing pillars of coal which have been used to support the roof of the mine.
roof bolting	The process of securing the roof material above the coal seam to the rock above the coal seam.
run-of-mine coal	Coal as it comes from the mine prior to cleaning.
spoil	Material from excavation.
total suspended solids	The concentration of suspended solids in water, usually stated in milligrams per liter.

ACRONYMS AND ABBREVIATIONS

As	arsenic
Btu	British thermal units
CO	carbon monoxide
Cr	chromium
dB	decibel
Fe	iron
gal	gallon
gpm	gallons per minute
ha	hectare
HC	hydrocarbon
Hg	mercury
kWh	kilowatt-hour
l	liter
lb	pound
mg	milligram
Mn	manganese
Ni	nickel
NO ₂	nitrogen dioxide
NO _x	nitrogen oxides
Pb	lead
pH	hydrogen ion concentration
ROM	run-of-mine (coal)
Se	selenium
SO ₂	sulfur dioxide
SO _x	sulfur oxides
TSS	total suspended solids
Zn	zinc

Eastern Surface Coal Mining

Environmental Characterization Information Report

October 1982

**U.S. Department of Energy
Assistant Secretary for Environmental
Protection, Safety, and
Emergency Preparedness
Office of Environmental Analysis**

CONTENTS

	<u>Page</u>
I. SUMMARY	A.9-3
II. PROCESS DESCRIPTION AND ENVIRONMENTAL POINTS OF INTEREST	A.9-7
1. Air Emissions From the Exploratory Process	A.9-7
2. Air Emission From Clearing and Grubbing.	A.9-11
3. Air Emissions From Topsoil Removal	A.9-13
4. Air Emissions From Overburden Removal.	A.9-15
5. Air Emissions From Coal Removal.	A.9-20
6. Air Emissions From Backfilling	A.9-24
7. Air Emissions From Topsoiling.	A.9-26
8. Air Emissions From the Revegetation Process.	A.9-27
9. Dust Emission From Coal Storage.	A.9-29
10. Emissions From the Transportation Process.	A.9-29
11. Air Emissions From Coal Storage at the Preparation Plant . .	A.9-29
12. Fugitive Dust From Coal Crushing	A.9-30
13. Dust From the Screening Process.	A.9-30
14. Dust Emissions From the Pick Table	A.9-30
15. Dust Emissions From the Wash Table	A.9-31
16. Solid or Sludge Waste From Coal Cleaning	A.9-32
17. Air Emissions From Cleaned Coal Stockpile.	A.9-32
18. Emissions From Transport Loading	A.9-33
19. Air Emissions From Waste Storage	A.9-34
20. Liquid Waste From Storage and Cleaning Process	A.9-35
21. Water Requirements of the Cleaning Plant	A.9-37
III. PHYSICAL REQUIREMENTS	A.9-38
IV. PERSONNEL.	A.9-40
V. OCCUPATIONAL SAFETY AND HEALTH	A.9-41
APPENDIX A. AIR EMISSIONS FOR EASTERN SURFACE MINING.	A.9-42
APPENDIX B. COST ESTIMATES.	A.9-43
GLOSSARY.	A.9-46
ACRONYMS AND ABBREVIATIONS.	A.9-47

I. SUMMARY

The Environmental Characterization Information Report (ECIR) for Eastern Surface Coal Mining has been prepared from the latest available environmental and technical information collected from a number of sources. The typical mine produces 470,000 tons/yr of subbituminous coal and has its own preparation plant.

The mining process and plant parameters, resources needed, and the environmental residuals and products are presented in the Summary Table 1. Annual resources and pollutant discharges are shown in metric and English units, as well as in terms of 10^{12} Btu of energy produced. These figures are given to allow comparison between different energy processes and to facilitate application of the information into certain computer models.

The Process Description and Environmental Points of Interest are discussed in Section II. Each environmental point of interest presented in Table 1 is addressed separately with a brief description of applicable process, pollutant, and resource involved, calculations showing derivation of quantities, and a list of references used.

Section III discusses the physical requirements of the mining operation and quantifies the amount of land, water, electricity, and diesel fuel that are needed.

Section IV describes personnel requirements and Section V describes occupational health data, specifically, fatality and accident rates.

A glossary and list of abbreviations and acronyms have been provided to define and identify technical terms used in this report.

TABLE 1. SUMMARY SHEET

EASTERN SURFACE COAL MINING

ENERGY SYSTEM DESCRIPTION

Eastern Surface Mine With 36-In. Seam Thickness. Contour Mining Operations, With Overburden Removal by Dragline, Coal Loaded by Front-End Loaders and Transported to Cleaning Plant by Haulage Trucks. Additional Mining With Auger, Onsite Coal Preparation To Yield a Product of 6-In. Diameter. Open Storage of Prepared Coal. Simultaneous Reclamation of Stripped Land by Backfilling.

FACILITY OPERATING PARAMETERS

Size	• Mine:	470 × 10 ³ tons
	• Preparation Plant:	340.8 × 10 ³ tons
Annual Capacity Factor:		82%
Annual Energy Production	• Preparation Plant:	8.72 × 10 ¹² Btu
Efficiency:		72.7%
Lifetime:		30 yr

PROCESS FLOW

RESOURCES USED

Code No.	Resource	Quantities Used			Remarks
		Reference Energy System Annual Levels		Per 10 ¹² Btu Energy Produced	
		English Units	Metric Units		
	<u>Diesel Fuel</u>				One-time usage
①	Exploratory drilling rig	9 × 10 ² gal	3.4 × 10 ³ liters	103 gal	
②	Cleaning and grubbing equipment	36 × 10 ³ gal	1.36 × 10 ⁶ liters	4.13 × 10 ³ gal	
③	Topsoil removal equipment	24 × 10 ³ gal	9.17 × 10 ⁴ liters	2.75 × 10 ³ gal	
④	Drill rigs used in overburden removal	63 × 10 ³ gal	2.4 × 10 ⁶ liters	7.22 × 10 ³ gal	
	Other equipment, overburden removal	472 × 10 ³ gal	1.79 × 10 ⁶ liters	5.41 × 10 ⁴ gal	

TABLE 1. (Continued)

EASTERN SURFACE COAL MINING

RESOURCES USED (Continued)

Code No.	Resource	Quantities Used		Per 10 ¹² Btu Energy Produced	Remarks
		Reference Energy System Annual Levels			
		English Units	Metric Units		
	<u>Diesel Fuel (continued)</u>				
5	Coal removal equipment				
	Trucks	325 × 10 ³ gal	1.23 × 10 ⁶ liters	3.73 × 10 ⁴ gal	
	Loaders	46.5 × 10 ³ gal	1.76 × 10 ⁶ liters	5.33 × 10 ³ gal	
	Auger	36 × 10 ³ gal	1.36 × 10 ⁶ liters	4.13 × 10 ³ gal	
6	Bulldozers used in backfilling	230 × 10 ³ gal	8.7 × 10 ⁶ liters	2.64 × 10 ⁴ gal	
7	Bulldozers used in topsoiling	180 × 10 ³ gal	6.83 × 10 ⁶ liters	2.06 × 10 ⁴ gal	
18	Loaders used in transport loading	11 × 10 ³ gal	4.18 × 10 ⁴ liters	1.26 × 10 ³ gal	
	<u>Electricity</u>				
4	Dragline	2.98 × 10 ⁶ kWh		3.42 × 10 ⁶ kWh	Load condition 50% of the time
21	Makeup water	9.4 × 10 ⁶ gal		1.08 × 10 ⁶ gal	Maximum requirement
	<u>Land</u>	320 acres	129.5 ha	36.7 acres	
	<u>Personnel</u>				
	Mine	46 workers		5.28 workers	
	Preparation plant	15 workers		1.72 workers	

COSTS

Facility	Reference Energy System	(1975 \$)	Per 10 ¹² Btu Energy Produced	Remarks
<u>Capital</u>				
• Mine	\$24.2 × 10 ⁶ total		\$2.8 × 10 ⁶ total	See Appendix B for details and data sources
• Preparation plant	(\$0.43-\$4.0) × 10 ⁶ total		(\$0.05-\$0.5) × 10 ⁶ total	
<u>Operation and maintenance</u>				
• Mine	(\$6.1-\$8.5) × 10 ⁶ /yr		(\$0.7-\$1.0) × 10 ⁶ /yr	
• Preparation plant	(0.24-\$3.0) × 10 ⁶ /yr		(\$0.03-\$0.34) × 10 ⁶ /yr	
<u>Environmental Controls</u>	Included in above costs			

ENVIRONMENTAL RESIDUALS AND PRODUCTS

		Quantities Used			
		Reference Energy System Annual Levels			
Code No.	Residual or Product	English Units	Metric Units	Per 10 ¹² Btu Energy Produced	Remarks
<u>Air Pollutants*</u>					
(1) - (15)	Fugitive dust	Negligible or Unquantifiable			
(17) - (19)					

TABLE 1. (Continued)

EASTERN SURFACE COAL MINING

ENVIRONMENTAL RESIDUALS AND PRODUCTS (Continued)

		Quantities Used			
		Reference Energy System			
		Annual Levels			
Code No.	Residual or Product	English Units	Metric Units	Per 10 ¹² Btu Energy Produced	Remarks
	<u>Air Pollutants* (Continued)</u>				
1	Carbon monoxide Exhaust hydrocarbons Nitrogen oxides Aldehydes Sulfur oxides Particulates				Sources individually meet federal emission standards
2					
3		127.3 × 10 ³ lb	5.775 × 10 ⁴ kg	1.46 × 10 ⁴ lb	
4		39.6 × 10 ³ lb	1.80 × 10 ⁴ kg	4.54 × 10 ³ lb	
5		609.6 × 10 ³ lb	2.765 × 10 ⁶ kg	6.99 × 10 ⁴ lb	
6		9.89 × 10 ³ lb	4.49 × 10 ³ kg	1.13 × 10 ³ lb	
7		44.4 × 10 ³ lb	2.02 × 10 ⁴ kg	5.09 × 10 ³ lb	
10		31.5 × 10 ³ lb	1.43 × 10 ⁴ kg	3.61 × 10 ³ lb	
18					
	<u>Liquid Waste</u>				
20	Runoff and leachate from storage pile		Unquantifiable		
20	Unrecycled water from cleaning process		Unquantifiable		
	<u>Solid Waste</u>				
16	Refuse from coal cleaning	1.3 × 10 ⁶ tons	117.3 × 10 ³ tonnes	1.49 × 10 ⁴ tons	

*Air emission factors for pollutant calculations are summarized in Appendix A.

PRODUCTS

Primary	Quantities Produced			Remarks
	Reference Energy System Annual Production		Per 10 ¹² Btu Energy Produced	
	English Units	Metric Units		
Beneficiated Coal	340.8 × 10 ³ tons	308.1 × 10 ³ tonnes	39.1 × 10 ³ tons	Heating value of beneficiated coal = 12,800 Btu/lb

OCCUPATIONAL SAFETY AND HEALTH

	Preparation Plant		Mine	
	Annual	Per 10 ¹² Btu	Annual	Per 10 ¹² Btu
Deaths	0.0108	0.0012	0.011	0.0013
Injuries	1.41	0.16	2.87	0.33

II. PROCESS DESCRIPTION AND ENVIRONMENTAL POINTS OF INTEREST

The coal mining operation described in this report is typical of a surface coal mine in the eastern United States with production of approximately 470,000 tons per year. The coal is sized and cleaned at an on-site preparation plant. The mine operates one shift daily and has a life expectancy of 30 years.

The mine uses a conventional strip mining process. First, the vegetation is removed, then the topsoil is removed and stored. Next, the loosened overburden is removed with a dragline and used to backfill a previously worked pit. After that, the coal is removed with loaders and trucks to a processing plant, where it is washed and sized. Finally, the topsoil is restored and the area is revegetated.

The process of coal mine development from exploration to transport loading is shown in flow diagram form in Table 1. The environmental points of interest have also been identified in Figure 1 and are described in the following sections along with the resource requirements for specific parts of the coal mining process. All equipment except the dragline uses diesel fuel which leads to gaseous emissions.

FIGURE 1. PROCESS FLOWCHART WITH ENVIRONMENTAL POINTS OF INTEREST QUANTIFIED — EASTERN SURFACE MINE WITH PREPARATION PLANT

1 Air Emissions From the Exploratory Process

Exhaust emissions from exploratory drilling of 50 test holes total about 530 pounds. Dust emissions are unquantifiable but are small.

CO	HC	NO ₂	HCHO	SO ₂	Particulates
59.3	18.6	405.0	5.18	28.1	13.3

During the exploration phase, emissions are limited to diesel engine exhaust, noise and dust. To establish whether enough reserves are available drilling is performed based on a grid pattern. From the drilling, information is obtained about coal continuity, quality, structural dip and lithologic changes in overburden.

In order to provide gross coal production of 4.29×10^5 tons/yr (strip) and 4.1×10^4 tons/yr (auger), approximately 320 acres of reserves are necessary. About 12 to 15 drill holes are needed for the initial exploratory₃ phase, with an extra 30 to 40 drill holes to supply more detailed information. The depth of each hole ranges between 30 feet and 90 feet and averages about 65 feet.

The dust emission from the drilling is unquantifiable but is small and short-lived.

The gaseous emissions from the diesel engine include carbon monoxide, exhaust hydrocarbons, nitrogen oxides, aldehydes, sulfur oxides, and particulates. The quantity of diesel fuel required per hole is first calculated.

D_f = Quantity of diesel fuel required per 65 ft hole

$$\begin{aligned} D_f &= (\text{time required for drilling})(\text{fuel consumption rate}) \\ &\quad + (\text{non-load fuel requirements})(\text{non-load equipment time}) \\ &= (1 \text{ hr})(8.2 \text{ gal/hr}) + (5.0 \text{ gal/hr})(2 \text{ hr}) \\ &= 18.2 \text{ gallons per hole} \end{aligned}$$

For the approximately 50 drill holes required, this leads to a fuel consumption of about 900 gallons. The gaseous emissions will be given by:

Gaseous emission of species, lb/yr

$$= (\text{specific emission for species, lb/gal})(\text{diesel fuel used, gal/yr})$$

The results are tabulated for the species of interest.

Pollutant Species	Specific ₂ Emission ₂ lb/10 ³ gal	x Diesel Fuel Used 10 ³ gal	= Annual Emissions lb
Carbon monoxide	65.9		59.3
Exhaust hydrocarbons	20.7		18.6
Nitrogen oxides	450.0	0.90	405.0
Aldehydes	5.76		5.18
Sulfur oxides	31.2		28.1
Particulate	14.8		13.3
Total			529.5

References

1. Ingersoll-Rand Equipment Corporation, Pittsburgh, Pennsylvania, personal communication, June 1981.
2. U. S. Environmental Protection Agency, Compilation of Air Pollutant Emission Factors, PB 275 525, Third Edition, Table 3.2.7-1.
3. Pfeleider, E., Surface Mining, The American Institute of Mining, Metallurgical, and Petroleum Engineers, Inc., New York, 1972.

2

Air Emission From Clearing and Grubbing

Exhaust emissions from clearing and grubbing total 18.3×10^3 pounds per year. Dust emissions are highly variable and unquantifiable.

CO	HC	NO ₂	HCHO	SO ₂	Particulates
3,150.0	903.6	11,952.0	223.9	1,119.6	910.8

The first step in the strip mining process is the removal of vegetation above the overburden. Trees large enough to be used for lumber are cut and removed. Smaller trees and undergrowth are then cleared with a bulldozer. Diversion ditches will be built to reduce the volume of water moving across denuded land. One bulldozer (D8-D9 size range) is needed. This bulldozer consumes up to 15 gallons of diesel fuel per hour under average load conditions.

Diesel fuel consumption = (fuel used/hour)(hours worked)

= (15 gal/hr)(8 hr/day x 300 day/yr)

= (15 gal/hr)(2,400 hr/yr)

= 36,000 gal/yr

The use of diesel fuel leads to gaseous emissions.

Gaseous emission of species, lb/yr

= (specific emission for species, lb/gal)(diesel fuel used, gal/yr)

Pollutant Species	Specific ₂ Emission lb/10 ³ gal	x Diesel Fuel Used 10 ³ gal	= Annual Emissions lb
Carbon monoxide	87.5		3,150.0
Exhaust hydrocarbons	25.1		903.6
Nitrogen oxides	332.0	36.0	11,952.0
Aldehydes	6.22		223.9
Sulfur oxides	31.1		1,119.6
Particulate	25.3		910.8
Total			18,300.

The dust emission varies with precipitation, ambient soil moisture, and type of material being moved, and is unquantifiable.

References

1. Caterpillar Tractor Company, Caterpillar Performance Handbook, Edition
2. U. S. Environmental Protection Agency, Compilation of Air Pollutant Emission Factors, PB 275 525, Third Edition, Table 3.2.7-1.

3

Air Emissions From Topsoil Removal

Exhaust emissions from topsoil removal total 12.3×10^3 pounds per year. Dust emissions are unquantifiable but are small.

CO	HC	NO ₂	HCHO	SO ₂	Particulates
2,121.0	608.0	8,048.0	150.8	753.9	613.3

After trees and brush are removed from the mine area, the topsoil is removed and stored for later use in the reclamation process. To support the mining rate of 470,000 tons per year, 0.31 acre must be cleared daily. The average soil thickness is 12 inches, and thus 500 cu yd of material must be moved daily; 150,040 cu yd of topsoil will be stored annually.

To minimize erosion from runoff, the stored topsoil is temporarily planted with a fast growing annual grass mixed with slower growing perennials. About 40 lb/acre of grass and 3 to 5 lb/acre of perennials are required. Soil amendments are mixed in as needed, based on soil tests. Collection ditches are constructed to channel runoff to sediment ponds to remove suspended solids. The cleaned water is then discharged into natural drainage ways.

A bulldozer (D-8 size range) is used for topsoil removal. It consumes 10.1 gallons of fuel per hour.²

$$\text{Diesel fuel consumption} = (\text{fuel used/hr})(\text{hours worked})$$

$$= (10.1 \text{ gal/hr})(8 \text{ hr/day})(300 \text{ days/yr})$$

$$= (10.1 \text{ gal/hr})(2,400 \text{ hr/yr})$$

$$= 24,240 \text{ gal/yr}$$

Emissions are calculated for each species by multiplying their specific emission by the amount of fuel used.

Pollutant Species	Specific Emission ₃ lb/10 ³ gal	x Diesel Fuel Used 10 ³ gal	= Annual Emissions lb
Carbon monoxide	87.5		2121.0
Exhaust hydrocarbons	25.1		608.0
Nitrogen oxides	332.0	24.2	8,048.0
Aldehydes	6.22		150.8
Sulfur oxides	31.1		753.9
Particulate	25.3		613.3
Total			12,300.0

A hydroseeding machine is required for seed and mulch application. Fuel usage is negligible since the machine will only be used for a short period of time.

Dust emissions from the stockpiling operation are highly variable, depending on precipitation and soil moisture.

Dust emission from the stockpiled topsoil through the storage period will be insignificant due to the vegetative control measures.

References

1. West Virginia Department of Natural Resources Division of Reclamation, Annual Interagency Evaluation of Surface Mine Reclamation in West Virginia, July 1976.
2. Caterpillar Tractor Company, Caterpillar Performance Handbook, Edition 5.
3. U. S. Environmental Protection Agency, Compilation of Air Pollutant Emission Factors, PB 275 525, Third Edition, Table 3.2.7-1.

4

Air Emissions From Overburden Removal

Exhaust emissions from overburden removal total 335×10^3 pounds per year. Dust emissions are unquantifiable but are small.

CO	HC	NO ₂	HCHO	SO ₂	Particulates
47,236	14,912	241,455	3,769	16,699	11,083

After the topsoil has been removed, the overburden must be fractured and removed. Blast holes are drilled, filled with ammonium nitrate-fuel oil mixture (ANFO) and detonated. The blasting fractures the overburden material. This overburden is then removed with a dragline and used to backfill the adjacent pit, which has previously been mined. For the initial pit, this overburden is removed with trucks and loaders and stockpiled on undisturbed ground upslope from the operation. This overburden stockpile is later used to backfill the last pit of the mine.

Four drill rigs are required for the drilling operation. A drill rig consumes 8.2 gallons of fuel per hour under load conditions and 5 gallons per hour under non-load conditions. They are operated for 4 hours each day on full load and another 4 hours a day under non-load conditions.

Diesel fuel used annually

$$\begin{aligned}
 &= (\text{fuel use under load})(\text{number of under load hr/yr}) \\
 &\quad + (\text{fuel used under no-load conditions})(\text{number of no-load hr/yr}) \\
 &= (8.2 \text{ gal/hr})(4 \text{ hr/day})(300 \text{ days/yr}) \\
 &\quad + (5 \text{ gal/hr})(4 \text{ hr/day})(300 \text{ days/yr}) \\
 &= 15,840 \text{ gal/yr (per drill rig)} \\
 &= 63,360 \text{ gal/yr (four drill rigs)}
 \end{aligned}$$

This results in the following air emissions

Pollutant Species	Specific ₂ Emission ₂ lb/10 ³ gal	x Diesel Fuel Used 10 ³ gal	= Annual Emissions lb
Carbon monoxide	65.9		4,175
Exhaust hydrocarbons	20.7		1,311
Nitrogen oxides	450.0	63.36	28,512
Aldehydes	5.76		365
Sulfur oxides	31.2		1,977
Particulate	14.8		938
Total			37,279

The dust emissions from the drilling operation are highly variable, depending on local soil moisture content and also on weather conditions.

The blasting operation also produces air emissions. At present, there is no known way to quantify the gaseous emissions, but they are believed to be small. The dust emission is also highly variable, as explained above.

The removal of overburden is accomplished with a dragline and the first cut is accomplished with bulldozer, front-end loaders and haul trucks. The amount of diesel fuel used annually is computed to be

Vehicle Type	Units	x	Specific Consumption gal/hr	x	hr/yr	=	Fuel Consumption gal/yr
85-ton truck	5		22.4*				268,800
Bulldozer, D-9 size	4		15.0		2,400		144,000
Loader, 3-5 cu yd	4		6.2				59,520
Total							472,320

* Reference 3

Air emissions from five haulage trucks are

Pollutant Species	Specific Emission ² lb/10 ³ gal	x	Diesel Fuel Used 10 ³ gal	=	Annual Emissions lb
Carbon monoxide	92.2				24,783
Exhaust hydrocarbons	30.0				8,064
Nitrogen oxides	524.0		268.8		140,851
Aldehydes	7.74				2,081
Sulfur oxides	31.2				8,387
Particulate	17.7				4,758
Total					188,923

Air emissions from four bulldozers are

Pollutant Species	Specific Emission ₂ lb/10 ³ gal	x Diesel Fuel Used 10 ³ gal	= Annual Emissions lb
Carbon monoxide	87.5		12,600
Exhaust hydrocarbons	25.1		3,614
Nitrogen oxides	332.0	144.0	47,808
Aldehydes	6.22		896
Sulfur oxides	31.1		4,478
Particulate	25.3		3,643
Total			73,040

Air emissions from four loaders are

Pollutant Species	Specific Emission ₂ lb/10 ³ gal	x Diesel Fuel Used 10 ³ gal	= Annual Emissions lb
Carbon monoxide	95.4		5,678
Exhaust hydrocarbons	32.3		1,923
Nitrogen oxides	408.0	59.5	24,284
Aldehydes	7.17		427
Sulfur oxides	31.2		1,857
Particulate	29.3		1,744
Total			35,913

The dragline is electrically powered and consumes approximately 1,865 kWh under load and 615 kWh under non-load conditions.⁴ The air emissions from the dragline are negligible.

The overburden from the initial cut is stockpiled for later use in backfilling the last pit. The surface runoff from the spoil is controlled by collection ditches and directed to sediment ponds or treatment facilities as needed. The surface runoff is directly related to the regional precipitation. Annual precipitation ranges between 40 and 42 inches.

References

1. Caterpillar Tractor Company, Caterpillar Performance Handbook, Edition 5.
2. U. S. Environmental Protection Agency, Compilation of Air Pollutant Emission Factors, PB 275 525, Third Edition, Table 3.2.7-1.
3. Ingersoll-Rand Equipment Corporation, Pittsburgh, Pennsylvania, Personal Communication, June 1981.
4. Pfleider, E., Surface Mining, The American Institute of Mining, Metallurgical, and Petroleum Engineers, Inc., New York, 1972.

5**Air Emissions From Coal Removal**

Exhaust emissions from coal removal equipment total 282×10^3 pounds per year. Dust emissions are unquantifiable.

CO	HC	NO ₂	HCHO	SO ₂	Particulates
37,839	12,516	207,312	3,097	12,727	8,208

After the overburden has been removed, access roads will be constructed into the pit. Loaders and haul trucks are used to loosen, load, and transport the coal to the preparation facility. Augering is employed on the highwall side to increase the total production and utilize some of the coal which is under too thick an overburden to be economically strip mined.

Based on an annual production of 41,000 tons, 12.7 acres are augered yearly. A 60 percent recovery rate is assumed. The auger is 22 inches in diameter and extends 150 feet into the coal.

To meet the design production rate of the mine, six 85-ton coal hauler trucks are required. These trucks are served by four front-end loaders ranging in size from 3 to 5 cubic yard buckets.

Haulage trucks consume on the average 22.6 gallons of diesel fuel per hour per truck. Operated 8 hours per day for 300 days per year, six haulage trucks would use 325,440 gallons of diesel fuel per year.

Diesel fuel consumed

$$\begin{aligned} &= (\text{Number of units})(\text{hourly consumption rate}) \\ &\quad (\text{hours worked per year}) \\ &= (6 \text{ units})(22.6 \text{ gal/hr})(2,400 \text{ hr/yr}) \\ &= 325,440 \text{ gal/yr} \end{aligned}$$

The air emissions from the coal haulage trucks are as follows

Pollutant Species	Specific Emission ² lb/10 ³ gal	x Diesel Fuel Used 10 ³ gal/yr	= Annual Emissions lb/yr
Carbon monoxide	92.2		30,006
Exhaust hydrocarbons	30.0		9,763
Nitrogen oxides	524.0	325.44	170,531
Aldehydes	7.74		2,519
Sulfur oxides	31.2		10,154
Particulate	17.7		5,760
Total			228,732

Front-end loaders ranging in size from 3 to 5 cubic yard buckets are used to load the coal. The loaders consume 3.4 gal/hr under low load conditions and 6.3 gal/hr under high load conditions, and operate under high load conditions half of the time. This yields an average consumption of 4.85 gal/hr. The loaders operate 8 hours per day for 300 days per year, or 2,400 hours per year.

Diesel fuel used by loaders

$$\begin{aligned}
 &= (\text{number of units})(\text{hourly usage})(\text{hr/yr}) \\
 &= (4)(4.85 \text{ gal/hr})(2,400 \text{ hr/yr}) \\
 &= 46,560 \text{ gal/yr}
 \end{aligned}$$

The air emissions from the loaders are as follows

Pollutant Species	Specific ₂ Emission lb/10 ³ gal	x Diesel Fuel Used 10 ³ gal	= Annual Emissions lb
Carbon monoxide	95.4		4,442
Exhaust hydrocarbons	32.3		1,504
Nitrogen oxides	408.0	46.56	18,997
Aldehydes	7.17		334
Sulfur oxides	31.2		1,453
Particulate	29.3		1,364
Total			28,093

Hourly fuel consumption rates for the auger equipment is unknown. If this equipment is assumed to be powered by a large diesel engine comparable in size to large bulldozer engines, its consumption will be about 15 gal/hr. This results in a fuel usage of 36,000 gallons per year.

Diesel fuel consumed by auger

$$= (\text{hourly rate})(\text{number of hr/yr})$$

$$= (15 \text{ gal/hr})(2,400 \text{ hr/yr})$$

$$= 36,000 \text{ gal/yr}$$

The air emissions from the auger are as follows

Pollutant Species	Specific Emission ² lb/10 ³ gal	x Diesel Fuel Used 10 ³ gal	= Annual Emissions lb
Carbon monoxide	94.2		3,391
Exhaust hydrocarbons	34.7		1,249
Nitrogen oxides	494.0	36.0	17,784
Aldehydes	6.78		244
Sulfur oxides	31.1		1,120
Particulate	30.1		1,084
TOTAL			24,872

Dust emissions from loading, hauling, and dumping are highly variable and are dependent on the precipitation rate, moisture in the coal, and watering of haul roads.

References

1. Caterpillar Tractor Company, Caterpillar Performance Handbook, Edition 5.
2. U. S. Environmental Protection Agency, Compilation of Air Pollutant Emission Factors, PB 275 525, Third Edition, Table 3.2.7-1.

6

Air Emissions From Backfilling

Emission of dust from backfilling is highly variable and unquantifiable. Exhaust emissions total approximately 117×10^3 pounds per year.

CO	HC	NO ₂	HCHO	SO ₂	Particulates
20,129	5,774	76,373	1,431	7,154	5,820

As the coal is loaded and transported to the preparation plant, the backfilling and regrading operation begins. As discussed previously, overburden is moved by the dragline into the mine out pit. This is done to facilitate reclamation and provide temporary storage for the spoil. Backfilling is accomplished with bulldozers smoothing the overburden to a shape approximately equal to the original land surface contour. The backfilling and regrading operations are delayed long enough to allow the actual mining operation to advance far enough so that there is no interference with the various operations.

Six bulldozers (D-9 size range) will be used for the backfilling operation. Each bulldozer will operate one-half time under high-load conditions, one-fourth time under medium-load conditions, and one-fourth time under light-load conditions. This calculates to an annual fuel consumption of 38,340 gallons per bulldozer, or a total of 230,040 gal/yr.

The air emissions from these bulldozers are as follows

Pollutant Species	Specific Emission ² lb/10 ³ gal	x Diesel Fuel Used 10 ³ gal	= Annual Emissions lb
Carbon monoxide	87.5		20,129
Exhaust hydrocarbons	25.1		5,774
Nitrogen oxides	332.0	230.0	76,373
Aldehydes	6.22		1,431
Sulfur oxides	31.1		7,154
Particulate	25.3		5,820
Total			116,681

Emission of dust from the backfilling process depends on weather and soil conditions, and is highly variable.

References

1. Caterpillar Tractor Company, Caterpillar Performance Handbook, Edition 5.
2. U. S. Environmental Protection Agency, Compilation of Air Pollutant Emission Factors, PB 275 525, Third Edition, Table 3.2.7-1.

⑦ Air Emissions From Topsoiling

Exhaust emissions from the topsoiling process total 91.6×10^3 pounds per year. Dust emissions are unquantifiable.

CO	HC	NO ₂	HCHO	SO ₂	Particulates
15,803	4,533	59,959	1,123	5,617	4,569

As the area is backfilled and regraded, the stockpiled topsoil is redistributed on the surface to provide a growth medium for the revegetation operations. This operation is again accomplished using bulldozers (D-9 size range). The soil will be spread to a thickness determined by the availability. If necessary, acceptable overburden material will be used as a supplement. Since 12 inches of soil were originally removed, approximately 12 inches will be spread uniformly over the backfilled area. Dust emissions are variable due to precipitation and soil moisture conditions.

Resource utilization entails diesel fuel, bulldozers, and manpower. Five bulldozers working half time under high-load and half time under low-load conditions are used for topsoiling. This results in an annual fuel consumption rate of 180,600 gallons. The emissions from the bulldozers are as follows

Pollutant Species	Specific Emission ² lb/10 ³ gal	x Diesel Fuel Used 10 ³ gal	= Annual Emissions lb
Carbon monoxide	87.5		15,803
Exhaust hydrocarbons	25.1		4,533
Nitrogen oxides	332.0		59,959
Aldehydes	6.22	180.6	1,123
Sulfur oxides	31.1		5,617
Particulate	25.3		4,569
Total			91,604

References

1. Caterpillar Tractor Company, Caterpillar Performance Handbook, Edition 5.
2. U. S. Environmental Protection Agency, Compilation of Air Pollutant Emission Factors, PB 275 525, Third Edition, Table 3.2.7-1.

Air Emissions From the Revegetation Process

Engine emissions from the revegetation process are negligible. Dust emissions from the process are negligible.

topsoil has been evenly redistributed over the regraded area, it is prepared for revegetation. This involves applying essential plant nutrients which were lost during storage and due to leaching. The basic nutrients applied are calcium, in the form of agricultural lime and nitrogen, phosphorus, and potassium in the form of fertilizer. Application rates are based on soil test recommendations and can vary between areas of the mine. Seeding rates also vary with the selected plant varieties chosen. In order to maintain an acceptable cover, it is important to include a legume and at least one quick-growing grass in the seeding plan. The fast-growing grass is designed to quickly establish ground cover to minimize erosion. The legume is designed to establish a nitrogen fixation cycle, thus reducing the need for long-term management.

Lime is applied before seeding and fertilization in order to raise the soil pH to acceptable levels. This application will, depending on the soil pH, range between 2 to 5 tons per acre. Spreading will be accomplished by truck-mounted spreaders. Seeding is done only twice a year, spring and early fall. Approximately 56 acres will be limed each season. This results in a semi-annual lime consumption of between 92 and 230 tons.

Once liming is completed, the area is seeded with a mixture of legumes and grasses. It is also necessary to fertilize and mulch the newly seeded areas. This entire operation is combined into one step. A hydroseeding unit applies fertilizer, seed, and mulch simultaneously. This reduces the manpower and time requirements. The following table gives an example of species and application rates for the legume-grass mixtures used for revegetation. Current prices are included as obtained from Southern States Cooperative. Mulch is applied at a 2 to 3 ton per acre rate at a cost of approximately \$60 per ton.

Emissions from the revegetation process are minimal and unquantifiable. Since the seeding is done in the spring and early fall when soil moisture and precipitation are usually maximal, dust is minimal. In addition, only 2 to 3 days are required to accomplish reseeding.

Table 2.

EXAMPLES OF SEED MIXTURES AND COST FOR EASTERN SURFACE MINE REVEGETATION

Species	Rates (lb/acre)	Number of Mixtures	Cost/lb*
<u>Grasses</u>			
Ky-31 Fescue	13-25	12	\$ 0.95
Annual rye grass and perennial	10-15	5	0.50
Perennial rye grass	10-15	5	1.20
Orchard grass	10	1	1.15
Bromegrass	10	1	0.90
<u>Legumes</u>			
Sweet clover (yellow and white)	8-12	3	\$ 0.55
Clover (Alsike, Red Ladino)	10	3	0.45
Birdsfoot Trefoil	10	7	4.70
Sericea lespedeza	15-20	4	1.70
Crown Vetch	15	1	16.00

- * Cost as of 7/16/81 quoted from Southern States Cooperative, Morgantown, West Virginia.

Reference

1. West Virginia Department of Natural Resources Division of Reclamation, Annual Interagency Evaluation of Surface Mine Reclamation in West Virginia, July 1976.

⑨ Dust Emission From Coal Storage

The dust emission from the temporary coal storage is unquantifiable.

Prior to preparation for shipment the coal is temporarily stockpiled. Dust is generated during the dumping and stacking operation. Quantities of this dust are highly variable, depending on the moisture contents of the coal and on precipitation.

⑩ Emissions From the Transportation Process

The emissions from trucks transporting the coal from the mine to the preparation plant are included in the calculation of emissions in Section ⑤ .

⑪ Air Emissions From Coal Storage at the Preparation Plant

Dust emissions from coal storage at the preparation plant are unquantifiable.

As discussed in Section ⑨ , quantities of dust generated during dumping and stacking operations are highly variable and depend upon the moisture content of the coal and on precipitation.

12 Fugitive Dust From Coal Crushing

Fugitive dust from the screening process is negligible because the operation is enclosed and sprays are used to reduce dust.

The ROM coal enters the plant and is initially crushed to a nominal 6-in size. This process is enclosed and dust is controlled by spray water.

Further crushing is accomplished after washing. This operation is also enclosed. Dust will be insignificant since the coal is wet during this crushing.

Reference

1. Leonard, Joseph M., Coal Preparation, 4th edition, The American Institute of Mining, Metallurgical, and Petroleum Engineers, Inc., Port City Press, Inc., Baltimore, 1979.

13 Dust From the Screening Process

Fugitive dust from the screening process is negligible because the operation is enclosed and screened wet.

The screening operations are enclosed and function in a wet mode so fugitive dust from these processes is minimal. The cleaning operation cleans both coarse and fine coal. The sizing dewatering screen separates the coal into portions, one for further cleaning and drying (1/4 inch x 0) and one for crushing and storage (6 inch x 1/4 inch). Water is recycled and there is no discharge of water from the screening processes.

14 Dust Emissions From the Pick Table

Dust emissions from the pick table operation are negligible.

A pick table is used to remove large refuse remaining in the coal after initial crushing and screening operations. This coal and refuse is still wet from the crushing and screening so fugitive dust is insignificant. Refuse picked from the coal is placed in the refuse pile.

15 Dust Emissions From the Wash Table

Fugitive dust emissions from washing are negligible as the system is enclosed and no thermal drying is used.

Jig and wash tables are used on all sizes of coal processed. Pretreatment includes crushing, preliminary washing and sizing to remove refuse and separate the coarse coal, which is not dried, from the fine coal which requires drying.

Coal moves from the pick tables to the jig where initial washing occurs. It then is dewatered and sized by screens and the coarse fraction, 6 inch x 3/4 inch, moves to a crusher and then to a wash table for additional cleaning prior to being stockpiled. The crusher reduces the coal to 2 inch x 0 inch size range. In addition, 3/4 inch x 1/4 inch coal moves to the wash table without being further reduced in size.

The fine fraction, 1/4 inch x 0 inch, moves from the dewatering screen to a classifying cyclone where cleaning is continued. The cyclone sequence and wash tables separate the coal and clean the smaller fraction prior to drying in the centrifuge.

The fine fraction of this coal, 28 mesh x 0 mesh, is processed through a hydro-cyclone which removes additional refuse in the form of suspended solids. This sludge is processed through a thickener and water that is removed is recycled through the plant. The thickened sludge is disposed of in the refuse area. Desliming screens also remove water and fines which are also cycled through the hydro-cyclone to recover fine coal and remove water. This fine fraction is then processed through the centrifuge for drying prior to stockpiling.

Since the system is enclosed and no thermal drying is used, fugitive dust emissions from the wash table operation are negligible.

16 Solid or Sludge Waste From Coal Cleaning

The coal preparation plant generates approximately 1.3×10^5 tons of solid waste per year.

An average of 25 to 30 percent of the coal cleaned ends up as refuse stored at the plant site. Calculations are based on 27.5 percent, an average of the solid waste generated from coal cleaning operations. This includes the thickened sludge generated by the wash table (see Section 15).

$$(1,570 \text{ tons/day of ROM coal})(0.275) = 431.8 \text{ tons/day solid waste}$$

$$(431.8 \text{ tons/day})(300 \text{ working days}) = 129,540 \text{ tons/yr}$$

17 Air Emissions From Cleaned Coal Stockpile

The dust emission from the coal stockpile is unquantifiable and generally negligible.

The crushed and cleaned coal is temporarily stockpiled while waiting to be loaded and transported. A continuous stockpile of 750 tons is maintained. This stockpile is usually wet so dust emissions will be negligible. If the weather is extremely dry, dust is controlled by spraying.

18

Emissions From Transport Loading

Air emissions from loading equipment total approximately 6.66×10^3 pounds per year. Emission of dust from transport loading is highly variable and unquantifiable.

CO	HC	NO ₂	HCHO	SO ₂	Particulates
1,053	357	4,504	79	345	324

Loading is accomplished by a front-end loader onto on-road haul trucks. The loader is a 3 cubic yard unit and the haul trucks are 20-ton units. The trucks operate mainly outside of the mine and are not included in the emissions analysis. Fuel consumption of the loader is approximately 4.6 gallons per hour.

$$\begin{aligned}
 \text{Annual fuel consumption} &= (\text{hourly fuel consumption})(\text{hr/yr}) \\
 &= (4.6 \text{ gal/hr})(2,400 \text{ hr/yr}) \\
 &= 11,040 \text{ gal/yr}
 \end{aligned}$$

The emissions from this front-loader are as follows

Pollutant Species	Specific Emission ² lb/10 ³ gal	x Diesel Fuel Used 10 ³ gal	= Annual Emissions lb
Carbon monoxide	95.4		1,053
Exhaust hydrocarbons	32.3		357
Nitrogen oxides	408.0	11.04	4,504
Aldehydes	7.17		79
Sulfur oxides	31.2		345
Particulate	29.3		324
Total			6,662

The dust emission from transport loading is highly variable, depending on weather conditions and moisture content of the coal.

References

1. Caterpillar Tractor Company, Caterpillar Performance Handbook, Edition 5.
2. U. S. Environmental Protection Agency, Compilation of Air Pollutant Emission Factors, PB 275 525, Third Edition, Table 3.2.7-1.

19 Air Emissions From Waste Storage

Dust emission from the waste storage pile is unquantifiable.

The waste storage pile, consisting of refuse from the coal cleaning process, may give off dust if it gets too dry. The amount of dust is highly variable and unquantifiable, depending on wind conditions and the moisture content of the pile.

20

Liquid Waste From Storage and Cleaning Process

Runoff and leachate from waste and coal storage piles are highly precipitation-dependent and cannot be quantified. Water from disturbed aquifers depends on the hydrologic conditions of the overburden. Waste water from the coal preparation plant is negligible.

Water is an emission from the overburden removal process, coal storage piles, waste storage piles, and the cleaning process.

In the overburden removal process, water originates from surface runoff or leaching due to precipitation, or from the aquifer originally occupying the overburden volume. Runoff and leachate are controlled by collection ditches and directed to sediment ponds and treatment facilities. The quantity of runoff and leachate cannot be determined since they fluctuate with precipitation. The quantity of water from aquifers depends on the hydrological characteristic of the overburden material. The quality of runoff from a typical mine is given in Table 3.

Runoff and leachate are also the major liquid effluent from coal or waste storage pile. The control method is exactly the same, i.e., collection by ditches and direction to sediment ponds or the treatment plant. The water is analyzed periodically and treated to conform with state or Federal regulations before discharging. The primary treatment method is reaction with soda ash in the form of briquettes. If the quality of the water is outside the limits treatable with soda ash, hydrated lime is used. The quantity of this water effluent from coal or waste storage piles is highly dependent on precipitation and therefore is highly variable.

The water used in the coal preparation plant is recycled and very little water is discharged.

Table 3

QUALITY OF PIT WATER BEFORE AND AFTER TREATMENT¹
(Eastern Surface Mine)

<u>Quality</u>	<u>Before Treatment</u>	<u>After Treatment</u>
pH	4.8	7.7
Acidity, ppm	290	30
Alkalinity, ppm	0	130
Iron, ppm	100	0.5
Magnesium, ppm	0.92	0.1
Sulphates, ppm	290	60
TSS	132	1
TDS	-	-

Reference

1. Dr. Donald L. Streib, Personal Communication, Science Applications, Inc., Morgantown, West Virginia, 1981.

21 Water Requirements of the Cleaning Plant

The makeup water requirement in the cleaning plant should not exceed 9.4×10^6 gallons per year.

Water required in the cleaning plant may come from a variety of sources: surface runoff, groundwater aquifers, or drilled wells. Quantities of water necessary for various cleaning plants vary and it is impossible to scale and depend on empirical experience with a particular preparation plant. However, the amount of makeup water required is found to be approximately 20 gal/ton of ROM coal.^{1,2} Using the annual output of 470,000 tons of ROM coal, the amount of water required is computed:

$$\begin{aligned}\text{Makeup water} &= (\text{makeup water per ton})(\text{number of tons of coal}) \\ &= (20 \text{ gal/ton})(470,000 \text{ tons/yr}) \\ &= 9.4 \times 10^6 \text{ gal/yr}\end{aligned}$$

All water used in this plant is recycled and very little water is discharged. Part of the water is lost as a result of evaporation from the surface of the partially dried coal.

References

1. U. S. Department of Energy, Coal Fired Power Plants (Eastern Coal), Environmental Characterization Information Report, #DOE/EP-0013, January 1981.
2. U. S. Department of Energy, Environmental Data -- Energy Technology Characterizations, Coal, #DOE/EV-0061/3, pp. 4-6.

III. PHYSICAL REQUIREMENTS

Land

Land is required for the strip mines and for the coal preparation plant. To provide gross coal production of 4.29×10^5 tons/yr strip and 4.1×10^4 tons/yr auger, approximately 320 acres of reserves are necessary. The land necessary for the coal preparation plant would include 2 acres for surface facilities and 1.2 acre/yr over 3 years for waste storage.

Water

As discussed in Section (21), water for the Eastern surface mine may come from either natural sources such as surface runoff and groundwater aquifers or from drilled wells if the natural source is not available. Makeup water in the cleaning plant should not exceed 9.4×10^6 gallons per year. Recycled water from the mining operation is used in the preparation plant and then is sent to sedimentation pond before final treatment and discharge.

Diesel Fuel¹

Drill rigs are used in the exploratory phase and overburden removal. The rig uses approximately 8.5 gallons of fuel per hour under load conditions, while under non-load conditions (i.e., set-up, pulling steel, transport, idle time, etc.), the rig consumes approximately 5 gallons of fuel per hour.

Bulldozers (D-8, D-9) use about 15 gallons of fuel per hour under average load conditions: clearing, grubbing, and overburden removal. For topsoil removal, 10.1 gallons per hour is assumed. For backfilling operations, calculations are based on each bulldozer operating one-half time under high-load, one-fourth time under medium load, and one-fourth time under light-load conditions, while for topsoil redistribution, calculations are based on bulldozers working half time under high-load and half time under low-load conditions.

Trucks (85-ton capacity) are used to remove the overburden and to transport the coal to the preparation plant. Average fuel consumption is about 22.5 gallons per hour.

Front-end loaders (3 to 5 cu yd) have a fuel consumption that ranges from 3.4 gallons per hour under low-load conditions to 6.3 gallons per hour under high-load conditions.

Hourly fuel consumption rate for auger equipment is unknown. It has been assumed that the diesel engine is comparable in size to a large bulldozer and will consume about 15 gallons of fuel per hour.

Electricity²

Overburden material is removed with a dragline that is electrically powered and consumes approximately 1,865 kWh under load and 615 kWh under non-load conditions.

References

1. Caterpillar Tractor Company, Caterpillar Performance Handbook, Edition 5.
2. Pfleider, E., Surface Mining, The American Institute of Mining, Metallurgical, and Petroleum Engineers, Inc., New York, 1972.

IV. PERSONNEL

The number of people required to operate the equipment for this Eastern surface mine is 46; however, this number of people may vary, depending on the operating philosophy of the owners. The amount of equipment that is used, the hours worked, and the number of employee shifts can all affect this number.

Fifteen employees are utilized by the coal preparation plant.

Reference

1. Mining Information Services of the McGraw-Hill Publishing Company, Key-stone Coal Industry Manual, George F. Nielson, Editor-in-Chief, 1976.

V. OCCUPATIONAL SAFETY AND HEALTH

Occupational safety and health implications of the surface mine and coal preparation plant have been examined using death and injury statistics. For surface mines, the report lists a death rate of 0.02 (in incidence per 200,000 employee-hours) and 5.2 injuries. The corresponding figures for processing plants are 0.067 and 7.82. Projections for the present mine are:

Number of incidents per year

= number of employee hours x incidence rate/200,000 employee hours

	<u>Coal Mine</u>	<u>Processing Plant</u>
Number of Employees	46	15
Number of Employee Hours/Year	110,400	36,000
Fatality rate, number/200,000 man-hrs	0.02	0.067
Fatalities, number/yr	0.011	0.0108
Fatalities, number/10 ¹² Btu	0.0013	0.0012
Injury rate, number/200,000 man-hrs	5.2	7.82
Injuries, number/yr	2.87	1.41
Injuries, number/10 ¹² Btu	0.33	0.16

Reference

1. U. S. Department of Labor, Mine Safety & Health Administration, Injury Experience in Coal Mining, 1979, Information Report LR1122 (1980).

APPENDIX A

AIR EMISSIONS FOR EASTERN SURFACE MINING

The pollutant emissions that result from diesel equipment include carbon monoxide (CO), exhaust hydrocarbon (HC), nitrogen oxides (NO_x), aldehydes (HCHO), sulfur oxides (SO_x), and particulates. Emissions that^x emanate from equipment vary depending upon the size of the mining operations, the type and quantity of equipment used, and the amount of time each piece is operated. Each type of equipment has a specific fuel emission rate as summarized below. The pollutant emission rate can be determined by multiplying the rate times the number of pieces of equipment times the amount of fuel used annually.

	Diesel Emission Factor ¹					
	(lb/10 ³ gal)					
	<u>CO</u>	<u>HC</u>	<u>NO_x</u>	<u>HCHO</u>	<u>SO_x</u>	<u>Particulates</u>
Drill Rigs	65.9	20.7	450	5.76	31.2	14.8
Bulldozer (D-8, D-9)	87.5	25.1	332	6.22	31.1	25.3
Truck (85-ton)	92.2	30.0	524	7.74	31.2	17.7
Loaders (3 to 5 cu yd)	95.4	32.3	408	7.17	31.2	29.3
Auger	94.2	34.7	494	6.78	31.1	30.1

Reference

1. U. S. Environmental Protection Agency, Compilation of Air Pollutant Emission Factors, PB 275 525, Third Edition, Table 3.2.7-1.

APPENDIX B COST ESTIMATES

Mining Cost Estimates

Estimates of capital investment and operating and maintenance (O&M) costs indicated in Table 1, Summary Sheet (Section I), were derived from modified general cost estimates presented in Reference 1. These data are shown in Table B-1.

The per unit cost estimate of \$48.30/ton for eastern surface coal mines from Table B-1 was used in conjunction with the approximate 0.5×10^6 ton/yr capacity of the hypothetical eastern surface coal mine to obtain the total capital cost estimate. The annual O&M costs were estimated by noting that O&M costs for western surface coal mines ranged from 2.5 to 3.5 percent of capital costs.² As is the case for the mine characterized in Reference 2, environmental control costs (land reclamation and treatment of water from mine drainage) are assumed to be included in overall capital and O&M costs. The derived cost estimates are presented in Table B-2.

Preparation Plant Cost Estimates

As indicated in the available literature on coal preparation costs, the degree of beneficiation and, therefore, the cost is largely determined by the product specifications of the intended market and the prospective rate of return to the investor. Current coal beneficiation processes encompass a broad spectrum of treatment, ranging from simple breaking to elaborate systems that include flotation circuits and thermal drying (Reference 1 defines seven levels of coal beneficiation). According to the literature, even bidding to identical and carefully drawn specifications, different contracting engineers might quote prices in a ratio of 2:1 between high and low bidder. Because of this uncertainty, a range of costs indicative of various levels of coal beneficiation are presented in Table 1, Summary Sheet, rather than point estimates.

Two ranges of cost estimates (References 2 and 1, respectively) are shown in Table B-3. The per unit cost ranges for the preparation plant with output capacity of 2 million ton/yr of beneficiated coal were used to compute the cost estimates for the preparation plant characterized in Reference 2. Reference 1 provides the methodology for calculating the relative costs of coal preparation. This methodology was used to compute the cost estimates for the 2×10^6 ton/yr preparation plant in Table B-3. Environmental control costs for the preparation plant (primarily wastewater treatment) are assumed to be included in overall capital and O&M costs.

Table B-1. Estimated Capital Costs for New Coal Mines

Mining Method	Annual Capacity (\$/ton)	
	Eastern	Western
Underground	\$57.20	\$57.20
Surface	\$48.30	\$18.00
Western surface, equivalent heating-value basis	---	\$21.60

Source: Modified from G.W. Land, "Capital Requirements for New Mine Development," presented at Third Conference on Mine Productivity, Pennsylvania State University, April 5-8, 1976.

Table B-2. Summary of Cost Estimates for an Eastern Surface Coal Mine

Cost Item	Capacity (ton/yr) (1975\$)
Total Capital Cost	$\$24.2 \times 10^6$
Capital Cost Per Ton	\$48.30
O&M Cost	
Per Year	$(\$6.1-\$8.5) \times 10^6$
Per Ton Produced	\$12.20-\$16.90
Environmental Control	Included in the above costs

Table B-3. Summary of Cost Estimates for Coal Preparation Plants

Cost Item	Capacity (tons/yr)		
	3 x 10 ⁶ (ROM coal) (1978\$)	2 x 10 ⁶ (beneficiated coal) (1975\$)	0.34 x 10 ⁶ (beneficiated coal) (1975\$)
Total Capital Cost	(\$6.8-\$50) x 10 ⁶	\$2.5-\$23.8 x 10 ⁶	\$0.43-\$4.0 x 10 ⁶
Capital Cost Per Ton	\$2.3-\$17	\$1.25-\$11.91	\$1.25-\$11.91
O&M Cost			
Per Year	(\$0.24-\$11) x 10 ⁶	(\$1.42-\$17.64) x 10 ⁶	\$0.24-\$3.0 x 10 ⁶
Per Ton Produced	\$0.08-\$3.66	\$0.71-\$8.82	\$0.71-\$8.82
Environmental Control	Included in the above cost estimates		

References

1. Schmidt, R.A., Coal In America--An Encyclopedia of Reserves, Production and Use, McGraw-Hill Publications Company, 1979.
2. U.S. Department of Energy, Basic Estimated Capital Investment and Operating Costs for Subbituminous and Lignite Coal Strip Mines--Mines With Annual Production of 3, 4, and 5 MMtpy ROM Coal, FE/EES 79/6, DOE Process Evaluation Office, Morgantown, West Virginia, April 1979.

GLOSSARY

auger mine	A mine usually found in a region of thick overburden where a hole is bored laterally into the coal seam in a drill-like fashion.
coal preparation	Process for upgrading raw coal by physical means.
contour mine	A type of coal mine which follows the shape of the mountains or hilly terrain in the region. Typically starts at coal outcrops and follows the seam until overburden becomes too thick to remove economically. Frequently followed by auger mining.
dragline	A massive scraper shovel.
fugitive emissions	Unintentional emissions such as blowing dust from a coal storage pile.
grubbing	To clear vegetative brush by uprooting roots and stumps.
leaching	The separation or dissolving of soluble minerals or metals into the water.
overburden	Material overlaying a coal deposit.
pH	The negative logarithm of the effective hydrogen ion concentration used in expressing both acidity and alkalinity on a scale with values ranging from 0 to 14 (values less than 7 indicate increasing acidity; values greater than 7 indicate increasing alkalinity).
reclamation	The process of restoring vegetation to the land area disrupted by the mining operation.
recycled water	Water that is collected, treated, and reused at the facility.
screening	A step in the coal cleaning process which separates fine coal by particle size and density.
strip mine	A mine that is worked from the earth's surface by stripping the overburden.
total dissolved solids	The concentration of solid matter that is dissolved in water, usually stated in milligrams per liter.
total suspended solids	The concentration of suspended solids in water, usually stated in milligrams per liter.

ACRONYMS AND ABBREVIATIONS

As	arsenic
ANFO	ammonia nitrate-fuel oil mixture (explosive)
Btu	British thermal unit
CO	carbon monoxide
cu yd	cubic yard
dB	decibel
gal	gallon
ha	hectare
HC	hydrocarbon
HCHO	aldehydes
kWh	kilowatt-hour
kg	kilogram
l	liter
lb	pound
mg	milligram
NO ₂	nitrogen dioxide
NO _x	nitrogen oxides
pH	hydrogen ion concentration
ppm	parts per million
ROM	run-of-mine
SO ₂	sulfur dioxide
SO _x	sulfur oxides
TDS	total dissolved solids
TSS	total suspended solids

Western Surface Coal Mining

Environmental Characterization Information Report

October 1982

**U.S. Department of Energy
Assistant Secretary for Environmental
Protection, Safety, and
Emergency Preparedness
Office of Environmental Analysis**

CONTENTS

	<u>Page</u>
I. SUMMARY	A.10-3
II. PROCESS DESCRIPTION AND ENVIRONMENTAL POINTS OF INTEREST.	A.10-6
1. Air Emissions From Exploration.	A.10-10
2. Air Emissions From Clearing and Grubbing.	A.10-10
3. Air Emissions From Topsoil Removal.	A.10-11
4. Air Emissions From Overburden Removal	A.10-14
5. Liquid Waste From Overburden Removal.	A.10-18
6. Liquid Waste From Spoil Storage	A.10-18
7. Air Emissions From Coal Removal	A.10-19
8. Air Emissions From Backfilling and Regrading.	A.10-20
9. Air Emissions From Topsoiling	A.10-22
10. Air Emissions From Coal Storage	A.10-24
11. Air Emissions From Coal Transport	A.10-25
12. Dust Emission at Coal Storage Site.	A.10-28
13. Air Emissions From Coal Preparation	A.10-29
14. Solid Waste From Coal Preparation	A.10-31
15. Liquid Wastes From Waste Storage Areas.	A.10-31
16. Air Emissions From Coal Loading	A.10-32
17. Liquid Waste From Coal Storage.	A.10-32
III. PHYSICAL REQUIREMENTS	A.10-33
IV. PERSONNEL	A.10-34
V. OCCUPATIONAL SAFETY AND HEALTH.	A.10-35
APPENDIX A: DIESEL EMISSION FACTORS.	A.10-36
APPENDIX B: COST ESTIMATES	A.10-37
GLOSSARY	A.10-40
ACRONYMS AND ABBREVIATIONS	A.10-41

I. SUMMARY

The Environmental Characterization Information Report (ECIR) for Western Surface Coal Mining has been prepared from the latest available environmental and technical information collected from a number of sources. The mine selected for characterization produces 9.7×10^6 tons/yr subbituminous coal and has its own preparation plant.

The mining process and plant parameters, resources needed, and the environmental residuals and products are presented in the Summary Table 1. Annual resources and pollutant discharges are shown in metric and English units, and in terms of 10^{12} Btu of energy produced. These figures are given to allow comparison between different energy processes and to facilitate application of the information in computer models.

The process description and environmental points of interest are given in Section II. Eighteen environmental points of interest are discussed individually, giving a brief description of the pollutants or resources involved, calculations showing the derivation of quantities, and a list of references used.

Section III discusses the physical requirements of the mining operation and quantifies the amounts of land, water, electricity, and fuel that are needed.

Section IV describes personnel requirements and Section V describes occupational health data, specifically, fatality and accident rates.

A glossary and list of abbreviations and acronyms have been provided to define and identify technical terms used in this report.

TABLE 1. SUMMARY SHEET

WESTERN SURFACE COAL MINING

ENERGY SYSTEM DESCRIPTION

Western Surface Mine With 23.1-Ft. Seam Thickness. The Overburden Thickness Is 100 Ft. (Stripping Ratio) 4/1 (Cover/Coal). About 35 Acres of Land Is Disturbed Annually by Mining Operations. The Overburden Removal Is Done by Drag-line, Stripping Shovels. Bulldozers Are Used for Backfilling and Regrading. There Is an Onsite Preparation Plant Using a Wet Method of Cleaning the Coal and Unit Trains Are Used for Final Shipment.

FACILITY OPERATING PARAMETERS

Size • Mine: 9.7×10^6 ton/yr
 • Preparation Plant: 8.73×10^6 ton/yr
 Annual Capacity Factor: 85% to 90%
 Annual Energy Production
 • Preparation Plant: 153×10^{12} Btu
 Efficiency
 • Preparation Plant: 90%
 Lifetime: 40 yr

PROCESS FLOW

Note: Environmental Points of Interest are discussed in Section II.

RESOURCES USED

		Quantities Used			
		Reference Energy System Annual Usage			
Code No.	Resource	English Units	Metric Units	Per 10 ¹² Btu Energy Produced	Remarks
4	Ammonium nitrate fuel oil mixture (ANFO)	1.25 × 10 ³ tons	1.13 × 10 ³ tonnes	8.2 tons	
1 - 4	Fuel	3.8 × 10 ⁶ gal	14.5 × 10 ⁶ liters	25 × 10 ³ tons	
8 9	Electricity (preparation plant)	9 × 10 ⁵ kWh		5.9 × 10 ³ kWh	
	Personnel				
	Mine	210 workers			Operation and maintenance personnel
	Preparation plant	20 workers			
10	Water	Unquantifiable			
11					
13	Land	35 acres	14.2 ha	0.23 acre	Land for mining operations. Mine occupies 2 × 10 ⁴ acres; ten acres are used for solid waste storage and facilities consumed 16.8 acres.

TABLE 1. (Continued)

WESTERN SURFACE COAL MINING

COSTS

	Reference Energy System	Per 10 ¹² Btu Energy Produced	Remarks
	(1978 \$)		
Facility			
• Capital	\$197 × 10 ⁶ total	\$1.3 × 10 ⁶ total	See Appendix B for details and data sources
• Mine	(\$12.1-\$116) × 10 ⁶ total	(\$0.08-\$0.8) × 10 ⁶ total	
• Preparation plant			
Operation and maintenance			
• Mine	≤\$50 × 10 ⁶ /yr	≤\$0.33 × 10 ⁶ /yr	
• Preparation plant	(\$6.9-\$85.6) × 10 ⁶ /yr	≤(\$0.05-\$0.56) × 10 ⁶ /yr	
Environmental Controls	Included in above costs		

ENVIRONMENTAL RESIDUALS

		Quantities Used			
		Reference Energy System Annual Levels			
Code No.	Residual	English Units	Metric Units	Per 10 ¹² Btu Energy Produced	Remarks
	<u>Air Pollutants</u>				
①	CO	147 tons	133 tonnes	0.97 ton	
②	}	47 tons	43 tonnes	0.31 ton	
③		734 tons	667 tonnes	4.8 tons	
④		12 tons	11 tonnes	0.08 ton	
⑧		48 tons	44 tonnes	0.32 ton	
⑨	SO ₂	48 tons	44 tonnes	0.32 ton	
⑨	Particulates	39 tons	35 tonnes	0.26 ton	
①-⑫	Fugitive Dust	107 tons	97 tonnes	0.70 ton	
	<u>Water Discharges</u>				
	All water used in the mine activity is recycled; amounts are not quantifiable				
⑭	Solid Waste	9.8 × 10 ⁶ tons	8.9 × 10 ⁶ tonnes	6.4 × 10 ³ tons	

PRODUCTS

Primary	Quantities Produced			Remarks
	Reference Energy System			
	Annual Production			
	English Units	Metric Units	Per 10 ¹² Btu Energy Produced	
Beneficiated Coal	8.73 × 10 ⁶ tons	7.89 × 10 ⁶ tonnes	57.1 × 10 ³ tons	H.V. = 8,750 Btu/lb

OCCUPATIONAL SAFETY AND HEALTH

	Preparation Plant		Mine	
	Annual	Per 10 ¹² Btu	Annual	Per 10 ¹² Btu
Deaths	0.014	0.09 × 10 ⁻³	0.05	0.33 × 10 ⁻³
Injuries	1.8	0.01	13.1	0.09

II. PROCESS DESCRIPTION AND ENVIRONMENTAL POINTS OF INTEREST

The coal mining operation described in this report is typical of a surface mine in the western United States with production of approximately 9.7 million tons per year. The coal is sized and cleaned at an on-site preparation plant. The mine operates three shifts daily and has a life expectancy of 40 years. Most of the equipment that is used in the strip auger mining is diesel powered, except for the dragline and stripping shovel which are electric.

The process of coal mine development from exploration to transport loading is shown in flow diagram form in Table 1. The environmental points of interest have been identified in Figure 1 and are described in the following sections along with the resource requirements for specific parts of the coal mining process.

Reference

1. Mining Informational Services of the McGraw-Hill Publishing Co., Keystone Coal Industry Manual, George F. Nielsen, Editor-in-Chief, 1976.

A.10-7

FIGURE 1. PROCESS FLOWCHART WITH ENVIRONMENTAL POINTS OF INTEREST QUANTIFIED — WESTERN SURFACE MINE WITH PREPARATION PLANT

①

Air Emissions From Exploration

The controlled residual pollutants emitted to the atmosphere as a result of exploration are:

Dust (from rotary drill) = unquantifiable

Diesel engine exhaust = 18.0 tons/yr

CO	HC	NO ₂	HCHO	SO ₂	Particulates
1.87	0.65	14.3	0.14	0.93	0.47

The mine will have a life expectancy of approximately 40 years. In order to provide an annual production of 9.7×10^8 tons, reserves averaging 23 feet thick and extending for 20,000 acres must be available.¹ To obtain this quantity of coal, extensive drilling and geologic investigations are necessary during the exploration process.

During the exploration and reserve evaluation phase, emissions are limited to diesel engine emissions, noise, and dust from drill equipment. Since these emissions are short-lived, they have a minimal impact on isolated environments. However, when a drill site is near public or private facilities, the impact of exploration activities becomes more important. Dust and noise are temporary problems for residents adjacent to drill sites. Potential for problems exists; however, due to the extreme variability of drilling conditions, media being drilled, and water encountered during drilling, the quantification of dust emissions is virtually impossible.

The process of drilling one 125-ft exploration hole takes approximately 4 hours, including set up, drilling and tear-down time. Under load conditions the drill rig uses approximately 8.5 gallons of fuel per hour, while under non-load conditions (i.e., set up, pulling steel, transport and idle time, etc.), the rig consumes approximately 5 gallons of fuel per hour.² The exploration and reserve assessment for a mine of this size entails drilling between 60 and 80 test holes with an average depth of 125 feet.

Quantity of diesel fuel required per 125 ft hole

$$\begin{aligned}
 &= [(\text{time for drilling}) (\text{fuel consumption rate})] \\
 &\quad + [(\text{non-load fuel requirements}) (\text{non-load drill time})] \\
 &= [(2 \text{ hrs})(8.5 \text{ gal/hr})] + [(2 \text{ hrs})(5.0 \text{ gal/hr})] \\
 &= 27 \text{ gallons of fuel}
 \end{aligned}$$

The emissions that emanate from the equipment used in the mine operation will vary depending on the size of the mine, the type and amount of equipment that

is used and the amount of time each piece is operated. Each type of equipment has a specific fuel emission rate.³ Therefore, the pollutant emission rate can be determined by multiplying the rate times the number of pieces of equipment times the hours each piece is used annually.

The pollutant emissions that result from diesel equipment include carbon monoxide, exhaust hydrocarbons, nitrogen oxides (NO_x as NO_2), aldehydes (HCHO), sulfur oxides (SO_x as SO_2) and particulates.

Diesel Engine Emissions:

$$= (\text{number of drills})(\text{hours/year})(\text{emission factor})$$

$$\begin{aligned}\text{CO} &= (2 \text{ drills})(4,680 \text{ hr/yr})(0.4 \text{ lb/hr}) \\ &= (3,744 \text{ lb/yr})/(2,000 \text{ lb/ton}) \\ &= 1.87 \text{ tons/yr}\end{aligned}$$

$$\begin{aligned}\text{HC} &= (2 \text{ drills})(4,680 \text{ hr/yr})(0.14 \text{ lb/hr}) \\ &= (1,310 \text{ lb/yr})/(2,000 \text{ lb/ton}) \\ &= 0.65 \text{ ton/yr}\end{aligned}$$

$$\begin{aligned}\text{NO}_2 &= (2 \text{ drills})(4,680 \text{ hrs/yr})(3.06 \text{ lb/hr}) \\ &= (28,642 \text{ lb/yr})/(2,000 \text{ lb/ton}) \\ &= 14.3 \text{ tons/yr}\end{aligned}$$

$$\begin{aligned}\text{Aldehydes} &= (2 \text{ drills})(4,680 \text{ hr/yr})(0.03 \text{ lb/hr}) \\ &= (280.8 \text{ lb/yr})/(2,000 \text{ lb/ton}) \\ &= 0.14 \text{ ton/yr}\end{aligned}$$

$$\begin{aligned}\text{SO}_2 &= (2 \text{ drills})(4,680 \text{ hr/yr})(0.2 \text{ lb/hr}) \\ &= (1,872 \text{ lb/yr})/(2,000 \text{ lb/ton}) \\ &= 0.93 \text{ ton/yr}\end{aligned}$$

$$\begin{aligned}\text{Particulates} &= (2 \text{ drills})(4,680 \text{ hr/yr})(0.1 \text{ lb/hr}) \\ &= (936 \text{ lb/yr})/(2,000 \text{ lb/ton}) \\ &= 0.47 \text{ ton/yr}\end{aligned}$$

References

1. Mining Informational Services of McGraw-Hill Publishing, Keystone Coal Industry Manual, George F. Nielsen, Editor-in-Chief, 1976.
2. Caterpillar Tractor Company, Caterpillar Performance Handbook, January 1975.
3. Diesel Engine Emission Factors, see Appendix A to this document.

2 Air Emissions From Clearing and Grubbing

Emissions from the clearing and grubbing operations are limited to diesel engine exhaust and dust from the actual grubbing.

Dust from grubbing = unquantifiable

Diesel engine exhaust = 8.7 tons/yr

CO	HC	NO ₂	HCHO	SO ₂	Particulates
1.5	0.4	5.7	0.10	0.53	0.44

Emissions from this operation includes the diesel engine exhaust and dust created during the actual grubbing (see Glossary) and clearing operations. The dust generated by the grubbing equipment varies depending on the climatic conditions and ground cover in the area; however, this quantity is minimal and presents no problems to the environment.

Diesel emissions from this operation come from two bulldozers operating for 3,900 hrs/yr.

Diesel Engine Emissions: ^{1,2}

= (number of bulldozers)(hrs/yr)(emission factor)

CO = (2 bulldozers)(3,900 hr/yr)(0.39 lb/hr)
= (3,042 lb/yr)/(2,000 lb/ton)
= 1.5 tons/yr

HC = (2 bulldozers)(3,900 hr/yr)(0.11 lb/hr)
= (858 lb/yr)/(2,000 lb/ton)
= 0.4 ton/yr

NO₂ = (2 bulldozers)(3,900 hr/yr)(1.47 lb/hr)
= (11,446 lb/yr)/(2,000 lb/ton)
= 5.7 tons/yr

Aldehydes = (2 bulldozers)(3,900 hr/yr)(0.027 lb/hr)
= (211 lb/yr)/(2,000 lb/ton)
= 0.10 ton/yr

SO₂ = (2 bulldozers)(3,900 hrs/yr)(0.137 lb/hr)
= (1,069 lb/yr)/(2,000 lb/ton)
= 0.53 ton/yr

Particulates = (2 bulldozers)(3900 hr/yr)(0.112 lb/hr)
= (874 lb/yr)/(2,000 lb/ton)
= 0.44 ton/yr

References

1. Caterpillar Tractor Company, Caterpillar Performance Handbook, January 1975.
2. Diesel Engine Emission Factors, see Appendix A to this document.

3

Air Emissions From Topsoil Removal

The annual residual pollutants emitted to the atmosphere as a result of topsoil removal are:

Dust from topsoil removal—scraping = 6.8 tons/yr
 Dust from topsoil removal—dumping = 0.8 ton/yr
 Exhaust emission from diesel equipment = 70.0 tons/yr

CO	HC	NO ₂	HCHO	SO ₂	Particulates
11.0	4.14	47.7	1.04	3.14	2.99

Dust emissions for this mine are based on averages for this region.¹ Scraping operations generate 0.08 lb/cu yd while dumping activities create 0.01 lb/cu yd of soil.

These calculations are based on data used to predict the airborne emissions assuming an impact at ground level 5 km from the source. Most topsoil removal is accomplished during the summer months, which is the driest time in this region. This tends to present a worst-case situation. The data are based on an average wind speed of 5.0 m/sec and a soil stability class D. In the western mining area, the topsoil varies between 10 and 122 cm (4 to 48 inches), average 36 inches at this site. To allow room for the development of these pits, approximately 35 acres are cleared annually.

Dust Emissions from Topsoil Removal (assuming 3-foot depth)
 = (emission factor)(volume of topsoil removed annually)

Scraping:

= (0.08 lb/cu yd)(35 acres/yr x 4,840 sq yd/acre x 1 yd)
 = (0.08 lb cu yd)(169,400 cu yd/yr)
 = (13,552 lb/yr)/(2,000 lb/ton)
 = 6.8 tons/yr

Dumping Operations:

= (0.01 lb/cu yd)(35 acres/yr x 4,840 sq yd/acres x 1 yd)
 = (0.01 lb/cu yd)(169,400 cu yd/yr)
 = (1,694 lb/yr)/(2,000 lb/ton)
 = 0.85 ton/yr

Diesel engine emissions in this operation are generated by three scrapers and three bulldozers which operate 3,900 hrs/yr. Each scraper consumes approximately 16 gal fuel/hr, and each bulldozer uses 15 gal fuel/hr.²

Diesel Engine Emissions³

for scrapers = (number of scrapers)(hr/yr)(emission factor)

for bulldozers = (number of bulldozers)(hr/yr)(emission factor)

CO

for Scraper = (3)(3,900 hr/yr)(1.5 lb/hr)
= (17,550 lb/yr)/(2,000 lb/ton)
= 8.7 tons/yr

for Bulldozer = (3)(3,900 hr/yr)(0.39 lb/hr)
= (4,563 lb/yr)/(2,000 lb/ton)
= 2.3 ton/yr

HC

for Scraper = (3)(3,900 hr/yr)(0.6 lb/hr)
= (7,020 lb/yr)/(2,000 lb/ton)
= 3.5 tons/yr

for Bulldozer = (3)(3,900 hr/yr)(0.11 lb/hr)
= (1,287 lb/yr)/(2,000 lb/ton)
= 0.64 ton/yr

NO₂

for Scraper = (3)(3,900 hr/yr)(6.7 lb/hr)
= (78,390 lb/yr)/(2,000 lb/ton)
= 39.1 tons/yr

for Bulldozer = (3)(3,900 hr/yr)(1.47 lb/hr)
= (17,199 lb/yr)/(2,000 lb/ton)
= 8.6 tons/yr

Aldehydes

for Scraper = (3)(3,900 hr/yr)(0.15 lb/hr)
= (1,755 lb/yr)/(2,000 lb/ton)
= 0.88 ton/yr

for Bulldozer = (3)(3,900 hr/yr)(0.027 lb/hr)
= (316 lb/yr)/(2,000 lb/ton)
= 0.16 ton/yr

$$\begin{aligned}
 \text{SO}_2 \text{ for Scraper} &= (3)(3,900 \text{ hr/yr})(0.4 \text{ lb/hr}) \\
 &= (4,680 \text{ lb/yr})/(2,000 \text{ lb/ton}) \\
 &= 2.34 \text{ tons/yr}
 \end{aligned}$$

$$\begin{aligned}
 \text{for Bulldozer} &= (3)(3,900 \text{ hr/yr})(0.137 \text{ lb/hr}) \\
 &= (1,603 \text{ lb/yr})/(2,000 \text{ lb/ton}) \\
 &= 0.80 \text{ ton/yr}
 \end{aligned}$$

$$\begin{aligned}
 \text{Particulates} \\
 \text{for Scraper} &= (3)(3,900 \text{ hr/yr})(0.4 \text{ lb/hr}) \\
 &= (4,680 \text{ lb/yr})/(2,000 \text{ lb/ton}) \\
 &= 2.34 \text{ tons/yr}
 \end{aligned}$$

$$\begin{aligned}
 \text{for Bulldozer} &= (3)(3,900 \text{ hr/yr})(0.112 \text{ lb/hr}) \\
 &= (1,310 \text{ lb/yr})/(2,000 \text{ lbs/ton}) \\
 &= 0.65 \text{ ton/yr}
 \end{aligned}$$

References

1. U. S. Environmental Protection Agency, User's Guide for HIWAY, A Highway Air Pollution Model, Research Triangle Park, North Carolina, Publication No. EPA-650/4-74-008, February 1975.
2. Caterpillar Tractor Company, Caterpillar Performance Handbook, January 1975.
3. Diesel Engine Emission Factors, see Appendix A to this document.

4

Air Emissions From Overburden Removal

The emissions created during the overburden removal portion of surface mining are:

<i>Dust from hole drilling</i>	<i>= 7.0 tons/mine/yr</i>
<i>Dust from blasting overburden</i>	<i>= 19.9 tons/mine/yr</i>
<i>Dust from overburden removal</i>	
<i>(dragline or stripping shovel)</i>	<i>= 1.8 tons/yr</i>
<i>Diesel engine exhaust</i>	<i>= 32.3 tons/yr</i>

<i>CO</i>	<i>HC</i>	<i>NO₂</i>	<i>HCHO</i>	<i>SO₂</i>	<i>Particulates</i>
<i>5.6</i>	<i>1.6</i>	<i>21.1</i>	<i>0.39</i>	<i>1.98</i>	<i>1.61</i>

Once the topsoil is removed and stockpiled, the overburden removal begins. The initial step in this phase of mining is the drilling of blast holes. Spacing, depth, and pattern depend on the hardness and thickness of the overburden material.

Once an adequate number of holes have been drilled in a section large enough to allow the dragline or stripping shovel to work efficiently, the holes are loaded with the explosive (ammonia nitrate fuel oil mixture [ANFO]) and detonated once a week. This blasting fractures the overburden material to facilitate removal by the dragline or stripping shovels.

After blasting, the overburden is removed and stored on the ground near the pit until the coal is removed. It is then replaced in the open pit during the reclamation phase. A mine of this size has three pits operating consecutively. Each pit has an equivalent complement of mining equipment. The primary equipment in each pit during the overburden removal phase is a blast hole drill and a dragline or stripping shovel.

Based on the annual production of this mine, an average of 0.4 acre of overburden is removed from each pit daily. Prior to dragline activity, this material is drilled and blasted. The pit is 100 feet wide and 175 feet long, which facilitates overburden handling with available equipment. Based on these dimensions, an average of 45 holes per pit per day are drilled. This results in a yearly average of 35,100 blast holes being drilled with an average 100 foot thick overburden. Since 3.51×10^6 feet of material drilled annually, with an average life expectancy of 3,000 feet per bit, average of 1,170 bits are used each year.

The amount of dust generated per hole is 0.4 lb, resulting in 7.0 tons of dust emissions annually.*

Dust emissions from blast hole drilling

$$\begin{aligned} &= (\text{Emission factor per hole})(\text{holes drilled daily}) \\ &\quad (\text{annual working days/yr})(\text{number of pits}) \\ &= (0.4 \text{ lb/hole})(45 \text{ holes/day/pit})(260 \text{ working days/yr})(3 \text{ pits/mine}) \\ &= (14,040 \text{ lb/yr/mine})/(2,000 \text{ lb/ton}) \\ &= 7.0 \text{ tons/yr/mine} \end{aligned}$$

With an average of 3.4 lb of dust per hole per blast, the annual dust emissions from overburden blasting will be approximately 20 tons.

Dust emissions from blasting overburden

$$\begin{aligned} &= (\text{Emission factor})(\text{shots/year})(\text{hole/shot}) \\ &= (3.4 \text{ lb/blast})(156 \text{ shots/yr})(75 \text{ holes/shot}) \\ &= (39,780 \text{ lb/yr})/(2,000 \text{ lb/ton}) \\ &= 19.9 \text{ tons of dust emissions/yr} \end{aligned}$$

As the overburden is fractured into sizes manageable for a dragline or stripping shovel, the overburden removal phase begins. For the initial cut, a dragline or stripping shovel removes the blasted rock and places it on undisturbed ground to the side and in back of the pit. The other draglines also places loosened overburden in back of and to the side of the pit. The difference is that equipment will be backfilling the mined-out pit of the first dragline.

Dust emissions from the dragline or stripping shovel average 1.8 tons of dust annually.

* Dust emissions from drilling are based on regional values without a fallout function 5.0 km from the source.

Dust emission from stripping shovels and dragline²

$$\begin{aligned} &= (\text{Emission factor})(\text{volume of overburden/day/pit}) \\ &\quad (\text{working days/yr})(\text{number of pits}) \\ &= (0.0007 \text{ lb/cu yd})(6,453 \text{ cu yd/day/pit})(260 \text{ days/yr})(3 \text{ pits}) \\ &= (3,520 \text{ lb/yr/mine})/(2,000 \text{ lb/ton}) \\ &= 1.8 \text{ tons/yr/mine} \end{aligned}$$

The amount of ANFO required to crack the overburden is about 0.5 lb/cu yd of material. This results in an average ANFO requirement of 1,250 tons/yr.

ANFO required

$$\begin{aligned} &= (\text{ANFO/overburden})(\text{total overburden}) \\ &= (0.5 \text{ lb/cu yd})(6,453 \text{ cu yd/day/pit}) \times 260 \text{ days/yr} \times 3 \text{ pits}) \\ &= (2.5 \times 10^6 \text{ lbs})/(2,000 \text{ lb/ton}) \\ &= 1.25 \times 10^3 \text{ tons} \end{aligned}$$

The drills consume an average of 6.8 gal fuel/hr.³ This results in an annual fuel usage of 127,000 gallons. By multiplying this total yearly diesel consumption rate by the emission rate per 1,000 gallons, the annual emission rate for this operation can be determined.

Diesel Engine Emissions for Drills⁴

$$\begin{aligned} &= (\text{total gal/yr used})(\text{emission rate}) \\ \text{CO} &= (127,000 \text{ gal/yr used})(87.5 \text{ lb}/10^3 \text{ gals}) \\ &= (11,112 \text{ lb/yr})/(2,000 \text{ lb/ton}) \\ &= 5.6 \text{ tons/yr} \\ \text{HC} &= (127,000 \text{ gal/yr})(25.1 \text{ lb}/10^3 \text{ gal}) \\ &= (3,188 \text{ lb/yr})/(2,000 \text{ lb/ton}) \\ &= 1.6 \text{ tons/yr} \end{aligned}$$

$$\begin{aligned}\text{NO}_2 &= (127,000 \text{ gal/yr})(332 \text{ lb}/10^3 \text{ gal}) \\ &= (42,164 \text{ lb/yr})/(2,000 \text{ lb/ton}) \\ &= 21.1 \text{ tons/yr}\end{aligned}$$

$$\begin{aligned}\text{Aldehyde} &= (127,000 \text{ gal/yr})(6.2 \text{ lb}/10^3 \text{ gal}) \\ &= (787 \text{ lb/yr})/(2,000 \text{ lb/ton}) \\ &= 0.39 \text{ ton/yr}\end{aligned}$$

$$\begin{aligned}\text{SO}_2 &= (127,000 \text{ gal/yr})(31.1 \text{ lb}/10^3 \text{ gal}) \\ &= (3,950 \text{ lb/yr})/(2,000 \text{ lb/ton}) \\ &= 1.98 \text{ tons/yr}\end{aligned}$$

$$\begin{aligned}\text{Particulates} &= (127,000 \text{ gal/yr})(25.3 \text{ lb}/10^3 \text{ gal}) \\ &= (3,213 \text{ lb/yr})/(2,000 \text{ lb/ton}) \\ &= 1.61 \text{ ton/yr}\end{aligned}$$

References

1. U. S. Environmental Protection Agency, Survey of Fugitive Dust from Coal Mines, PEDCo-Environmental, Inc., Cincinnati, Ohio, February 1978.
2. U. S. Environmental Protection Agency, Compilation of Air Pollutant Emission Factors, 3rd Edition, August 1977.
3. Caterpillar Tractor Company, Caterpillar Performance Handbook, January 1975.
4. Diesel Engine Emission Factors, see Appendix A to this document.

5 Liquid Waste From Overburden Removal

The quantity of liquid waste from the overburden removal area is negligible.

If the overburden material carried groundwater prior to blasting and removal, then this water is intercepted by the cut and collected in the pit. From here, the water is pumped to the treatment pond prior to discharge into the natural drainage system. The quantity of this water is more dependent on the hydraulic characteristics of the overburden material than on seasonal precipitation rates.

6 Liquid Waste From Spoil Storage

The quantity of liquid waste from the spoil storage area is negligible.

The outslopes of the spoil piles drain externally. That is, the surface runoff from the outslope enters the natural drainage system external to the mining operation. This water is controlled by collection ditches channeling water to sediment ponds or, if necessary, treatment facilities. The amount of runoff is related directly to the precipitation in the region. The runoff entering the sediment or treatment ponds fluctuates seasonally with precipitation.

7

Air Emissions From Coal Removal

The residual pollutants emitted to the atmosphere as a result of coal removal are:

Dust from coal drilling = 0.5 ton/yr

Dust from coal blasting = 1.4 tons/yr

Due to the thickness, western coal seams are usually blasted prior to removal. Coal blasting is similar to overburden blasting; the major differences are the spacing and pattern of blast holes and the amount of ANFO used. For the western seam, the holes will be spaced on 25 foot centers and less ANFO is used. Three times a week, coal drills are used to drill blast holes in each pit. The coal, like the overburden, is shot in 0.4 acre blocks with dimensions of 100 x 175 feet. Twenty-eight holes are drilled and loaded with ANFO. The dust generated from drilling each blast hole is approximately 0.05 lb. This results in approximately 0.55 ton of dust annually.

Dust emission from coal drilling

$$\begin{aligned}
 &= (\text{Emission factor})(\text{number of holes/pit})(\text{number of pits}) \\
 &\quad (\text{number of working days annually}) \\
 &= (0.05 \text{ lb/hole})(28 \text{ holes/pit})(3 \text{ pits})(260 \text{ working days/yr}) \\
 &= (1,092 \text{ lb/mine/yr})/(2,000 \text{ lb/ton}) \\
 &= 0.55 \text{ ton/mine/yr}
 \end{aligned}$$

Once the holes are drilled, each is charged with ANFO and detonated to loosen the coal. Dust emissions are 1.4 tons annually.

Annual dust emissions from coal blasting²

$$\begin{aligned}
 &= (\text{Emission factor})(\text{blasts/week})(\text{week/yr})(\text{pits/mine}) \\
 &= (6.0 \text{ lb/blast})(3 \text{ pits/mine})(152 \text{ blasts/yr}) \\
 &= (2,736 \text{ lb/yr})/(2,000 \text{ lb/ton}) \\
 &= 1.4 \text{ tons/yr}
 \end{aligned}$$

References

1. U. S. Environmental Protection Agency, Survey of Fugitive Dust from Coal Mines, PEDCo-Environmental, Inc., Cincinnati, Ohio, February 1978.
2. U. S. Environmental Protection Agency, Development of Emission Factors for Fugitive Dust, Research Triangle Park, North Carolina, Publication No. EPA-450/3-74-037, June 1974.

8

Air Emissions From Backfilling and Regrading

Emissions generated during the backfilling and regrading phase of surface mining are:

Dust from exposed areas = 24.5 tons/yr

Emission from diesel equipment = 126.9 tons/yr

CO	HC	NO ₂	HCHO	SO ₂	Particulates
21.9	6.3	83	1.6	7.8	6.3

It is very difficult to develop an emission factor for the dust generated from backfilling; however, this source of dust is significant enough for an estimate to be included in this analysis. A procedure for estimating emissions from the exposed areas, based on USDA's wind erosion index, is presented in the EPA publication Development of Emission Factors for Fugitive Dust Sources.¹ For the soil and climatic conditions of various regional western surface mines,² calculations indicate emission rates ranging from 0.4 to 1.0 ton/acre/yr. Using an average emission rate of 0.7 ton/acre/year and based on an average of 35 acres of land disturbed annually for mining operations, it can be estimated that 24.5 tons/year of dust result from backfilling and regrading operations.

Dust Emissions from Backfilling and Regrading

= (emission factor)(acres of land)

= (0.7 ton/acre/yr)(35 acres)

= 24.5 tons/yr

Diesel emissions generated from bulldozers used in this operation total 126.6 tons/year.³

Diesel Engine Emissions for Bulldozers

= (Emission rate)(total gallons used)

CO = (87.5 lb/1,000 gal)(500,000 gal/yr)

= (43,750 lb/yr)/(2,000 lb/ton)

= 21.9 tons/yr

$$\begin{aligned}
 \text{HC} &= (25.1 \text{ lb/1,000 gal})(500,000 \text{ gal/yr}) \\
 &= (12,550 \text{ lb/yr})/(2,000 \text{ lb/ton}) \\
 &= 6.3 \text{ tons/yr} \\
 \\
 \text{NO}_2 &= (332 \text{ lb/1,000 gal})(500,000 \text{ gal/yr}) \\
 &= (166,000 \text{ lb/yr})/(2,000 \text{ lb/ton}) \\
 &= 83 \text{ tons/yr} \\
 \\
 \text{Aldehydes} &= (6.2 \text{ lb/1,000 gal})(500,000 \text{ gal/yr}) \\
 &= (3,100 \text{ lbs/yr})/(2,000 \text{ lb/ton}) \\
 &= 1.6 \text{ tons/yr} \\
 \\
 \text{SO}_2 &= (31.2 \text{ lb/1,000 gal})(500,000 \text{ gal/yr}) \\
 &= (15,600 \text{ lb/yr})/(2,000 \text{ lb/ton}) \\
 &= 7.8 \text{ tons/yr} \\
 \\
 \text{Particulates} &= (25.3 \text{ lb/1,000 gal})(500,000 \text{ gal/yr}) \\
 &= (12,650 \text{ lb/yr})/(2,000 \text{ lb/ton}) \\
 &= 6.3 \text{ tons/yr}
 \end{aligned}$$

References

1. U. S. Environmental Protection Agency, Development of Emission Factors for Fugitive Dust Sources, Research Triangle Park, North Carolina, Publication No. EPA-450/3-74-037, June 1974.
2. U. S. Environmental Protection Agency, User's Guide for HIWAY, A Highway Air Pollution Model, Research Triangle Park, North Carolina, Publication No. EPA-650/4-74-008, February 1975.
3. Diesel Engine Emission Factors, see Appendix A to this document.

9

Air Emissions From Topsoiling

Emissions generated from topsoil spreading are:

Dust emissions—scrapping = 6.8 tons/yr
Dust emissions—dumping = 0.8 ton/yr
Diesel engine emissions = 55.8 tons/yr

CO	HC	NO ₂	HCHO	SO ₂	Particulates
8.8	3.3	37.9	0.83	2.54	2.42

As backfilling and regrading operations are completed, the stockpiled topsoil is redistributed on the surface in preparation for revegetation. This material is spread at thicknesses dependent on the amount of available soil. Since 3 feet were originally removed, the final thickness of topsoil should be approximately 3 feet. Dust emissions are equal to the removal phase, which is approximately 0.08 lb/cu yd for scraping and grading and 0.01 lb/cu yd for dumping of soil.^{1,2} Approximately 35 acres of land are topsoiled annually, resulting in 6.8 tons of dust during scraping and 0.85 ton during dumping operations.

Dust emissions from topsoil replacement

= (emission factor)(volume of top soil)

Scraping and grading

= (0.08 lb/cu yd)(35 acres/yr x 4,840 sq yd/acre x 1 yd)
 = (0.08 lb/cu yd)(169,400 cu yd/yr)
 = (13,552 lbs/yr)/(2,000 lb/ton)
 = 6.8 tons/yr

Dumping Operations

= (0.01 lb/cu yd)(35 acres/yr x 4,840 sq yd/acre x 1 yd)
 = (0.01 lb/cu yd)(169,400 cu yd/yr)
 = (1,694 lb/yr)/(2,000 lb/ton)
 = 0.85 ton/yr

The equipment needed for topsoil replacement consists of three scrapers and three bulldozers. Each scraper consumes 16 gallons of fuel per hour and each bulldozer consumes 15 gallons of fuel per hour. The average annual working day for this equipment is 12 hours per day, resulting in a total fuel consumption of 290,000 gals/yr. The diesel emissions from this operation are as follows:

Diesel Engine Emissions³

for scrapers = (number of scrapers)(hr/yr/scrapper)
(emission factor)

for bulldozers = (number of bulldozers)(hr/yr/bulldozer)
(emission factor)

CO for Scraper = (3 scrapers)(3,120 hr/yr)(1.5 lb/hr)
= (14,040 lb/yr)/(2,000 lb/ton)
= 7.0 tons/yr

for Bulldozer = (3 bulldozers)(3,120 hr/yr)(0.39 lb/hr)
= (3,650 lb/yr)/(2,000 lb/ton)
= 1.8 tons/yr

HC for Scraper = (3 scrapers)(3,120 hr/yr)(0.6 lb/hr)
= (5,616 lb/yr)/(2,000 lb/ton)
= 2.8 tons/yr

for Bulldozer = (3 bulldozers)(3,120 hr/yr)(0.11 lb/hr)
= (1,030 lb/yr)/(2,000 lb/ton)
= 0.5 ton/yr

NO₂ for Scraper = (3 scrapers)(3,120 hr/yr)(6.7 lb/hr)
= (62,712 lb/yr)/(2,000 lb/ton)
= 31 tons/yr

for Bulldozer = (3 bulldozers)(3,120 hr/yr)(1.47 lb/hr)
= (13,759 lb/yr)/(2,000 lb/ton)
= 6.9 tons/yr

Aldehydes

for Scraper = (3 scrapers)(3,120 hr/yr)(0.15 lb/hr)
= (1,404 lb/yr)/(2,000 lb/ton)
= 0.70 ton/yr

for Bulldozer = (3 bulldozers)(3,120 hr/yr)(0.027 lb/hr)
= (253 lb/yr)/(2,000 lb/ton)
= 0.13 ton/yr

SO₂ for Scraper = (3 scrapers)(3,120 hr/yr)(0.4 lb/hr)
= (3,744 lb/yr)/(2,000 lb/ton)
= 1.9 tons/yr

for Bulldozer = (3 bulldozers)(3,120 hr/yr)(0.137 lb/hr)
= (1,282 lb/yr)/(2,000 lb/ton)
= 0.64 ton/yr

Particulates

for Scraper = (3 scrapers)(3,120 hr/yr)(0.4 lb/hr)
= (3,744 lb/yr)/(2,000 lb/ton)
= 1.9 tons/yr

for Bulldozer = (3 bulldozers)(3,120 hr/yr)(0.112 lb/hr)
= (1,048 lb/yr)/(2,000 lb/ton)
= 0.52 ton/yr

Revegetation

Topsoil is evenly spread over the area in preparation for revegetation in the early spring and fall. Since these are the times when precipitation and soil moisture are greatest, emissions are minimal. The diesel emissions depend on the type of equipment used and the length of time in operation and, therefore, cannot be quantified.

References

1. U. S. Environmental Protection Agency, Survey of Fugitive Dust from Coal Mines, PEDCo-Environmental, Inc., Cincinnati, Ohio, February 1978.
2. U. S. Environmental Protection Agency, Development of Emission Factors for Fugitive Dust Sources, Research Triangle Park, North Carolina, Publication No. EPA-450/3-74-037, June 1974.
3. U. S. Environmental Protection Agency, Compilation of Air Pollutant Emission Factors, 3rd Edition, August 1977.

10 Air Emissions From Coal Storage

The fugitive dust from temporary coal storage is negligible.

After the coal is removed from the mine, it may be briefly stored prior to transport by truck to the preparation plant. The coal is wetted down to prevent significant air emissions. Therefore, the amount of fugitive dust from this source is negligible.

11

Air Emissions From Coal Transport

Dust from coal loading = 2.4 tons/yr

Dust from coal hauling = 53 tons/yr

Diesel engine exhaust = 746 tons/yr

CO	HC	NO ₂	HCHO	SO ₂	Particulates
101.6	32.2	544.9	8.2	33.2	26.4

After the coal is fractured, it is loaded into trucks for transport to the preparation plant. This loading is done by shovels or front-end loaders and generates approximately 0.0005 lb of dust per ton of coal loaded. This yields an annual dust emission of 2.4 tons.

Dust emissions from coal loading

$$\begin{aligned}
 &= (\text{Emission factor})(\text{coal loaded annually}) \\
 &= (0.0005 \text{ lb/ton})(9.7 \times 10^6 \text{ tons/yr}) / (2,000 \text{ lbs/ton}) \\
 &= 2.4 \text{ tons/yr}
 \end{aligned}$$

Haul roads generally have the highest annual emission rates of the western surface mining operations. The exact amounts of dust generated annually are difficult to calculate due to the various dust control methods used. These methods range from periodic applications of water to longer lasting and more expensive chemical treatment. The mine under consideration uses water, but exact application rates are unknown. Emission rates are calculated on a lb/vehicle-mile and, as the mining operations move further from the preparation plant, the annual rate of dust emissions increases. Each pit has four coal haulage trucks working, with an average round trip of 10 miles throughout the life of the mine operation.

Annual dust emissions from the haul roads average approximately 1.3 lb/vehicle-mile. This figure includes travel other than just the coal haulage trucks. Considering the emission rate per vehicle mile, the annual hauling process generates about 53 tons of dust annually.* This value is calculated from a region average of western surface mines employing water for dust control.

* Dust emissions from drilling are based on regional values without a fall-out function 5.0 km from the source.

Dust emission from haul roads

$$\begin{aligned} &= (\text{Emission factor})(\text{miles traveled annually}) \\ &= (1.3 \text{ lb/vehicle-mile})(81,450 \text{ vehicle-miles/yr})/(2,000 \text{ lb/ton}) \\ &= 53 \text{ tons/yr} \end{aligned}$$

Front-end loading equipment consumes approximately 24 gallons of fuel/hr under high load and 12.8 gallons of fuel/hr under light load.² Approximately half of the operating time is under high-load conditions and the other half under light-load conditions, resulting in an annual fuel consumption rate for the two loaders of 230,000 gallons of diesel fuel.

Coal loading shovels are powered by diesel or electricity. This mine uses diesel-powered loading shovels which have a fuel consumption that is approximately equal to two large loaders.

The haulage trucks used on this mine have a capacity of 100 tons each. Fuel use ranges from a high of 33.7 gal/hr to a low of 19.2 gal/hr.² Based on 12 trucks operating 260 days per year, the annual fuel consumption is 1.9×10^6 gallons of diesel fuel. These figures are calculated on 1.3 trips per hour and minimum down time for equipment. In the event of equipment failure, there is one extra truck provided.

Diesel emissions generated by the trucks and the front-end loaders used in this operation total 773 tons per year.

$$\text{Diesel Emissions}^3 = (\text{total gallons fuel consumed})(\text{emission rate})$$

$$\begin{aligned} \text{CO for trucks} &= (1.9 \times 10^6 \text{ gal/yr})(95.4 \text{ lb/1,000 gal}) \\ &= (181,260 \text{ lb/yr})/(2,000 \text{ lb/ton}) \\ &= 90.6 \text{ tons/yr} \end{aligned}$$

$$\begin{aligned} \text{front-end loaders} &= (2.3 \times 10^5 \text{ gal/yr})(95.4 \text{ lb/1,000 gal}) \\ &= (21,942 \text{ lb/yr})/(2,000 \text{ lb/ton}) \\ &= 11 \text{ tons/yr} \end{aligned}$$

$$\begin{aligned} \text{HC for trucks} &= (1.9 \times 10^6 \text{ gal/yr})(30 \text{ lb/1,000 gal}) \\ &= (57,000 \text{ lb/yr})/(2,000 \text{ lb/ton}) \\ &= 28.5 \text{ tons/yr} \end{aligned}$$

$$\begin{aligned} \text{front-end loaders} &= (2.3 \times 10^5 \text{ gal/yr})(32.3 \text{ lb/1,000 gal}) \\ &= (7,429 \text{ lb/yr})/(2,000 \text{ lb/ton}) \\ &= 3.7 \text{ tons/yr} \end{aligned}$$

NO ₂ for trucks	= (1.9 x 10 ⁶ gal/yr)(524 lb/1,000 gal)
	= 995,600 lb/yr)/(2,000 lb/ton)
	= 498 tons/yr
front-end loaders	= (2.3 x 10 ⁵ gal/yr)(408 lb/1,000 gal)
	= (93,840 lb/yr)/(2,000 lb/ton)
	= 46.9 tons/yr
Aldehydes for trucks	= (1.9 x 10 ⁶ gal/yr)(7.74 lb/1,000 gal)
	= (14,706 lb/yr)/(2,000 lb/ton)
	= 7.4 tons/yr
front-end loaders	= (2.3 x 10 ⁵ gal/yr)(7.17 lb/1,000 gal)
	= (1,649 lb/yr)/(2,000 lb/ton)
	= 0.82 ton/yr
SO ₂ for trucks	= (1.9 x 10 ⁶ gal/yr)(31.2 lb/1,000 gal)
	= (59,280 lb/yr)/(2,000 lb/ton)
	= 29.6 tons/yr
front-end loaders	= (2.3 x 10 ⁵ gal/yr)(31.2 lb/1,000 gal)
	= (7,176 lb/yr)/(2,000 lb/ton)
	= 3.6 tons/yr
Particulates for trucks	= (1.9 x 10 ⁶ gal/yr)(24.2 lb/1,000 gal)
	= (45,980 lb/yr)/(2,000 lb/ton)
	= 23.0 tons/yr
front-end loaders	= (2.3 x 10 ⁵ gal/yr)(29.3 lb/1,000 gal)
	= (6,739 lb/yr)/(2,000 lb/ton)
	= 3.4 tons/yr

References

1. U. S. Environmental Protection Agency, Survey of Fugitive Dust from Coal Mines, EPA-908/1-78-0003, PEDCo-Environmental, Inc., Cincinnati, Ohio, February 1978.
2. Caterpillar Tractor Company, Caterpillar Performance Handbook, January 1975.
3. Diesel Engine Emission Factors, see Appendix A to this document.

12 Dust Emission at Coal Storage Site

Dumping of the coal at the storage silos creates 4.9 tons of dust annually.

The run-of-mine coal is dumped in storage silos prior to cleaning and processing the coal at the preparation plant. The dust generated by this operation is based on annual coal production for the mine.

Dust emission from truck dumping¹

$$\begin{aligned} &= (\text{Emission factor})(\text{annual production}) \\ &= (0.001 \text{ lb/ton})(9.7 \times 10^6 \text{ tons/yr})/(2,000 \text{ lb/ton}) \\ &= 4.9 \text{ tons/yr} \end{aligned}$$

Reference

1. U. S. Environmental Protection Agency, Compilation of Air Pollutant Emission Factors, 3rd Edition, August 1977.

13 Air Emissions From Coal Preparation

Air emissions from this preparation plant are minimal since the facility is enclosed and water is used for dust suppression.

There is no open storage of raw or processed coal. The only open storage is temporary for the crushing refuse, therefore, any fugitive dust emitted from this waste would be negligible.

Coal Preparation

Coal preparation at this site includes storage, crushing, and screening.² During this process only one size coal is prepared (1-1/2" x 0"). A flow diagram of this operation is illustrated in the following flow chart. Any additional cleaning is conducted prior to final use at the end destination of the coal.

Resources used in the preparation plant include water, land, electricity, and chemicals for treatment of liquid waste. Water in this plant is used only for dust suppression and quantities are undeterminable. The quantity of water runoff from the spoils pile is dependent on precipitation. Approximately 10 acres of land is required for crushing equipment and the temporary storage of waste. The waste generated by crushing will be returned to the pit for burial during the backfilling operation.

Screening

Fugitive dust from the screening process is negligible because the operation is enclosed and spray water is used for dust control. Water is recycled and there is no liquid discharge from this process.

Loading and Transport

This mine loads three unit trains daily. Processed coal is stored in enclosed silos and then belted directly to the moving cars.² It takes approximately 4 hours to load each train.

Reference

1. Department of the Interior, Final Environmental Statement, Development of Coal Resources in Southwestern Wyoming, Vol. 2.
2. Mining Informational Services of McGraw-Hill Publishing, Keystone Coal Industry Manual, George F. Nielsen, Editor-in-Chief, 1976.

10% REFUSE

A.10-30

FLOWCHART — COAL PREPARATION

14 Solid Waste From Coal Preparation

The amount of solid waste generated each year is 970,000 tons.

Solid waste is temporarily stored in open areas while awaiting transport back to the pit for backfilling. This storage area requires, approximately 10 acres of land. An average of 10 percent of the coal material processed ends up as solid waste. This generates approximately 970,000 tons of refuse annually from the 9.7×10^6 tons/yr of raw coal production.

Water requirements vary with the moisture content of the coal and various other factors and, therefore, are unquantifiable.

15 Liquid Wastes From Waste Storage Areas

The quantity of liquid waste from refuse storage areas is negligible.

Runoff does occur from the solid waste storage areas; however, it is collected, chemically treated, and allowed to settle prior to discharge into the natural drainage system. There is no liquid waste discharged directly from the crushing operation since water is recycled within the plant. All water discharges meet state and Federal guidelines for quality. Quantities vary with rainfall, generally being highest in the spring and early summer.

Waste water from the preparation plant originates from rain water and adsorbed water added to the material during crushing and screening operations.

16 Air Emissions From Coal Loading

Emissions from loading are negligible.

The emissions from the loading of coal into the railroad cars are minimal due to residual moisture in the coal that remains after the crushing and screening operation. The coal is enclosed until the loading operation; therefore, there would be negligible air emissions at this stage.

17 Liquid Waste From Coal Storage

The liquid waste from coal storage is unquantifiable because the quantities of chemicals and water are generated and used sporadically.

Quantitative runoff and leachate from the temporary coal storage piles is dependent on precipitation. These quantities vary seasonally and treatment is conducted only when necessary. This water is collected in treatment and sediment ponds and meets all state and Federal requirements prior to discharge. The peak period for precipitation is the spring and early summer.

Liquid waste is unquantifiable both because of the short time that the coal is stored and the variable factors such as precipitation that affect the quantity of runoff.

III. PHYSICAL REQUIREMENTS

The major resource requirements for the surface mining operation, including the coal preparation plant, are land, water, electricity, and chemicals for liquid waste treatment.

Land is required to support the western mine operations. This includes 20,000 acres, which contain the coal reserves for the life of the mine, 10 acres of land for the storage of solid waste, and about 17 acres for office facilities, preparation plant, loading facilities, and parking, as well as land associated with the railroad operation. Approximately 35 acres of land are disturbed annually by mining operations.

Water consumption in this mine is limited to dust suppression and is unquantifiable. However, it has been estimated that a similar surface mine in the West with an annual coal production of 8×10^6 tons uses approximately 100 acre-ft/yr. All other water used in the cleaning operation is recycled within the plant.

Electrical power is required for the crushers in the cleaning operation. Power requirements for the crushers vary with the size of the coal to be crushed. The annual power requirements are calculated using the horsepower ratings of the crushers and a conversion factor of 0.746 kW/hp. Power consumption required for coal greater than 6 inches in size is 73 kWh compared to 145 kWh for coal less than 6 inches in size. The total electricity used per year at the site is approximately 900,000 kWh/yr.

Crusher power requirements¹

$$\begin{aligned}\text{kW/ton} > 6'' &= 97.5 \text{ hp} \times 0.746 \\ &= 72.73 \text{ kW}\end{aligned}$$

$$\begin{aligned}\text{kW/ton} < 6'' &= 194.0 \text{ hp} \times 0.746 \\ &= 144.72 \text{ kW}\end{aligned}$$

$$\text{Total annual electricity utilization} = 217.4 \times \text{hr/yr}$$

$$\begin{aligned}&= (72.7 \text{ kW} + 144.7 \text{ kW})(\text{hr/yr}) \\ &= (217.4 \text{ kW})(4,160 \text{ hr/yr}) \\ &= 900,000 \text{ kWh/yr}\end{aligned}$$

Reference

1. Mining Informational Services of McGraw-Hill Publishing, Keystone Coal Industry Manual, George F. Nielsen, Editor-in-Chief, 1976.

IV. PERSONNEL

The number of personnel required to operate a 9.7×10^6 ton/yr western surface mine will vary, depending on factors such as the type of equipment used at the mine as well as the operating philosophy of the owner. It is estimated that this mine operates three shifts per day and employs 210 workers. The preparation plant employs 20 workers and operates two shifts per day.

Reference

1. Mining Informational Services of McGraw-Hill Publishing, Keystone Coal Industry Manual, George F. Nielsen, Editor-in-Chief, 1976.

V. OCCUPATIONAL SAFETY AND HEALTH

Data on the incidence of injuries and deaths due to accidents in underground and surface coal mines are collected and published by the U. S. Department of Labor's Mine Safety and Health Administration.

For the western surface coal mine producing 9.7×10^6 tons/yr of coal with 210 employees, the annual fatality rate is 5.0×10^{-2} and the injury rate is 1.3×10^{-1} (including fatalities) per year.

For the coal preparation plant having 20 employees, the expected fatality rate is 1.4×10^{-2} per year. The injury rate (including fatalities) is 1.8 per year.

<u>Western Surface Strip Mine</u>		<u>Coal Preparation Plant</u>
Annual Deaths	0.05	0.014
Annual Injuries	13.0	1.8

Reference

1. U. S. Department of Labor, Mine Safety and Health Administration, Injury Experience in Coal Mining, 1979, Information Report LR 1122 (1980).

APPENDIX A DIESEL EMISSION FACTORS

Code
Number

- ① Drill rig uses approximately 8.5 gallons of fuel per hour under load conditions, while under non-load conditions (i.e., set up, pull steel, transport, idle time, etc.) the rig consumes about 5 gallons per hour (6.8 gal/hr average).
- ⑨ Bulldozers use approximately 15 gallons of fuel per hour.
- ⑫ Scrapers consume about 16 gallons of fuel per hour.
- Truck (100-ton capacity) fuel consumption ranges from 33.7 gallons per hour to 19.2 gallons per hour.
- Front-end Loaders consume about 24 gallons of fuel per hour under high load and 12.8 gallons per hour under light load.

Diesel Emission Factor (lb/hr)

		CO	HC	NO ₂	HCHO	SO ₂	Particulates
①	Drills	0.4	0.14	3.06	0.03	0.2	0.1
②③⑨	Bulldozer	0.39	0.11	1.47	0.017	0.137	0.112
	Scraper	1.5	0.6	6.7	0.15	0.4	0.4

Emission Rate, lb/10³ gal

④	Drills	87.5	25.1	332.0	6.2	31.1	25.3
⑦	Trucks	95.4	30.0	524.0	7.74	31.2	24.2
	Loader	95.4	32.3	408.0	7.17	31.2	29.3
⑧	Bulldozer	87.5	25.1	332.0	6.2	31.2	25.3

APPENDIX B COST ESTIMATES

Mining Cost Estimates

Estimates of capital investment and operating and maintenance (O&M) costs indicated in Table 1, Summary Sheet (Section I), were derived from one of a series of cost analysis reports prepared by the DOE Process Evaluation Office for hypothetical coal mines using various mining methods.¹ The basic intent of the report cited is to provide an indication of the approximate economics of underground mining of coal under average conditions using a continuous mining system.

Table B-1 summarizes the basic capital investment and O&M costs for two hypothetical subbituminous and lignite coal strip mines (in the Northern Great Plains Province) with annual production capacities of 4 and 5 million tons. The corresponding cost estimates for the 9.7×10^6 ton/yr facility, characterized environmentally in Reference 1, are also indicated and were derived by assuming the per-unit capital and O&M cost estimates for the 5×10^6 ton/yr facility apply for a mine approximately twice this size. Normally, economies of scale would be expected to accrue in per-unit O&M costs as plant capacity increases (indicated by the "less than or equal to" symbol in Table B-1).

Table B-1. Summary of Cost Estimates for Western Surface Coal Mines

Cost Item	Capacity (ton/yr) (1978\$)		
	4.0×10^6	5.0×10^6	9.7×10^6
Total Capital Cost	$\$67.2 \times 10^6$	$\$101 \times 10^6$	$\$197 \times 10^6$
Capital Cost Per Ton	\$16.79	\$20.26	\$20.26
O&M Cost			
Per Year	$\$24.1 \times 10^6$	$\$25.5 \times 10^6$	050×20^6
Per Ton Produced	\$6.02	\$5.11	\$5.11
Environmental Control	Included in the above costs		

Preparation

As indicated in the available literature on coal preparation costs, the degree of beneficiation and, therefore, the cost is largely determined by the product specifications of the intended market and the prospective rate of return to the investor. Current coal

beneficiation processes encompass a broad spectrum of treatment, ranging from simple breaking to elaborate systems that include flotation circuits and thermal drying (Reference 2 defines seven levels of coal beneficiation). According to the literature, even bidding to identical and carefully drawn specifications, different contracting engineers might quote prices in a ratio of 2:1 between high and low bidder. Because of this uncertainty, a range of costs indicative of various levels of coal beneficiation are presented in Table 1, Summary Sheet, rather than point estimates.

Two ranges of cost estimates (from References 1 and 2, respectively) are shown in Table B-2, one expressed in terms of mine capacity and the other in terms of beneficiated coal. The per-unit cost ranges for the latter were used to estimate the total capital and O&M cost per year for the coal preparation plant depicted in Reference 1. The reader is referred to Reference 2 for the methodology developed for determining the relative costs of coal preparation. This methodology was used to compute the cost estimates for the 2×10^6 ton/yr preparation plant depicted in Table B.2.

Table B-2. Summary of Cost Estimates for Coal Preparation Plants

Cost Item	Capacity (ton/yr)		
	3×10^6 (ROM coal) (1978\$)	2×10^6 (beneficiated coal) (1975\$)	9.7×10^6 (beneficiated coal) (1975\$)
Total Capital Cost	(\$6.8-\$50) $\times 10^6$	(\$2.5-\$23.8) $\times 10^6$	(\$12.1-\$116) $\times 10^6$
Capital Cost Per Ton	\$2.3-\$17	\$1.25-\$11.91	\$1.25-\$11.91
O&M Cost			
Per Year	(\$0.24-\$11) $\times 10^6$	\$1.42-\$17.64 $\times 10^6$	\$6.9-\$85.6 $\times 10^6$
Per Ton Produced	\$0.08-\$3.66	\$0.71-\$8.82	\$0.71-\$8.82
Environmental Control	Included in the above costs		

Environmental Control Costs

Environmental control for coal mining and preparation plants is limited primarily to treatment of mine water discharges, to treatment of preparation plant water discharge, and to reclamation of mined land. Environmental control cost consideration was included in the cost analyses that produced Reference 1. There is mention that items of capital equipment are interchanged between operating and

environmental requirements functions. It has been assumed that environmental control costs are included in the overall cost estimates for the hypothetical coal preparation plants.

References

1. U.S. Department of Energy, Basic Estimated Capital Investment and Operating Costs for Subbituminous and Lignite Coal Strip Mines--Mines With Annual Production of 3, 4, and 5 MMtpy ROM Coal, FE/EES 79/6, DOE Process Evaluation Office, Morgantown, West Virginia, April 1979.
2. Schmidt, R.A., Coal In America--An Encyclopedia of Reserves, Production and Use, McGraw-Hill Publications Company, 1979.

GLOSSARY

coal preparation	Process for upgrading raw coal by physical means.
dragline	A massive scraper shovel.
fugitive emissions	Unintentional emissions such as blowing dust from coal storage pile.
grubbing	To clear vegetative brush by uprooting roots and stumps.
leaching	The separation or dissolving of soluble minerals or metals into the water.
overburden	Material overlaying a coal deposit.
pH	The negative logarithm of the effective hydrogen ion concentration used in expressing both acidity and alkalinity on a scale with values ranging from 0 to 14 (values less than 7 indicate increasing acidity; values greater than 7 indicate increasing alkalinity).
reclamation	The process of restoring vegetation to the land area disrupted by the mining operation.
recycled water	Water that is collected, treated, and reused at the facility.
screening	A step in the coal cleaning process which separates fine coal by particle size and density.
strip mine	A mine that is worked from the earth's surface by stripping the overburden.
total dissolved solids	The concentration of solid matter that is dissolved in water, usually stated in milligrams per liter.
total suspended solids	The concentration of suspended solids in water, usually stated in milligrams per liter.

ACRONYMS AND ABBREVIATIONS

ANFO	Ammonia nitrate-fuel oil mixture (explosive)
Btu	British thermal unit
CO	Carbon monoxide
HC	Hydrocarbon
HCHO	Aldehydes
kWh	Kilowatt-hour
MWh	Megawatt-hour
NO ₂	Nitrogen dioxide
NO _x	Nitrogen oxides
ROM	run-of-mine (coal)
SO ₂	Sulfur dioxide
SO _x	Sulfur oxides

Alcohol Fermentation Plant

Environmental Characterization Information Report

September 1981

U.S. Department of Energy
Assistant Secretary for Environmental
Protection, Safety, and
Emergency Preparedness
Office of Environmental Analysis

CONTENTS

	<u>Page</u>
I. SUMMARY	A.11-3
II. PROCESS DESCRIPTION AND ENVIRONMENTAL POINTS OF INTEREST.	A.11-7
1. Grain Receiving, Storage, and Preparation	A.11-7
2. Mash Cooking and Starch Conversion.	A.11-11
3. Fungal Amylase Production	A.11-17
4. Fermentation to Ethanol	A.11-19
5. Distillation and Dehydration.	A.11-24
6. Denaturation and Product Storage.	A.11-31
7. Raw Chemical Storage.	A.11-32
8. Stillage Drying and Evaporation	A.11-33
9. Flue Gas Scrubber	A.11-35
10. By-Product DDGS Storage and Outloading.	A.11-39
11. Coal Receiving, Storage, and Conveying.	A.11-41
12. Boiler.	A.11-43
13. Wastewater Treatment System	A.11-47
14. Raw Water Treatment System.	A.11-51
15. Cooling Tower	A.11-52
III. PHYSICAL REQUIREMENTS	A.11-54
IV. PERSONNEL	A.11-57
V. OCCUPATIONAL SAFETY AND HEALTH.	A.11-59
APPENDIX A: REGULATORY CONSIDERATIONS	A.11-68
APPENDIX B: COST INFORMATION.	A.11-71
APPENDIX C: PLANT CAPACITY EXCURSIONS	A.11-76
APPENDIX D: ALTERNATIVE FEEDSTOCKS AND BY-PRODUCTS.	A.11-80
APPENDIX E. BIOMASS-TO-FUEL ETHYL ALCOHOL TECHNOLOGY.	A.11-83
APPENDIX F. PHYSICAL REQUIREMENTS AND SOIL PARAMETERS ASSOCIATED WITH CULTIVATING AND HARVESTING AGRICULTURAL FEEDSTOCKS.	A.11-87
GLOSSARY	A.11-93
ABBREVIATIONS & ACRONYMS	A.11-93

I. SUMMARY

The fermentation plant characterized in this Environmental Characterization Information Report (ECIR) consists of a 50-million-gal/yr fuel alcohol plant equipped with a coal-fired boiler. Corn is the process feedstock, while high-sulfur, Illinois No. 6 coal is used in the boiler to provide most of the plant's utility requirements. The process, plant operating parameters, resources needed, environmental residuals, and products associated with the alcohol fermentation plant are shown in Table 1, Summary Set. A 90-percent capacity factor was assumed to account for shutdown periods and for routine maintenance.

In addition to annual quantities, in English and metric units, the summary table gives quantities in terms of 10^{12} Btu of energy produced. These figures are provided to allow comparison between different energy processes. Also, only post-control (i.e., released) environmental residuals are included in Table 1. The product streams and emissions that are either recycled in the process or substantially reduced via control techniques are identified and discussed in detail in Section II. Section II also describes each step of the plant's process flow with sample calculations for the various parameters and residuals associated with these steps. (Water effluents from each step are fed to a central wastewater treatment facility.) Among the quantities calculated are environmental residuals, by-products generated, and amounts of resources used.

In the preliminary processing and fermentation segments of the alcohol plant, the major emissions are particulates in the form of fugitive emissions from the grain preparation segment and carbon dioxide with trace quantities of organic compounds from the fermentation and fungal amylase preparation segments. Liquid effluents include various wash waters and condensate return. The only solid waste of concern is the oversize grain rejects stream, consisting of stones, mold clumps, twigs, and other extraneous matter.

In the distillation and dehydration segments, the major sources of atmospheric emissions are the condenser vents on the alcohol recovery columns; however, their impact will be negligible. Small amounts of liquid effluents also will be produced. No solid wastes are obtained during the alcohol purification steps. Grain dust generated during the processing of Distillers' Dried Grains with Solubles will require some control prior to release. Boiler emissions, with control technologies, are not expected to be significant.

The remaining sections in this ECIR include information on physical requirements, personnel, and occupational safety and health. The appendixes describe regulatory considerations, cost information, excursions on plant capacities and feedstock material as well as current trends in fuel ethyl alcohol technology and physical requirements associated with cultivating and harvesting corn and other ethanol-yielding crops.

TABLE 1. SUMMARY SHEET

ALCOHOL FERMENTATION PLANT

ENERGY SYSTEM DESCRIPTION

The Fermentation Plant Is Designed To Produce 50×10^6 Gal/Yr of 99.5 Volume Percent (199-Proof) Ethanol From Corn Along With Distillers' Dried Grain with Solubles, a Commercial Animal Feed. Process Heat Requirements Are Obtained by Burning High-Sulfur, Illinois No. 6 Coal. Particulates and SO_x Emissions in the Boiler Flue Gas Are Removed by a Flue Gas Scrubbing System Employing Ammonia as the Sorbent While Wastewater Is Treated in a Two-Stage Activated Sludge Treatment Facility Prior to Disposal.

FACILITY OPERATING PARAMETERS

Plant Output: 50×10^6 gal/yr
Annual Capacity Factor: 90%
Overall Plant Efficiency: 68.9%
Annual Energy Production: 3.78×10^{12} Btu
Lifetime: 20 yr

PROCESS FLOW

RESOURCES USED

Code
No.

Resource

Feed Materials

19

Corn

11a

Fuel

Coal

Quantities Used

Reference Energy System
Annual Usage*

English Units	Metric Units	Per 10^{12} Btu Energy Produced
544×10^3 tons	494×10^3 tonnes	144×10^3 tons
97.9×10^3 tons	88.9×10^3 tonnes	25.9×10^3 tons

TABLE 1. (Continued)

ALCOHOL FERMENTATION PLANT

RESOURCES USED (Continued)		Quantities Used			
Code No.	Resource	Reference Energy System Annual Usage*		Per 10 ¹² Btu Energy Produced	
		English Units	Metric Units		
	<u>Water</u>				
2a	Process water	330 × 10 ⁶ gal	1250 × 10 ⁶ litre	87.3 × 10 ⁶ gal	
14b	Raw water makeup	83.1 × 10 ⁶ gal	315 × 10 ⁶ litre	22.0 × 10 ⁶ gal	
15a	Cooling tower makeup	280 × 10 ⁶ gal	1060 × 10 ⁶ litre	74.1 × 10 ⁶ gal	
	<u>Processing Materials</u>				
3a	Air input to amylase production	223 × 10 ³ tons	202 × 10 ³ tonnes	59.0 × 10 ³ tons	
4a	Yeast	396 tons	360 tonnes	105 tons	
	Iodine sterilizing solution	7.92 × 10 ³ gal	30.0 × 10 ³ litre	2.1 × 10 ³ gal	
5a	Hydrocarbon solvent	9.03 × 10 ³ gal	34.2 × 10 ³ litre	2.39 × 10 ³ gal	
6a	Denaturant	1.00 × 10 ⁶ gal	3.79 × 10 ⁶ litre	264 × 10 ³ gal	
8a	Air input to dryer	652 × 10 ³ tons	592 × 10 ³ tonnes	173 × 10 ³ tons	
9b	Anhydrous ammonia	3.04 × 10 ³ tons	2.76 × 10 ³ tonnes	804 tons	
12a	Air input to boiler	1.10 × 10 ⁶ tons	1.00 × 10 ⁶ tonnes	291 × 10 ³ tons	
14a	<u>Water treatment chemicals</u>				
	Sodium chloride	396 tons	360 tonnes	105 tons	
	Lime	792 tons	719 tonnes	210 tons	
	Sludge polymer	7.9 tons	7.17 tonnes	2.09 tons	
	<u>Land</u>	50.0 acres	20.2 hectares	13.2 acres	
	<u>Personnel</u>				
	Operation	159 workers	159 workers	42.1 workers	

*Assumes a 90% capacity factor.

COSTS	Facility	Reference Energy System	Per 10 ¹² Btu Energy Produced	Remarks
		(1981 \$)*		
Construction		\$69.7 × 10 ⁶ total	\$18.4 × 10 ⁶ total	
Operation and maintenance		\$61.5 × 10 ⁶ /yr	\$16.2 × 10 ⁶ /yr	
Environmental controls**		\$ 9.07 × 10 ⁶ total	\$ 2.40 × 10 ⁶ total	Capital cost only

*Operating cost estimate for 1983 plant startup.
**These costs have been included in the above estimates for total construction (capital) costs.

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ENVIRONMENTAL RESIDUALS

		Quantities Used			
		Reference Energy System Annual Levels			
Code No.	Residuals	English Units	Metric Units	Per 10 ¹² Btu Energy Produced	Remarks
	Air Pollutants				
1c	Particulates from grain cleaning	163 tons	148 tonnes	43.1 tons	
2d	Emissions from starch conversion	Negligible			
3	Emissions from enzyme production	Negligible			
4c	Emissions from fermentation:				
	Ethanol	1.80 × 10 ³ tons	1.63 × 10 ³ tonnes	476 tons	
	Water vapor	2.48 × 10 ³ tons	2.25 × 10 ³ tonnes	656 tons	
	Carbon dioxide	170 × 10 ³ tons	154 × 10 ³ tonnes	45.0 × 10 ³ tons	
5b	Distillation/dehydration pollutants:				
	Carbon dioxide	2.81 × 10 ³ tons	2.55 × 10 ³ tonnes	743 tons	
	Water vapor	41.2 tons	37.4 tonnes	10.9 tons	
6b	Emissions from product handling	Negligible			
7a	Emissions from raw chemical storage	Negligible			

TABLE 1. (Continued)

ALCOHOL FERMENTATION PLANT

ENVIRONMENTAL RESIDUALS (Continued)

		Quantities Used			
		Reference Energy System Annual Levels			
Code No.	Residuals	English Units	Metric Units	Per 10 ¹² Btu Energy Produced	Remarks
9c	Scrubber emissions:				
	Sulfur dioxide	947 tons	860 tonnes	250 tons	1.25 × 10 ³ tons**
	Particulates	104 tons	94.4 tonnes	27.5 tons	104 tons**
	Nitrogen oxides	726 tons	659 tonnes	192 tons	730 tons**
	Water vapor	120 × 10 ³ tons	109 × 10 ³ tonnes	31.8 tons	
10c	Exhaust from DDGS handling	5.31 tons	4.82 tonnes	1.41 tons	
11c	Fugitive dust from coal handling	49.0 tons	44.5 tonnes	13.0 tons	
15c	Cooling tower evaporative & drift losses	242 × 10 ⁶ gal	916 × 10 ⁶ litre	64.0 × 10 ⁶ gal	
	Water Pollutants				
	Water runoff from coal storage	Not Quantifiable			
12c	Boiler blowdown	7.92 × 10 ⁶ gal	30.0 × 10 ⁶ litre	2.10 × 10 ⁶ gal	
13c	Wastewater effluent to river	363 × 10 ⁶ gal	1374 × 10 ⁶ litre	96.0 × 10 ⁶ gal	
15c	Cooling tower blowdown	38 × 10 ⁶ gal	144 × 10 ⁶ litre	10.1 × 10 ⁶ gal	
	Solid Wastes				
1e	Grain cleaning rejects	54.4 tons	49.4 tonnes	14.4 tons	
12c	Boiler bottom ash	3 × 10 ⁶ tons	2.72 × 10 ³ tonnes	794 tons	
12c	Boiler fly ash	4.75 × 10 ³ tons	4.31 × 10 ³ tonnes	1.26 × 10 ³ tons	

*A capacity factor of 90% is assumed.

**Federal regulatory compliance levels.

PRODUCTS

	Quantities Used			Remarks
	Reference Energy System Annual Production			
	English Units	Metric Units	Per 10 ¹² Btu Energy Produced	
Primary				
Ethanol (199 proof)	50 × 10 ⁶ gal	190 × 10 ⁶ litre	13 × 10 ⁶ gal	
Byproducts				
Distiller's dark grains	177 × 10 ³ tons	161 × 10 ³ tonnes	46.8 × 10 ³ tons	
Dry ammonium sulfate	10.4 × 10 ³ tons	9.47 × 10 ³ tonnes	2.76 × 10 ³ tons	
Fusel oils*	760 tons	690 tonnes	201 tons	

*Fusel oils are usually mixed with the grain ethanol product prior to blending with gasoline.

OCCUPATIONAL SAFETY AND HEALTH

	Reference Energy System Annual Average	Per 10 ¹² Btu Energy Produced	Remarks
Deaths	8.61 × 10 ⁻³	2.28 × 10 ⁻³	
Injuries	6.84	1.81	

II. PROCESS DESCRIPTION AND ENVIRONMENTAL POINTS OF INTEREST

The base case alcohol fermentation plant is designed to produce 50 million gallons per year of 99.5 volume percent (199 proof) ethanol from corn. In addition, it will produce 177,111 tons per year of Distillers' Dark Grain (also known as Distillers' Dried Grain with Solubles or DDGS), a commercial animal feed. The plant is assumed to be located in Central Illinois, close to a source of Illinois No. 6 coal, which is used to fuel the plant.

The alcohol plant, designed by Raphael Katzen Associates, Cincinnati, Ohio, generally uses existing process technology currently employed in grain alcohol plants. It operates as a continuous flow process, except for the fermentation and fungal amylase sections which are operated batchwise as in conventional alcohol plants. The distillation system employs a two-pressure concept currently utilized in industrial and beverage alcohol production and in other chemical processing fields. The process also utilizes several heat economy measures which result in a total steam usage of 31.7 lbs/gal of ethanol. The distillation system uses 21.4 lbs/gal of steam of which 2.8 lbs/gal is obtained as flash vapors from mash cooking. Feedstock to the plant will consist of shelled corn at a rate of 58,900 bushels per day. No distress corn (e.g., corn contaminated with aflatoxins, pesticides, etc.) is contemplated for use in this facility; No. 2 shelled corn (less than 15½% moisture content) will be used.

All the utility requirements, with the exception of electricity, are produced within the boundaries of the plant. Water is obtained from a well field located close to the plant. The boiler burns relatively low cost, high sulfur coal. The plant is designed to effectively utilize most of the waste streams with final disposal in an environmentally acceptable manner. Flue gas from the boiler is used to dry the stillage residue to yield Distillers' Dark Grain as a product. Wastewater is treated in a two-stage, activated sludge treatment facility. The resultant sludge is dewatered and fed to the boiler. Cooling water from the various condensers is recycled through a two-cell cooling tower. A flue gas scrubbing system employing ammonia is utilized to remove particulates and SO_x emissions, producing ammonium sulfate. The latter could be utilized as a fertilizer.

The plant employs modern sanitary design principles that reduce air, wastewater and solid wastes problems to a comparatively minor concern. Nineteen environmental residuals are associated with this process. 42 environmental points of interest have been identified and discussed individually in this section (See Figure 1). Plant segments 100 through 800 and 1000 describe the alcohol fermentation process; segments 1100 and 1200 cover the utility requirements of the plant while the major pollution abatement steps are included in segments 900, 1300, 1400, and 1500. Other environmental control methods are included within each segment.

FIGURE 1. PROCESS FLOW CHART WITH ENVIRONMENTAL POINTS OF INTEREST — ALCOHOL FERMENTATION PLANT — 90% CAPACITY FACTOR

1

Grain Receiving, Storage, and Preparation

The quantity of grain dust particles released to the atmosphere after controls is 163 tons/yr. Approximately 54.4 tons/yr of oversize rejects from the grain cleaning operation also are generated.

1a

Corn

The annual corn requirement for the fermentation plant is 544×10^3 tons. A brief discussion on the effect of using alternative feedstocks is included in Appendix D.

1b

Fugitive Emissions from Grain Handling

Particulate emissions constitute the main pollutant from grain processing facilities. Large quantities of emissions in the form of dust and bees' wings are created by the many different unit operations performed in an alcohol fermentation plant including grain receiving, cleaning and conveying in addition to storage, milling and processing of the corn. The majority of the emissions are fugitive and arise primarily from raw material handling.

Control of particulate emissions is necessary not merely because of the resultant improvement in air quality, but also because of the reduction in fire and explosion hazards as well as improved sanitation. The particulates are often fairly large and dry, thereby facilitating collection. Several simple controls such as covering open bins and hoppers, and maintaining equipment that facilitate containment of these fugitive emissions can be implemented. Operating equipment under a slight vacuum also helps reduce emissions since the air flow is into rather than out of the system. In cases where preventive controls are not adequate, particulate emissions can be reduced by venting through filters, cyclones, baghouses or electrostatic precipitators. (1,2,3)

The emission factors shown below in Table 2 represent the amount of dust generated per ton of corn processed through each of the designated operations. These correspond to an emission factor of 12 lbs of particulate emissions/ton of corn processed. (4) These uncontrolled emission factors are dependent on many variables such as the amount of grain received, amount cleaned, and grain moisture content.

Table 2. Particulate Emission Factors
for Grain Processing Operations ⁽⁴⁾
(Uncontrolled)

<u>Type of Source</u>	<u>Emission Factor, lbs/ton</u>
Receiving	1.0
Precleaning and handling	5.0
Cleaning	6.0

Fugitive dust generated:

$$12 \text{ lbs/ton} \times 544 \times 10^3 \text{ tons/yr} \times 1 \text{ ton}/2000 \text{ lbs}$$

$$= 3.26 \times 10^3 \text{ tons/yr}$$

The average composition of the corn used in the plant is shown in Table 3.

Table 3. Proximate Analysis of Corn (Grain Portion) ⁽⁵⁾

<u>Component</u>	<u>Concentration, Weight Percent (Moisture Free)</u>
Starch	72.0
Protein	10.0
Oil	4.5
Fiber and Ash	13.5
Total	100.0
Moisture Content, wt%	15.5
Weight per bushel, lbs.	56.0
Bushels per ton	35.7

A variety of pesticides also are found in the corn feedstock. In a recent study for the U.S. Environmental Protection Agency (EPA), Radian Corporation identified nine (9) commonly used pesticides in concentrations ranging from 0.003 parts per million (ppm) to 16.2 ppm. The types and concentrations of these pesticides are listed in Table 4.

Table 4. Pesticide Level in Feedstock Grain⁽⁶⁾

<u>Pesticide</u>	<u>Concentration, ppm</u>
p,p'-DDT	16.2
Endrin	1.0
DDD and/or β -Endosulfan	0.1
Dieldrin and/or p,p'-DDE	0.35
α -Endosulfan	0.06
Heptachlor and/or β -BHC	0.04
Aldrin and/or Δ -BHC	0.008
Heptachlor Epoxide	0.007
α -BHC	0.003

Because of the dust problem associated with these front-end operations, the grain receiving, storage and milling areas for the base case alcohol plant have been separated from other plant processing areas.

1c Exhaust from Particulate Collector

In an effort to contain these fugitive emissions, the alcohol fermentation facility employs a baghouse filter which has a particulate removal efficiency of at least 95 percent.⁽⁴⁾ Assuming a 95 percent removal of the fugitive dust, the residuals from segment 100 which include the grain receiving, storage and preparation operations can, therefore, be calculated.

Particulate exhaust from baghouse exhaust:

$$\begin{aligned}
 & (1 - \text{removal efficiency}) \times (\text{emission factor}) \\
 & = (1 - 0.95) \times 12 \text{ lbs/ton} \\
 & = 0.6 \text{ lbs/ton of corn processed.}
 \end{aligned}$$

On an annual basis:

$$\begin{aligned}
 & 0.6 \text{ lbs/ton} \times 544 \times 10^3 \text{ tons/yr} \times 1 \text{ ton/2000 lbs} \\
 & = 163 \text{ tons/yr}
 \end{aligned}$$

1d Collected Particulates from Grain Handling

The particulates collected from the baghouse filter are periodically removed and transported to Segment 600, Stillage Drying and Evaporation, where they are mixed with the DDGS by-product.

Collected particulates:

(removal efficiency) x (emission factor for grain processing operations)

= 0.95 x 12 lbs/ton

= 11.4 lbs/ton of corn processed

On an annual basis:

11.4 lbs/ton x 544 x 10³ tons/yr x 1 ton/2000 lbs

= 3.10 x 10³ tons/yr

(1e) Grain Cleaning and Oversize Rejects

Incoming corn contains considerable amounts of dirt and extraneous matter such as stover, cobs and twigs. Following delivery to the plant, the grain is lifted by bucket elevators and discharged directly or indirectly via grain storage bins into a surge hopper. From the surge hopper, the grain is discharged into a grain cleaner where foreign materials are removed from the grain. These include sand, tramp metal, mold clumps, stones and other oversize rejects. The amounts and composition of oversize rejects will vary depending on the corn producing region, the type of corn, mode of transportation, prior cleaning, etc. (2,5,7) Assume that the corn contains 0.2 lb of extraneous matter per ton of incoming grain.

Grain cleaning:

0.2 lb/ton of corn x 544 x 10³ tons x 1 ton/2000 lbs

= 54.4 tons/yr.

The materials rejected from the grain cleaner are periodically removed from a collecting bin and disposed of in a landfill.

References

- (1) U.S. Department of Energy, "Environmental Readiness Document - Alcohol Fuels from Biomass (Prepublication Draft)," Assistant Secretary for Environmental Protection, Safety and Emergency Preparedness, Washington, D.C., May 1981.
- (2) The Aerospace Corporation, "Environmental Control Perspective for Ethanol Production from Biomass," Aerospace Report No. ATR-80 (7848-01)-1 for U.S. Department of Energy, Washington, D.C., August 1980.
- (3) Argonne National Laboratory, "Alcohol Production from Agricultural and Forestry Residues," U.S. Department of Energy, Report No. DOE/EV-0108, Washington, D.C., September 1980.
- (4) U.S. Environmental Protection Agency, "Compilation of Air Pollution Emission Factors," Second Edition, Publication No. AP-42, Office of Air and Water Programs, Research Triangle Park, N.C., April 1973.
- (5) Raphael Katzen Associates, "Grain Motor Fuel Alcohol Technical and Economic Assessment Study," U.S. Department of Energy, Report No. HCP/J6639-01, Washington, D.C., June 1979.
- (6) Scarberry, R.M. and M.P. Papai, "Source Test and Evaluation Report: Alcohol Facility for Gasohol Production," Radian Corporation for U.S. Environmental Protection Agency, Cincinnati, Ohio, November 1979.
- (7) U.S. Department of Energy, "Environmental Development Plan: Alcohol Fuels from Biomass (Draft)," Office of Alcohol Fuels, Assistant Secretary for Environment, Washington, D.C., January 1981.

2 Mash Cooking and Starch Conversion

It is not possible to accurately quantify the air emissions from the mash cooking and starch conversion operation. These pollutants, however, will be negligible under proper housekeeping and maintenance procedures.

2a Water Input

The raw process water requirement for the cooking and saccharification segments is approximately 330×10^6 gal/yr.

2b Liquid Effluents from Mash Cooking and Saccharification

In the Mash Cooking and Saccharification Segment (Segment 2000), the incoming grain after milling is gelatinized and solubilized by heat and α -amylase enzyme treatment followed by flash cooking and saccharification to glucose using gluco-amylase enzymes. After the cleaning procedure, the grain is hammermilled and mixed with recycled thin stillage and water. This mash is then heated by both indirect heat via heat exchangers as well as by direct injection of live steam to a temperature of about 177°C (350°F). The cookers consist of several 20-foot lengths of 10-inch diameter pipe connected with 180° return bends and are sized to provide the necessary cooking time of approximately 1.5 minutes.⁽¹⁾ During this heat treatment, the proteins in the grain are hydrolyzed to amino acids. These amino acids can be utilized for yeast growth during fermentation. In addition, many pesticides which are vulnerable to heat are apparently decomposed during the cooking step. As mentioned earlier, pesticides were detected in the feedstock grain; however, no traces of pesticides were found in the solid wastes or wastewater effluent streams.^(2,3)

The mash cooking and starch conversion operation is periodically subjected to hot water, caustic and other chemical runs for cleaning purposes. The pipeline cookers and saccharifiers do not require frequent cleaning. However, two precooker tanks and their associated pipes and pumps will require cleaning once a week. The usual cleaning cycle consists of a water wash followed by a series of chemical washes. Water is usually sprayed through 1/2" round-edged orifice. Assuming a 100-psi head loss through each orifice, the flow rate of water through the orifice is approximately 35×10^3 lbs/hr or 4.2×10^3 gal/hr.⁽⁴⁾ Generally, each nozzle in the precoolers has two orifices which results in a total flow rate of 8.4×10^3 gal/hr per nozzle. This flow rate of water to the precoolers, however, is not continuous, but lasts only about 20 minutes. The water wash,

therefore, equals $8.4 \times 10^3 \bullet 3$ or 2.8×10^3 gallons per nozzle, and usually a precooker is equipped with one nozzle.

Assuming that the connecting pipes and pumps will require an added 25 percent of water wash, the total equipment wash water requirement can be calculated as follows:

Annual wash water requirement:

$$\begin{aligned} & 2.8 \times 10^3 \text{ gal} \times 2 \text{ tanks} \times 52 \text{ wk/yr} \times 0.9 \times 1.25 \\ & = 328 \times 10^3 \text{ gal/yr} \end{aligned}$$

The wastewater from a cleaning operation has a high pH, is usually high in total solids and suspended solids content, and also has a high Biochemical Oxygen Demand (BOD₅).⁽²⁾ It would, therefore, require treatment in a wastewater treatment system prior to disposal. The wastewater characteristics for a typical plant and equipment wash are shown in Table 5.

Table 5. Wastewater Characteristics
of Plant and Equipment Wash⁽²⁾

<u>Parameter</u>	<u>Concentration, ppm</u>
Total Solids	1050
Suspended Solids	400
BOD ₅	650

(2c) Condensate Return from Mash Cooking

The cooked mash is initially cooled by flashing in pressure flash tanks. Some of the steam from this flash is used to preheat the mash, and the remaining flash steam is used for beer heating in the distillation section. Final and complete cooling is accomplished by vacuum flash cooling at approximately 3.3 psia.⁽¹⁾ The condensate from all the heaters and condensers of the mash cooling operations produces a stream that has a high BOD₅ content and contains low levels of total dissolved solids and total suspended solids.⁽²⁾ This is illustrated in Table 6.

Table 6. Effluent Composition of
Flash Cooling Condensate⁽²⁾

<u>Parameter</u>	<u>Concentration, ppm</u>
Total Solids	13.0
Total Dissolved Solids	8.0
Total Suspended Solids	4.5
BOD ₅	1,880.0

(2d)

Air Emissions from Mash Cooking and Saccharification

No major air emissions are anticipated from the mash cooking and saccharification step. There is a possibility, however, for some hydrocarbon emissions from the flash cooling operation which is performed under vacuum, and from other decomposition reactions that might take place in the reactor vessels.⁽²⁾ These emissions which usually occur in trace quantities can be controlled by proper housekeeping and maintenance procedures such as flaring or scrubbing the gas prior to disposal.

References

- (1) Raphael Katzen Associates, "Grain Motor Fuel Alcohol Technical and Economic Assessment Study," U.S. Department of Energy, Report No. HCP/J6639-01, Washington, D.C., June 1979.
- (2) Scarberry, R.M. and M.P. Papai, "Source Test and Evaluation Report: Alcohol Facility for Gasohol Production," Radian Corporation for U.S. Environmental Protection Agency, Cincinnati, Ohio, November 1979.
- (3) The Aerospace Corporation, "Environmental Control Perspective for Ethanol Production from Biomass," Aerospace Report No. ATR-80 (7848-01)-1 for U.S. Department of Energy, Washington, D.C., August 1980.
- (4) Swain, Philip, ed., "Power Handbook," Part One, March 1951.
- (5) U.S. Department of Energy, "Environmental Readiness Document - Alcohol Fuels from Biomass (Prepublication Draft)," Assistant Secretary for Environmental Protection, Safety and Emergency Preparedness, Washington, D.C., May 1981.

3

Fungal Amylase Production

The quantity of air emissions generated during the production of fungal amylase enzymes is negligible.

3a

Air Input

Total air required by the amylase production system is approximately 12,500 SCFM (440×10^6 lbs/yr).

3b

Air Emissions from Amylase Production

Fungal amylase is prepared batchwise using a seed tank to grow the inoculum which is initially started in a laboratory. The seed tank then feeds into a larger fermenter for final amylase production. A period of 5 days is required for completion of the batch. During this time, the fermenter is sufficiently agitated and aerated with compressed air.⁽¹⁾ Several enzyme nutrients are usually added at the beginning of the fermentation cycle. These include ammonium salts, urea and other compounds. Chemicals or antibiotics also may be added to the mash to control the growth of undesired organisms and by-products.

During amylase production, several foul-smelling compounds are produced in trace amounts in the fermenters. These substances are usually released to the air. It is not certain as to what types of chemicals are produced but certain compounds such as mercaptans and sulfides have been suggested. No major environmental hazards are anticipated from the release of these compounds. In instances, where the pollutant level in the bleedstream is high, the latter would require treatment either in a water scrubber or by carbon adsorption. In the case of carbon adsorption, reactivation of the adsorption bed would be necessary; the spent water would require treatment if a water scrubber is employed.

Alternatively, many ethanol fermentation plants would rather buy their enzymes than manufacture them. In such cases, no wastes or environmental residuals would be generated.

3c

Wash Effluents from Amylase Production

The fungal amylase preparation system consists of 7 seed tanks and 7 batch tanks which deliver the enzyme product to the mash cooking and saccharification section (Segment 200). Prior to filling the batch tanks with mash, they are thoroughly cleaned and, after filling, the mash is sterilized with steam followed by well water cooling.⁽¹⁾ The seed tanks also

will require thorough washing prior to inoculation. A set of one seed tank and one batch tank will require cleaning every day.

As described earlier, the total amount of wash water required per tank is 2,800 gallons. Assuming the same conditions as discussed in (2b), the annual wash water requirements for equipment employed in Segment 300, Amylase Production, can be calculated.

Annual wash water requirements:

$$\begin{aligned} & 2.8 \times 10^3 \text{ gal/tank} \times 2 \text{ tanks} \times 365 \text{ days/year} \times 0.9 \times 1.25 \\ & = 2.30 \times 10^6 \text{ gal/yr} \end{aligned}$$

The wash water requirement is independent of tank volume. Cleaning chemicals are usually recycled several times prior to disposal after wastewater treatment. The batch tanks also will require occasional descaling.

The composition of a typical wastewater stream from a plant and equipment wash is shown in Table 5 in (2b).

References

- (1) Raphael Katzen Associates, "Grain Motor Fuel Alcohol Technical and Economic Assessment Study," U.S. Department of Energy, Report No. HCP/J6099-01, Washington, D.C., June 1979.
- (2) Scarberry, R.M. and M.P. Papai, "Source Test and Evaluation Report: Alcohol Facility for Gasohol Production," Radian Corporation for U.S. Environmental Protection Agency, Cincinnati, Ohio, November 1979.

4

Fermentation to Ethanol

The controlled air emissions released to the atmosphere as a result of the fermentation process are:

Ethanol	1.80×10^3 tons/yr
Water vapor	2.48×10^3 tons/yr
Carbon dioxide	170×10^3 tons/yr

4a

Yeast Input

The yeast requirement for the fermentation process is 396 tons/yr. Approximately 7.92×10^3 gal/yr of iodine sterilizing solution also would be required.

4b

Emissions from Fermentation

Large amounts of carbon dioxide are produced during the fermentation of C_6 sugar by the yeast, Saccharomyces cerevisiae. This carbon dioxide stream which is vented to the atmosphere contains small amounts of water vapor along with trace quantities of volatile organic compounds. Besides ethanol, these include acetaldehyde and furfural which are by-products of the saccharification and fermentation reactions.^(1,2) Some of these organic compounds are foul smelling. Prior to venting, the carbon dioxide stream is passed through a water scrubber which removes most of the odorous substances, ethanol, and other soluble organic compounds from the gas.⁽³⁾

Approximately 515 tons/day of carbon dioxide are produced during the fermentation reaction.⁽¹⁾ This carbon dioxide (CO_2) is released from the fermenters at 1 atmosphere pressure (atm) and an average temperature of 27°C (80°F), and is assumed to be in equilibrium at this temperature with a water-alcohol mixture containing 7.1 weight percent ethanol. Using equilibrium partial pressure data for aqueous ethanol solutions, the concentrations of ethanol and water vapor in the CO_2 stream can be calculated.

At 27°C (80°F) and 1 atm ⁽⁴⁾:

vapor pressure of pure water	=	26.3 mm Hg
partial pressure of ethanol	=	7.5 mm Hg
partial pressure of water	=	25.5 mm Hg

For the gas leaving the fermenters, therefore;

$$\text{ethanol concentration} = \frac{\text{partial pressure of ethanol}}{\text{total pressure}}$$

$$\text{ethanol concentration} = \frac{7.5 \text{ mm Hg}}{760 \text{ mm Hg}} = 9.86 \times 10^{-3} \text{ mole fraction ethanol}$$

$$= 9.86 \times 10^{-3} \text{ volume percent ethanol}$$

$$\text{water vapor concentration} = \frac{\text{partial pressure of water vapor}}{\text{total pressure}}$$

$$= \frac{25.5}{760}$$

$$= 33.6 \times 10^{-3} \text{ mole fraction water}$$

$$= 3.36 \text{ volume percent water}$$

$$\begin{aligned} \text{Total CO}_2 \text{ out} &= 515 \text{ tons/day} \times 2,000 \text{ lbs/ton} \\ &= 1.03 \times 10^6 \text{ lbs/day} \end{aligned}$$

$$\begin{aligned} \text{CO}_2 \text{ out (lb mole)} &= 515 \text{ tons/day} \times 2,000 \text{ lbs/ton} \div (44 \text{ lb/lb mole}) \\ &= 23.4 \times 10^3 \text{ lb moles/day} \end{aligned}$$

$$\begin{aligned} \text{Total gas out (lb mole)} &= \frac{23.4 \times 10^3 \text{ lb moles/day}}{1 - (\text{mole fraction ethanol}) - (\text{mole fraction water})} \\ &= \frac{23.4 \times 10^3 \text{ lb moles/day}}{1 - 0.00986 - 0.0336} \\ &= 23.5 \times 10^3 \text{ lb moles/day} \end{aligned}$$

$$\begin{aligned} \text{Total ethanol out} &= 24.5 \times 10^3 \text{ lb moles/day} \times 9.86 \times 10^{-3} \\ &\quad \times (46 \text{ lb/lb mole}) \\ &= 11.1 \times 10^3 \text{ lbs day} \end{aligned}$$

$$\begin{aligned} \text{Total H}_2\text{O out} &= 24.5 \times 10^3 \text{ lb moles/day} \times 33.6 \times 10^{-3} \times 0.0336 \\ &\quad \times 18 \text{ lb/lb mole} \\ &= 14.8 \times 10^3 \text{ lbs/day} \end{aligned}$$

On an annual basis, therefore,

$$\text{Total CO}_2 \text{ out} = 170 \times 10^3 \text{ tons/yr}$$

$$\text{Total H}_2\text{O out} = 2.44 \times 10^3 \text{ tons/yr}$$

$$\text{Total ethanol out} = 1.83 \times 10^3 \text{ tons/yr}$$

The ethanol emission from fermentation is equivalent to:

$$\begin{aligned} & 1,830 \times 2,000 \text{ lbs/yr} + 6.6 \text{ lbs/gal} \\ & = 555 \times 10^3 \text{ gal/yr} \end{aligned}$$

For a plant producing 50 million gallons of ethanol/yr, this would represent a loss of approximately 1.1 percent of plant output.

(4c)

Exhaust from Water Scrubber

Approximately 98 percent of the incoming ethanol can be recovered. (4)

Assuming that the gas leaving the absorber is saturated with water, the concentration of the exhaust gas from the water scrubber can be calculated as shown below. The CO_2 absorption rate will be negligible. (4)

$$\begin{aligned} \text{Ethanol out} &= (\text{removal efficiency}) \times (\text{quantity of ethanol in feed}) \\ &= 0.98 \times 11.1 \times 10^3 \text{ lbs/day} \\ &= 10.9 \times 10^3 \text{ lbs/day} \\ &= 1.65 \times 10^3 \text{ gal/day} \end{aligned}$$

$$\begin{aligned} \text{Water vapor out} &= \frac{(\text{CO}_2 \text{ out}) \times (\text{vapor pressure of H}_2\text{O in mmHg})}{760 \text{ mmHg} - (\text{vapor pressure of H}_2\text{O in mmHg})} \\ &= \frac{23.4 \times 10^3 \text{ lb moles/day} \times 26.3 \text{ mmHg}}{(760 - 26.3) \text{ mmHg}} \times 18 \text{ lb/lb mole} \\ &= 15.1 \times 10^3 \text{ lbs/day} \end{aligned}$$

On an annual basis, therefore,

$$\begin{aligned} \text{Ethanol out} &= 1.80 \times 10^3 \text{ tons/yr} \\ \text{Water vapor out} &= 2.48 \times 10^3 \text{ tons/yr} \\ \text{CO}_2 \text{ out} &= 170 \times 10^3 \text{ tons/yr} \\ \text{Total gas out} &= 174 \times 10^3 \text{ tons/yr} \end{aligned}$$

Effluent from Water Scrubber

For an economical liquid rate, assume the absorption factor, A, at 1.6 (4). Therefore,

$$\begin{aligned} A &= \text{Absorption Factor} = L/mG = 1.6 \\ m &= \text{slope of the equilibrium curve} = 0.73 \end{aligned}$$

G = average gas flow rate = 24.5×10^3 lb moles/day

L = liquid flow rate

$$= A \times m \times G$$

$$= 1.6 \times 0.73 \times 24.5 \times 10^3 \text{ lb moles/day} \times 18 \text{ lb/lb mole}$$

$$= 515 \times 10^3 \text{ lb/day}$$

$$\text{or } 515 \times 10^3 \text{ lbs/day} + 8.3 \text{ lbs/gal} = 61.8 \times 10^3 \text{ gal/day}$$

On an annual basis, therefore:

$$\text{Total water required to absorb the ethanol} = 20.4 \times 10^6 \text{ gal/yr}$$

Besides ethanol, the water effluent from the scrubber will contain small amounts of odorous and other soluble organic compounds. The scrubber water can be collected and sent to the distillation/dehydration section for alcohol recovery. Alternatively, if the recovery is not cost effective, the scrubber stream can be sent to the wastewater treatment system prior to disposal.

(4e)

Fermenter Wash Water

In the fermentation segment, the fermenters are batch operated and consist of sixteen 250,000-gallon vessels which are arranged in sets of four to ensure a continuous flow of ethanol to the distribution section. Total fermentation time is about 48 hours. At the end of fermentation, the fermenters are cleaned and sterilized by means of automatic sprayers which are installed in each fermenter tank. Each tank has 2 sprayers. After each fermentation cycle, the tank is washed with a cleaning solution, sterilized with iodine solution and rinsed with clean sterile water in preparation for the next cycle.⁽¹⁾

Using the same assumptions as discussed earlier in (2b) the total amount of fermenter wash water required can be calculated.

Annual wash water requirement:

$$\text{No. of washes per year} = 365 \text{ days/yr} \times 0.9 \times \frac{1 \text{ wash}}{2 \text{ days}}$$

$$= 164 \text{ washes}$$

$$\begin{aligned} \text{Total water} &= 2.8 \times 10^3 \text{ gal/fermenter} \times 4 \text{ fermenters} \times 164 \times 1.25 \\ &= 2.30 \times 10^6 \text{ gal/yr} \end{aligned}$$

The fermentation wash contains high levels of dissolved and suspended solids. It also contains trace amounts of alkali and organics.^(2,3) This is probably due to the variety of nutrients and wash chemicals employed in the fermentation process. Some of these parameters are illustrated in Table 5 in (2b).

References

- (1) The Aerospace Corporation, "Environmental Control Perspective for Ethanol Production from Biomass," Aerospace Report No. ATR-80 (7848-01)-1 for U.S. Department of Energy, Washington, D.C., August 1980.
- (2) Scarberry, R.M. and M.P. Papai, "Source Test and Evaluation Report: Alcohol Facility for Gasohol Production," Radian Corporation for U.S. Environmental Protection Agency, Cincinnati, Ohio, November 1979.
- (3) Raphael Katzen Associates, "Grain Motor Fuel Alcohol Technical and Economic Assessment Study," U.S. Department of Energy, Report No. HCP/J6639-01, Washington, D.C., June 1979.
- (4) Treybal, R.E., Mass Transfer Operations, Second Edition, McGraw-Hill Book Company, New York, N.Y., 1968.

5 Distillation and Dehydration

The quantities of air emissions released during the ethanol recovery operations are:

Carbon dioxide	2.87×10^3 tons/yr
Water vapor	41.2 tons/yr

5a Degasser and Vent Emissions from Distillation and Dehydration

The dilute beer feed from the fermentation section of the plant collected in a beer well from where it passes continuously to the distillation section. Following a series of preheating steps, the beer is passed into a degassing drum where the carbon dioxide dissolved in the beer feed is flashed off. ⁽¹⁾ This CO_2 represents one of the by-products of the fermentation reaction. Relative to stream (4b) the amount of CO_2 released here is very small and is not recovered. Any alcohol or water vapor accompanying the vented carbon dioxide is condensed in a condenser from where it flows into the feed stream for ethanol recovery.

Assuming no interference from the other components and a mass flow rate of beer feed of 7.07×10^3 tons/day, ⁽¹⁾ the amount of CO_2 dissolved in the dilute beer feed can be calculated as shown below: ^(2,3)

At 27°C (80°F) and 1 atm:

Solubility of CO_2 in aqueous solution
 $= 0.126 \text{ gms}/100 \text{ gms of H}_2\text{O}$

Therefore,

$$\begin{aligned} X_{\text{CO}_2} &= \text{mole fraction of } \text{CO}_2 \text{ in the beer} \\ &= \frac{0.1260/44}{0.1260/44 + 100/18} \\ &= 515 \times 10^{-6} \end{aligned}$$

Mass flow rate of beer feed ⁽¹⁾

$$\begin{aligned} &= 7.07 \times 10^3 \text{ tons/day} \times 2000 \text{ lbs/ton} \\ &= 14.1 \times 10^6 \text{ lbs/day} \end{aligned}$$

Molal flow rate

$$\begin{aligned} &= (14.1 \times 10^6 \text{ lbs/day}) / (\text{average molecular weight}) \\ &= (14.1 \times 10^6) / 18.82 \text{ lb/lb mole} \\ &= 751 \times 10^3 \text{ lb moles/day} \end{aligned}$$

Therefore,

Amount of CO_2 in the solution

$$\begin{aligned}
 &= X_{\text{CO}_2} \times (\text{molal flow rate of beer feed}) \\
 &= 515 \times 10^{-6} \times 751 \times 10^3 \frac{\text{lb moles}}{\text{day}} \times 44 \frac{\text{lb}}{\text{lb mole}} \times \frac{1 \text{ ton}}{2000 \text{ lbs}} \\
 &= 8.51 \text{ tons/day or} \\
 &= 2.81 \times 10^3 \text{ tons/yr}
 \end{aligned}$$

Therefore, the amount of CO_2 released by the degassing drum is 2810 tons/yr.

Assume that the CO_2 leaving is saturated with water.

At 1 atm pressure and 80°F , vapor pressure of water

$$(P_{\text{H}_2\text{O}}) = 26.3 \text{ mm Hg}$$

$$\begin{aligned}
 \text{Water vapor out} &= \text{CO}_2 \text{ lb mol/day} \times \frac{P_{\text{H}_2\text{O}}}{760 \text{ mm Hg} - P_{\text{H}_2\text{O}}} \\
 &= 515 \times 10^{-6} \times 751 \times 10^3 \frac{\text{lb mol}}{\text{day}} \times \frac{26.3 \text{ mm Hg}}{760 \text{ mm Hg} - 26.3 \text{ mm Hg}} \times \frac{18 \text{ lb}}{\text{lb mole}} \\
 &= 250 \text{ lb/day or } 41.2 \text{ tons/yr}
 \end{aligned}$$

The CO_2 gas stream from the degassing drum also will contain some ethanol. Using the equilibrium partial pressures for ethanol-water solutions, the amount of ethanol escaping with the CO_2 can be calculated as follows: ⁽³⁾

For the gas leaving the degasser

Y = mole fraction of ethanol in the gas

$$= \frac{\text{partial pressure of ethanol at } 120^\circ\text{F}}{\text{total pressure}}$$

$$= \frac{60.0 \text{ mm Hg}}{760 \text{ mm Hg}}$$

$$= 78.9 \times 10^{-3}$$

Ethanol out = $Y \times (\text{Molal Flow Rate of } \text{CO}_2)^*$

$$= 78.9 \times 10^{-3} \times 515 \times 10^{-6} \times 751 \times 10^3 \frac{\text{lb moles}}{\text{day}} \times \frac{46 \text{ lb}}{\text{lbmole}}$$

$$= 1.41 \times 10^3 \text{ lbs/day or } 232 \text{ tons/yr}$$

*Assumes negligible contribution from other components of degasser gas.

In the EPA study performed by Radian Corporation, total hydrocarbon and benzene concentration as well as emission rates for the various air emission streams from the distillation and dehydration sections were measured. These are summarized in Table 7.⁽⁴⁾ The study determined that the highest concentration of hydrocarbons occurred in the condenser vent of the stripping column. Benzene accounted for about 95 percent of the hydrocarbons in this stream. The condenser vent on the dehydration column also had a high concentration of hydrocarbons, half of which was benzene. Although these vents had a high concentration of hydrocarbons, the total emissions from these sources were small due to the low gas flow rates from these vents. In the absence of controls, these organic compounds will be released to the atmosphere. As the streams are too dilute for economic recovery of the organic substances, proper housekeeping and maintenance procedures such as flares can be employed to control these emissions.

The base case ethanol plant assumed for this ECIR employs a slightly different approach to distillation and dehydration compared to that assumed by Radian Corporation. Consequently, the emissions from the various condenser vents will be slightly different; but they will still be negligible.

Table 7. Total Hydrocarbon and Benzene Analysis⁽⁴⁾

Stream/Parameter	Average ^a Concentration (ppm CH ₄)	Emissions (lb CH ₄ /hr)	Annual Rate ^b (lbs CH ₄ /yr)
Beer Still Condenser Vent			
THC ^c	219	0.024	168.2
Rectifier Condenser Vent			
THC	1530	-	-
Dehydration Column Condenser Vent			
THC	29,900	0.110	770.9
Benzene	17,000	0.059 ^d	413.5
Stripping Column Condenser Vent			
THC	55,300	0.209	1464.7
Benzene	52,900	0.198 ^e	1387.6

^a concentrations were measured as ppm methane (CH₄)
^b for a plant producing 15 x 10⁶ gal/yr
^c total hydrocarbon
^d this is equivalent to 0.68 lbs/hr benzene
^e this is equivalent to 2.16 lbs/hr benzene

(5b) Exhaust from Condenser

The CO_2 and other vent gases from the distillation and dehydration section are passed through a condenser which condenses most of the ethanol and other volatile organic compounds. The amounts of these organics will be small. Assume that all the ethanol is recovered by condensation. Therefore, from (5a),

Quantity of exit gas:

= 2810 tons/yr of CO_2 + 41.2 tons/yr of water vapor

= 2851 tons/yr

(5c) Condenser Effluent

This stream which consists essentially of the condensed ethanol also contains minor amounts of other volatile organic compounds. The total amount of this stream, from (5a), is approximately 232 tons/yr.

(5d) Liquid Effluents from Distillation and Dehydration

There are several sources of liquid effluents in the distillation and dehydration sections of the plant. These include:

- stripper-rectifier bottoms
- dehydration tower bottoms, and
- hydrocarbon stripper bottoms

Bottom water from the stripper-rectifier, although high in BOD_5 concentration, is a small volume stream. The solids content of this stream is small. (5) Depending on the nature of the dehydrating agent, the bottoms from the dehydration tower will contain trace quantities of the hydrocarbon. In the sampling program conducted by Radian Corporation at a plant employing benzene as the dehydrating agent, several liquid streams revealed benzene concentrations in the range of 2.7 to 59.4 parts per billion. (4,5) The accuracy is rather low at these concentration as these values are near the detection limit for benzene.

These liquid effluents contribute only minor loadings to the treatment plant. (5) However, certain precautionary measures must be exercised while handling these streams. This is due to the toxicity and other health hazards that might be associated with some of the organic chemicals in these effluent streams. No pesticides were detected in these effluent streams.

(5e) Condensate Return from Distillation and Dehydration

Large amounts of thermal energy in the form of steam are utilized by

the process. Steam is made available to the various segments of the plant from the Stillage Drying and Evaporation Segment. During the concentration of stillage, the water from the stillage bottoms is removed by a combination of centrifuges and vapor recompression evaporations. Approximately 200,000 lbs/hr of steam at 150 psig is produced in Segment 600. About 58.5 percent is utilized in the distillation section, 30.5 percent in the mash cooking cycle with the rest scattered between the other process steps.⁽¹⁾ The condensate return whose composition is shown below in Table 8 is collected and sent to the raw water treatment system for conditioning and reuse in the process.

Table 8. Wastewater Characteristics of Condensate Return⁽⁴⁾

<u>Parameter</u>	<u>Concentration, ppm</u>
Total Solids	130
Suspended Solids	12
BOD ₅	650

5f

Stillage

Stillage, approximately 2.13×10^6 tons/yr, is the residual from the first distillation column. The stillage from corn feedstock is relatively high in protein concentration and contains unconverted starches and sugars, various fermentation products and yeast cells. Unless properly treated, this stream, as illustrated in Table 9, has a high pollution potential. It contains high levels of Biochemical Oxygen Demand (BOD₅), Chemical Oxygen Demand (COD), Total Solids (TS), Suspended Solids (SS) and Volatile Solids (VS). In addition, a variety of other residual alcohols and acids also might be present in measurable concentrations.

In the alcohol fermentation plant, the stillage is initially centrifuged to remove majority of the solids. A portion of the resultant filtrate (known as thin stillage) is recycled to the mash cooking section while the remainder is evaporated in a vapor recompression evaporator to about 55 percent solids. Final drying is accomplished in rotary driers. The total amount of dried grains produced by the plant corresponds to 177×10^3 tons/yr and will be marked as an animal feed. The nutritive value of DDGS is illustrated in Table 10.

Table 9. Summary of Stillage Composition^(4,5,6)

<u>Parameter</u>	<u>Concentration Range, ppm</u>
BOD ₅	20,800-54,400
COD	23,100-98,700
TS	12,200-52,000
VS	9,870-49,000
Total Nitrogen	224- 546
Sulfate	299- 466
Phosphate	400- 700
Magnesium	88
Iron	3
Copper	1
Potassium	0.13- 0.38
Zinc	4.41- 13.00
Ethanol	6,000-16,000
Propanols	3.5- 66.5
Butanols	0.0- 14.9
Pentanols	0.0- 40.1
Acetic Acid	557- 1,910
Propionic Acid	2- 145
Butyric Acid	0- 400
Calcium	Trace
Barium	Trace

Table 10. Nutritive Composition of Distillers' Dried Grains with Solubles⁽⁵⁾

<u>Parameter</u>	<u>Concentration, wt%</u>
Moisture	9.00
Protein	27.00
Fat	8.00
Fiber	8.50
Ash	4.50
Carbohydrate	43.00
Total	100.00

5g

Hydrocarbon Solvent Input

The total amount of hydrocarbon solvent required for the dehydration of ethanol is 9.03×10^3 gal/yr.

References

- (1) Raphael Katzen Associates, "Grain Motor Fuel Alcohol Technical and Economic Assessment Study," Report No. HCP/J6639-01, for U.S. Department of Energy, Washington, D.C., June 1979.
- (2) Treybal, R.E., Mass Transfer Operation, Second Edition, McGraw-Hill Book Company, New York, New York, 1968.
- (3) Perry, R.H., C.H. Chilton and S.D. Kirkpatrick, Perry's Chemical Engineering Handbook, Fourth Edition, McGraw Hill Book Company, New York, New York, 1963.
- (4) Scanberry, R.M. and M.P. Papai, "Source Test and Evaluation Report: Alcohol Facility for Gasohol Production," Radian Corporation for U.S. Environmental Protection Agency, Cincinnati, Ohio, November 1979.
- (5) The Aerospace Corporation, "Environmental Control Perspective for Ethanol Production from Biomass," Aerospace Report No. ATR-80 (7848-01)-1 for U.S. Department of Energy, Washington, D.C., August 1980.
- (6) Dahab, M.F. and J.C. Young, "Energy Recovery from Alcohol Stillage Using Anaerobic Filters," presented at the Third Symposium on Biotechnology in Energy Production and Conservation, Gatlinburg, Tennessee, May 12-15, 1981.

6 Denaturation and Product Storage

The emissions associated with denaturation and product storage are negligible.

6a Denaturant Input

Annual denaturant requirement for the alcohol fermentation plant is $x 10^6$ gallons.

6b Emissions from Denaturation and Product Storage

Denaturation is the addition of certain chemicals to ethanol in order to render the alcohol unfit for human consumption. Several denaturants have been approved by the Bureau of Alcohol, Tobacco and Firearms for fuel alcohol.⁽¹⁾ A recently approved formula, known as CDA No. 20, allows the use of unleaded gas as a denaturant. The formula requires the addition of 2 gallons of unleaded gasoline to 100 gallons of ethanol of at least 195 proof.

Evaporative emissions during denaturation and product storage are likely. These can, however, be controlled through the use of tanks equipped with either floating roofs, fixed covers or internal floating covers in order to reduce the air spaces above the liquids. Fixed covers are usually preferred with venting through condensers or dessicants. The emissions from these sources, therefore, should be small.^(2,3)

References

- Federal Register, Vol. 46, 9644, January 29, 1981.
- (2) The Aerospace Corporation, "Environmental Control Perspective for Ethanol Production from Biomass," Aerospace Report No. ATR-80 (7848-01)-1 for U.S. Department of Energy, Washington, D.C., August 1980.
- (3) Scarberry, R.M. and M.P. Papai, "Source Test and Evaluation Report: Alcohol Facility for Gasohol Production," Radian Corporation for U.S. Environmental Protection Agency, Cincinnati, Ohio, November 1979.

7 Raw Chemical Storage

The quantity of air emission from the raw chemical storage area is negligible.

7a

Emissions from Raw Chemical Storage

Control measures during the storage of process chemicals such as gasoline, ammonia, benzene or other organic chemicals will be required in the alcohol fermentation facility. These procedures, however, are well established. Evaporative emissions can be controlled through the use of tanks equipped with floating roofs or with internal floating covers in an effort to reduce the air space above the stored liquids. Floating roofs reduce hydrocarbon evaporative emissions by approximately 85 percent and internal floating covers reduce emissions by about 95 percent. Another option is to use a vapor recovery system. Evaporative emissions, therefore, from raw chemical storage will be negligible.

In some instances, Federal agencies such as EPA and OSHA, and State laws will impose restrictions on the storage of certain chemicals, for example, benzene. If the alcohol fermentation facility were to use benzene or other regulated chemicals, it will have to adhere to these regulations.

References

- (1) The Aerospace Corporation, "Environmental Control Perspective for Ethanol Production from Biomass," Aerospace Report No. ATR-80 (7848-01)-1 for U.S. Department of Energy, Washington, D.C., August 1980.

8 Stillage Drying and Evaporation

Pre-control particulate emissions from stillage drying operations amount to 443 tons/yr. Control of this pollutant is achieved in segment 900, Flue Gas Scrubber system.

8a Air Input

Supplemental heated air required to dry the stillage amounts to 6.5×10^3 tons/yr.

8b Flue Gas from Stillage Drying

Stillage from the distillation area, mixed with the collected dust from Segment 100, (1d), is initially centrifuged in solid bowl centrifuges which separate the stillage into two fractions: thin stillage containing about 6.5-10 weight percent total solids and thick stillage containing about 35 weight percent solids. Part of the thin stillage is recycled to the mash cooking and saccharification section. The remainder is evaporated in a vapor recompression evaporator. The wet grains are then tumbled in a series of indirect rotary dryers which are in contact with the hot flue gas feeding from the power boiler. Supplemental heat for drying the grains is provided by hot air. The air leaving the dryers contains entrained solids primarily of these particulates are removed in a series of cyclone collectors, and recycled to the dryers. (1) Sometimes excess condensate is produced in the evaporator. This is collected and treated in the secondary wastewater system prior to disposal.

The U.S. Environmental Protection Agency reports an emission factor of 5 lbs. of particulates per ton of spent grains dried (uncontrolled). (2) This corresponds to:

Particulate emissions from spent grain drying:

$$\begin{aligned} & 5 \text{ lbs/ton} \times 177 \times 10^3 \text{ tons/yr} \times \frac{1 \text{ ton}}{2,000 \text{ lbs}} \\ & = 443 \text{ tons/yr} \end{aligned}$$

Gaseous hydrocarbons also are emitted during the drying process. Although, emission levels have not been reported, they are expected to be minor. (2,3)

8c

Collected Particulates from Stillage Drying

Assuming a 70 percent removal efficiency in the cyclone collectors, the amount of particulates that are removed, collected and recycled corresponds to:

$$443 \text{ tons/yr} \times 0.7 = 310 \text{ tons/yr}$$

References

- (1) Raphael Katzen Associates, "Grain Motor Fuel Alcohol Technical and Economic Assessment Study," U.S. Department of Energy, Report No. HCP/J6639-01, Washington, D.C., June 1979.
- (2) U.S. Environmental Protection Agency, "Compilation of Air Pollution Emission Factors," Second Edition, Publication No. AP-42, Office of Air and Water Programs, Research Triangle Park, N.C., April 1973.
- (3) Scarberry, R.M. and M.P. Papai, "Source Test and Evaluation Report: Alcohol Facility for Gasohol Production," Radian Corporation for U.S. Environmental Protection Agency, Cincinnati, Ohio, November 1979.

9 Flue Gas Scrubber

The air emissions and pollutants from the scrubber operations are as follows:

Sulfur dioxide	947 tons/yr
Nitrogen oxides	726 tons/yr
Particulates	104 tons/yr
Water vapor	120×10^3 tons/yr
Volatile compounds	Trace

9a Feed to Flue Gas Scrubber

Since 70 percent of the grain dusts from the drying operation are recycled to the stillage drying operations, the remaining 30 percent (443 tons/yr - 310 tons/yr = 133 tons/yr) will find its way into the flue gas scrubber feed.

In addition, boiler flue gas that feeds the Stillage Drying and Evaporative Segment already contains 5.1×10^3 lbs/day of particulates in the form of fly ash (see (12f)). This flue gas is combined with the dryer flue gas prior to entering the desulfurization system. The composition of the resultant gaseous mixture is summarized in Table 11.

Table 11. Composition of Flue Gas Scrubber Feed

Component	Quantity lbs/day
Carbon Dioxide	1.36×10^6
Water	1.54×10^6
Nitrogen	8.08×10^6
Oxygen	1.28×10^6
Sulfur Dioxide	41.0×10^3
Carbon Monoxide	300
Organics	90
Nitrogen Oxides	5.34×10^3
Aldehydes	2
Particulates, including fly ash	5.91×10^3
Total	12.3×10^6

9b

Anhydrous Ammonia Input

The total amount of anhydrous ammonia required by the flue gas scrubber is 3.04×10^3 tons/yr.

9c

Emissions from Flue Gas Scrubber

The hot flue gas from the dryers contains several criteria air pollutants currently regulated by EPA. Consequently, it will require treatment prior to release. The alcohol fermentation facility employs a desulfurization system which uses ammonia as the sorbent and recovers the SO_2 emissions as ammonium sulfate. This chemical recovery desulfurization system differs from the more conventional limestone scrubbing system in that no calcareous sludge is produced in the system. The only by-product is ammonium sulfate.

In this system, water sprays are introduced into the gas in order to cool it and remove the particulates, in 3 stages. The first stage removes particulates only. This is followed by a two-stage absorption process where ammonia reacts with SO_2 to yield an ammonium sulfite/bisulfite solution. Additional particulates also are removed in these two stages by water spraying. The solution is then neutralized and oxidized to ammonium sulfate. The latter, available as a 40 weight percent solution, is suitable for sale as an agricultural fertilizer.

The cooled effluent gas from the scrubber contains less than 0.9 lbs SO_2 per million Btu's fired.⁽¹⁾ This is well below the current EPA New Source Performance Standard for coal-fired steam generating units (with an input capacity greater than 250 million Btu/hr) of 1.2 lbs SO_2 /million Btu's fired.^(2,3) Although no information is available for NO_x and particulate emissions, it is assumed that they will be controlled below the EPA allowable limits. The composition of the flue gas exiting from the desulfurization system is summarized in Table 12. Removal efficiencies also are illustrated in the table.

The flue gas also contains some water vapor. Assuming saturation at the air exit temperature of 110°F , the approximate amount of water vapor present in the air can be calculated as shown below, assuming no interference or contribution by the other components of the flue gas.

Amount of water vapor in flue gas at 760 mm Hg pressure: ⁽⁴⁾

$$\begin{aligned}
 & 0.622 \times \frac{\text{vapor pressure of pure water at } 110^{\circ}\text{F, mm Hg}}{760 - \text{vapor pressure of pure water at } 110^{\circ}\text{F, mm Hg}} \\
 & = 0.622 \times \frac{65.9}{760 - 65.9} \\
 & = 59 \times 10^{-3} \text{ lb water vapor/lb flue gas at saturation}
 \end{aligned}$$

Table 12. Composition of Flue Gas Scrubber Emissions

Component	EPA Compliance Levels, lb/10 ⁶ Btu fired	Quantity tons/yr*
Sulfur Dioxide	1.2	947
Particulates	0.1	104
Nitrogen Oxides	0.7	726
Volatile Compounds	-	NA

* Based on 263 x 10⁶ Btu/hr coal feed
NA - Data not available

On an annual basis, therefore:

Amount of water vapor in flue gas:

$$\begin{aligned}
 & = (0.0591 \text{ lb/lb flue gas}) \times (12.3 \times 10^6 \text{ lbs/day})^* \\
 & = 72.5 \times 10^3 \text{ lbs/day or } 120 \times 10^3 \text{ tons/yr}
 \end{aligned}$$

*Total quantity from Table 11 minus sulfur dioxide, particulates and nitrogen oxides from Table 12.

9d

Flue Gas Scrubber Wastewater Effluents

Particulates which are precipitated in the cooling and absorption sections of the desulfurization system are initially removed by cyclone cleaners followed by concentration in a clarifier. This material is then combined with sludge from the wastewater treatment system, dewatered and sent to the coal-fired boiler for steam production. The boiler is equipped with special feeder/spreader to handle the dewatered sludge.

Assuming that the flue gas from the desulfurization system meets EPA New Source Performance Standards:

Solids in scrubber effluent:

$$\begin{aligned} & 5.91 \times 10^3 \text{ lbs/day} - [0.1 \text{ lb}/10^6 \text{ Btu} \times 263 \times 10^6 \text{ Btu/hr} \\ & \quad \times 24 \text{ hrs/day}] \\ & = 5.91 \times 10^3 \text{ lbs/day} - 631 \text{ lbs/day} \\ & = 5.28 \times 10^3 \text{ lbs/day or } 866 \text{ tons/yr} \end{aligned}$$

References

- (1) Raphael Katzen Associates, "Grain Motor Fuel Alcohol Technical and Economic Assessment Study," U.S. Department of Energy, Report No. HCP/J6639-01, Washington, D.C., June 1979.
- (2) Personal Communication, Mr. Walt Stevenson, Emission Standards and Engineering Division, Environmental Protection Agency, Research Triangle Park, North Carolina.
- (3) Research Triangle Institute, "A Handbook of Key Federal Regulation and Criteria for Multimedia Environmental Control," Report No. RTI/1603/18-01F, for U.S. EPA, Research Triangle Park, June 1979.
- (4) Treybal, R.E., Mass Transfer Operation, Second Edition, McGraw-Hill Book Company, New York, New York, 1968.

10 By-Product DDGS Storage and Outloading

The quantity of particulates released to the atmosphere after controls is 5.31 tons/yr.

10a Fugitive Emissions from By-Product (DDGS) Handling

The alcohol fermentation plant produces 177×10^3 tons/yr of Stillers Dried Grains with Solubles (DDGS). The primary use of this material is as cattle feed, although other uses have been identified such as soil amendments and human nutrition. The nutritive value of DDGS is shown in Table 10 (see 5f).

The storage and loading of corn DDGS generates considerable amounts of dust. (1) No data are currently available on dust emissions with regard to DDGS handling. Consequently, the emission factors as discussed earlier for grain handling will be assumed here. These are illustrated in Table 13.

Table 13. Particulate Emission Factors for DDGS Handling⁽¹⁾

Type of Source	Emission Factor, lb/ton
Handling	1.00
Unloading	5.00

The total emissions (uncontrolled), therefore, for the alcohol fermentation plant can be calculated:

Uncontrolled dust emissions:

$$\begin{aligned} & 6 \text{ lbs/ton} \times 177 \times 10^3 \text{ tons/yr} \times 1 \text{ ton/2000 lbs} \\ & = 531 \text{ tons/yr} \end{aligned}$$

10b Exhaust From By-Product Handling

The emissions from DDGS storage and unloading are controlled by a r of baghouse filters which are located in the by-product storage section. The baghouse filters have high removal efficiencies, averaging at least 95 percent. Assuming a 99 percent removal efficiency for the collection system, the amount of particulates released equals:

$$531 \text{ tons/yr} \times (1-0.99) = 5.31 \text{ tons/yr.}$$

10c

Collected Particulates from DDGS Handling

The particulates removed by the baghouse filters are collected and recycled to DDGS storage. These amount to:

$$531 \text{ tons/yr} \times 0.99 = 526 \text{ tons/yr.}$$

References

- (1) U.S. Department of Energy, "Environmental Readiness Document - Alcohol Fuels from Biomass" (Prepublication Draft), Assistant Secretary for Environmental Protection, Safety and Emergency Preparedness, Washington, D.C., May 1981.
- (2) Raphael Katzen Associates, "Grain Motor Fuel Alcohol Technical and Economic Assessment Study," U.S. Department of Energy, Report No. HCP/J6639-01, Washington, D.C., June 1979.
- (3) U.S. Environmental Protection Agency, "Compilation of Air Pollution Emission Factors," Second Edition, Publication No. AP-42, Office of Air and Water Programs, Research Triangle Park, North Carolina, April 1973.

11 Coal Receiving, Storage, and Conveying

Coal dust emissions from the receiving and storage operations amount to 49.0 tons/yr. The quantity of liquid runoff, although not quantifiable, should be negligible.

11a Coal Input

The annual coal feed to the boiler amounts to 97.9×10^3 tons.

11b Fugitive Dust from Coal Receiving, Onsite Storage and Conveying

Coal handling generates considerable amounts of atmospheric dusts. The air pollution impact of a fugitive dust source depends on the quantity and drift potential of the dust particles injected into the atmosphere as well as the type and nature of coal and the exposed surface area of the storage pile. In addition to large dust particles that settle out near the source, significant amounts of fine particles also are generated and dispensed over large distances from the source.⁽¹⁾

The emission rate and annual emissions for the various coal handling operations are summarized in Table 14.

Table 14. Emissions from Coal Handling Operations (2)

Type of Source	Emission Rate lb/ton	Total Emissions* tons/yr
Receiving	0.50	24.5
Storage	0.50	24.5
Conveying	Negligible	Negligible

*Based on 98×10^3 tons/yr coal feed

Fugitive emissions, therefore, from coal receiving, storage and conveying are approximately 49 tons/yr.

$$\begin{aligned}\text{Fugitive Emissions} &= \text{Emissions (Receiving)} + \text{Emissions (Storage)} \\ &= 24.5 \text{ tons/yr} + 24.5 \text{ tons/yr} = 49.0 \text{ tons/yr}\end{aligned}$$

(11c)

Runoff from Onsite Coal Storage

Control techniques for fugitive dust emissions generally involve watering, chemical treatment or reduction of surface wind speed through the use of windbreaks or enclosed areas. Watering, the most common and generally least expensive method, provides only temporary dust control. The use of chemicals to treat exposed surfaces provides longer term dust suppression but may be costly and may have adverse impacts on plant and animal life, or possibly contaminate the treated material. (3)

The water sprays employed to control dust emissions are generally used intermittently. Their amounts will vary depending on the type of coal and the mode of handling at the site. The water requirements for the alcohol fermentation plant will not exceed 100×10^3 gal/yr (based on water requirements of 3×10^6 gal/yr for a plant handling 10×10^3 tons/day). (3)

Rainwater that falls on the coal pile also will contribute to this effluent stream. Some of this wastewater might be lost through evaporation. (4) The rest will require treatment prior to disposal. This stream to the water treatment plant will contain both suspended and dissolved solids and might be acidic. The amount of rainfall and, therefore, the effluent wastewater stream, is dependent on the season and the climatic conditions for the site. It is, therefore, not possible to accurately quantify this waste stream.

References

- (1) Wilson, William, G., "Coal-Fired Power Plant (Eastern Coal) - Environmental Characterization Information Report," U.S. Department of Energy, Office of Environmental Assessments, Washington, D.C., DOE/EV-0072. June 1980.
- (2) Moskowitz, P.D., S.C. Morris, and A.S. Albanese, "The Global Carbon Dioxide Problem: Impacts of U.S. Synthetic Fuel - and Coal - Fired ELectricity Generating Plants," Journal of the Air Pollution Control Association, 30, #4, 353 (1980)
- (3) Wilson, William, G., "Coal-Fired Power Plant (Western Coal) - Environmental Characterization Information Report," Edition 1, (Draft) U.S. Department of Energy, Office of Environmental Assessments, Washington, D.C. January 1981.
- (4) U.S. Environmental Protection Agency, "Compilation of Air Pollution Emission Factors," Second Edition, Publication No. AP-42, Office of Air and Water Programs. Research Triangle Park, N.C. April 1973.

12 Boiler

Boiler blowdown amounts to approximately 7.92×10^6 gal/yr. The amounts of bottom ash and fly ash generated are 3×10^3 tons/yr and 4.75×10^3 tons/yr respectively.

12a Air

The amount of combustion air required by the coal-fired boiler is 1.10×10^6 tons/yr.

12b Boiler Blowdown

Steam for the alcohol plant is provided by a coal-fired boiler. The boiler is rated at 250×10^3 lbs/hr (6×10^6 lbs/day) of steam at 600 psig and 600° F. Total steam usage by the plant is calculated to be 200×10^3 lbs/hr (4.8×10^6 lbs/day).⁽¹⁾

Boiler feedwater is provided by condensate return from the process, where possible, and by make-up water that has been filtered and conditioned in a conventional boiler water treatment system. Approximately three-fifths of the boiler feedwater or 2.9×10^6 lbs/day is condensate return. Raw water make-up from the wells is about 2.1×10^6 lbs/day, for a total water supply to the boiler of 5.0×10^6 lbs/day.

Since the boiler produces 4.8×10^6 lbs/day of steam, boiler blowdown can be calculated as shown below:

$$\begin{aligned}\text{Boiler Blowdown} &= 5.0 \times 10^6 \text{ lbs/day} - 4.8 \times 10^6 \text{ lbs/day} \\ &= 200 \times 10^3 \text{ lbs/day} \\ &= 24 \times 10^3 \text{ gal/day} \\ &= 7.92 \times 10^6 \text{ gal/yr}\end{aligned}$$

Although, this wastewater will have a negligible BOD_5 content, the solids content might be high.⁽²⁾ Consequently, the blowdown might require treatment prior to disposal.

12c Bottom Ash from Coal Combustion

The relative amount of bottom ash is dependent on the type of coal, boiler feeder and the condition in the boiler.

The firing rate of the coal-fired boiler is 12.4 tons/hr of stoker-sized Illinois No. 6 coal containing 8.8 percent ash.⁽¹⁾ Assuming that 35 percent of the total ash in the coal feed becomes bottom ash, the ash generated by coal combustion can be calculated as follows:⁽²⁾

Bottom ash:

$$12.4 \text{ tons/day} \times 0.35 \times 0.088 \times 24 \text{ hrs/day} \\ = 9.2 \text{ tons/day or } 3 \times 10^3 \text{ tons/yr}$$

As described earlier, the boiler also burns dewatered sludge from the wastewater treatment system. Approximately 15 tons/day of dewatered sludge is fed to the boiler which produces 1.2 tons/day or 396 tons/yr of solid waste. (1)

(12d)

Boiler feed consists essentially of Illinois No. 6 coal with a minor fuel input by dewatered sludge from the wastewater treatment system. The ultimate analysis of Illinois No. 6 coal is listed in Table 15. Coal is fed to the boiler by four stoker-spreader units.

Table 15. Composition and Properties of
Illinois No. 6 Coal (1) (as received basis)

<u>Component</u>	<u>Composition, wt %</u>
Carbon	61.35
Hydrogen	4.66
Oxygen	8.71
Nitrogen	1.14
Sulfur	3.34
Ash	8.80
Moisture	<u>12.00</u>
	100.00
Gross (Higher) Heating Value (dry) = 12,080 Btu/lb	
(wet) = 10,630 Btu/lb	

When this coal is fired in the steam generating boiler, utilizing 30 percent excess air, the flue gas produced will have the composition and properties as shown below in Table 16.

Table 16. Boiler Flue Gas Composition
and Properties (1,3)
(30% excess air)

Component	Composition; Wt %	Total Emissions lbs/day
Carbon Dioxide	18.8	1.36×10^6
Water	5.7	410×10^3
Nitrogen	70.0	5.05×10^6
Oxygen	4.9	354×10^3
Sulfur Dioxide	0.6	41×10^3
Carbon Monoxide	0.004	300
Organics	0.001	90
Nitrogen Oxides	0.074	5.34×10^3
Aldehydes	-	2
		7.22×10^6

Average Molecular Weight of Flue Gas = 29.37

In addition, the flue gas will contain some particulates in the form of fly ash, and trace quantities of unburned hydrocarbons. Approximately 65 percent of the ash in the coal is emitted as fly ash, or

$$\begin{aligned}
 \text{Fly Ash} &= (\text{Ash Content of Coal}) \times (\text{Coal Feed}) \times (\text{Fly Ash Content}) \\
 &= 0.088 \times 297 \text{ tons/day} \times 0.65 \\
 &= 17 \text{ tons/day or } 5.6 \times 10^3 \text{ tons/yr}
 \end{aligned}$$

Therefore, the total amount of flue gas emitting from the boiler is approximately 7.22×10^6 lbs/day or 1.2 million tons/yr.

This flue gas passes through a particulate control unit and exits the boiler at 725°F. It is then fed directly to the stillage drying segment where its heat is used to dry the stillage.

(12e) Fly Ash From Particulate Control

The boiler flue gas is passed through a pair of particulate collectors consisting of numerous small cyclones (multiclones housed in a single chamber). These cyclones have fairly high efficiencies, generally ranging between 85-90 percent.⁽³⁾ It is assumed that 85 percent of the particulate fly ash will be captured by the collectors with the rest controlled in the flue gas scrubber system downstream.⁽²⁾ Therefore,

Collected fly ash from collectors:
(removal efficiency)x(fly ash content of boiler flue gas)
= $0.85 \times 34 \times 10^3$ lbs/day
= 28.9×10^3 lbs/day or 4.75×10^3 tons/yr

Or, the amount of fly ash that finds its way into the boiler flue gas is 5.1×10^3 lbs/day (837 tons/yr).

(12f) Flue Gas to Stillage Drying

The flue gas entering the Stillage Drying Evaporation section consists of the emissions noted in Table 16 plus the fly ash emission, or approximately 7.23×10^6 lbs/day.

References

- (1) Raphael Katzen Associates, "Grain Motor Fuel Alcohol Technical and Economic Assessment Study," U.S. Department of Energy, Report No. HCP/J6639-01, Washington, D.C., June 1979.
- (2) Scarberry, R.M. and M.P. Papai, "Source Test and Evaluation Report: Alcohol Facility for Gasohol Production," Radian Corporation for U.S. Environmental Protection Agency, Cincinnati, Ohio, November 1979.
- (3) U.S. Environmental Protection Agency, "Compilation of Air Pollution Emission Factors," Second Edition, Publication No. AP-42, Office of Air and Water Program, Research Triangle Park, N.C., April 1973.

13 Wastewater Treatment System

The amount of sludge generated by the wastewater treatment system (on a dry basis) is 4.95×10^3 tons/yr. Approximately 363×10^6 gal/yr of treated wastewater is discharged into the river.

13a Wastewater Influent Into Treatment System

Wastewaters from the alcohol plant arise principally from two sources: process water and sanitary wastewater. The wastewater from the various processing steps is collected at a lift station and is pumped to the treatment plant.

It is difficult to ascertain the exact characteristics of this influent wastewater. Besides process variables, this stream is dependent on the location of the plant. Generally, however, the flows are acidic in nature. They will contain significant amounts of solids and will have a moderate BOD_5 loading. They will also contain trace quantities of organic compounds such as ethanol, benzene or other hydrocarbons employed by the fermentation facility. Table 17 presents data on the characteristics of the influent wastewater stream generated by a hypothetical plant.⁽¹⁾ Annual quantities of the various impurities also are included in Table 17. Approximately 3.9×10^6 gal/yr of sanitary sewage also are produced by the plant; this stream is mixed with the process wastewater flows prior to secondary wastewater treatment.

Table 17. Characteristics of Influent Wastewater^(1,5)

<u>Item</u>	<u>Concentration</u> ppm	<u>Annual</u> <u>Quantity</u>
Total Wastewater Stream	-	360×10^6 gal (760 gpm)
Total Solids	843	1275 tons
Suspended Solids	104	157 tons
BOD_5	246	372 tons
pH	4-8	

In the EPA study, Radian Corporation performed a priority pollutant analysis for the various liquid streams generated by a 15×10^6 gal/yr ethanol plant. The results for the wastewater influent stream are presented in Table 18.

Table 18. Analytical Results for Priority Pollutants Metals, Total Cyanide, and Total Phenol (1)

<u>Analytical Parameter</u>	<u>Wastewater Influent (ppb)</u>
Antimony	10.0 $\pm$ 5
Arsenic	2.4 $\pm$ 0.1
Beryllium	<1
Cadmium	1.0 $\pm$ 0.1
Chromium	7.0 $\pm$ 0.4
Copper	950
Lead	<5
Mercury	<0.2
Nickel	4 $\pm$ 2
Selenium	<0.3
Silver	<0.06
Thallium	<2
Zinc	270 $\pm$ 10
Benzene	1.6
Methylene chloride	15.0
Toluene	1.6
2-Nitrophenol	10.0
Phenol	7.0
bis (2-Ethylhexyl) phthalate	22.0
Di-n-butyl phthalate	5.5
Diethyl phthalate	7.5
Anthracene	1.5
Phenanthrene	1.5
Total Cyanide	<20
Total Phenol	84

The wastewater treatment facility employed at the plant is designed for secondary treatment with two extended aeration tanks and two settling tanks. The facility will provide a removal of at least 95 percent of the influent

BOD₅. The sludge from the aeration tanks is pumped to a sludge thickener and then to a dewatering press where it is mixed with the sludge from the flue gas scrubber. The solids from the dewatering presses are chopped up in a flaker and finally conveyed to the boiler for burning. (2)

(13b) Wastewater Effluent from Treatment System

The total aqueous discharge from the plant is approximately 1.1 x 10⁶ gal/day. Since this liquid stream is continuously discharged into navigable waters, it will require adherence to the water quality standards for the state in which the plant is located. The general water quality standards for the state of Illinois are shown in Table 19.

Table 19. Water Quality Standards for Illinois (3)

<u>Parameter</u>	<u>Concentration</u>
Sulfates, mg/l	250
Chloride, mg/l	250
Total Dissolved Solids, mg/l	500
Dissolved Oxygen, mg/l	>5 at any time >6 during at least 16 hours of any 24-hour per- iod
pH	6.5 - 9.0
Arsenic, mg/l	1.0
Cadmium, mg/l	0.05
Chromium, Hexavalent, mg/l	0.05
Trivalent, mg/l	1.00
Mercury, mg/l	0.0005
Zinc, mg/l	1.0
General Toxic Substances	<10% of the 96- hour median threshold limit for native fish or other essential fish food organics

Presently, the EPA is in the process of evaluating the need for effluent guidelines for alcohol fuel plants. (4)

(13c) Dewatered Sludge from Wastewater Treatment System

Approximately 4.95×10^3 tons/yr of dewatered sludge, produced in the Wastewater Treatment System, are recycled to the boiler for burning.

References

- (1) Scarberry, R.M. and M.P. Papai, " Source Test and Evaluation Report: Alcohol Facility for Gasohol Production," Radian Corporation for U.S. Environmental Protection Agency, Cincinnati, Ohio, November 1979.
- (2) Raphael Katzen Associates, "Grain Motor Fuel Alcohol Technical and Economic Assessment Study," U.S. Department of Energy, Report No. HCP/J6639-01, Washington, D.C. June 1979.
- (3) U.S. Environmental Protection Agency, "Water Quality Standards Criteria Digest - A Compilation of State/Federal Criteria
 - Dissolved Solids (December 1979)
 - Dissolved Oxygen (December 1979)
 - Acidity-Alkalinity (pH) (December 1979)
 - Arsenic (July 1980)
 - Cadmium (July 1980)
 - Chromium (July 1980)
 - Mercury (July 1980)
 - Zinc (June 1980)
 - General Toxic Substances (July 1980)"
- (4) Federal Register, Vol. 46, No. 80, 23715, (April 27, 1981).
- (5) Groves, C.J., et al., "South Point Gasohol Project-A Water Assessment Study," Ohio Department of Natural Resources, for U.S. Water Resources Council, Contract No. WR20424491, Washington, D.C., May 1981.

14 Raw Water Treatment System

Raw water makeup for the plant is 83.1×10^6 gal/yr. The boiler feed water requirements are approximately 198×10^6 gal/yr.

14a Treatment Chemicals Input

The following water treatment chemicals would be required:

Lime: 792 tons/yr

Sodium chloride: 396 tons/yr

Sludge polymer: 7.9 tons/yr

14b Raw Water Makeup

Makeup requirements for the alcohol fermentation plant amount to approximately 83.1×10^6 gal/yr.

14c Combined Inputs from 2e and 5e

The total condensate return to the raw water treatment system is 488×10^3 tons/yr (115×10^6 gal/yr).

14d Liquid Effluents from Raw Water Treatment System

The condensate return from the process, primarily from the cooking and distillation sections, provide the boiler with part of its water requirements. (1) This effluent liquid stream is conditioned in a conventional boiler feedwater system prior to reuse. Depending on the nature of the treatment system, its size and the type of treatment chemicals employed, the wastewater stream will contain significant amounts of solids. For lack of information on the raw water treatment system, it is not possible to accurately quantify this stream. However, its impact on the wastewater influent stream will be small.

14e Boiler Feed Water

The output of the raw water treatment system provides the water feed to the boiler. This amounts to approximately 825×10^3 tons/yr (198×10^6 gal/yr).

References

- (1) Raphael Katzen Associates, "Grain Motor Fuel Alcohol Technical and Economic Assessment Study," U.S. Department of Energy, Report No. HCP/J6639-01, Washington, D.C., June 1979.

15 Cooling Tower

The cooling tower blowdown is 38×10^6 gal/yr. The evaporative and drift losses into the atmosphere are approximately 242×10^6 gal/yr for a total cooling tower water requirement of 280×10^6 gal/yr.

15a Makeup Requirement for Cooling Tower

The cooling tower system is designed to provide a 16,000 gpm circulation rate for a 30°F drop in temperature across the tower. The number of cycles of concentration that the tower feedwater would undergo as a result of evaporation to attain this temperature drop would be a function of its chemical composition and the type of chemical treatment used in the tower. Assuming seven cycles of concentration of the solids in the makeup water before the tower is blown down and diluted with fresh makeup water, the resulting makeup stream would be 3.7% of the recirculation rate. (1)

The makeup water requirement is actually composed of three types of losses from the cooling tower: 1) drift/windage, 2) evaporation, and 3) blowdown.

Windage or drift losses are fine droplets of water that are entrained in the circulating air and tower carry over. While these losses vary with the type of tower, they typically comprise 0.1 to 0.3 percent of the recirculation rate through the tower. For this particular application, an average windage loss of 0.2% of recirculation is assumed.

The blowdown and evaporation loss rates are very closely related to the cycles of concentration. This relationship is defined in the following formula.

$$\text{Cycles of Concentration} = \frac{\text{Evaporation Rate (E)} + \text{Blowdown Rate (B)}}{\text{Blowdown Rate (B)}}$$

At seven cycles of concentration, then this equation is:

$$7 = (E + B) + B$$

The makeup rate has been determined to be 3.7% and the windage loss rate is assumed to be 0.2%. Thus, since

$$\text{Makeup rate} = \text{Windage loss rate} + \text{Evaporation rate} + \text{Blowdown rate}$$
$$\text{then } 0.037 = 0.002 + E + B.$$

By solving for the two unknowns from the above two equations, the Evaporation Rate (E) and the Blowdown Rate (B) are determined to be 3% and 0.5% of the recirculation rates respectively.

Since the cooling system has an estimated recirculation of 16,000 gallons per minute (gpm), the losses are calculated as follows:

Windage Losses	=	(0.002) x (16,000 gpm)	=	32 gpm
Evaporative Losses	=	(0.03) x (16,000 gpm)	=	480 gpm
Blowdown Losses	=	(0.005) x (16,000 gpm)	=	80 gpm
Makeup Water Req't	=	(.037) x (16,000 gpm)	=	592 gpm

On an annual basis,

Makeup water requirement:

592 gal/min or 280×10^6 gal/yr

(15b) Evaporative and Windage Losses from Cooling Tower

On an annual basis, the total windage and evaporative losses correspond to 242×10^6 gal/yr.

(15c) Cooling Tower Blowdown

The annual blowdown loss from the cooling tower is estimated to be 38×10^6 gal/yr.

The composition of this stream varies widely depending on the makeup water source, the materials of construction used in the cooling water system and the condensates which are added to the system. It will generally contain significant amounts of solids with a very low BOD_5 loading.⁽²⁾

References

- (1) Betz, Betz Handbook of Industrial Water Conditioning, 7th ed., Betz Laboratories Inc., Trevese, PA, 1976.
- (2) Scarberry, P.M. and M.P. Papai, "Source Test and Evaluation Report: Alcohol Facility for Gasohol Production," Radian Corporation for U.S. Environmental Protection Agency, Cincinnati, Ohio, November 1979.

III. PHYSICAL REQUIREMENTS

Table 20 summarizes the land and water requirements for the base case ethanol plant. These requirements should not be construed as complete and final and are highly dependent on the inherent assumptions made while designing the plant, including process characteristics and geographical location of the plant.

Land

As mentioned earlier, the facility is a complete plant erected on a new site and will be located in Central Illinois, in the heart of the Corn Belt. The plant will purchase electric power as opposed to generating it. As presently envisioned, using an optimized plant layout, the facility will require approximately 38.5 acres. The purchased land for the plant, however, will be 50 acres in order to accommodate adjacent areas under plant control for possible future expansion.

The optimized plant layout assumes the following:

- There will be a free running river with a minimum flow rate of 75 ft³/sec that will be contiguous to the plant. This river would accept the effluent after secondary water treatment from the wastewater treatment facility also located on the site.
- The plant will contain the necessary alcohol manufacturing and long-term storage facilities.
- The facility will contain the necessary grain storage sites.
- The facility will include a site for the drying of stillage and, therefore, the production of DDGS and its storage.
- The plant will have its own coal-fired boiler. It also will have pollution control equipment capable of meeting environmental standards. A modest stockpile of coal will be maintained on the site.
- The plant will have a cooling tower facility on the site to allow for the internal recirculation of much of the cooling water required. A well field will be included to supply process water as well as makeup water for the boiler and cooling tower.
- Other support facilities, such as a fire protection system, laboratory, administration building, parking, railroad siding and truck access roads, also will be included.

Table 20. Water and Land Requirements -
50 x 10⁶ gpy Base Case⁽¹⁾

	<u>Annual</u>	<u>Per 10¹² Btu</u>
Water, gallons	413 x 10 ⁶	1.09 x 10 ⁸
Land, acres	50	13.2

The alcohol fermentation plant also produces solid waste in the form of coal ash from the boiler. Another source of solid waste is the rejects from the grain cleaning operation. These are removed and will require periodical disposal. Assuming a density of 50 lb/ft³⁽¹⁾ and a 30-foot depth, the land requirements for waste disposal can be calculated using the following equation:

$$\text{Land Requirements (acres/yr)} = \frac{0.34 \times \text{Solid Waste (tons/day)}}{\text{Disposal Site Depth (ft)}}$$

The alcohol fermentation plant generates 27.6 tons/day of solid wastes. For a 20-year plant lifetime, the land required for waste disposal is, therefore, approximately 7.0 acres. This does not include waste disposal needs of a coal preparation plant which can be very high.

Water

As shown in Table 20, the total fresh water requirements for the base case ethanol plant are 870 gallons per minute (gpm): 695 gpm for the process and 175 gpm for makeup. This represents 8.3 gallons of water/gallon of ethanol produced or 1.09 x 10⁸ gallons of water/10¹² Btu of output energy. Total aqueous discharge to the river is approximately 1.1 x 10⁶ gal/day (including boiler and cooling tower blowdown).

Process water is supplied by a well field located close to the plant. Three wells with capacities of 1800 gpm are required. Due to the low temperature of the well water, it also is used as a cooling medium for the fermentation section. In all other cases, cooling water is obtained from a two-cell cooling tower with makeup water to the towers supplied from the wells.

References

- (1) Raphael Katzen Associates, "Grain Motor Fuel Alcohol Technical and Economic Assessment Study." Report No. HCP/J6639-01, for U.S. Department of Energy, Washington, D.C., June 1979.
- (2) Wilson, William G., "Coal-Fired Power Plant (Eastern Coal) - Environmental Characterization Information Report," U.S. Department of Energy, Office of Environmental Assessments, Washington, D.C., DOE/EV-0072, June 1980.
- (3) U.S. Department of Agriculture, "Crop Production, 1980 Annual Summary," Washington, D.C., January 1981.

IV. PERSONNEL

Personnel requirements for the operation, supervision, and maintenance of an alcohol producing facility is dependent on many factors including plant size, the nature of feedstock, the type and arrangement of process equipment, the degree of instrumentation and control, and other unique design features of the plant. For the base case ethanol plant, the personnel requirements are listed in Table 21. The table includes a breakdown of manpower requirements by segments along with the support personnel required for the manufacturing facility. An estimated 159 persons will be employed in the plant. This translates to slightly more than 3 persons per million gallons per year of capacity. The plant has 13 operator positions which will be manned by 43 employees, 24 hours a day for seven days a week. The plant is scheduled to operate in four shifts for a complete and continuous operation.⁽¹⁾ Approximately 1,330 workers would be required to construct the base case ethanol plant.⁽²⁾

The manpower requirements mentioned above are "plant gate," and precludes auxiliary personnel required for raw materials handling and transportation as well as the distribution of ethanol and the process by-products to potential markets. It also does not include personnel required to support this facility, such as farming and coal mining. Some of these are highly dependent on the complexity of the operation, geographical location and other factors. However, through proper training programs, plant labor will be utilized on a year-round basis, ameliorating somewhat the seasonal employment problems in agricultural areas.⁽¹⁾

Table 21. Plant Personnel Requirements -
Base Case - 50 x 10⁶ gal/yr⁽¹⁾

Segment No.	Technicians		Operators		Laborers	
	Positions	Personnel	Positions	Personnel	Positions	Personnel
100			2	5	2	2
200			1	4	2	8
300	1/2	2	1	4	1	4
400	1/2	2	1	4	2	8
500	1/2	2	1	4	1	4
800	1/2	2	2	8	2	8
600, 1000			2	2	2	2
900, 1100-1500			3	12	3	12
Totals	2	8	13	43	15	54

ADDITIONAL PERSONNEL

PERSONNEL

Plant Manager	1
Asst. Plant Manager	1
Personnel Manager	1
General Operations Mgr.	1
Chemist	1
Engineers	3
Medical Doctor	1/2
Nurses	4
Safety Engineer	1
Secretaries	3
Accountant	1
Receptionist	1
Inventory Clerk	1
Guards	4
Maintenance	30

53-1/2

Total Persons Employed = 158-1/2

References

- (1) Raphael Katzen Associates, "Grain Motor Fuel Alcohol Technical and Economic Assessment Study," Report No. HCP/J6639-01, U.S. Department of Energy, Washington, D.C., June 1979.
- (2) Anderson, M. and C. Parisi, "American Jobs from Alcohol Fuel," Employment Research Associates, Lansing, MI, February 1981.

V. OCCUPATIONAL SAFETY AND HEALTH

Accidents, Fires and Explosions

There are many similarities between the distilling industry and an ethanol-for-fuel producing facility. The alcohol beverage industry is involved in the process of making high-proof, potable products from grains via fermentation followed by distillation with the resultant distilled spirits stored in barrels, tanks or vats for aging purposes. Besides the mode of storage, the other major difference between the two industries lies in the quality of the final product. In the distilling industry, the product is a beverage; government regulations and controls are particularly severe for an industry making a product for human consumption. There also is a high tax levied on the products of the distilled spirits industry. In contrast, Government regulations require that ethanol not meant for human consumption should be made nonpotable by the addition of certain specified chemicals (also called denaturants).

The Distilled Spirits Council of the United States, Inc., has developed data regarding fires and accidents that have occurred in the industry since the repeal of prohibition. These data are summarized in Table 22 for sections of a distilled spirits plant that are similar to and applicable to an ethanol-for-fuel facility. The table also includes a breakdown of incidents between the United States, Canada, France, and the United Kingdom. A total of 60 fires were identified in these countries between 1933 and 1979 with the United States leading the injuries category with 37 followed by the United Kingdom and Canada with 1 and 2 injuries respectively. The United Kingdom leads in the number of deaths followed by the United States and Canada.⁽¹⁾

These data fail to uncover a single example of a sprinkler-protected barrel whiskey warehouse that suffered a major fire loss, except for one which suffered a structural failure, explosion and fire. Fires in nonsprinklered warehouses, however, accounted for the bulk of occupational losses over the period. This is not a major consideration with fuel alcohol plants since both ethanol storage and load out will be carried out in bulk quantities. There have also been several still building fires. In contrast to warehouse, milling and drier building fires, most of the major still building losses have occurred in sprinklered buildings. This is due to the explosion potential in the distilling area that must be controlled by other means such as proper still

Table 22. Summary of Distilling Industry
Fire Losses, 1933 - 1979⁽¹⁾

<u>Equipment</u>	<u>Number of Incidents</u>	<u>Loss</u> <u>Injuries</u>	<u>Deaths</u>
Warehouse			
Sprinkled	7	6	0
Nonsprinkled	17	30	26
Still Building			
Sprinkled	12	0	7
Nonsprinkled	8	1	0
Mill and Grain Dryer Buildings			
Sprinkled	10	1	0
Nonsprinkled	<u>6</u>	<u>2</u>	<u>5</u>
Total	60	40	38
Countries			
United States	34	37	13
Canada	16	1	1
United Kingdom	9	2	24
France	1	0	0

controls, venting to the exterior of the building, and control of ignition sources, including proper electrical equipment.⁽¹⁾

Between 1960 and 1977, the average annual production of distilled spirits in the United States was approximately 273×10^6 gallons. During the same period, the Distilled Spirits Council of the United States reports that there were 20 accidents in that industry in the United States. These resulted in 6 injuries. No fatalities were reported during these accidents.

Based on reports submitted to the U.S. Department of Labor (DOL), the Bureau of Labor Statistics has compiled data on occupational injury for several industries. Since the ethanol-for-fuel industry is relatively new, no information is readily available for that industry. However, occupational injury incidence rates for several related industries have been listed in the DOL survey. These are summarized in Table 23. Ethanol also is an industrial organic chemical. Consequently, the alcohol fermentation plant can be considered as a manufacturing facility that produces an industrial chemical. The Department of Labor reports that in 1979, manufacturing industries which employ 20.3×10^6 workers suffered 1.10×10^3 fatalities. This corresponds to 5.41×10^{-3} deaths per 100 employees. Using this statistic and the 1979

Table 23. Summary of Occupational Injury Incidence Rates^(2,3)

<u>Industry</u>	Incidence Rates per 100 Full-Time Workers		
	<u>1977</u>	<u>1978</u>	<u>1979</u>
Flour and Other Grain Mill Products	15.0	15.0	15.9
Wines, Brandy and Brandy Spirits ^a	18.3	22.4	24.1
Distilled Liquor, Except Brandy ^a	15.7	15.8	17.3
Industrial Organic Chemicals	4.8	4.4	4.3

^aIncludes the bottling plant

DOL injury incidence rates for industrial organic chemical plants, the projected deaths and injuries for the base case ethanol plant can be calculated based on 159 personnel. These are summarized in Table 24.

Table 24. Projected Deaths and Injuries
Base Case - 50×10^6 gal/yr

	<u>Annual</u>	<u>Per 10^{12} Btu</u>
Deaths	8.60×10^{-3}	2.28×10^{-3}
Injuries	6.84	1.81

Noise

Several sources of noise are present in the plant. These include grain grinding equipment, air compressors and turbine drives. During operation, these sources may reach noise levels of 80-85 decibels (dB).⁽⁵⁾ To mitigate these potential noise hazards, the equipment will be housed in closed building structures with appropriate enclosures and sound baffling equipment to meet Occupational Safety and Health Administration (OSHA) requirements. Current OSHA regulations set the noise standard at 90 dB, which is the recommended maximum level to which an employee can be exposed for an 8-hour period. Higher noise levels are allowed for shorter periods of time. The alcohol fermentation plant will generally be within the current allowable standards. Therefore, the noise problem from the process is relatively modest.

Dust

Cereal grains are usually received by the plant at or below 15.5 percent moisture content. The unloading, conveying, cleaning, grinding and storing operations for grains create a dust condition which could be explosive. Small particles of dust will settle on beams, ledges, machinery, walls, and other surfaces. At rest, these dust particles are harmless and difficult to ignite. However, when these particles are agitated and ignited in air, the flame propagation may be so rapid that an explosion results. Self induced heating also can occur, resulting in spontaneous combustion. The handling of coal and distillers' dark grains in the alcohol fermentation plant also produces a dust cloud which could be hazardous.

Between 1900 and 1965, the National Fire Protection Association reports that there were 1173 dust explosions from various sources in the United States.⁽⁶⁾ In these explosions, 681 persons were killed and at least 1791 people were injured. In addition, property damage was extensive. Explosions of grain, flour, feed and cereal dusts have been the most frequent and if closely related starch dust explosions are included, over half the deaths (370 out of 681) were due to explosions involving dusts from grain processing. During the same period, 69 explosions involving coal dust particles were recorded. These explosions, which do not include explosions in coal mines, resulted in 31 deaths and 47 injuries. It is, therefore, clear that explosions involving finely divided particles can be very devastating.

All dust suspensions should be considered explosive. The hazard potential of a dust condition depends on particle size, dust concentration, turbulence, presence of impurities, oxygen concentration, uniformity of dispersion and the strength of the ignition source. The smaller the particle size, the easier the ignition. The damage potential of the explosion, however, is related to the maximum pressure and the rate of pressure rise. The higher the rate of pressure rise, the greater the severity of the explosion. A decrease in particle size increases the rate of pressure rise compounding the destructive effect of the explosion. A sharp, rapid detonation will, therefore, cause the most damage.^(1,6)

The upper explosion limits for various dusts have not been determined mainly due to experimental difficulties. For all practical purposes, it may not even exist. The lower explosion limits (LEL) for materials used in alcohol fermentation are listed in Table 25. The greatest potential for an explosion will occur at concentrations slightly above LEL.^(1,6)

Table 25. Lower Explosion Limits
For Certain Dusts⁽⁶⁾

	<u>Minimum Explosion Concentration, oz/ft³</u>
Corn	0.055
Wheat, untreated	0.065
Wheat, flour	0.050
Coal, Kentucky (Bimuminous)	0.050
Coal, Pennsylvania (Pittsburg)	0.055

The hazard of a dust explosion can be prevented in two ways^(1,7):

1. by preventing the formation of hazardous dust conditions,
2. by eliminating the source of ignition. These include overheated bearings, stray iron in the grain, friction from a slipping conveyor belt, faulty electrical equipment and static electricity.

Settled dust will not explode since it is not dispersed in air. However, it still has an explosion potential because it is capable of being dispersed quickly by various means such as a water spray or an air hose. Consequently, dust accumulations should be kept to a minimum via thorough cleaning operations.⁽¹⁾ The use of dust-tight equipment such as dust-tight access doors for conveyors and elevator heads would help reduce dust concentrations near an ignition source. Explosion-proof motors along with ignition-proof electrical equipment are preferred for safety.⁽⁸⁾ Exposures to dust explosions also can be minimized by creating an inert atmosphere in the dust area with carbon dioxide or nitrogen. The intent is to reduce the oxygen concentration below the ignition point which is approximately 13 percent for most dusts.⁽⁷⁾

Explosive venting is recommended for dusty areas such as the grinding, dry or pulverizing operations including dust collection. Also, there should be a minimum of ledges or other surfaces upon which dust can settle or accumulate.⁽¹⁾

A potential fire hazard also exists in an alcohol fermentation plant since dried grain is combustible. Although this hazard is not considered as serious as the handling of cereal grains, a buildup of DDGS on overheated surfaces can cause ignition. DDGS can ignite spontaneously if it is not dried adequately (approximately 9 percent moisture content).⁽¹⁾

Similar precautions must be exercised while handling coal.

Chemical Exposures

A major potential threat to worker health and safety arises from exposure to hazardous and corrosive chemicals used in the alcohol fermentation plant. The current technology for the final distillation step to produce anhydrous ethanol uses reagents that could present an occupational hazard under certain conditions. Due to the proprietary nature of the process, the DOE study selected for this ECIR does not identify the particular chemical used to dehydrate the ethanol-water mixture. However, the reagents commonly used include benzene and, to some extent, ethyl ether and cyclohexane. (9)

During denaturation, ethanol is mixed with certain approved chemicals to render it unfit for human consumption. Recently, the Bureau of Alcohol, Tobacco and Firearms (BATF) gave final approval to the use of unleaded gasoline as a denaturant for ethanol. The ruling requires that 2 gallons of unleaded gasoline should be added to every 100 gallons of ethyl alcohol of not less than 195 proof. The above method is referred to as CDA Formula No. 20 and the resultant alcohol is restricted to fuel use only. (10)

Both the dehydrating agents and the denaturant are toxic, and health problems may arise from accidents and improper handling. Storage facilities and the handling of these and other chemicals, including ethanol, will require that certain precautions be exercised with these materials during the process. Some of these chemicals also are flammable. When mixed with the proper concentration of air, their vapors present a significant explosion hazard which would require adequate control and care.

Table 26 summarizes the principal chemicals utilized in alcohol fermentation plants and Table 27 presents some information relating to flammability and toxicity properties of these chemicals.

Table 26. Chemicals Used in Fermentation Plants

<u>Purpose</u>	<u>Chemicals</u>
Dehydrating agent	Benzene Ethyl ether Cyclohexane
Denaturant	Gasoline (unleaded)
Flue gas scrubber sorbent	Ammonia
Distillation/fermentation by-product (vented)	Carbon Dioxide
Process water disinfectant	Chlorine
Cleaning agent	Sodium hydroxide
Fumigant	Various
Sterilizing agent	Iodine compound

Table 27. Properties of Chemicals Used in an Alcohol Plant

	Flash Point, °F	Ignition Temperature, °F	Flammable Limits, % By Volume		Threshold Limit Value ppm (mg/m ³)	OSHA Standards ppm (mg/m ³)
			Lower	Upper		
Ethanol	55	793	4.3	19.0	1000 (1900)	1000 (1900)
Benzene	12	1044	1.3	7.1	10 (30)	10 (30)
Ethyl Ether	-49	356	1.9	48.0	400 (1200)	400 (1200)
Cyclohexane	-4	500	1.3	8.0	300 (1050)	300 (1050)
Gasoline	~-50	430-500	1.4	7.6	*	*
Ammonia	(gas)	1204	16	25	25 (18)	50 (35)
Carbon Dioxide	N.A.	N.A.	N.A.	N.A.	5000 (9000)	5000 (9000)
Chlorine	N.A.	N.A.	N.A.	N.A.	1 (3)	1 (3)
Sodium Hydroxide	N.A.	N.A.	N.A.	N.A.	(2)	(2)
Iodine	N.A.	N.A.	N.A.	N.A.	0.1 (1)	0.1 (1)

*Depends on aromatic hydrocarbon content

N.A. - Not Applicable

References

- (1) Distilled Spirits Council of the United States, Inc., "Safe Practices Guide for the Distilled Spirits Industry," Washington, D.C., November 1973.
- (2) U.S. Bureau of Labor Statistics, "Occupational Injuries and Illnesses in the United States by Industry, 1978," Washington, D.C., August 1980 (U.S. Government Printing Office, Stock No. 1980 0-328-086/6523).
- (3) U.S. Bureau of Labor Statistics, "Occupational Injuries and Illnesses in 1979: Summary," Washington, D.C., April 1981.
- (4) U.S. Bureau of the Census, Statistical Abstract of the United States: 1978, 99th Edition, Washington, D.C., 1978.
- (5) Energy and Environmental Analysis, Inc., "Environmental Assessment of the U.S. Department of Energy's Interim Alcohol Fuels Production Goal of 60,000 Barrels of Ethanol Per Day," for U.S. Department of Energy, Washington, D.C., January 1981.
- (6) Tryon, George, H. and G.P. McKinnon, ed., Fire Protection Handbook Thirteenth ed., National Fire Protection Association, Boston, MA, 1969.
- (7) Broderick, H.M., ed., The Practical Brewer, Second ed., Masters Brewers Association of the Americas, Madison, Wisconsin, 1977.
- (8) The Aerospace Corporation, "Environmental Control Perspective for Ethanol Production from Biomass," Aerospace Report No. ATR-80 (7848-01)-1 for U.S. Department of Energy, Washington, D.C., August 1980.
- (9) Shreve, R.N., Chemical Process Industries, Third Edition, Mc-Graw-Hill Book Company, New York, New York, 1967.
- (10) Federal Register, 46, 9644, January 29, 1981.

APPENDIX A. REGULATORY CONSIDERATIONS

AIR EMISSIONS

Air emissions may be considered for two broad areas: fuel burning equipment and processing plant emissions. For the plant herein, the coal-fired plant will be subject to Federal New Source Performance Standards (NSPS) and Illinois state and local air quality regulations. Federal NSPS for coal-fired steam plants with heat inputs exceeding 250×10^6 Btu/hr are summarized below:

<u>Pollutant</u>	<u>Standard</u>
Particulates	0.10 lb/million Btu
Sulfur Dioxide	1.2 lb/million Btu
Nitrogen Oxides	0.70 lb/million Btu

Depending upon the exact location of the plant facility, other Federal air regulations may include prevention of significant deterioration (PSD) or nonattainment provisions. Currently, no NSPS exist for steam plants with capacities less than 250×10^6 Btu/hr heat input. However, EPA is developing standards for industrial fossil fuel boilers. An Advanced Notice of Proposed Rulemaking was issued on June 28, 1979, and the Final Rule is anticipated in December 1982. The regulations are expected to incorporate limits for NO_x , SO_2 , and particulates. In any case, industrial boilers are required to meet state and local regulations. EPA decided (as of September 1981) not to develop regulations specific to alcohol fuel plants.

The State of Illinois emission standards for particulates, SO_2 and NO_x from the coal fired power plant are identical to the Federal NSPS cited above. (1) Detailed State regulations applying to grain receiving, handling, and outloading are contained in Rule 203 (d)(8) - "Grain Handling and Grain - Drying Operations" and specify housekeeping measures, equipment design, and minimum particulate collector efficiencies for some ventilated areas. For a plant located outside major population area, this minimum efficiency is 90 percent by weight. Other State regulations apply to visual emissions (<20 percent opacity for fuel combustion; <30 percent opacity for other sources), fugitive particulate matter, organic material storage and odors.

WATER EFFLUENTS

Since the aqueous discharge from the plant is continuously discharged into navigable waters, it will require adherence to the water quality standards for the state in which the plant is located. The general water quality standards for the state of Illinois are shown below.

Water Quality Standards for Illinois⁽²⁾

<u>Parameter</u>	<u>Concentration</u>
Sulfates, mg/l	250
Chloride, mg/l	250
Total Dissolved Solids, mg/l	500
Dissolved Oxygen, mg/l	>5 at any time >6 during at least 16 hours of any 24-hour per- iod
pH	6.5 - 9.0
Arsenic, mg/l	1.0
Cadmium, mg/l	0.05
Chromium, Hexavalent, mg/l	0.05
Trivalent, mg/l	1.00
Mercury, mg/l	0.0005
Zinc, mg/l	1.0
General Toxic Substances	<10% of the 96- hour median threshold limit for native fish or other essential fish food organics

Presently, the EPA is in the process of evaluating the need for effluent guidelines for alcohol fuel plants.

Details on wastewater streams and effluent limitations are presented in

13

SOLID WASTE

The major solid waste stream from the plant is the combined bottom ash and fly ash generated by the coal-fired steam plant. At the present time, these wastes are not considered hazardous wastes under the EPA Resource Conservation and Recovery Act (RCRA) regulations. This designation is a temporary deferral and is in response to a desire by Congress to exempt these wastes from regula-

tion for a limited time pending completion of certain EPA studies. Thus, for the short term, these wastes are subject only to any state or local limitations regarding their disposal. However, they may eventually be subject to the EPA RCR regulations with their attendant, higher handling, storage and disposal costs.

The other solid waste streams include sludge from the wastewater treatment plant and debris from the incoming grain cleaning operation. The former is dewatered and fed to the boiler so any ash produced is mixed with the coal. The latter, consisting of stover, cobs, twigs, mold clumps, sand, stones, and oversize rejects, is simply landfilled. The amount of this waste is less than 1 percent by weight of the quantity of waste generated by the coal-fired power plant.

References

- (1) State of Illinois Pollution Control Board Rules and Regulations, Chapter 2: Air Pollution, August 1980.
- (2) U.S. Environmental Protection Agency, "Water Quality Standards Criteria Digest - A Compilation of State/Federal Criteria"
 - Dissolved Solids (December 1979)
 - Dissolved Oxygen (December 1979)
 - Acidity-Alkalinity (pH) (December 1979)
 - Arsenic (July 1980)
 - Cadmium (July 1980)
 - Chromium (July 1980)
 - Mercury (July 1980)
 - Zinc (June 1980)
 - General Toxic Substances (July 1980)"

APPENDIX B. COST INFORMATION

Investment Cost Summary

In the study for the Department of Energy, Raphael Katzen Associates performed a detailed cost analysis for the 50×10^6 gal/yr (base case) ethanol plant. The fixed capital investment required to build complete facilities for the base case alcohol plant is estimated at $\$83.7 \times 10^6$, first quarter 1983 basis. The investment includes all support facilities including land, pollution control devices and the production of Distillers' Dark Grains. Process steam is produced by a coal-fired boiler which includes flue gas desulfurization and coal handling equipment. Working capital is estimated at $\$10.0 \times 10^6$ for the first year of operation. The earliest start-up date is first quarter 1983, with a construction start date of first quarter 1981.

Table B-1 contains a breakdown of the investment estimate per section of the plant. The DOE study estimates the total capital required in equivalent last quarter 1978 dollars. For this ECIR, the investment figure has been inflated assuming a 50 percent capital investment in 1981 with the remaining in 1983 for an average capital investment cost in 1982. Plant cost indices were obtained from a recent issue of Chemical Engineering.⁽³⁾ An examination of the capital cost breakdown indicates that the Distillers' Dark Grain Recovery and Utilities Sections make up approximately 53 percent of the investment. A complete breakdown of the investment estimates along with cost factors and equipment specifications is available in the DOE report.

Figure B-1 shows the effect of inflation on the fixed capital investment required to build the base case ethanol plant. Plant cost estimates for 1978 through 1980 were calculated using actual plant cost index obtained from Chemical Engineering⁽³⁾, while the estimates for 1981 and 1982 were projected using a 9.5 percent inflation factor. These estimates represent the actual cost of designing, constructing and operating the alcohol plant in that particular year.

Annual Operating Cost

The annual operating cost for the base case ethanol plant is \$73.13 million or \$1.47/gal of alcohol produced (1983 basis). This cost includes straight-line depreciation over twenty years. The cost increases to \$77.32 million or \$1.55/gal for a 10-year plant life and 10-year depreciation.

Table B-1. Total Capital Investment
Base Case - 50 x 10⁶ gal/yr

<u>Segment No.</u>	<u>Identification</u>	<u>Cost, \$</u>	<u>Percent of Investment</u>
100	Receiving, Storage & Milling	3,010,000	3.96
200	Cooking and Saccharification	4,073,800	5.36
300	Fungal Amylase Production	5,028,100	6.61
400	Fermentation	6,051,800	7.96
500	Distillation	7,390,600	9.72
800	Dark Grain Recovery	18,777,900	24.69
600,1000	Alcohol Storage, Denaturing & By-Product Storage	6,356,500	8.35
900,1100-1500	Utilities	21,766,000	28.62
Other	Building, General Services and Land	3,597,400	4.73
		<hr/>	<hr/>
		76,052,100	100.0
	+ 10% Contingency	<u>7,605,000</u>	
	Total Plant Cost	\$83,657,000	
	Working Capital	<u>10,040,000</u>	
	Total Capital Investment	\$93,697,000	

Similar to the capital investment estimate, the DOE study includes an operating cost summary in last quarter 1978 dollars. These costs have been adjusted to first quarter 1983 dollars using plant and chemical cost indices obtained from Chemical Engineering. The operating cost summary for the first year of operation, 1983, is shown in Table B-2.

It is interesting to note that the operating cost is relatively insensitive to plant investment since the capital investment items (fixed charges) represent only a small percentage of the total cost. However, the major cost item is the purchase price of corn. For corn at \$3.52/bushel (first quarter 1981), equivalent to \$4.18/bushel in 1983, the feedstock alone costs \$1.37/gal of ethanol. At \$4.18/bushel, the feedstock represents \$1.63/gal of ethanol produced or approximately 80 percent of the total product cost. A \$0.50/bushel increase in corn grain prices (without a proportionate increase in prices for the Distillers' Dried Grain) would raise the ethanol cost by \$0.19/gal.

To obtain a 20 percent return on investment, using \$4.18/bushel of corn (1983 basis), would require an ethanol selling price of \$1.88/gal (Table B-3).

A-11-73

Figure B-1. Effect of Inflation on Total Fixed Investment Cost for the Base Case Ethanol Plant

Table B-2. Plant Operating Cost
Base Case - 50 x 10⁶ gal/yr

	1983 Cost	
	<u>\$/millions</u>	<u>\$/gal</u>
<u>Fixed Charges</u>		
Depreciation ^a	4.183	0.084
License Fees	0.045	0.001
Maintenance	2.866	0.057
Tax & Insurance	<u>1.432</u>	<u>0.029</u>
Subtotal	8.526	0.171
<u>Raw Materials</u>		
Yeast	0.542	0.011
NH ₃	0.623	0.013
Corn ^b	81.273	1.626
Coal ^c	2.800	0.056
Misc. Chemicals	<u>0.308</u>	<u>0.006</u>
Subtotal	85.546	1.712
<u>Utilities</u>		
Electric Power	2.815	0.056
Diesel Fuel	<u>0.021</u>	<u>0.001</u>
Subtotal	2.836	0.057
<u>Labor</u>		
Management	0.376	0.008
Supervisors/Operators	3.438	0.069
Office and Laborers	<u>1.884</u>	<u>0.038</u>
Subtotal	5.698	0.118
Total Product Cost	102.606	2.055
<u>By-Products</u>		
Dark Grains	(32.798)	(0.656)
Ammonium Sulfate	<u>(0.706)</u>	<u>(0.014)</u>
Subtotal	(33.504)	(0.670)
<u>Miscellaneous Expenses</u>		
SG&A ^d	4.034	.081
Total Operating Cost	73.136	1.466

^a Assumes a 20-year project life, straight-line depreciation

^b Chicago Market Price of Corn = \$3.52/bushel, 4/21/80

^c Contract Coal Price = \$28.56/ton

^d Sales, General Overhead and Administration

Table B-3. Projected Ethanol Production Costs
Base Case - 50 x 10⁶ gal/yr^a

	<u>\$ million</u>	<u>\$/gal</u>
Total Operating Costs	73.136	1.466
Interest Expense ^b	11.244	0.225
Taxes ^c	4.685	0.094
Return on Equity ^d	4.685	0.094
Ethanol Product Cost	93.750	1.879

^a Neglects the time value of money, investment tax credits, accelerated depreciation, etc.

^b Total Fixed Investment \$83,660,000
Working Capital 10,040,000
Total Capital Investment \$93,700,000
Assume Debt/Equity Ratio of 75/25 at 16% rate of interest.

^c Tax Rate of 50% of income before taxes. This is equivalent to return on equity.

^d 20% Return on Equity

References

- (1) Energy Use News, April 13, 1981.
- (2) Chemical Engineering, May 5, 1980.
- (3) Chemical Engineering, April 20, 1981.
- (4) Peters, Max S. and K.D. Timmerhaus, Plant Design and Economics for Chemical Engineers, Second Edition, McGraw-Hill Book Company, New York, N.Y., 1968.
- (5) Raphael Katzen Associates, "Grain Motor Fuel Alcohol Technical and Economic Assessment Study." U.S. Department of Energy, Report No. HCP/J6639-01, Washington, D.C., June 1979.

APPENDIX C. PLANT CAPACITY EXCURSIONS

With the exception of a recent announcement by a large corn wet miller to build a 200 million gallon/day plant, most commercial plants will be in the 10 to 100 million gallon/year size range. A DOE study on the 50 million gallon/year base case provides some cost estimates for excursions within the 10 to 100 million gallon/year range.⁽¹⁾ These excursions contemplate no changes in technology, and, except for the "building, general services and land" category, there is little change in the percent of total investment by segment of the plant.

The significant influences of the size excursions can be seen from the comparison of capital costs per annualized capacity and in-plant operating costs.

The capital costs for the three plants (10, 50, and 100 million gallons/year) were developed in the same manner as "Appendix B. Cost Information." The summary data are listed in Table C-1 and displayed in Figure C-1.

Table C-1. Total Plant Capital Cost for Various Plant Sizes

<u>Size</u> <u>(gal/yr)</u>	<u>Capital Cost</u> <u>(\$ million)</u>	<u>Cost/Annual Gal</u> <u>(\$/ann. gal)</u>
10 x 10 ⁶	36.4	3.64
50 x 10 ⁶ (base case)	83.7	1.67
100 x 10 ⁶	144.3	1.44

*Includes 10% contingency but not working capital

Plant operating costs other than depreciation also can be expected to vary with plant capacity. The plant operating costs presented in Table C-2 were developed in the same manner as "Appendix B. Cost Information" for the two cost excursions.

Most important in examining the range of plant sizes is the effect of plant size on the final price of the product. While a detailed comparative financial annalysis is beyond the scope of this report, some simplifying assumptions can be made that will provide approximate but comparative information based on a desired 20% return on investment. Such comparison is made

FIGURE C-1. CAPITAL COST VS. PLANT SIZE

Table C-2. Cost Parameters Vs. Plant Size

Size (gal/yr)	Capital Cost (\$ million)	Operating Cost (\$/annual gallon)
10 x 10 ⁶	20.5	2.05
50 x 10 ⁶ (base case)	73.1	1.47
100 x 10 ⁶	137	1.37

in Table C-3 using the same assumptions used in "Appendix B. Cost Information."
Figure C-2 graphically displays ethanol price as a function of plant size.

Table C-3. Ethanol Price Vs. Plant Size

	Plant Size					
	10x10 ⁶ gal/yr		50x10 ⁶ gal/yr		100x10 ⁶ gal/yr	
	\$ x 10 ⁶	\$/gal	\$ x 10 ⁶	\$/gal	\$ x 10 ⁶	\$/gal
Total Fixed Investment	36.4		83.7		144.3	
Working Capital	<u>3.2</u>		<u>10.0</u>		<u>18.3</u>	
Total Capital Investment	39.6		93.7		162.6	
Total Operating Costs	20.5	2.05	73.1	1.47	137	1.37
Interest Expense (16%)	4.76	0.476	11.2	0.225	19.5	0.195
Taxes (50% Operating Profit)	1.98	0.198	4.69	0.094	8.13	0.081
Net Profit (20% Return on Equity)	<u>1.98</u>	<u>0.198</u>	<u>4.69</u>	<u>0.094</u>	<u>8.13</u>	<u>0.081</u>
Ethanol Revenue & Price	29.2	2.92	93.7	1.88	173	1.73

FIGURE C-2. ETHANOL SALES PRICE VS. PLANT SIZE

In these times of high inflation, the relationship of the high cost of financing to sales price is not always fully appreciated. Table C-4 highlights how much of the price variance with plant size comes from actual operations versus how the operations are financed and taxed. Table C-4 is derived from Table C-3 via differentials from the base case. Table C-4 highlights several important elements and relationships that strongly influence the price at which ethyl alcohol can be sold. The following comparisons to the base case plant are evident from the tables.

Table C-4. Operations Vs. Financing
Differentials in Sales Price, \$/Gal

	10 million gal/yr	Plant Size 50 million gal/yr	100 million gal/yr
Operating Costs	\$ 0.58/gal	0	\$(0.10)* /gal
Financing and Taxes	0.46	0	(0.05)*
Total	\$ 1.04/gal	0	\$(0.15)* /gal

*Denotes negative differential.

1. Doubling the size of the plant from 50 to 100 million gal/yr lowers the price at which the alcohol can be sold by \$0.15 gallon or \$0.15/gallon + $\$1.88/\text{gallon} \times 100 = 8.0\%$ indicating that only minor reductions in price can be achieved by increasing plant size above 50 to 100 million gallons/year.
2. On the other hand, reducing the size of plant from 50 to 10 million gallons/year sharply increases sales price by \$1.04/gallon or \$1.04/gallon $\div \$1.88/\text{gallon} \times 100 = 55.3\%$ which would be a major sales deterrent.
3. Of the sharp increase in sales price from the smallest plant, 10 million gallons/year, compared to the base case, about one half (\$0.58/gallon) is due to plant operations and one half (\$0.46/gallon) is due to how the plant is financed (and taxed). High interest rates are therefore an important factor in the price at which ethyl alcohol could be sold and, consequently, in any consideration of constructing a plant.

References

- (1) Raphael Katzen Associates, "Grain Motor Fuel Alcohol Technical and Economic Assessment Study," U.S. Department of Energy, Report No. HCP/J6639-01, Washington, D.C., June 1979.

APPENDIX D. ALTERNATIVE FEEDSTOCKS AND BY-PRODUCTS

Corn was assumed as the feedstock for the Katzen study⁽¹⁾ because it is the most abundant starchy feedstock by far as shown in Table D-1.

Table D-1. 1980 Crop Acreage and Production

<u>Crop and Unit</u>	<u>Area Harvested 1000 Acres</u>	<u>Production(1,000)</u>
Corn for grain, bu	73,061	6,647,534
Sorghum for grain, bu	12,722	587,997
Oats, bu	8,646	457,593
Barley, bu	7,233	358,544
Wheat, bu	51,374	2,369,666
Rice, cwt	3,295	145,063
Rye, bu	664	16,265
Potatoes, cwt	1,155	301,006

With minimum plant modifications, grains other than corn could be accommodated. Conversely, grain alcohol plants designed specifically for a crop other than corn would be very similar to the Katzen plant. Tables D-2 and D-3 illustrate the similarities between various grains. Differences in process and output would relate mostly to changes in mass balances due to starch/non-starch ratio between grains.

The similarity of both grain feedstock and processing indicates that the environmental influences from all grain-to-alcohol plants of similar design will also be very similar.

Grain-to-alcohol plants of other designs are possible. With wheat, it would make economic sense to separate the vital gluten prior to fermentation for sale as a premium byproduct rather than include it in the DDGS. The largest producer of fuel ethyl alcohol, Archer-Daniels-Midland Co. (ADM) uses a "wet milling", front-end process from which the by-products are edible corn oil, 60% protein gluten meal and 21% protein gluten feed rather than DDGS. Without detailed information (similar to that of the Katzen study) on these processes, it is not possible to make environmental comparisons. Of interest in the Archer-Daniels-Midland program is the developmental work of the company on hydroponic greenhouses that could use waste heat and CO₂ from the alcohol plant to produce vegetables. CO₂ from an alcohol plant can be

Table D-2. Input-Output Relationships for Converting
Selected Raw Materials to Ethanol⁽³⁾

Item	Corn	Grain sorghum	Wheat
Input			
Unit	bu	bu	bu
Weight per unit (lb)	56	56	60
Moisture content(percent)	13	13	13
Output(yield)per unit in percent			
Ethanol	30.7	31.8	30.2
Distillers by-product	33.0	30.9	33.8
Carbon dioxide	29.3	30.3	28.8
Water	<u>7.0</u>	<u>7.0</u>	<u>7.2</u>
Total	100.0	100.0	100.0
Output(yield)per unit in weight (lbs)			
Ethanol	17.2	17.8	18.1
Distillers by-product(dry)	18.5	17.3	20.3
Carbon dioxide	16.4	17.0	17.3
Water	<u>3.9</u>	<u>3.9</u>	<u>4.3</u>
Total	56.0	56.0	60.0
Conversion rate, gallons ethanol per unit	2.6	2.7	2.74

Table D-3. Average Composition of Possible Feedstock
for Ethanol Production⁽³⁾

	<u>Carbohydrates</u>					
	Water	Protein	Fat	Fiber	N-free extract	Mineral matter
Corn, dent no. 3	16.5	8.9	3.8	2.0	67.5	1.3
Sorghum	11.0	10.9	3.0	2.3	70.7	2.1
Rice	12.2	9.1	2.0	1.1	74.5	1.1
Rye	10.5	12.6	1.7	2.4	70.9	1.9
Wheat, hard winter southern plains	10.6	13.5	1.8	2.8	69.2	2.1

recovered but the market for CO₂ is very localized. As a rule of thumb, the low market price of CO₂ does not justify shipping liquid CO₂ over 200 miles. With many alcohol plants in the corn belt, CO₂ may not be a worthwhile plant by-product.

Raw materials other than grain may have markedly different plant design. Sugar cane to alcohol plants are normally fired by the corn stock residue, called bagasse, that remains after juice extraction. Plants utilizing the emerging cellulose technologies are expected to burn residue, mostly lignins, also. Such plants can be expected to have significantly different environmental considerations from the Katzen plant.

References

- (1) Raphael Katzen Associates, "Grain Motor Fuel Alcohol Technical and Economic Assessment Study," U.S. Department of Energy, Report No. HCP/J6639-01, Washington, D.C., June 1979.
- (2) Crop Reporting Board, U.S. Department of Agriculture, "Crop Production - 1980 Annual Summary, GrPr 2-1 (81), Washington, D.C., January 14, 1981.
- (3) U.S. Department of Agriculture, "Small Scale Fuel Alcohol Production," Washington, D.C. 20250, March, 1980.

APPENDIX E. BIOMASS-TO-FUEL ETHYL ALCOHOL TECHNOLOGY

The purpose of this appendix is not to quantify environmental impacts or potential technological advances but rather to broadly outline the diversity of changing technologies, the extent to which they may change traditional processes, and the timing perspective.

When World War II ended, the price of oil was so attractively low that almost all industrial alcohol production was converted from fermentation process to synthetic process wherein ethylene was hydrated to ethyl alcohol. The beverage alcohol industry concentrated into a few firms and a consumer shift to the grain neutral-like gins and vodkas was provided for primarily from waste streams of large corn processing plants. These events were complementary in providing little or no incentive to initiate R & D activities relative to production of ethyl alcohol by fermentation for over thirty years. Recent political and international events have quickly revised this situation and there is now considerable R & D work, including a number of projects that may provide technological breakthroughs. Biomass-to-fuel ethyl alcohol technology thus should be considered to be in a state of technology transition. The Katzen study of a stand-alone ethyl alcohol plant is state-of-the-art which most would consider to be traditional.⁽¹⁾

As the fuel ethyl alcohol industry develops, however, a significant share of the output will come from plants that are incremental expansions of existing facilities. U.S. production of fuel-grade ethyl alcohol through at least 1982 will come primarily from one company, Archer-Daniels-Midland, who operate their alcohol plants in conjunction with their wet corn milling plants. Wet corn millers are expected to produce more than one billion gallons of ethanol annually by 1986, and the average capital cost per annual gallon of ethanol capacity will be about \$1.10 in 1981 dollars which is to 1/2 the capital cost of stand-alone new plants.⁽²⁾ Add-on plants can be expected to have approximately the same environmental considerations as stand-alone plants with similar technology since the technology does not change, only its economic organization.

It can be expected that where there are significant changes in technology, there also will be changes in environmental considerations. A brief review of a few of the potentially significant technology changes may give some in-

sight into the nature and extent of such changes and their potential environmental impacts.

1. Crop Improvements - Crops bred specifically for alcohol production may yield more gallons per acre with less fossil fuel energy intensity for farming and fertilizing. Sweet sorghum and Jerusalem artichokes are frequently cited as such crops. Breeding programs for future energy crops are, however, generally long term programs that are evolutionary rather than breakthroughs.

2. Cellulose as a Raw Material - There are two technologies currently receiving much attention for their potential in economically converting cellulose to glucose for alcohol fermentation. Since cellulose is the most abundant biomass resource on the earth, breakthroughs in these technologies will open up vast new resources that do not compete with food crops. The source of cellulose can be as diverse as trees, grasses, corn cobs and urban waste. At their current state of development, both processes are ready to undergo commercialization.

The enzymatic process uses a genetically improved fungus to hydrolyze the cellulose to glucose. Cellulose, however, exists in nature in a crystalline form and is locked in a lignin structure, which seriously impedes enzymatic hydrolysis. Front-end pretreatment is thus required to unlock the cellulose. This pretreatment can take several forms and considerable effort has been spent on developing efficient pretreatments. From an environmental viewpoint, a cellulose enzyme plant will be considerably different than a corn plant, particularly in the pretreatment and by-product areas.

The acid hydrolysis process uses a high pressure, short residence time extruder to disrupt the raw material structure and an acid to hydrolyze the exposed cellulose to glucose. The hydrolysis conditions of temperature, pressure, and acid are more severe than the enzymatic process but, otherwise, the plants are similar.

Environmental benefits will be substantial if either of these technologies can be applied to urban waste, particularly in the large cities where landfill space is rapidly disappearing.

3. Fermentation - Continuous fermentation has been targeted as a capital and operating cost improvement over the traditional batch fermentation process. While much developmental work has been in this field and one alcohol plant - Georgia-Pacific Corporation at Bellingham, WA - is operating, continuous

fermentation must still be classed as developmental. An even further compaction of fermentation space and equipment may be possible with biomass reactors that rely on a fixed matrix of yeast into which a sugar solution enters one end, is fermented as it flows through the matrix, and exits fully fermented. Neither continuous nor fixed fermentation are expected to have significant environmental impact.

4. Distillation Alternatives - A number of schemes have been proposed to avoid the energy intensive distillation step and the equally energy intensive dehydration step. Among the candidates for improving distillation are liquid-liquid extraction, liquid CO₂ extraction, and alcohol enrichment via ultra-filtration techniques. The dehydration function candidates are molecular sieves and the adsorption of water by starch or cellulose.

5. Water Management - Removal of water from the stillage is a significant problem in many respects: in terms of capital costs, operating costs, energy consumption, and wastewater treatment. Concentration of the stillage solids via ultrafiltration is a promising field and could be used in other plant processes as well, including concentrating alcohol prior to distillation.

Water management implies by-product management as well. A preservation method that would allow wet thick stillage to be kept for weeks would reduce the cost of this normally expensive step. Similarly, thin stillage might be used for fish ponds or other aquatic ecosystems. As pointed out in Appendix C (Raw Materials and By-Products), hydroponic greenhouses attached to alcohol plants can utilize waste streams of water, CO₂, and heat.

6. Genetic Engineering - Contemporary with the resurgence of R & D on alcohol production has been a spectacular rise of interest in genetic engineering. The possibilities and promise of genetic engineering in ethyl alcohol production are great. Crops with nitrogen fixing roots, improved yeast strains, micro-organisms that convert starch or cellulose directly to alcohol without the usual fermentation step, genetically improved crops, and yeast with greater tolerance toward high sugar and high alcohol fermentations are but a few. The promise of genetic engineering is in the long term rather than the near term.

7. Solar Topping Plants - A "topping" plant is a commercial scale facility that purchases low proof ethyl alcohol from farms for enrichment to commercial grade anhydrous fuel in a production/processing/distribution system similar to that of pasteurized milk. Powering the topping plant by solar

collectors and photovoltaics permits smaller and more dispersed plants compared to conventional coal-fired ethyl alcohol plants. The environmental impacts of a solar topping system are minimal because the plant is not coal-fired and most of the water and all of the organic residue remain on farm for animal feed and eventual recycle to the soil. Central solar topping plants will thus be technically sophisticated, highly automated, capital intensive but environmentally benign facilities.

The emerging technologies for fuel alcohol production can thus range from environmentally benign to those of unknown impact. Some may even prove environmentally beneficial, such as use of urban waste as a raw material and nitrogen fixing crops that contribute no nitrogen to field run-off.

References

- (1) Raphael Katzen Associates, "Grain Motor Fuel Alcohol Technical and Economic Assessment Study," U.S. Department of Energy, Report No. HCP/J6639-01, Washington, D.C., June 1979.
- (2) Alcohol Week, Vol. 2, No. 21, May 25, 1981. Inside Washington Publishers, P. O. Box 7167, Ben Franklin Station, Washington, D.C. 20044.

APPENDIX F. PHYSICAL REQUIREMENTS AND SOIL PARAMETERS ASSOCIATED WITH CULTIVATING AND HARVESTING AGRICULTURAL FEEDSTOCKS

Table F-1 summarizes the physical requirements and soil parameters associated with producing ethanol from several feedstocks. It provides data on the use of fertilizers and biocides (herbicides, insecticides and fungicides) for corn and other alternative ethanol-yielding crops along with the crop water and land requirements needed to support the base case (50×10^6 gal/yr) alcohol plant. The estimates in Table F-1 were developed from the U.S. Department of Agriculture (USDA) 1974 crop year data for the entire United States⁽¹⁾, the latest year for which such information is available.

The land requirements for the base case alcohol plant indicate that potatoes are the highest ethanol yielding crop (based on acreage) followed by corn and rice. In contrast, oats and rye require the maximum amount of acreage, approximately 5.5 times that required by potatoes.

Based on existing irrigation rates, corn demands a rate of approximately 13.9×10^9 gal/yr (42.7×10^3 acre-ft/yr). Only oats require a smaller amount of irrigation water (6.05×10^9 gal/yr); all the other crops identified in Table F-1 have higher total water requirements. Although this suggests that the water requirements for the crops are different, this demand would differ by region due to the type of soil, amount of rainfall, and other climatic variations.

Based on the 1974 fertilizer and biocide use data, the estimates indicate that potatoes would require the greatest amount of fertilizers. The biocide use for potatoes would also be very high, approximately 1.91×10^9 lbs/yr and second only to oats (2.32×10^9 lbs/yr). Grain sorghum, barley, oats and wheat also require fertilizer but to a lesser extent than corn. The mix of fertilizers consumed by the various crops also vary. While most crops consume large amounts of nitrogen-based fertilizers, the use of potash and phosphate fertilizers differ widely among the various crops. Corn, for example, consumes an equal amount of potash and phosphate fertilizers, while grain sorghum, barley, rice and wheat require a greater proportion of phosphate fertilizers compared to potash. The use of biocides for corn is lower than that for grain sorghum but higher than barley, oats and wheat. In addition, only potatoes

Table F-1. Physical Requirements and Soil Parameters Associated with Agricultural Production^(1,2,3,4,5)
Base Case: 50x10⁶ gal/yr

	Feedstock Requirements (annual)	Land, ^a acres	Irrigation, gal/yr	Fertilizers, lbs			Biocides, lbs			Erosion, tons/yr
				Nitrogen	Phosphate	Potash	Herbicides	Insecticides	Fungicides	
Corn	19.5x10 ⁶ bu	195x10 ³	13.9x10 ⁹	27.7x10 ⁶	15.0x10 ⁶	15.0x10 ⁶	448x10 ³	87.9x10 ³	---	314x10 ³
Grain Sorghum	22.5x10 ⁶ bu	410x10 ³	72.0x10 ⁹	35.2x10 ⁶	13.8x10 ⁶	4.38x10 ⁶	932x10 ³	175x10 ³	---	381x10 ³
Barley	26.3x10 ⁶ bu	526x10 ³	36.2x10 ⁹	24.5x10 ⁶	16.7x10 ⁶	3.32x10 ⁶	220x10 ³	---	---	137x10 ³
Oats	48.1x10 ⁶ bu	921x10 ³	6.05x10 ⁹	18.8x10 ⁶	18.5x10 ⁶	11.1x10 ⁶	150x10 ³	---	---	221x10 ³
Potatoes	2.18x10 ⁶ tons	164x10 ³	40.2x10 ⁹	52.4x10 ⁶	40.2x10 ⁶	30.3x10 ⁶	1.10x10 ⁶	485x10 ³	325x10 ³	NA
Rice	629x10 ³ tons	280x10 ³	199x10 ⁹	29.3x10 ⁶	21.7x10 ⁶	9.40x10 ⁶	1.34x10 ⁶	174x10 ³	803x10 ³	364x10 ³
Rye	22.7x10 ⁶ bu	895x10 ³	861x10 ⁶	30.3x10 ⁶	24.2x10 ⁶	21.9x10 ⁶	---	---	---	161x10 ³
Wheat	19.5x10 ⁶ bu	590x10 ³	13.8x10 ⁹	24.4x10 ⁶	16.4x10 ⁶	5.99x10 ⁶	159x10 ³	597x10 ³	---	124x10 ³

^aBased on the following average yields/acre over the last three years (1978, 1979, 1980): corn = 100 bu/ac; grain sorghum = 55 bu/ac; barley = 50 bu/ac; oats = 52.3 bu/ac; potatoes = 266 cwt/ac; rice = 4,495 lbs/ac; rye = 25.4 bu/ac; wheat = 33 bu/ac.

NA - data not available.

and rice require the large scale use of fungicides. No fungicides usage is reported for the other crops.

In terms of soil erosion, wheat, barley, and rye present the smallest soil erosion potential followed by corn, rice, and grain sorghum, in that order. The magnitude of soil erosion depends on the climatic variations within the United States and will also vary with the harvesting method employed. The environmental impacts of soil erosion have been addressed elsewhere^(5,6,7) and is beyond the scope of this document.

References

1. U.S. Department of Agriculture and Federal Energy Administration, "Energy and U.S. Agriculture: 1974 Data Base," Washington, D.C., September 1976 (GPO Stock No. 041-018-00128-0).
2. Crop Reporting Board, U.S. Department of Agriculture, "Crop Production - 1980 Annual Summary," GrPr 2-1 (81), Washington, D.C., January 14, 1981.
3. U.S. Department of Agriculture, "Small-Scale Fuel Alcohol Production," Washington, D.C., March 1980.
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5. Dock, J. S., et al., "Environmental Control Perspective for Ethanol Production from Biomass," The Aerospace Corporation, presented at the Energy from Biomass and Wastes V at Lake Buena Vista, FL, January 26-30, 1981.
6. Office of Technology Assessment, "Energy from Biological Processes, Volume II: Technical and Environmental Analyses," Congress of the United States, Washington, D.C., September 1980.
7. U.S. Department of Energy, "Alcohols from Biomass: State of Knowledge Survey of Environmental, Health and Safety Aspects" (Review Draft), Office of Environmental Programs, Washington, D.C., September 1981.

GLOSSARY

Alpha-amylase	an enzyme that acts specifically to accelerate the hydrolysis of starch to dextrins.
Amino acids	the naturally-occurring, nitrogen-containing building blocks of protein.
Anhydrous	a compound that does not contain water either absorbed on its surface or as water of crystallization.
Anhydrous ethanol	100 percent alcohol, neat alcohol, 200 proof alcohol.
Azeotrope	a solution of 2 or more liquids, the composition of which does not change upon distillation. For example, ethanol and water cannot be separated further than 191.2 proof because at this concentration, alcohol and water form an azeotrope and vaporize together; also known as a constant boiling mixture.
Back set (also called set back)	the liquid portion of the stillage that is recycled as part of the process liquid in mash preparation.
Batch fermentation	fermentation conducted from start to finish in a single vessel.
Beer	the fermented mash.
Bees' wings	pieces of corn husks similar in appearance to bees' wings.
Blowdown	water discharged from the boiler and cooling tower basin to control concentrations of salts and other impurities in the circulating steam and water respectively.
BOD 5	a measure of the amount of impurities by the amount of oxygen required to oxidize it by biochemical means.
COD	a measure of the amount of impurities by the amount of oxygen required to oxidize it by strong chemical oxidants.

Continuous fermentation	a steady-state fermentation system that operates without interruption; each stage of fermentation occurs in a separate section of the fermenter, and flow rates are set to correspond with required residence times.
Cooker	a tank or vessel designed to cook a liquid or extract or digest solids in suspension.
Cooling tower	a structure used to cool water by evaporation for use in the condensers.
Cooling tower drift	the portion of cooling water that becomes entrained in the moving airstreams of the cooling tower and is carried out of the tower in drop-let form.
DDGS	see Distillers Dried Grains with Solubles.
Dehydration	the removal of water from any substance.
Dextrins	high molecular weight sugars, intermediates obtained in the conversion of starch to fermentable sugar.
Denaturant	a substance added to ethanol to make it unfit for human consumption without impairing its usefulness for other purposes.
Distillation	the process of separating the components of a mixture by differences in boiling point.
Distillers' Dried Grains with Solubles (DDGS)	the product obtained after the removal of ethyl alcohol by distillation from the yeast fermentation of a grain or a grain mixture by condensing and drying at least 3/4 of the solids of the resultant whole stillage.
Enzymes	any of numerous complex proteins, produced by living cells, that catalyze specific biochemical reaction, e.g. alpha-amylase.
Fermentation	a microbiologically mediated transformation of organic substances, such as carbohydrates into useful products, generally accompanied by the evolution of a gas.
Fusel Oil	a clear, colorless, poisonous liquid mixture of alcohols obtained as a byproduct of grain fermentation; generally amyl, isoamyl, propyl, isopropyl, butyl, isobutyl alcohols and acetic and lactic acids.

Glucose	a monosaccharide; occurs free or combined and is the most common sugar; chemical formula $C_6H_{12}O_6$.
Hydrolysis	a chemical reaction of a substance with water that involves breaking of a bond and addition of water, e.g. starch reacting with water (in the presence of alpha-amylase) to form sugar (see saccharification).
Inoculum	a small amount of microorganism obtained from a pure culture which is used to start a new culture.
Mash	a mixture of grain and other ingredients with water.
Proof	a measurement of the alcohol concentration in an alcohol-water mixture, equal to twice the volume percentage of the alcohol, e.g. 80 volume percent alcohol equals 160 proof, 100 volume percent alcohol equals 200 proof.
Protein	any of a class of high molecular weight polymer compounds composed of a variety of amino acids joined by a peptide linkage.
Saccharification	the breaking of complex carbohydrates (starch) into simple sugars (hydrolysis).
Spent grains	the nonfermentable solids remaining after fermentation of a grain mash.
Starch	a carbohydrate polymer composed of glucose monomers linked together by a glycosidic bond and organized in repeating units; starch hydrolyzes to several forms of dextrin and glucose.
Stillage	the nonfermentable residue from the fermentation of a mash to produce alcohol.
Suspended Solids	a mixture of fine, nonsettling particles of any solid within a liquid or gas, the particles being the dispersed phase, while the suspending medium (e.g., water) is the continuous phase.
Yeast	single-cell microorganisms (fungi) that produce alcohol and CO_2 under anaerobic conditions and acetic acid and CO_2 under aerobic conditions; the microorganism that is capable of changing sugar to alcohol by fermentation.

ABBREVIATIONS & ACRONYMS

A	absorption factor
ADM	Archer Daniels Midland
BATF	Bureau of Alcohol, Tobacco and Firearms
biochemical oxygen demand
Btu	British thermal unit
bu	bushel
CDA	completely denatured alcohol
CH ₄	methane
CO ₂	carbon dioxide
COD	chemical oxygen demand
cwt	hundred weight
dB (A)	decibels (absolute)
DDGS	Distillers' Dried Grains with Solubles
DOE	Department of Energy
ECIR	Environmental Characterization Information Report
EPA	Environmental Protection Agency
ft ³	cubic feet
G	gas flow rate
gal	gallons
gal/hr	gallons per hour
gallons per minute
SPY	gallons per year
H ₂ O	water
hr	hour
l	liter
L	liquid flow rate

lb(s)	pound(s)
LEL	lower explosion limit
m ³	cubic meters
mg	milligram
mm Hg	millimeters of mercury (pressure units)
NSPS	New Source Performance Standards
OSHA	Occupational Safety and Health Administration
oz	ounce
p	vapor pressure
ppb	parts per billion
ppm	parts per million
PSD	Prevention of Significant Deterioration
RCRA	Resource Conservation and Recovery Act
SCFM	standard cubic feet per minute
SO ₂	sulfur dioxide
SS	suspended solids
TS	total solids
wt	weight
wt%	percent by weight
X	mole fraction of a component in liquid
Y	mole fraction of a component in gas
yr	year

Residential Wood Stoves

Environmental Characterization Information Report

September 1982

U.S. Department of Energy
Assistant Secretary for Environmental
Protection, Safety, and
Emergency Preparedness
Office of Environmental Analysis

CONTENTS

	<u>Page</u>
I. SUMMARY	A.12-2
II. PROCESS DESCRIPTION AND ENVIRONMENTAL POINTS OF INTEREST	A.12-6
1. Harvesting Emissions	A.12-9
2. Erosion.	A.12-10
3. Harvested Wood Supply.	A.12-11
4. Gasoline for Transporting Wood	A.12-13
5. Wood Transportation Vehicle Emissions.	A.12-15
6. Runoff from Wood Storage	A.12-17
7. Seasoned Wood Supply	A.12-18
8. Flue Gas Emissions	A.12-19
9. Indoor Air Pollutants.	A.12-23
10. Wood Ash	A.12-24
11. Heat Output to House	A.12-26
III. PHYSICAL REQUIRMENTS	A.12-29
IV. SAFETY AND HEALTH.	A.12-31
APPENDIX A: AIR EMISSIONS.	A.12-35
APPENDIX B: COST INFORMATION	A.12-38
GLOSSARY.	A.12-40
ACRONYMS AND ABBREVIATIONS.	A.12-42

I. SUMMARY

This Environmental Characterization Information Report (ECIR) for a Residential Wood Stove has been prepared from recent environmental and technical publications. The wood stove chosen is an airtight, baffled stove constructed of mild steel with a firebox lined with firebrick. The stove burns seasoned wood and provides approximately 50 percent of the home's space heating needs.

The process, operating parameters, resources needed, and the environmental residuals and products associated with the wood stove are presented in Table 1, Summary Sheet. Annual resource usage and pollutant discharges are shown in English and metric units assuming an annual capacity factor of 32 percent. In addition to annual quantities, the Summary Sheet gives quantities in terms of 10^{12} Btu of energy produced. These figures are provided to allow comparison between different energy processes and to facilitate application of the information in computer models.

The supporting information and calculation procedures for the data are given in Section II. Eleven environmental points of interest are discussed individually, giving a brief description of the pollutant, resource, or product involved and example calculations showing the derivation of quantities.

The remaining sections include information on physical requirements and safety and health. The appendices describe air emissions and cost information. In addition, a glossary and a list of acronyms and abbreviations are included.

TABLE 1. SUMMARY SHEET

RESIDENTIAL WOOD STOVE

ENERGY SYSTEM DESCRIPTION

Wood Stove for Residential Space Heating; Provides 24×10^6 Btu/yr of Heat To Meet Approximately 50 Percent of Annual Space Heating Needs of a Home in Tennessee; Welded Steel Construction With Firebrick Lined Firebox; Two Cords of Green Wood Seasoned for a Year to 20 Percent Moisture Content; Onsite Wood Storage and Ash Disposal; Free Wood Collected From Public Land.

FACILITY OPERATING PARAMETERS

Size:	3.28 ft ³ firebox
Annual Capacity Factor:	32% (2800 hr/yr)
Annual Energy Production:	24×10^6 Btu
Efficiency:	50%
Lifetime:	20 yr

PROCESS FLOW

RESOURCES USED

Code No.	Resource	Quantities Used			Remarks
		Reference Energy System Annual Levels*		Per 10 ¹² Btu Energy Produced	
		English Units	Metric Units		
	<u>Fuel</u>				
③	Harvested wood supply	12.4 × 10 ³ lb	5.62 × 10 ³ kg	517 × 10 ⁶ lb	50 percent moisture content
⑦	Seasoned wood supply	7.73 × 10 ³ lb	3.51 × 10 ³ kg	322 × 10 ⁶ lb	20 percent moisture content
④	Gasoline	22.5 gal	85.2 liters	938 × 10 ³ gal	
	<u>Land**</u>				
	Forest land	12.4 acres	5.02 ha	517 × 10 ³ acres	Public land
	Storage land	2.94 × 10 ⁻³ acres	1.19 × 10 ⁻³ ha	123 acres	Stove owner's land
	<u>Construction Materials**</u>				
	Steel	300 lb	136 kg	12.5 × 10 ⁶ lb	1/4 in. and 5/16 in. thickness
	Cast iron	22 lb	9.98 kg	917 × 10 ³ lb	Door
	Firebrick	78 lb	35.4 kg	3.25 × 10 ⁶ lb	Firebox liner
	<u>Water</u>	None			

*Based on assumed 2800 hr/yr at low firing rate.

**One-time acquisition; not an annual requirement.

TABLE 1. (Continued)

RESIDENTIAL WOOD STOVE

COSTS

<u>Facility Capital Cost</u>	<u>Reference Energy System</u>	<u>Per 10¹² Btu Energy Produced</u>	<u>Remarks</u>
	(1982 \$)		
Wood stove and accessories	\$960	\$40.0 × 10 ⁶	
Brick chimney	\$879	\$36.7 × 10 ⁶	

ENVIRONMENTAL RESIDUALS AND PRODUCTS

Quantities Released					
Reference Energy System Annual Levels*					
Code No.	Residual or Product	English Units	Metric Units	Per 10 ¹² Btu Energy Produced	Remarks
①	Harvesting Emissions	Not Determined			
⑤	Vehicle Emissions				
	Carbon monoxide	14.3 lb	6.49 kg	596 × 10 ³ lb	
	Nitrogen oxides	1.83 lb	0.830 kg	76.3 × 10 ³ lb	
	Hydrocarbons	1.35 lb	0.612 kg	56.3 × 10 ³ lb	
⑧	Flue Gas Emissions				
	Particulates	27.1 lb	12.3 kg	1.13 × 10 ⁶ lb	
	Condensable organics	30.9 lb	14.0 kg	1.29 × 10 ⁶ lb	
	Nitrogen oxides	4.64 lb	2.10 kg	193 × 10 ³ lb	
	Carbon monoxide	1.38 × 10 ³ lb	626 kg	57.5 × 10 ⁶ lb	
	Sulfur dioxide	1.55 lb	0.703 kg	64.6 × 10 ³ lb	
	Polycyclic organic matter	2.16 lb	0.980 kg	90.1 × 10 ³ lb	
⑨	Indoor Air Pollutants	Not Determined			
	Water Pollutants				
②	Erosion	930 lb	422 kg	38.8 × 10 ⁶ lb	Contributes to water pollution
⑥	Runoff from wood storage	965 gal	3.65 × 10 ³ liters	40.2 × 10 ⁶ gal	
	Solid Waste				
⑩	Wood ash	155 lb	70.3 kg	6.46 × 10 ⁶ lb	
	Product				
⑪	Heat	24 × 10 ⁶ Btu	25.3 × 10 ⁹ joules	1 × 10 ¹² Btu	

*Based on assumed 2800 hr/yr at low firing rate.

SAFETY AND HEALTH

	<u>Annual</u>		<u>Per 10¹² Btu Energy Produced</u>	
	<u>Injuries</u>	<u>Deaths</u>	<u>Injuries</u>	<u>Deaths</u>
Harvesting	4.06 × 10 ⁻³	25 × 10 ⁻⁶	169	1.04
Transportation	158 × 10 ⁻⁶	2.69 × 10 ⁻⁶	6.59	112 × 10 ⁻³
Fires	150 × 10 ⁻⁶	17.2 × 10 ⁻⁶	6.26	717 × 10 ⁻³
Burns	643 × 10 ⁻⁶	—	26.8	—

II. PROCESS DESCRIPTION AND ENVIRONMENTAL POINTS OF INTEREST

A baffled, air-tight, radiant heating, wood burning stove was selected for characterization. The stove is made of steel plate, lined with firebrick and is typical of many currently being manufactured. The stove is the key component in the residential wood combustion system shown in Figure 1. Figure 2 illustrates the stove which is approximately 34½ inches long, 33½ inches high and 18½ inches wide. It weighs about 400 pounds and has a firebox size of 24½ inches x 14 inches x 16½ inches. Combustion air enters through draft registers in the cast iron door; two registers provide primary air into the lower portion of the firebox and one provides secondary air from high in the door. The baffled construction is intended to improve combustion efficiency by causing combustion products to follow a longer "s"-shaped flow path in the stove and thus increase flue gas retention time. The stove efficiency is estimated to be 50 percent. This stove was selected for characterization largely because it is typical of many stoves and is one of the few on which significant emissions data are available.¹

The stove is utilized so as to provide approximately 50 percent of the space heating requirements of a typical 1500 ft² two story residence located in Nashville, Tennessee. A mix of well-seasoned wood types totalling two (2) cords/yr is used per heating season. The wood is assumed to have a moisture content of 50 percent when harvested and 20 percent after it has been seasoned for one year.

The significant environmental residuals are the air emissions discharged in the exiting flue gas. Eleven environmental points of interest are identified in Figure 1. Items ① through ⑦ deal with the wood fuel supply, ⑧ and ⑨ deal with air emissions, ⑩ addresses the wood ash solid waste, and ⑪ deals with the heat output to the house.

Cost information for the wood stove and harvesting equipment is provided in Appendix B.

Reference

1. DeAngelis, D. G., et al., "Preliminary Characterization of Emissions from Wood-Fired Residential Combustion Equipment," EPA-600/7-80-040, prepared for the U.S. EPA by Monsanto Research Corporation, Dayton, Ohio, March 1980.

**FIGURE 1. PROCESS FLOWCHART WITH ENVIRONMENTAL POINTS OF INTEREST
RESIDENTIAL WOOD STOVE**

Figure 2. Baffled Air-Tight Stove Showing Primary and Secondary Combustion Air Flow Pattern¹

1 Harvesting Emissions

Air emissions from harvesting wood have not been determined but are relatively minimal.

Emissions resulting from the harvesting of wood by the wood stove owner are primarily fugitive dust from roads and trails and emissions from a gasoline-powered chain saw. Fugitive dust emissions caused by the homeowner will be minimal due to the limited activity involved during several wood-gathering days of the year. In addition, such emissions are likely to settle within a few hundred feet of their source. No emission factors for gasoline-powered chain saws are available.¹ However, annual emissions would be insignificant since only several gallons of fuel are required to gather the required wood.

Reference

1. U.S. Environmental Protection Agency, "Compilation of Air Pollutant Emission Factors," AP-42, Supplement No. 4, January 1975.

2 Erosion

Erosion from the harvested forest is estimated to be 930 lb/yr.

Erosion rates of undisturbed forests generally are extremely small, often less than 75 pounds of soil per acre per year. Increased erosion caused by wood removal varies from negligible for light thinning to hundreds of tons per acre per year for poorly managed clearcut areas on steep slopes in high rainfall areas.¹ For recently harvested forests, a recent report suggests a loss of 7 or 8 tons of sediment per acre per year as a mean value. However, the variation around this mean is quite large.¹

For this characterization, the erosion rate for undisturbed forest land is assumed since the quantity of wood harvested to meet the requirements of the wood stove owner is relatively small. Therefore, the minimum erosion resulting from the harvesting of wood from 12.4 acres of forest land (see Section III-Physical Requirements - Land) is calculated as follows:

$$\begin{aligned}\text{Erosion} &= (\text{forest land harvested}) (\text{erosion rate}) \\ &= (12.4 \text{ acres}) (75 \text{ lb/acre/yr}) \\ &= 930 \text{ lb/yr}\end{aligned}$$

Reference

1. U.S. Office of Technology Assessment, "Energy from Biological Processes, Volume II - Technical and Environmental Analyses," Washington, D.C., September 1980.

3 Harvested Wood Supply

The annual amount of "green" wood obtained for the wood stove is estimated to be 12.4×10^3 lb.

Wood is assumed to be cut by the stove owner on public land. The wood is cut with a gasoline powered chain saw and various handsaws and is split with wedges and mauls. A wide mix of types of trees is used although there is a preference for hardwoods due to their higher heat value per cord and lesser tendency to deposit creosote in chimneys. Wood has a high moisture content (50 to 150 percent on an oven-dry basis or 33.3 to 60 percent on a wet wood basis) when first cut from live trees.¹ Therefore, the wood must be stored outside to "season" or dry for six to twelve months. Approximate weights and heating values per cord of various woods are given in Table 2.

The typical wood stove application considered in this characterization consumes an estimated 2 cords of wood per heating season. This quantity was estimated as the average amount of wood consumed in auxiliary wood stoves in Tennessee in 1976.³ By definition, a cord is defined as a carefully stacked pile of wood which is 4 feet high, 8 feet wide and 4 feet deep. The amount of solid wood in this 128 cubic foot pile is often estimated to be 90 cubic feet.

To compute the quantity of wood harvested, the average weight per cord of the wood listed in Table 2 is noted to be 3.51×10^3 lb/cord containing 12 percent moisture on a wet basis. Therefore, the weight of dry wood is computed as follows:

Table 2. Approximate Weights and Heat Values per Cord of Fuel Woods^{a2}

Variety of Wood	Weight per cord con- taining 90 ft ³ of solid wood, lb	High heat value per cord, million Btu
Ash, white	3,690	28.3
Beech	4,050	31.1
Birch, yellow	3,960	30.4
Chestnut	2,700	20.7
Cottonwood	2,520	19.4
Elm, white	3,150	24.2
Hickory	4,590	35.3
Maple, sugar	3,960	30.4
Maple, red	3,420	26.3
Oak, red	3,960	30.4
Oak, white	4,230	32.5
Pine, yellow	3,240	26.0
Pine, white	2,250	18.1
Walnut, black	3,420	26.3
Average	3,510	27.1

^aWood with 12 percent moisture content

Dry wood weight =

$$\begin{aligned} & (\text{wood weight @ 12\% moisture}) (1 - \text{moisture content}) \\ & = (3.51 \times 10^3 \text{ lb/cord}) (1.0 - 0.12) \\ & = 3.09 \times 10^3 \text{ lb/cord} \end{aligned}$$

Assuming the wood as harvested contains 50 percent moisture on a wet basis (or 100 percent on an oven-dry basis), the total wood harvested is calculated as follows:

Harvested wood =

$$\begin{aligned} & \frac{(\text{dry weight/cord}) (\text{number of cords})}{(1 - \text{moisture content})} \\ & = \frac{(3.09 \times 10^3 \text{ lb/cord}) (2 \text{ cords/yr})}{(1 - 0.50)} \\ & = 12.4 \times 10^3 \text{ lb/yr} \end{aligned}$$

In each case, the quantity of wood used is determined by a number of factors, principal among which is the time and effort the owner desires to spend cutting the wood and tending the stove. The amount of wood assumed for this characterization, 2 cords, represents a significant commitment of time and effort for cutting, splitting and transporting. Other important factors in determining wood usage include:

- stove efficiency
- residential heating load
- wood availability and cost
- mode of operation used by the owner (longer, low level fires vs. more frequent, intense fires)

Some of these factors are discussed in greater detail in item ⑪, Heat Output to House.

References

1. Shelton, J., The Woodburners Encyclopedia, Vermont Crossroads Press, Inc., Waitsfield, Vermont, December 1976.
2. Baumeister, T., Ed., Standard Handbook for Mechanical Engineers, McGraw-Hill Book Company, 1967.
3. DeAngelis, D. G., et al., "Source Assessment: Residential Combustion of Wood," EPA-600/2-80-042b, prepared by Monsanto Research Corporation for the U.S. Environmental Protection Agency, March 1980.

4 Gasoline for Transporting Wood

A light-duty truck will require 22.5 gallons of gasoline a year to transport the wood.

A typical 1/2 ton capacity truck is used to transport the wood from the source to the residence. The number of trips required to transport the annual wood requirement is calculated as follows:

$$\begin{aligned}\text{Annual vehicle trips} &= \\ &= (\text{annual wood requirement}) \div (\text{vehicle cargo capacity}) \\ &= (12.4 \times 10^3 \text{ lb/yr}) \div (1000 \text{ lb/trip}) \\ &= 12.4 \text{ trips/yr} \\ &\text{or approximately 12 trips/yr}\end{aligned}$$

A 1982 standard, gasoline-powered truck with a six-cylinder engine and 3-speed, automatic transmission is assumed to be used. It has an estimated gasoline consumption rating of 18 miles per gallon (mpg).¹ Assuming a reduction in fuel efficiency of 2 percent for each 100 pounds of cargo,² the fuel economy of the truck transporting 1000 pounds of wood is calculated as follows:

$$\begin{aligned}\text{Loaded vehicle fuel economy} &= (\text{rated fuel economy}) \\ &\times \left[1 - \frac{(\text{wood load}) (\text{percent mpg reduction})}{(100 \text{ lb})} \right] \\ &= (18 \text{ mpg}) \left[1 - \frac{(1000 \text{ lb}) (0.02)}{(100 \text{ lb})} \right] \\ &= 14.4 \text{ mpg}\end{aligned}$$

The wood source is assumed to be 15 miles from the stove owner's residence. Therefore, the annual gasoline requirement is calculated as follows:

Annual gasoline requirement =

$$\begin{aligned} & ((\text{trips/yr}) (\text{mileage to source}) \div (\text{empty vehicle fuel economy})) \\ & + ((\text{trips/yr}) (\text{mileage from source}) \div (\text{loaded vehicle fuel economy})) \\ & = ((12 \text{ trips/yr}) (15 \text{ miles/trip}) \div (18 \text{ miles/gal})) \\ & + ((12 \text{ trips/yr}) (15 \text{ miles/trip}) \div (14.4 \text{ miles/gal})) \\ & = 22.5 \text{ gal/yr} \end{aligned}$$

References

1. U.S. Department of Energy, "1982 Gas Mileage Guide, EPA Fuel Economy Estimates," DOE/CE-0019, First Edition, September 1981.
2. Reynolds Electrical & Engineering Co., Inc., "Driver Education Conservation Awareness Training," Las Vegas, Nevada, January 1980.

5 Wood Transportation Vehicle Emissions

Vehicle emissions from the transportation of a year's supply of wood are estimated to be:

Carbon Monoxide	14.3 lb/yr
Nitrogen Oxides	1.83 lb/yr
Hydrocarbons	1.35 lb/yr

As noted in item ④, Gasoline for Transporting Wood, approximately twelve (12) round-trips of 30 miles each would be required to transport a year's supply of wood for the wood stove. To compute the emissions from the gasoline-powered pickup truck transporting the wood, the Federal exhaust emissions standards for light-duty trucks (less than 8,500 pounds gross vehicle weight) are used.¹ These standards are:

Carbon Monoxide	18 g/mi
Oxides of Nitrogen	2.3 g/mi
Hydrocarbons	1.7 g/mi

In addition, the standards for gasoline-fueled vehicles prohibit all crankcase emissions and limit the loss of gasoline by evaporation from the carburetor and fuel tank to no more than 2.0 grams per test. However, actual evaporative emissions will be dependent on the number of cold and hot startups, "hot soak" periods, and other factors and are not quantified here. Therefore, the annual emissions are calculated as follows:

$$\text{CO, NO}_x, \text{HC} =$$

$$(\text{annual truck mileage}) (\text{emission factor}) (\text{lb/gm})$$

For the gasoline-powered pickup truck traveling 360 miles per year,

$$\text{CO} = (360 \text{ mi/yr}) (18 \text{ g/mi}) (2.205 \times 10^{-3} \text{ lb/gm})$$

$$= 14.3 \text{ lb/yr}$$

$$\text{NO}_x = (360 \text{ mi/yr}) (2.3 \text{ g/mi}) (2.205 \times 10^{-3} \text{ lb/gm})$$

$$= 1.83 \text{ lb/yr}$$

$$\text{HC} = (360 \text{ mi/yr}) (1.7 \text{ g/mi}) (2.205 \times 10^{-3} \text{ lb/gm})$$

$$= 1.35 \text{ lb/yr}$$

These are theoretical limits based on maximum Federal emission standards. Actual emissions will differ since newly certified vehicles will have emissions somewhat less than the maximum emission limits and in-service vehicle emissions generally deteriorate over time depending on vehicle use and maintenance. With respect to new vehicles, for example, the 1982 model year Federal Certification Test Results for gasoline-fueled, 2-wheel drive pickup trucks with 3-speed automatic transmissions and achieving 18 miles per gallon fuel economy indicated the following range of emissions:¹

Carbon Monoxide	2.7 - 13 g/mi
Oxides of Nitrogen	0.67 - 2.1 g/mi
Hydrocarbons	0.27 - 1.3 g/mi

References

1. U.S. Environmental Protection Agency, "Federal Certification Test Results for 1982 Model Year, Control of Air Pollution from New Motor Vehicles and New Motor Vehicle Engines," 1982.

6 Runoff from Wood Storage

The annual quantity of liquid runoff from one year's supply of wood stored on the wood stove owner's land is estimated to be 965 gal/yr.

The quantity of liquid runoff due to rainfall generally is a product of the relative quantity of precipitation at the site, the effective surface area covered by the wood storage pile, and a runoff coefficient which is dependent on the characteristics of the drainage area. In general, the runoff coefficient accounts for losses such as interception by vegetation or other covering, infiltration into permeable soils, retentions in surface depressions, and evaporation/transpiration during rainfall periods. Estimated values for runoff coefficients range from 0.95 for concrete surfaces to as low as 0.05 for flat, sandy soil lawns.¹ A medium value of 0.5 is used for this calculation.

For a typical site in eastern Tennessee, the annual rainfall is estimated to be 840×10^6 gallons per square mile.² Therefore, the annual liquid runoff from a wood pile of two cords is calculated as follows:

$$\begin{aligned} \text{Effluent} &= (\text{annual precipitation}) (\text{runoff coefficient}) \\ &\quad \times (\text{area of cord}) (\text{number of cords}) (\text{mi}^2/\text{ft}^2) \\ &= (840 \times 10^6 \text{ gal}/\text{mi}^2/\text{yr}) (0.5) \\ &\quad \times (4 \text{ ft} \times 8 \text{ ft}) (2 \text{ cords}/\text{yr}) (35.9 \times 10^{-9} \text{ mi}^2/\text{ft}^2) \\ &= 965 \text{ gal}/\text{yr} \end{aligned}$$

Little information is available on the quality of the runoff effluent, but it may have moderate to high biological oxygen demand (BOD) loading (100 mg/l to 1000 mg/l) resulting from organic compounds leached from the wood and an acidic leachate.³ One analysis of leachate from a wood chip stockpile indicated relatively high concentrations of COD, K, T-PO₄ (total phosphate), and kjel-N (total organic and ammonia nitrogen).⁴

References

1. Water Pollution Control Federation, "Design and Construction of Sanitary and Storm Sewers," Washington, D.C., 1969.
2. U.S. Department of Commerce, "Climatic Atlas of the United States," Washington, D.C., June 1968.
3. Braunstein, H. M., et al., Biomass Energy Systems and the Environment, Pergamon Press, Inc., New York, N. Y., 1981.
4. Yurczyk, Jr., J. A. and T. Al Austin, "Analysis of Leachates Produced from Biomass and Biomass Ash Residues," Department of Civil Engineering, Iowa State University, Ames, Iowa, November 1980.

7 Seasoned Wood Supply

The annual amount of seasoned wood supplied to the wood stove is estimated to be 7.73×10^3 lb.

As noted in item ③, Harvested Wood Supply, the weight of dry wood collected is 3.09×10^3 lb/cord. The wood is assumed to season or dry from an initial 50 percent moisture content on a wet basis (100 percent on an oven-dry basis) to 20 percent moisture content on a wet basis (25 percent on an oven-dry basis) while stored on the wood stove owner's property for one year. Therefore, the total wood feed to the stove is calculated as follows:

Seasoned wood supply =

$$\begin{aligned} & \frac{(\text{dry weight/cord}) (\text{number of cords})}{(1 - \text{moisture content})} \\ &= \frac{(3.09 \times 10^3 \text{ lb/cord}) (2 \text{ cords/yr})}{(1 - 0.20)} \\ &= 7.73 \times 10^3 \text{ lb/yr} \end{aligned}$$

To calculate the heating value of the seasoned wood supply, a heating value of 8.6×10^3 Btu/lb of dry wood is assumed.¹ Thus, the total available heat is calculated as follows:

Total heat available =

$$\begin{aligned} & (\text{dry weight/cord}) (\text{number of cords}) (\text{dry wood heat content}) \\ &= (3.09 \times 10^3 \text{ lb/cord}) (2 \text{ cords/yr}) (8.6 \times 10^3 \text{ Btu/lb}) \\ &= 53.1 \times 10^6 \text{ Btu/yr} \end{aligned}$$

As noted in item ⑪, Heat Output to House, not all of this energy is available for space heating. Some is necessary to vaporize the remaining 20 percent moisture in the seasoned wood and some is lost in the water formed during combustion.

Reference

1. Shelton, J., The Woodburners Encyclopedia, Vermont Crossroads Press, Inc., Waitsfield, Vermont, December 1976.

8 Flue Gas Emissions

Emissions that are part of the flue gas emitted to the ambient atmosphere are as follows:

Particulates	27.1 lb/yr
Condensable Organics	30.9 lb/yr
Nitrogen Oxides	4.64 lb/yr
Carbon Monoxide	1.38×10^5 lb/yr
Sulfur Oxides	1.55 lb/yr
Polycyclic Organic Matter	2.16 lb/yr

A number of significant empirical investigations have been conducted in recent years to characterize emissions from residential wood stoves. A summary of results from published studies is provided in Appendix A. For this characterization of an airtight, baffled wood stove, emission factors measured by Monsanto Research Corporation using hardwood and seasoned pine will be used. These factors are expressed as grams of pollutant emitted per kilogram of wood burned, or alternately, pound of pollutant emitted per 1000 pounds of wood burned.¹

Particulates

Tests on an airtight, baffled stove have resulted in measurements of filterable or "front-half catch" particulate emission rates of 2.5 to 3.9 g/kg with an average of 3.5 g/kg or 3.5 lb/1000 lb of wood burned.¹ The annual particulate discharge is calculated as follows:

Particulate matter =

(annual wood requirement) (particulate emission factor)

= $(7.73 \times 10^3 \text{ lb/yr}) (3.5 \text{ lb/1000 lb})$

= 27.1 lb/yr

Condensable Organics

The same tests noted earlier have indicated an average "back-half catch" condensable organic emission rate of 4.0 g/kg or 4.0 lb/1000 lb when burning hardwoods or seasoned pines. It is noted that values as high as 14.3 g/kg were measured when green pine was burned in the same stove. However, using the average emission rate, the annual emissions of condensable organics are calculated as follows:

Condensable organics =

(annual wood requirement) (condensable organics emission factor)

= $(7.73 \times 10^3 \text{ lb/yr}) (4.0 \text{ lb/1000 lb})$

= 30.9 lb/yr

Nitrogen Oxides

The results of tests for nitrogen oxide (NO_x) emissions for burning hardwoods and seasoned pine indicated emission rates ranging from 0.1 g/kg to 1.2 g/kg.¹ An average value of approximately 0.6 g/kg or 0.6 lb/1000 lb of wood is used to calculate the annual emission of NO_x from the wood stove.

Nitrogen oxides =

(annual wood requirement) (nitrogen oxide emission factor)

= $(7.73 \times 10^3 \text{ lb/yr}) (0.6 \text{ lb/1000 lb})$

= 4.64 lb/yr

A statistical analysis of the NO_x emission results of the Monsanto study indicated that the stage of the burning cycle had a negligible effect on NO_x emissions.

Carbon Monoxide

Carbon monoxide (CO) is a product of incomplete combustion and is a major pollutant emitted from wood stoves. Emission rates reported for burning hardwoods and seasoned pine ranged from 110 g/kg to 270 g/kg with an average rate of 178 g/kg or 178 lb/1000 lb of wood burned. Therefore, the annual CO emissions are calculated as follows:

Carbon monoxide =

(annual wood requirement) (carbon monoxide emission factor)

= $(7.73 \times 10^3 \text{ lb/yr}) (178 \text{ lb/1000 lb})$

= $1.38 \times 10^3 \text{ lb/yr}$

Formulation of CO is apparently sensitive to changing fuel bed conditions since high variability was found in emissions during a burn cycle. For example, during one combustion cycle, CO concentrations varied over an order of magnitude in 20 minutes.

Sulfur Oxides

The sulfur content of wood is very low, and as a result, the sulfur dioxide emissions are correspondingly low. Tests made on a similar, but non-barked, stove to that characterized indicated emission rates of 0.2 g/kg or 0.2 lb/1000 lb of wood burned. Therefore, the total annual SO₂ production is calculated as follows:

Sulfur oxides =

(annual wood requirement) (sulfur oxide emission factor)

= $(7.73 \times 10^3 \text{ lb/yr}) (0.2 \text{ lb/1000 lb})$

= 1.55 lb/yr

Polycyclic Organic Matter

Polycyclic organic matter (POMs), including benzo(a)pyrene, have been identified and quantified in several wood stove emission characterization investigations.^{1, 2, 3, 4} In the Monsanto study, an average emission rate of 0.28 g/kg or 0.28 lb/1000 lb. was measured when burning seasoned oak and seasoned pine. Therefore, the annual POM emission to the ambient air is calculated as follows:

Polycyclic organic matter =

(annual wood requirement) (POM emission factor)

= $(7.73 \times 10^3 \text{ lb/yr}) (0.28 \text{ lb/1000 lb})$

= 2.16 lb/yr

It should be noted that the above POM emission factor is considerably higher than ones found by others (see Appendix A).

References

1. DeAngelis, D. G., et al., "Preliminary Characterization of Emissions from Wood-Fired Residential Combustion Equipment," EPA-600/7-80-040, prepared for the U.S. EPA by Monsanto Research Corporation, Dayton, Ohio, March 1980.
2. Allen, M. and W. Cooke, "Control of Emissions from Residential Wood Burning by Combustion Modification," EPA-600/7-81-091, prepared for the U.S. EPA by Battelle Columbus Laboratories, Columbus, Ohio, May 1981.
3. Hubble, B. R. and J. B. L. Harkness, "Results of Laboratory Tests on Wood-Stove Emissions and Efficiency," Argonne National Laboratory, Chicago, Illinois. Presented at the Conference on Wood Combustion Environmental Assessment, New Orleans, Louisiana, February 21-24, 1981.
4. Hubble, B. R., et al., "Experimental Measurements of Emissions from Residential Wood-Burning Stoves," Argonne National Laboratory, Argonne Illinois. Presented at the 1981 International Conference on Residential Solid Fuels, Portland, Oregon, June 1-4, 1981.

9 Indoor Air Pollutants

Although studies indicate a correlation between the use of a wood stove and elevated indoor pollutant concentrations, emissions from wood stoves to the indoor ambient air have not been determined.

Several recent studies suggest that the use of wood stoves can contribute to indoor pollution levels of suspended particulates and carbon monoxide. Table 3 summarizes the results of two studies of respirable suspended particulate ($<3.5 \mu\text{m}$) concentrations involving homes with wood stoves. Results of another investigation of indoor and outdoor air quality indicated a correlation between elevated total suspended particulates, carbon monoxide, and benzo(a)-pyrene indoor concentrations for woodburning days compared to non-wood burning days.³ However, no studies have determined emission rates per se from wood stoves to the indoor air.

Table 3. Indoor-Outdoor Respirable Suspended Particulate Concentrations

Study	Woodstove in Home	No. of Days Sampled	Outdoor Concentration ^a ($\mu\text{g}/\text{m}^3$)	Indoor Concentration ^a ($\mu\text{g}/\text{m}^3$)
Spengler ¹	No	30	10.9 (2.4-18.3)	20.9 (7.6-72.4)
	Yes	30	12.5 (4.8-24.0)	27.5 (8.4-60.3)
Moschandreas, et al. ²	Yes	14	34.2 (22.6-57.6)	44.0 (14.3-72.5)
	No ^b	14	27.4 (13.9-53.7)	28.0 (23.9-31.6)

^aThe concentration range is in parentheses.

^bThis is the same residence as the entry directly above, except the woodstove is not in operation.

References

- Spengler, J. D. and C. Ju, "Room-to-Room Variations in Concentration of Respirable Particulates in Residences," Environmental Science & Technology, Vol. 15, No. 5, pp. 592-596, May 1981.
- Moschandreas, D. J., et al., "The Effects of Woodburning on the Indoor Residential Air Quality," Environment International, Vol. 4, pp. 463-468, 1980.
- Moschandreas, D. J., et al., "The Effects of Woodburning on Indoor Pollutant Concentrations," Paper No. 81-22.2, presented at the 1981 Air Pollution Control Association Annual Meeting, Philadelphia, Pennsylvania, June 21-26, 1981.

10 Wood Ash

The annual quantity of wood ash generated is estimated to be 155 lbs.

The ash composition of wood can range from 0.2 percent to 2.2 percent.¹ The exact quantity that remains in the stove as bottom ash is undetermined. In addition, bottom ash also may contain unburned organic matter. For this typical residential wood stove, 2 percent bottom ash by weight is assumed. The annual quantity of ash produced is calculated as follows:

Annual wood ash =

(annual wood requirement) (ash fraction of wood)

$$= (7.73 \times 10^3 \text{ lb/yr}) (0.02)$$

$$= 155 \text{ lb/yr}$$

To compute the annual volume of ash produced, a wood ash density of 40 lb/ft³ is assumed.² Therefore,

Ash volume = (ash weight) ÷ (wood ash density)

$$= (155 \text{ lb/yr}) \div (40 \text{ lb/ft}^3)$$

$$= 3.89 \text{ ft}^3/\text{yr}$$

This is disposed of on the stove owner's property, usually mixed with soil.

The composition of one typical wood ash is given in Table 4.

Table 4. Composition of Wood Ash²

<u>Element</u>	<u>Assumed Form</u>	<u>Percent</u>
Calcium	CaO	30-60
Potassium	K ₂ O	10-30
Sodium	Na ₂ O	2-15
Magnesium	MgO	5-10
Iron	Fe ₂ O ₃	1-2
Silicon	SiO ₂	2-7
Phosphorous	P ₂ O ₅	5-15
Sulfur	SO ₃	1-5

With respect to the degree of health hazard posed by wood ash, one study reported the results of tests to ascertain mutagenicity or toxicity of wood ash residues. No mutagenic activity (with the Ames test) was observed for the samples and they exhibited either low or no toxicity.³

References

1. DeAngelis, D. G., et al., "Source Assessment: Residential Combustion of Wood," EPA-600/2-80-042b, prepared for the U.S. Environmental Protection Agency by Monsanto Research Corporation, Dayton, Ohio, March 1980.
2. Shelton, J. and A. Shapiro, The Woodburners Encyclopedia, Vermont Crossroads Press, Inc., Box 333, Waitsfield, Vermont, December 1976.
3. DeAngelis, D. G., et al., "Preliminary Characterization of Emissions from Wood-Fired Residential Combustion Equipment," EPA-600/7-80-040, prepared for the U.S. Environmental Protection Agency by Monsanto Research Corporation, Dayton, Ohio, March 1980.

11 Heat Output to House

The annual heat output from the stove to the house is estimated to be 24.0×10^6 Btu/yr.

In order to calculate the heat that is actually usable for space heating, several factors are considered. Of primary importance is the stove efficiency. In addition, some of the energy in the wood is required to vaporize the remaining moisture in the seasoned wood, and the water formed during the combustion of the dry wood represents an energy loss. As calculated in item 7, Seasoned Wood Supply, the seasoned wood burned per year weighs 7.73×10^3 lb and has a moisture content of 20 percent. Assuming a heat of vaporization of 1060 Btu/lb,¹ the amount of energy required to evaporate the moisture is calculated as follows:

$$\begin{aligned} \text{Energy for evaporating wood moisture} &= \\ &= (\text{heat of vaporization}) (\text{annual wood requirement}) (\text{wood moisture content}) \\ &= (1060 \text{ Btu/lb}) (7.73 \times 10^3 \text{ lb/yr}) (0.20) \\ &= 1.64 \times 10^6 \text{ Btu/yr} \end{aligned}$$

When burned completely, each pound of moisture-free wood produces about 0.54 pounds of water vapor as a result of the combustion of hydrogen in the wood.² The lost energy value of this water vapor is calculated as follows:

$$\begin{aligned} \text{Energy content of water vapor} &= \\ &= (\text{water vapor produced}) (\text{heat of vaporization}) \\ &\times (\text{annual wood requirement}) (1 - \text{wood moisture content}) \\ &= (0.54 \text{ lb H}_2\text{O/lb wood}) (1060 \text{ Btu/lb H}_2\text{O}) \\ &\times (7.73 \times 10^3 \text{ lb wood/yr}) (1 - 0.20) \\ &= 3.54 \times 10^6 \text{ Btu/yr} \end{aligned}$$

Assuming a stove efficiency of 50 percent, based on the heat transfer properties of the stove and its appurtenances, the useful heat output of the stove is calculated as follows:

Heat output to house = (stove efficiency)

x (energy content of dry wood

- energy for evaporating wood moisture

- energy content of water vapor)

= (0.50) (53.1 x 10⁶ Btu/yr - 1.64 x 10⁶ Btu/yr

- 3.54 x 10⁶ Btu/yr)

= 24.0 x 10⁶ Btu/yr

In order to determine the relative contribution that the wood stove makes to the total annual home heating load, several assumptions must be made. It is assumed that the house has 1500 ft² of floor area and has a building load coefficient of 9 Btu per square foot per degree day. This value represents a typical two story house with 3.5 inches of glass fiber insulation in the walls, 6 inches of glass fiber insulation in the ceiling, single pane windows, and an air infiltration rate equivalent to one air change per hour. Using 3.58 x 10³ heating degree days for Nashville, Tennessee,³ the annual heating load of the house is calculated as follows:

Annual heating load =

(building load coefficient) (floor area)

x (annual degree days)

= (9 Btu/ft² - degree days) (1.5 x 10³ ft²)

x (3.58 x 10³ degree days/yr)

= 48.3 x 10⁶ Btu/yr

efore, the relative heating contribution of the wood stove is as follows:

Wood stove contribution =

$$\frac{(\text{heat output of wood stove})}{(\text{annual heating load})}$$

$$= \frac{24 \times 10^6 \text{ Btu/yr}}{48.3 \times 10^6 \text{ Btu/yr}}$$

$$= 0.50 \text{ or } 50\%$$

References

1. Perry, R. H., Ed., Chemical Engineers' Handbook, Mc-Graw-Hill Book Company, New York, N.Y., 1963.
2. Shelton, J., The Woodburners Encyclopedia, Vermont Crossroads Press, Waitsfield, Vermont, 1976.
3. American Society of Heating, Refrigerating, and Air-Conditioning Engineers, Inc., ASHRAE Handbook - 1981 Fundamentals, Atlanta, Georgia, 1981.

III. PHYSICAL REQUIREMENTS

The physical requirements for the typical residential wood stove include forest land for a sustained wood supply, residential land to store a minimum one year's supply of fuel wood, and construction materials for the wood stove. No water is required.

Land

The amount of forest land required to provide a sustained supply of wood depends on many factors. These include forest land availability and proximity, wood productivity, competition from other users, and sophistication of harvesting techniques. For this characterization, the wood stove owner is assumed to rely on forest residues and on thinning of the forest land for the stove owner's annual fuel wood supply. An average density of forest residue of 0.5 tons per acre per year has been estimated for Southern states for sustained harvesting.¹ Therefore, the amount of forest land required to provide an annual fuel wood supply of 12.4×10^3 lb/yr is calculated as follows:

$$\begin{aligned}\text{Forest land} &= \frac{(\text{annual wood supply})}{(\text{forest land productivity}) (\text{lb/ton})} \\ &= \frac{12.4 \times 10^3 \text{ lb/yr}}{(0.5 \text{ tons/acre/yr}) (2000 \text{ lb/ton})} \\ &= 12.4 \text{ acres}\end{aligned}$$

With respect to the wood stove owner's land requirements to store the wood supply, a minimum of one year's supply is needed. As the wood pile is depleted, the stove owner can replace the used wood so that at the end of the heating season, his supply has been restored and it can season prior to the next heating season. In practice, the owner is assumed to provide a two year supply in order to allow one pile to season for a full year while the other supplies the current heating season needs. Therefore, the on-site storage land requirement is calculated as follows:

$$\begin{aligned}\text{Wood storage land} &= \\ &(\text{area of cord}) (\text{cords/yr}) (\text{number of yrs}) (\text{acres/ft}^2) \\ &= (4 \text{ ft} \times 8 \text{ ft}) (2 \text{ cords/yr}) (2 \text{ yrs}) (23 \times 10^{-6} \text{ acres/ft}^2) \\ &= 2.94 \times 10^{-3} \text{ acres}\end{aligned}$$

Construction Materials

Quantities of construction materials have been estimated for the residential wood stove based on the general size of the baffled stove noted in Figure 2. Additional materials are required for the chimney, chimney connector, non-combustible floor and wall coverings, and wood stove accessories.

The stove is assumed to be constructed of 5/16-inch thick steel plate and has a cast iron, front-loading door. In addition, the firebox is lined with firebrick. Estimated construction materials are listed in Table 5.

Table 5. Wood Stove Construction Materials

<u>Material</u>	<u>Weight, lb</u>
Steel	300
Cast Iron	22
Firebrick	<u>78</u>
Total	400

References

1. DiNova, S. T., et al., "Preliminary Environmental Assessment of Biomass Conversion to Synthetic Fuels," EPA-600/7-78-204, prepared by Battelle Columbus Laboratories for the U.S. Environmental Protection Agency, October 1978.

IV. SAFETY AND HEALTH

A number of safety and health implications are associated with heating with wood. These include hazards of harvesting and transporting wood, fires from stoves, chimney connectors, and chimneys, burns, and indoor air pollution such as elevated particulate and carbon monoxide levels.

Harvesting

Occupational safety hazards of harvesting wood have been addressed in several recent reports.^{1,2} Death and injury rates for tree residue removal have been estimated to be 0.47 and 76.5 per 10¹² Btus of wood harvested, respectively.¹ Therefore the annual risk of gathering a year's supply of wood is calculated as follows:

Injuries =

$$\begin{aligned} & (\text{injury rate}) (\text{annual wood harvested}) \\ &= (76.5 \text{ injuries}/10^{12} \text{ Btu}) (53.1 \times 10^6 \text{ Btu/yr}) \\ &= 4.06 \times 10^{-3} \text{ injuries/yr} \end{aligned}$$

Deaths =

$$\begin{aligned} & (\text{death rate}) (\text{annual wood harvested}) \\ &= (0.47 \text{ deaths}/10^{12} \text{ Btu}) (53.1 \times 10^6 \text{ Btu/yr}) \\ &= 25 \times 10^{-6} \text{ deaths/yr} \end{aligned}$$

It should be noted that these values are based on occupational harvesting experience and not for the weekend wood cutter. In addition, they are for tree residue collection rather than for whole tree harvesting which has experienced lower rates.

Transportation

Risks of death and injuries from transporting a year's supply of wood is assumed to be equal to the average risks experienced by the general driving population. One study of accident rates in a Southern state estimated the rate of driver injury to be 0.44 per million vehicle miles traveled in a full-sized car.³ Applying this value to the total miles traveled to and from the wood harvesting site provides the following driver injury rate:

Driver injuries =

$$\begin{aligned} & (\text{injury rate}) (\text{vehicle miles traveled}) \\ &= (0.44 \text{ driver injuries}/10^6 \text{ miles}) (360 \text{ miles/yr}) \\ &= 158 \times 10^{-6} \text{ injuries/yr} \end{aligned}$$

Comparable driver death rates were not provided in the above cited study. However, an estimate can be made by adjusting the total (driver and non-driver) motor vehicle death rate of 0.035 per million vehicle miles traveled⁴ by the ratio of driver injuries (0.44/10⁶ miles)³ to total non-fatal injuries (2.06/10⁶ miles).⁴ Therefore, the estimated death rate is calculated as follows:

Driver deaths =

$$\begin{aligned} & (\text{driver death rate}) (\text{vehicle miles traveled}) \\ & \times \left[\frac{\text{driver injuries}}{\text{total motor vehicle injuries}} \right] \\ &= (0.035 \text{ deaths}/10^6 \text{ miles}) (360 \text{ miles/yr}) \\ & \times \left[\frac{0.44 \text{ driver injuries}}{2.06 \text{ total injuries}} \right] \\ &= 2.69 \times 10^{-6} \text{ deaths/yr} \end{aligned}$$

Residential Fire Losses

In 1980, an estimated 77,900 fires, 210 deaths and 1820 injuries were associated with residential solid fuel stoves, chimney connectors and chimneys.⁵ In order to estimate the injury and death risks associated with these systems, a total residential wood energy consumption value of 650×10^{12} Btu/yr is assumed.⁶ The annual death and injury rates thus are estimated to be 0.323/10¹² Btus and 2.82/10¹² Btus, respectively. Therefore, the annual deaths and injuries from residential fires are calculated as follows:

Fire injuries =

$$\begin{aligned} & (\text{fire injury rate}) (\text{annual wood consumption}) \\ & = (2.82 \text{ injuries}/10^{12} \text{ Btu}) (53.1 \times 10^6 \text{ Btu/yr}) \\ & = 150 \times 10^{-6} \text{ injuries/yr} \end{aligned}$$

Fire deaths =

$$\begin{aligned} & (\text{fire death rate}) (\text{annual wood consumption}) \\ & = (0.323 \text{ deaths}/10^{12} \text{ Btu}) (53.1 \times 10^6 \text{ Btu/yr}) \\ & = 17.2 \times 10^{-6} \text{ deaths/yr} \end{aligned}$$

Burns

Another hazard posed by residential wood stoves is injury resulting from accidentally contacting the hot surface of the stove or from falling against it. In 1980, an estimated 9800 persons were treated in hospital emergency rooms for injuries from solid fuel stoves.⁷ The majority of these injuries (approximately 80 percent) were non-fire related burns. Therefore the burn injury rate is estimated to be:

$$\begin{aligned} & (9800 \text{ injuries}) (0.8)/650 \times 10^{12} \text{ Btu/yr} \\ & = 12.1 \text{ burn injuries}/10^{12} \text{ Btu} \end{aligned}$$

The annual injuries resulting from burns are calculated as follows:

$$\begin{aligned} \text{Injuries} & = (\text{burn injury rate}) (\text{annual wood consumption}) \\ & = (12.1 \text{ injuries}/10^{12} \text{ Btu}) (53.1 \times 10^6 \text{ Btu/yr}) \\ & = 643 \times 10^{-6} \text{ injuries/yr} \end{aligned}$$

Indoor Air Pollution

As noted in item ⑨, Indoor Air Pollutants, wood stoves contribute to elevated levels of particulates and carbon monoxide in the home. Of these, carbon monoxide is of most immediate concern to the welfare of the inhabitants. However, data compiled by the Consumer Product Safety Commission indicate that this is probably not much of a problem since in 1977 only 2 CO deaths were reported from solid fuel stoves compared to 123 from gas heaters, and 118 from other heating equipment.⁸ Over the long-term, elevated levels

of particulates, particularly POMs, may represent a more significant health hazard. However, such risks have not been quantified.

References

1. Hopp, W. J., et al., "Technology Assessment of Solar Energy Systems: Availability and Impacts of Woody Biomass Utilization in the Pacific Northwest," PNL - 3933, prepared by the Pacific Northwest Laboratory for the U.S. Department of Energy, September 1981.
2. Petty, P. N. and W. J. Hopp, "Technology Assessment of Solar Energy Systems: Residential Use of Fuelwood in the Pacific Northwest," PNL - 3918, prepared by the Pacific Northwest Laboratory for the U.S. Department of Energy, August 1981.
3. Dutt, A. K., and D. Reinfurt, "Accident Involvement and Crash Injury Rates by Make, Model and Year of Car: A Follow-Up," prepared by the University of North Carolina for the U. S. Department of Transportation, June 1977.
4. Motor Vehicle Manufacturers Association of the United States, Inc., "MVMA Motor Vehicle Facts and Figures - 1982," Detroit, Michigan, 1982.
5. Harwood, B., U. S. Consumer Product Safety Commission, Washington, D. C., Personal Communication, December 1981.
6. Resource and Technology Management Corporation, "1975-1980 Actual Energy Contribution and Market Penetration by Sector," Alternative Energy Data Summary for the United States, Quarterly, Volume 1, Arlington, Virginia, 1981.
7. Harwood, B., "Coal and Wood Stove Label Rule," U.S. Consumer Product Safety Commission, Washington, D.C., March 1981.
8. Harwood, B. and P. Kluge, "Hazard Associated with the Use of Wood or Coal-Burning Stoves or Free-Standing Fireplaces," U. S. Consumer Product Safety Commission, Washington, D.C., February 1980.

APPENDIX A. AIR EMISSIONS

A number of significant empirical investigations have been conducted in recent years to characterize emissions from residential woodstoves. A summary of results from published studies is provided in Table A-1. No attempt has been made to develop a single composite emission factor from these values. This table is intended to give credence or priority to one study over another. Some variables between the studies include:

- study goals and objectives
- test/sampling methods employed
- woodburning appliance type(s)
- wood type, shape, and size
- burn rate and firebox temperature

For example, eleven wood types were involved among the studies and burn rates varied from 0.82 to 14.5 kg/hr. Some measurements were taken under steady-state burning conditions only, while others reflect complete cycles from start-up to burn-out. Although it is not possible to state that one or more of these studies is representative of "typical" residential operations, it is fair to speculate that residential stoves that do not incorporate thermal storage are operated at low burn rates to increase fuel efficiency and to maximize recharging intervals.

Characterizations of emissions from residential wood burning appliances have indicated the presence of significant amounts of particulates, both filterable and condensed organics, and carbon monoxide. Compared to conventional oil and gas residential units, emissions from wood-fired appliances can be two to three orders of magnitude higher when compared on a unit energy basis. The majority of particulates are of respirable size and the presence of a number of known carcinogens, such as benzo(a)pyrene, has been reported in many studies. It also appears that operating conditions which are most conducive to increased heating efficiency also promote the formation of increased particulate loadings. However, the amount of polycyclic organic matter (POM) generated may be less under these same conditions.

Table A-1. Summary of Recent Residential Wood Stove
Emission Characterization Studies^a

Study	Appliance Type ^b	Wood Type ^c	Burn Rate, kg/hr	Emission Factor, g/kg or lb/1000 lb						
				CO	Particulates ^d	Condensable Organics	Volatile Organics	Total Hydro- carbons	NO _x	POMs
ANL ⁽¹⁾	1-WS	sro	0.82-2.58	138-196	0.8-22.2	N.D.	N.D.	N.D.	N.D.	N.D.
ANL ⁽¹⁾	1-WS	sro	3.9 -7.7	55-148	0.5 - 2.3	N.D.	N.D.	N.D.	N.D.	N.D.
ANL ⁽²⁾	1-WS	sro	0.82-2.58	N.D.	N.D.	3.0-8.4	N.D.	N.D.	N.D.	0.004-0.04
ANL ⁽²⁾	1-WS	sro	3.9 -7.7	N.D.	N.D.	0.8-2.1	N.D.	N.D.	N.D.	0.008-0.03
Battelle ⁽³⁾	4-WS	o, gp, fb	2.6-14.5	33-400	N.D.	N.D.	N.D.	2-112	0.1-4.9	0.011-0.05
Butcher, et al. ⁽⁴⁾	2-WS	o, p	0.93-3.97	N.D.	1.3 - 24	N.D.	N.D.	N.D.	N.D.	N.D.
Butcher, et al. ⁽⁵⁾	1-WS	o, h	1.72-3.36	63-158	1.6 -6.4	N.D.	N.D.	N.D.	N.D.	N.D.
CARB ⁽⁶⁾	2-WS	o, p	1.2-5.3	4-147	7.6 - 45	N.D.	N.D.	0.25-16.5	1.6-7.3	N.D.
CCRL ⁽⁷⁾	4-WS	ssm	1.15-4.46	87-184	N.D.	N.D.	N.D.	20 - 43	N.D.	N.D.
Monsanto ⁽⁸⁾	2-WS	so, go, sp, gp	6.0 - 8.4	91-370	1.8 - 6.3	3.3-12.0	0.3-3.0	N.D.	0.2-0.8	0.19-0.37
Oregon DEQ ⁽⁹⁾	5-WS	df	1.5 - 4.5	N.D.	2.6 - 42.5	7.0-32.1	N.D.	N.D.	N.D.	N.D.

^a Adapted from Ref. 2 and References cited.

^b WS - wood stove

^c sro - seasoned red oak; o - oak; gp - green pine; fb - fir brands; p - pine; h-hemlock; ssm - seasoned sugar maple;
so - seasoned oak; go - green oak; sp - seasoned pine; gp - green pine; df - Douglas fir

^d "front-half" catch

N.D. - not determined

References

1. Hubble, B. R., and J. B. L. Harkness, "Results of Laboratory Tests on Wood-Stove Emissions and Efficiency," Argonne National Laboratory, Argonne, Illinois.*
2. Hubble, B. R., et al., "Experimental Measurements of Emissions from Residential Wood-Burning Stoves," Argonne National Laboratory, Argonne, Illinois.**
3. Allen, M. and W. Cooke, "Control of Emissions from Residential Wood Burning by Combustion Modification," EPA-600/7-81-091, prepared for the U.S. EPA by Battelle Columbus Laboratories, Columbus, Ohio, May 1981.
4. Butcher, S. and S. Edmund; "A Study of Wood Stove Particulate Emissions," Journal of the Air Pollution Control Association, Vol. 29, No. 7, pp. 724-728, August 1979.
5. Butcher, S. and M. Ellenbecker, "Particulate Emission Factors for Small Wood and Coal Stoves," Journal of the Air Pollution Control Association, Vol. 32, No. 4, pp. 380-384, April 1982.
6. Kosel, H., "Pollution and Fireplaces in California," California Air Resources Board, Sacramento, California.*
7. Hayden, A. C. S. and R. W. Braaten, "Performance of Domestic Wood-Fired Appliances," Canadian Combustion Research Laboratory, Ottawa, Canada.*
8. DeAngelis, D. G., et al., "Preliminary Characterization of Emissions from Wood-Fired Residential Combustion Equipment," EPA-600/7-80-040, prepared for the U.S. EPA by Monsanto Research Corporation, Dayton, Ohio, March 1980.
9. Kowalczyk, J. F., et al., "Particulate Emissions from New Low Emission Wood Stove Designs Measured by EPA Method V," Oregon Department of Environmental Quality, Portland, Oregon.**

* "Proceedings: Conference on Wood Combustion Environmental Assessment," sponsored by the U.S. Environmental Protection Agency and the Wood Heating Alliance, New Orleans, Louisiana, February 21-24, 1981.

** "Proceedings of the 1981 International Conference of Residential Solid Fuels," sponsored by the Oregon Graduate Research Center, et al., Portland, Oregon, June 1-4, 1981.

APPENDIX B. COST INFORMATION

The estimated acquisition costs of the wood stove, accessories, and harvesting equipment are listed in Table B-1. The total investment by the wood stove owner can vary considerably. For example, the owner who installs his own stove to an existing, adequate chimney will incur an additional cost for a few feet of stove pipe only (approximately \$4/ft for single-wall pipe). However, the owner who requires a new chimney system will incur a significant expense depending on the complexity of the installation (straight-up, thru-the-wall, off-set, mobile home, etc.) Estimated chimney construction costs for both a brick chimney and a prefabricated metal chimney are noted in Table B-2. In addition, the cost of having the stove installed by a professional is estimated to be \$340. Therefore, the total initial cost can vary from approximately \$960 for the owner installing the stove with an existing chimney to \$2180 for the owner requiring a new, brick chimney and having the stove installed by a professional.

Table B-1. Cost for Wood Stove, Accessories and Harvesting Equipment (1982 Dollars)^a

<u>Item</u>	<u>Cost, \$</u>
Wood Stove	500
Noncombustible Wall and Floor Panels	190
Maintenance Kit	20
Chain Saw (16" guide bar)	200
Maul, Wedge and Saw	<u>50</u>
TOTAL	960

^a Estimated from vendors' literature and consumer product catalogs

The annual cost to the owner is primarily a function of the availability of the wood. If the owner has access to a free and relatively close supply of wood and has adequate means of transporting the wood, the annual costs will be minimal. In this case, costs would be associated with:

- vehicle fuel
- chain saw fuel
- chain saw maintenance (e.g., chain replacement)

Table B-2. Chimney Construction Cost^a (1982 Dollars)¹

<u>Chimney Type</u>	<u>Unit Costs</u>	<u>Units</u>	<u>Total</u>
<u>Brick</u>			
16 in x 16 in standard brick with 8 in x 8 in flue	\$31/ft	24 ft	\$744
Foundation (concrete)	\$135/yd ³	1 yd ³	<u>135</u>
		Total	\$879
<u>Prefabricated Metal</u>			
(double wall, stainless steel, 8 in diameter)			
Chimney	\$25/ft	22 ft	\$550
Ceiling support	\$31/each	2	62
Insulated tee	\$86/each	1	86
Roof flashing	\$79/each	1	79
Round top	\$50/each	1	<u>50</u>
		Total	\$827

^aIncludes materials, labor, overhead and profit

- chimney cleaning
- stovepipe replacement
- firebrick replacement
- gasket replacement
- stove paint

The first four items constitute annual requirements and the latter four items may be incurred on an as-needed or as-desired basis.

Reference

1. Robert Snow Means Company, Inc., Repair and Remodeling Cost Data - 1982 Commercial and Residential, 3rd Annual Edition, Kingston, Mass., 1982.

GLOSSARY

Airtight stove	A stove whose primary source of air enters through air inlet(s) that can be controlled.
Ames test	Short term assay test to determine if a substance induces a mutagenic response.
Ash	Noncombustible residues of wood combustion that are collected and removed from the bottom of the stove.
Baffled stove	Stove equipped with a metal baffle plate located several inches above the burning wood to lengthen the gas-phase residence time.
Chimney connector	That portion of a stove's venting system between the stove and its chimney. Chimney connectors are usually made of single-walled metal.
Cord	A common measure of firewood equal to the amount of wood in a stacked pile of wood which is 4 feet high, 8 feet wide and 4 feet deep. The amount of solid wood in this 128 cubic foot pile is usually estimated to be approximately 90 cubic feet.
Creosote	Chimney deposits originating as condensed organic vapors.
Degree day	A unit based on temperature and time used in estimating fuel consumption and specifying nominal heating load of a building in winter. For any one day, when the mean temperature is less than 65°F, there are as many degree days as between the mean temperature for the day and 65°F.
Firebrick	Brick capable of withstanding high temperatures resulting from the combustion of fuel.
Flue gases	Gases generated from the combustion of the wood in the stove.
Green wood	Freshly cut wood from a live tree containing a high percentage of moisture.
Leachate	Liquid which has extracted and/or suspended constituents from a solid material.

Ovendry wood

Wood defined to have zero moisture content.

Polycyclic organic
matter

Organic molecules that contain two or more
bound closed rings of atoms.

Seasoned wood

Wood which has lost a significant amount of
its original moisture.

Sustained harvest

Sustained harvesting involves taking wood
from an area at a rate no larger than the
rate at which new wood is growing in the
area.

ACRONYMS AND ABBREVIATIONS

ANL	Argonne National Laboratory
BOD	biological oxygen demand
Btu	British thermal unit
CaO	calcium oxide
CARB	California Air Resources Board
CCRL	Canadian Combustion Research Laboratory
CO	carbon monoxide
COD	chemical oxygen demand
DEQ	Department of Environmental Quality, Oregon
df	Douglas fir
°F	degrees Fahrenheit
fb	fir brands
Fe ₂ O ₃	ferric oxide
ft	foot
ft ²	square foot
ft ³	cubic foot
g	gram
gal	gallon
go	green oak
gp	green pine
h	hemlock
ha	hectare
HC	hydrocarbons
hr	hour
H ₂ O	water
K	potassium
kg	kilogram
kjel-N	total organic and ammonia nitrogen
K ₂ O	potassium oxide
l	liter
lb	pound
m ³	cubic meter
mg	milligram
MgO	magnesium oxide
mi	mile
mi ²	square mile
mpg	miles per gallon
Na ₂ O	sodium oxide
N.D.	not determined
NO _x	nitrogen oxides

o	oak
p	pine
P ₂ O ₅	phosphorus pentoxide
POM	polycyclic organic matter
SiO ₂	silicon dioxide
so	seasoned oak
SO ₂	sulfur dioxide
S	sulfur trioxide
sp	seasoned pine
sro	seasoned red oak
ssm	seasoned sugar maple
T-PO ₄	total phosphate
yd ³	cubic yard
yr	year
μm	micrometer

Industrial Wood-Fired Boiler

Environmental Characterization Information Report

September 1982

**U.S. Department of Energy
Assistant Secretary for Environmental
Protection, Safety, and
Emergency Preparedness
Office of Environmental Analysis**

CONTENTS

	<u>Page</u>
I. SUMMARY	A.13-3
II. PROCESS DESCRIPTION AND ENVIRONMENTAL POINTS OF INTEREST.	A.13-6
1. Wood to Wood Storage.	A.13-6
2. Runoff from Onsite Wood Storage	A.13-10
3. Wood Feed to Steam Boiler	A.13-10
4. Combustion Air to Steam Boiler.	A.13-11
5. Bottom Ash from Steam Boiler.	A.13-13
6. Ash from Sand Classifier.	A.13-15
7. Fly Ash from Electrostatic Precipitator	A.13-18
8. Solid Waste Disposal.	A.13-21
9. Flue Gas.	A.13-23
10. Boiling Makeup Water.	A.13-28
11. Raw Water Treatment Chemicals	A.13-29
12. Boiler Blowdown	A.13-30
13. Water Treatment Facility Discharge.	A.13-31
III. PHYSICAL REQUIREMENTS.	A.13-33
IV. PERSONNEL	A.13-34
V. OCCUPATIONAL SAFETY AND HEALTH.	A.13-35
APPENDIX A: REGULATORY CONSIDERATIONS	A.13-36
APPENDIX B: BOILER MAKEUP WATER CALCULATION	A.13-37
APPENDIX C. COST INFORMATION.	A.13-41
GLOSSARY	A.13-43
ACRONYMS AND ABBREVIATIONS	A.13-45

I. SUMMARY

This Environmental Characterization Information Report (ECIR) for Industrial Wood-Fired Boilers has been prepared from recent environmental and technical publications. The typical boiler chosen is a spreader-stoker, water tube boiler rated at 150×10^6 Btu/hr heat input and supplies steam to an industrial process. It fires wood wastes at 50 percent moisture content and is equipped with mechanical collectors and an electrostatic precipitator for particulate control.

The process, boiler operating parameters, resources needed, and the environmental residuals and products associated with the boiler plant are presented in Table I, Summary Sheet. Annual resource usage and pollutant discharges are shown in English and metric units assuming an annual capacity factor of 60 percent. In addition to annual quantities, the Summary Sheet gives quantities in terms of 10^{12} Btu of energy produced. These figures are provided to allow comparison between different energy processes and to facilitate application of the information in computer models.

The supporting information and calculation procedures for the data are given in Section II. Thirteen environmental points of interest are discussed individually, giving a brief description of the pollutants or resources involved and example calculations showing the derivation of quantities.

The remaining sections include information on physical requirements, personnel, and occupational safety and health. The appendices describe regulatory considerations, makeup water calculations and cost information. Also included are a glossary and a list of acronyms and abbreviations.

TABLE 1. SUMMARY SHEET

INDUSTRIAL WOOD-FIRED BOILER

ENERGY SYSTEM DESCRIPTION

Wood-Fired Steam Boiler for Industrial Process; Spreader-Stoker, Water Tube Boiler Rated at 150×10^6 Btu/hr Heat Input; Provides 78.4×10^3 lb/hr Process Steam at 250 psig and 406°F With 70 Percent Condensate Return; Wood Fuel at 50 Percent Moisture Content; Mechanical Collectors Followed by Electrostatic Precipitator for Particulate Control; On-site Ash Disposal; and Onsite Water Treatment. New Boiler Meets Draft New Source Performance Standards for Non-fossil, Fuel-Fired Boilers for Particulates and Opacity.

FACILITY OPERATING PARAMETERS

Size: 150×10^6 Btu/hr heat input; 16.5 ton/hr wood feed rate

Annual Capacity Factor: 60%

Annual Energy Production: 0.495×10^{12} Btu

Efficiency: 65%

Lifetime: 30 yr

PROCESS FLOW

RESOURCES USED

Quantities Used					
Reference Energy System Annual Usage*					
Code No.	Resource	English Units	Metric Units	Per 10 ¹² Btu Energy Produced	Remarks
	<u>Fuel</u>				
①	Wood to wood storage	86.5 × 10 ³ tons	78.5 × 10 ³ tonnes	175 × 10 ³ tons	
③	Wood feed to boiler	86.5 × 10 ³ tons	78.5 × 10 ³ tonnes	175 × 10 ³ tons	
	<u>Air</u>				
④	Combustion air to boiler	429 × 10 ³ tons	389 × 10 ³ tons	867 × 10 ³ tons	
	<u>Water</u>				
⑩	Boiler makeup water	15.8 × 10 ⁶ gal	59.8 × 10 ⁶ litres	31.9 × 10 ⁶ gal	Assumes 70 percent condensate return
	Ash disposal water needs	854 × 10 ³ gal	3.23 × 10 ⁶ litres	1.73 × 10 ⁶ gal	
	<u>Land</u>				
	Boiler plant**	7.4 acres	3.0 ha	15 acres	
	Solid waste disposal	0.2 acres	81 × 10 ⁻³ ha	0.40 acres	
⑪	<u>Raw Materials</u>				
	Sodium chloride	13.9 tons	15.3 tons	28.1 tons	Other raw water treatment chemicals not determined
	<u>Construction Materials**</u>				
	Steel	150 tons	136 tonnes	303 tons	
	Refractory	140 tons	127 tonnes	283 tons	
	<u>Personnel</u>				
	Boiler plant	7 man-yr		14 man-yr	
	Construction (1.5 yr)	77 man-yr		156 man-yr	

*Based on assumed 60% capacity factor.

**One-time acquisition — not an annual requirement.

TABLE 1. (CONTINUED)

INDUSTRIAL WOOD-FIRED BOILER

COSTS

Facility	Reference Energy System	Per 10 ¹² Btu Energy Reduced	Remarks
	(1982 \$)		
Capital cost	\$9.15 × 10 ⁶ total	\$18.5 × 10 ⁶ total	
Annualized cost	\$3.16 × 10 ⁶ /yr	\$ 6.38 × 10 ⁶ /yr	
Air emission controls (capital)*	\$1.61 × 10 ⁶ total	\$ 3.25 × 10 ⁶ total	

*Included in above estimates for total capital costs.

ENVIRONMENTAL RESIDUALS AND PRODUCTS

		Quantities Used			
		Reference Energy System			
		Annual Levels*			
Code No.	Residual or Product	English Units	Metric Units	Per 10 ¹² Btu Energy Produced	Remarks
9	<u>Air Pollutants</u>				
	Particulates	39.4 tons	35.7 tonnes	79.6 tons	
	Oxides of nitrogen (NO _x)	80.4 tons	72.9 tonnes	162 tons	
	Carbon monoxide (CO)	644 tons	584 tonnes	1300 tons	
	Hydrocarbons (HC)	161 tons	146 tonnes	325 tons	
	Sulfur dioxide (SO ₂)	<34.6 tons	<31.4 tonnes	<70.0 tons	
	Polycyclic organic matter (POM)	<0.29 tons	<0.263 tonnes	<0.586 tons	
	<u>Water Pollutants</u>				
2	Wood storage runoff	Not Determined			
13	Water treatment discharge	1.22 × 10 ⁶ gal	4.62 × 10 ⁶ liters	2.46 × 10 ⁶ gal	
	<u>Solid Wastes</u>				
5	Bottom ash (dry)	585 tons	531 tonnes	1180 tons	
6	Classifier ash (dry)	848 tons	769 tonnes	1710 tons	
7	Electrostatic precipitator ash (dry)	344 tons	312 tonnes	695 tons	

*Based on assumed 60% capacity factor.

PRODUCTS

Quantities Used			
	Reference Energy System Annual Production		Per 10 ¹² Btu Energy Produced	Remarks
	English Units	Metric Units		
Primary Steam	206 × 10 ³ tons	187 × 10 ³ tonnes	416 × 10 ³ tons	Steam delivered to industrial process

OCCUPATIONAL SAFETY AND HEALTH

	Annual	Per 10 ¹² Btu Energy Produced	Remarks
Deaths	0-4.7 × 10 ⁻³	0-9.5 × 10 ⁻³	
Injuries	79 × 10 ⁻³ - 94 × 10 ⁻³	0.16 - 0.19	

II. PROCESS DESCRIPTION AND ENVIRONMENTAL POINTS OF INTEREST

The industrial wood-fired boiler is a spreader-stoker, water tube boiler rated at 150×10^6 Btu/hr heat input capacity (44MW). It provides 78.4×10^3 lb/hr process steam at 250 psig and 406°F assuming 70 percent condensate return and a boiler efficiency of 65 percent. The wood used in the analysis has a heating value of 4560 Btu/lb at 50 percent moisture and an ash content of 1.0 percent.

The significant environmental residuals are particulates discharged in the exiting flue gas and ash and noncombustible solid wastes generated by the boiler and air emission collection equipment. Particulate collection equipment includes mechanical collectors (80 percent collection efficiency) followed by an electrostatic precipitator (minimum 90 percent collection efficiency) and reduces emissions to less than 0.1 lb/ 10^6 Btu/hr heat input. Ash and noncombustible solid wastes are handled in a wet state and are landfilled onsite. Thirteen environmental points of interest are identified in Figure 1. Items ① through ③ deal with wood fuel supply, ④ addresses combustion air requirements, ⑤ through ⑧ deal with solid wastes, ⑨ deals with flue gas quantity and composition and ⑩ through ⑬ deal with water and chemical treatment requirements and wastewater treatment.

Cost information for the boiler plant is given in Appendix C.

Note: The Environmental Points of Interest labeled on this flowchart are discussed in further detail in Section II.

FIGURE 1. PROCESS FLOWCHART WITH ENVIRONMENTAL POINTS OF INTEREST
INDUSTRIAL WOOD-FIRED BOILER 60% CAPACITY FACTOR

1 Wood to Wood Storage

The amount of wood required for a 150×10^6 Btu/hr boiler operating at 60 percent capacity is 86.5×10^3 tons/yr.

The heating value of the hogged wood fuel is assumed to be 4560 Btu/lb as fired.¹ This low heating value results from the high moisture content (50 percent) of the fuel. A representative ultimate analysis is shown in Table 2.

Table 2. Ultimate Analysis of Wood Fuel As Fired¹

<u>Constituent</u>	<u>Percent (wt)</u>
Carbon	26.95
Hydrogen	2.85
Oxygen	19.10
Nitrogen	0.08
Sulfur	0.02
Water	50.00
Ash	1.00

The daily wood requirement to fire the 150×10^6 Btu/hr boiler is calculated as follows:

$$\begin{aligned}\text{Daily wood requirement} &= \frac{(\text{hourly heat input}) (\text{hr/day})}{(\text{wood heating value}) (\text{lb/ton})} \\ &= \frac{(150 \times 10^6 \text{ Btu/hr}) (24 \text{ hr/day})}{(4560 \text{ Btu/lb}) (2000 \text{ lb/ton})} \\ &= 395 \text{ tons/day}\end{aligned}$$

On a yearly basis,

$$\begin{aligned}\text{Yearly wood requirement} &= (\text{daily wood requirement}) (\text{capacity factor}) (\text{days/yr}) \\ &= (395 \text{ tons/day}) (0.60) (365 \text{ days/yr}) \\ &= 86.5 \times 10^3 \text{ tons/yr}\end{aligned}$$

Prior to storing, a sizing system is used to produce particles of a uniform size for facilitating additional handling and good combustion. Such a system is shown schematically in Figure 2. A hog, a machine for reducing the size of wood pieces, is used to reduce the oversized wood rejected by the screen. By placing the hog in the bypass, only oversized particles are run through it, thus minimizing the load on the hog. Other features of such a system may include iron and nonferrous metal removal schemes, depending on the source and quality of the delivered waste wood.

Figure 2. Sizing System for Wood Fuel²

References

1. Hall, E. H., et al., "Comparison of Fossil and Wood Fuels," EPA-600/2-76-056, prepared by Battelle Columbus Laboratories for the U.S. Environmental Protection Agency, March 1976.
2. Levi, M. P. and M. J. O'Grady, "Decisionmaker's Guide to Wood Fuel for Small Industrial Energy Users," SERI/TR-8234-1, prepared by North Carolina State University for the DOE Solar Energy Research Institute, February 1980.

② Runoff from Onsite Wood Storage

It is not possible to accurately quantify the liquid runoff from the wood storage area because the source of this liquid, primarily rainfall, varies.

The quantity of runoff is generally proportional to the surface area of the wood storage pile and the relative quantity of precipitation at the site.

Little information is available on the quality of the runoff effluent, but it is expected to have moderate to high biological oxygen demand (BOD) loading (100 mg/l to 1000 mg/l) resulting from organic compounds leached from the wood and an acidic leachate.¹ One analysis of leachate from a wood chip stockpile indicated relatively high concentrations of COD, K, T-PO₄ (total phosphate), and kjel-N (total organic and ammonia nitrogen).²

References

1. Braunstein, H. M., et al., Biomass Energy Systems and the Environment, Pergamon Press, Inc., New York, N. Y., 1981.
2. Yurczyk, Jr., J. A. and T. Al Austin, "Analysis of Leachates Produced from Biomass and Biomass Ash Residues," Department of Civil Engineering, Iowa State University, Ames, Iowa, November 1980.

③ Wood Feed to Steam Boiler

The amount of wood required for a 150×10^6 Btu/hr steam boiler operating at 60 percent capacity is 86.5×10^3 tons/yr.

The annual wood requirement to operate the steam boiler was calculated in item ①, Wood to Wood Storage, to be 86.5×10^3 tons.

4 Combustion Air to Steam Boiler

The quantity of combustion air required is 429×10^3 tons/yr.

The combustion air requirements can be calculated in a straightforward manner if complete combustion is assumed. The calculation is as follows:

Ultimate Analysis, lb/lb Fuel As Fired ¹		Combustion Constant ²		Dry Air Required, lb/lb Fuel @ 100% Total Air	
C	0.2695	x	11.53	=	3.107
H ₂	0.0285	x	34.34	=	0.979
O ₂	0.191				
N ₂	0.0008				
S	0.0002	x	4.29	=	0.0009
H ₂ O	0.500				
Ash	0.010				
Sum	1.0000				<u>4.087</u>
Less air equivalent of O ₂ in fuel					<u>0.825</u>
Required air (@ 100% total air)					3.262

To sustain combustion of the wood fuel, excess air is assumed to be 50 percent. A portion of the combustion air is injected through the grate to drive off the volatiles and burn the char, while the remainder is fed into the boiler above the grate to complete combustion.³ The total dry air requirement is calculated to be:

Dry air required @ 150 percent excess air

$$= (\text{dry air required}) (\text{percent excess air}/100)$$

$$= (3.26 \text{ lb/lb fuel fired}) (1.5)$$

$$= 4.89 \text{ lb/lb fuel fired or}$$

$$4.89 \text{ ton/ton fuel fired}$$

The amount of moisture in the combustion air is assumed to be 0.013 lb per lb of dry air. This is used as the standard in the boiler industry and corresponds to 80°F and 60 percent relative humidity conditions.² The quantity of corresponding air required is:

Combustion air

$$\begin{aligned} &= (\text{tons of dry air/ton fuel fired}) (1 + \text{moisture fraction}) \\ &\times (\text{tons fuel fired}) \\ &= (4.89 \text{ tons/ton fuel fired}) (1 + 0.013) (395 \text{ tons/day}) \\ &= 1.96 \times 10^3 \text{ tons/day} \end{aligned}$$

On a yearly basis

$$\begin{aligned} \text{Combustion air} &= (\text{daily combustion air}) (\text{capacity factor}) (\text{days/yr}) \\ &= (1.96 \times 10^3 \text{ tons/day}) (0.60) (365 \text{ days/yr}) \\ &= 429 \times 10^3 \text{ tons/yr} \end{aligned}$$

References

1. Hall, E. H., et al., "Comparison of Fossil and Wood Fuels," EPA-600-2-76-056, prepared by Battelle Columbus Laboratories for the U.S. Environmental Protection Agency, March 1976.
2. Steam, Its Generation and Use, 39th Edition, Babcock & Wilcox Company, New York, N. Y., 1978.
3. U.S. Environmental Protection Agency, "Nonfossil Fuel Fired Industrial Boilers - Background Information, Draft EIS," EPA-450/3-82-007, Office of Air Quality Planning and Standards, Research Triangle Park, N. C., March 1982.

5 Bottom Ash from Steam Boiler

The amount of bottom ash generated is 585 tons/year.

bottom ash from the steam boiler is assumed to be composed of 60 percent of fuel ash input and 5 percent of the unburned combustibles. The mass rate of unburned combustibles is assumed to be 1.5 percent of the wood feed rate and is mostly carbon.¹ Therefore, the bottom ash is calculated as follows:

$$\begin{aligned}\text{Bottom ash} &= [(\text{ash fraction in wood}) (\text{wood feed rate}) \\ &\quad \times (\text{bottom ash fraction})] \\ &+ [(\text{unburned combustibles in wood}) (\text{wood feed rate}) \\ &\quad \times (\text{unburned combustibles fraction})] \\ &= [(0.01) (395 \text{ tons/day}) (0.60)] \\ &+ [(0.015) (395 \text{ tons/day}) (0.05)] \\ &= 2.67 \text{ tons/day}\end{aligned}$$

On an annual basis,

$$\begin{aligned}\text{Bottom ash} &= [(\text{daily bottom ash rate}) (\text{capacity factor}) \\ &\quad \times (\text{days/yr})] \\ &= (2.67 \text{ tons/day}) (0.60) (365 \text{ days/yr}) \\ &= 585 \text{ tons/yr}\end{aligned}$$

In a recent study of industrial wood-fired boilers, bottom ash samples were analyzed for trace elements.² The results are noted in Table 3.

Table 3. Bottom Ash Trace Elements²

<u>Trace Element</u>	<u>Concentration (ppm)</u>
Al	11,270
As	10
Ba	1,640
Be	< 1
Ca	119,000
Cd	< 1
Co	17
Cr	2,300
Cu	129
Fe	32,670
K	28,530
Li	6
Mn	9,230
Na	4,330
Ni	185
P	9,770
Pb	23
Si	91,330
V	69

References

1. U.S. Environmental Protection Agency, "Nonfossil Fuel Fired Industrial Boilers - Background Information, Draft EIS," EPA-450/3-82-007, Office of Air Quality Planning and Standards, Research Triangle Park, N. C., March 1982.
2. Shih, C. C. and A. M. Takata, "Emissions Assessment of Conventional Stationary Combustion Systems: Summary Report," prepared by TRW Environmental Engineering Division for the U.S. Environmental Protection Agency, July 1981.

6 Ash from Sand Classifier

The amount of classifier bottom ash generated is 848 tons/year.

Fly ash reinjection is employed to increase overall boiler efficiency and to reduce solid waste. Prior to fly ash reinjection, a sand classifier is used to separate the combustible and noncombustible materials.¹

The bottom ash leaving the sand classifier is the difference between the ash collected by the mechanical collectors and the percent ash reinjected into the boiler. This is noted as Ash_C in Figure 3 below where:

$$Ash_C = Ash_A - Ash_B$$

and Ash_B is some fraction of Ash_A .

Figure 3. Material Balance for Stream Ash_C

Therefore, it is necessary to calculate the quantity of ash leaving the boiler and entering the mechanical collectors, Ash_{MC} . Ash_{MC} is composed of three components:^{2,3}

1. Forty percent of the wood ash input,
2. Ninety-five percent of the unburned combustibles, and
3. Fifty percent of the reinjected material, Ash_B .

The latter component is based on the assumption that 50 percent of the reinjected material burns and the remainder is entrained in the flue gas stream entering the mechanical collectors. As noted in item ⑤, the unburned combustibles are 1.5 percent of the wood feed rate. Finally, a reinjection rate of 45 percent is assumed.^{2,3} Therefore, Ash_{MC} is calculated as follows:

$$\begin{aligned}
 \text{Ash}_{\text{MC}} &= \text{fly ash to mechanical collectors} = \\
 &(\text{ash fraction in wood}) (\text{wood feed rate}) (\text{fly ash fraction}) \\
 &+ (\text{unburned combustibles in wood}) (\text{wood feed rate}) \\
 &(\text{unburned combustibles fraction}) \\
 &+ \text{Ash}_{\text{B}} (\text{unburned reinjection material fraction})
 \end{aligned}$$

$$\begin{aligned}
 \text{but, } \text{Ash}_{\text{B}} &= (\text{Ash}_{\text{A}}) (\text{reinjection rate}) \\
 &= (\text{Ash}_{\text{MC}}) (\text{collector efficiency}) (\text{reinjection rate})
 \end{aligned}$$

$$\begin{aligned}
 \text{thus, } \text{Ash}_{\text{MC}} &= (0.01) (395 \text{ tons/day}) (0.40) \\
 &+ (0.015) (395 \text{ tons/day}) (0.95) \\
 &+ (\text{Ash}_{\text{MC}}) (0.80) (0.45) (0.50) \\
 &= 7.21 \text{ tons/day} + 0.18 (\text{Ash}_{\text{MC}})
 \end{aligned}$$

$$\text{or } \text{Ash}_{\text{MC}} = 8.79 \text{ tons/day}$$

The quantity of classifier bottom ash generated is calculated as follows:

$$\begin{aligned}
 \text{Classifier bottom ash} &= \text{Ash}_{\text{C}} = \text{Ash}_{\text{A}} - \text{Ash}_{\text{B}} \\
 &= \text{Ash}_{\text{A}} - \text{Ash}_{\text{A}} (\text{reinjection rate}) \\
 &= (\text{Ash}_{\text{MC}}) (\text{collector efficiency}) (1 - \text{reinjection rate}) \\
 &= (8.79 \text{ tons/day}) (0.80) (1 - 0.45) \\
 &= 3.87 \text{ tons/day}
 \end{aligned}$$

On a yearly basis,

Classifier bottom ash =

(daily classifier bottom ash rate) (capacity factor)

x (days/year)

= (3.87 tons/day) (0.60) (365 days/yr)

= 848 tons/year

References

1. Schwieger, R., "Power from Wood," Power, Vol. 124, No. 2, February 1980.
2. U.S. Environmental Protection Agency, "Nonfossil Fuel Fired Industrial Boiler - Background Information, Draft EIS," EPA-450/3-82-007, Office of Air Quality Planning and Standards, Research Triangle Park, N. C., March 1982.
3. Barnett, K., Radian Corporation, "Calculation of Material and Energy Balances of Nonfossil Fuel Boilers," Memorandum to EPA Nonfossil Fuel Boiler File, Docket No. A-79-02, Washington, D.C., September 29, 1981.

7 Fly Ash from Electrostatic Precipitator

The amount of fly ash from the electrostatic precipitator is 344 tons/yr.

The typical boiler is assumed to meet the draft EPA New Source Performance Standard (NSPS) of 0.1 lb/10⁶ Btu/hr heat input for particulate matter from nonfossil fuel fired boilers with heat inputs in excess of 100 x 10⁶ Btu/hr.^{1,2}

In item ⑥, Ash from Sand Classifier, the particulate matter in the flue gas stream entering the mechanical collectors was calculated to be 8.79 tons/day, or

$$8.79 \text{ tons/day} \times 1 \text{ day/24 hrs} \times 2000 \text{ lb/ton} = 732 \text{ lb/hr.}$$

Assuming a mechanical collector efficiency of 80 percent, the particulate matter content of the flue gas leaving the mechanical collector is calculated to be:

$$\begin{aligned} \text{Particulates from mechanical collector} &= \\ &= (\text{particulates entering collector}) (1 - \text{collector efficiency}) \\ &= (732 \text{ lb/hr}) (1 - 0.80) \\ &= 146 \text{ lb/hr} \end{aligned}$$

Since the boiler is rated at 150 x 10⁶ Btu/hr heat input, this equates to a particulate loading of:

$$(146 \text{ lb/hr}) / (150 \times 10^6 \text{ Btu/hr}) = 0.973 \text{ lb/10}^6 \text{ Btu/hr.}$$

This is well above the draft NSPS of 0.1 lb/10⁶ Btu/hr. In addition, although the overall mechanical collector efficiency is noted to be 80 percent, it is only 10 to 50 percent efficient in removing particulate matter with a mean particle diameter of less than 10 microns,¹ and as noted in Figure 4, the majority of particle matter can be below this 10 micron diameter size. Therefore, an electrostatic precipitator (ESP) is used for additional particulate matter control. Although ESPs have been shown to have removal efficiencies in excess of 99 percent for uncontrolled flue gas streams, a collection efficiency of 90 percent is assumed for the flue gas stream from the mechanical collector. The amount of fly ash collected is calculated as follows:

Figure 4. Particle size distribution of uncontrolled particulate emissions from a wood-fired, spreader-stoker boiler. (3,4)

ESP fly ash =

(particulates from mechanical collector) (ESP efficiency)

= (146 lb/hr) (0.90)

= 131 lb/hr

On a yearly basis,

ESP fly ash =

(hourly fly ash) (hr/day) (days/yr) (capacity factor)/(lb/ton)

= [(131 lb/hr) (24 hr/day) (365 days/yr) (0.60)]

÷ (2000 lb/ton)

= 344 tons/yr

The difference between the particulate matter entering the ESP and the fly ash collected is:

$$(146 \text{ lb/hr}) - (131 \text{ lb/hr}) = 15.0 \text{ lb/hr}$$

Since the boiler is rated at 150×10^6 Btu/hr, the particulate loading leaving the ESP is:

$$(15 \text{ lb/hr}) / (150 \times 10^6 \text{ Btu/hr}) = 0.10 \text{ lb}/10^6 \text{ Btu}$$

Therefore, an ESP with a minimum removal efficiency of 90 percent meets the draft EPA NSPS of $0.1 \text{ lb}/10^6$ Btu heat input.

References

1. U.S. Environmental Protection Agency, "Draft Standards of Performance for New Stationary Sources, Industrial Boilers," Emission Standards and Engineering Division, Research Triangle Park, N. C., April 23, 1982.
2. U.S. Environmental Protection Agency, Docket No. A-79-02: Industrial Boiler New Source Performance Standard, Washington, D.C.
3. Peters, J. A. and W. H. McDonald, "Nonfossil Fueled Boilers: Emission Test Report for Owens-Illinois," Publication No. EMB-80-WFB-2, prepared by Monsanto Research Corporation for the U.S. Environmental Protection Agency, Research Triangle Park, N. C., February 1980.
4. U.S. Environmental Protection Agency, "Nonfossil Fuel Fired Industrial Boilers - Background Information, Draft EIS," EPA-450/3-82-007, Office of Air Quality Planning and Standards, Research Triangle Park, N.C., March 1982.

8 Solid Waste Disposal

The typical plant and associated pollutant controls generate 1.78×10^3 tons/yr (dry basis) of wood ash.

Waste streams entering the disposal site include bottom ash from the boiler, bottom ash from the sand classifier serving the mechanical collectors, and fly ash from the electrostatic precipitator. All ash is handled in a wet state and is delivered to a central storage and dewatering tank.¹

The dry ash quantities calculated in items (5), Boiler Bottom Ash, (6) Classifier Bottom Ash, and (7), ESP Fly Ash, are 585 tons/yr, 848 tons/yr and 344 tons/yr, respectively. Therefore, the total dry ash is the sum of these, or 1.78×10^3 tons/yr. Assuming a density of 40 lb/ft³ for the dry ash² and a landfill depth of 10 ft, the land required to landfill this material can be calculated as follows:

Land requirement =

$$\frac{(\text{ash quantity}) (\text{lb/ton}) (\text{plant lifetime})}{(\text{ash density}) (\text{landfill depth}) (\text{ft}^2/\text{acre})}$$
$$= \frac{(1.78 \times 10^3 \text{ tons/yr}) (2000 \text{ lb/ton}) (30 \text{ years})}{(40 \text{ lb/ft}^3) (10 \text{ ft}) (43,560 \text{ ft}^2/\text{acre})}$$
$$= 6.13 \text{ acres}$$

Although the ash is handled in a wet state, the water is assumed to increase the weight and density of the ash, but not its volume. Under certain conditions, water can act as a compaction agent for dry ash and thereby reduce the overall volume.

Little data are available on the environmental effects of landfilling wood ash. However, one analysis of leachates produced from wood bottom ash and fly ash compared column leachate concentration levels to the EPA Extraction Procedure (EP) guidelines and to Federal drinking water standards.³ The latter regulations do not apply directly to column leachate generation tests, but a comparison between these contaminant level guidelines and the maximum concentrations observed may reveal a potentially hazardous disposal problem. The results indicated that:

- o No sample tested had contaminant levels which exceeded the concentration limits for the EP extraction test.
- o Wood bottom ash surpassed the National Interim Primary Drinking Water Regulations for maximum contaminant concentrations of Pb, Ba and Se.

- o Wood fly ash surpassed the National Interim Primary Drinking Water Regulations for maximum contaminant concentrations of Pb, As, Ba, and Se and the Safe Drinking Water Act standard for SO₄.

However, it was noted that the combined effects of dilution and the attenuation of leachate pollutants by soils may reduce the contaminants below hazardous levels. Thus, under proper landfill disposal conditions, the ash residues should not pose any serious environmental hazard.³

References

1. Newby, W. M., "Large Scale Combustion Technology for Steam Production," Proceedings of the Energy Generation and Cogeneration from Wood Conference, Atlanta, Ga., February 18-20, 1980. Published by the Forest Products Research Society, Madison, Wis.
2. Shelton, J. and A. B. Shapiro, The Woodburners Encyclopedia, Vermont Crossroads Press, Inc., Box 333, Waitsfield, Vt., December 1976.
3. Yurczyk, Jr., J. A. and T. Al Austin, "Analysis of Leachates Produced from Biomass and Biomass Ash Residues," Department of Civil Engineering, Iowa State University, Ames, Iowa, November 1980.

9 Flue Gas

The quantity of flue gas and the pollutants that are part of the flue gas emitted to the ambient atmosphere are as follows:

Flue Gas	514×10^3 tons/yr
Particulates	39.4 tons/yr
NO _x	80.4 tons/yr
CO	644 tons/yr
HC	161 tons/yr
SO ₂	<34.6 tons/yr
POM	<0.290 tons/yr

Flue Gas Quantity

In order to calculate the quantity of flue gas exiting the ESP, the quantity of excess oxygen used must be known. This calculation is analogous to that shown in item (4).

Ultimate Analysis lb/lb Fuel as Fired ¹		Combustion Constant ²		O ₂ Required lb/lb Fuel @ 100% Total Air	
C	0.2695	x	2.66	=	0.717
H ₂	0.0285	x	7.94	=	0.226
O ₂	0.191				
N ₂	0.0008				
S	0.0002	x	1.00	=	0.0002
H ₂ O	0.5				
Ash	0.010				
Sum	1.0000				0.943
Less O ₂ in fuel					0.191
					0.752

$$\text{Excess O}_2 = (\text{lb O}_2/\text{lb fuel}) (\text{percent excess air})$$

$$= (0.752 \text{ lb/lb fuel}) (0.50)$$

$$= 0.376 \text{ lb/lb fuel}$$

To calculate the quantity of flue gas, complete combustion is assumed.

Products of Combustion

					lb/lb Fuel @ 150% Total Air
CO ₂	0.2695	x	3.66	=	0.986
H ₂ O	(0.0285	x	8.94)		
	+(4.89	x	0.013)		
	+ 0.50			=	0.818
SO ₂	0.0002	x	2.00	=	0.0004
O ₂				=	0.376
N ₂	0.0008				
	+(4.89	x	0.7685)	=	3.76
Weight, wet					<u>5.94</u>

Therefore, the flue gas weight is calculated as follows:

$$\begin{aligned}
 \text{Flue gas weight} &= (\text{tons of flue gas/ton wood fired}) \\
 &\quad \times (\text{wood feed}) \\
 &= (5.94 \text{ tons/ton wood}) (395 \text{ tons/day}) \\
 &= 2.35 \times 10^3 \text{ tons/day}
 \end{aligned}$$

On an annual basis,

$$\begin{aligned}
 \text{Flue gas} &= (\text{daily flue gas}) (\text{capacity factor}) (\text{days/yr}) \\
 &= (2.35 \times 10^3 \text{ tons/day}) (0.60) (365 \text{ days/yr}) \\
 &= 514 \times 10^3 \text{ tons/yr}
 \end{aligned}$$

Particulate Matter

In Item ⑦, the difference between the particulate matter entering the electrostatic precipitator and the fly ash collected was calculated to be 15 lb/hr. Therefore, the annual particulate matter emitted by the boiler to the ambient air is calculated as follows:

Particulate matter =

$$\begin{aligned} & \frac{(\text{hourly discharge}) (\text{hrs/day}) (\text{days/yr}) (\text{capacity factor})}{(\text{lb/ton})} \\ &= \frac{(15 \text{ lb/hr}) (24 \text{ hrs/day}) (365 \text{ days/yr}) (0.60)}{(2000 \text{ lb/ton})} \\ &= 39.4 \text{ tons/yr} \end{aligned}$$

Nitrogen Oxides, Carbon Monoxide, and Hydrocarbons

No New Source Performance Standards are likely for nitrogen oxides (NO_x), carbon monoxide (CO), and hydrocarbons (HC) for wood-fired industrial boilers. To calculate the emissions of these pollutants, emission factors of 1.86 lb/ton wood fired, 14.88 lb/ton wood fired, and 3.72 lb/ton wood fired are assumed for NO_x , CO and HC, respectively.³ Hence, the emissions are calculated as follows:

$$\text{NO}_x, \text{CO}, \text{HC} = (\text{emission factor}) (\text{annual wood requirement})$$

For this boiler,

$$\begin{aligned} \text{NO}_x &= (1.86 \text{ lb/ton}) (86.5 \times 10^3 \text{ tons/yr}) / (2 \times 10^3 \text{ lb/ton}) \\ &= 80.4 \text{ tons/yr} \\ \text{CO} &= (14.88 \text{ lb/ton}) (86.5 \times 10^3 \text{ tons/yr}) / (2 \times 10^3 \text{ lb/ton}) \\ &= 644 \text{ tons/yr} \\ \text{HC} &= (3.72 \text{ lb/ton}) (86.5 \times 10^3 \text{ tons/yr}) / (2 \times 10^3 \text{ lb/ton}) \\ &= 161 \text{ tons/yr} \end{aligned}$$

Sulfur Dioxide

Earlier in this section, the SO_2 component of the products of combustion was noted to be 0.0004 lb/lb wood fired or 0.0004 ton/ton wood fired. Therefore, the annual emission is calculated as follows:

$$\begin{aligned}
 \text{SO}_2 &= (\text{ton SO}_2/\text{ton wood fired}) (\text{annual wood fired}) \\
 &= (0.0004 \text{ ton SO}_2/\text{ton wood fired}) (86.5 \times 10^3 \text{ tons/yr}) \\
 &= 34.6 \text{ tons/yr}
 \end{aligned}$$

The above quantity is based on the assumption that all the sulfur in the wood is converted into SO_2 . However, test data have shown SO_2 emissions to be below 0.02 lb/10⁶ Btu (equivalent to 8 tons/yr for this typical plant) and in many cases to be below the detection limit for the applicable EPA test method.² One study showed that just over 5 percent of the sulfur contained in a bark sample was emitted as SO_2 and the remainder was accounted for in the ash combustion products.⁴

Trace Elements

A number of trace element emissions have been reported in studies of industrial wood fired boilers. Some of these are listed in Table 4.

Table 4. Trace Elements from Wood-Fired Industrial Boilers³

Al	K
As	Li
Ba	Mn
Be	Na
Ca	Ni
Cd	P
Co	Pb
Cr	Si
Cu	V
F	

In addition, polycyclic organic matter (POM) has been identified as a pollutant from wood combustion. In one study of five industrial wood-fired stoker boilers, an average emission factor for POM was reported as 6.7 x 10⁻³ lb/ton of wood fired.³ For the typical boiler firing 86.5 x 10³ tons of wood per year, would amount to:

$$\begin{aligned}
 \text{POM emissions} &= \frac{(\text{POM emission factor}) (\text{annual wood fired})}{(\text{lb/ton})} \\
 &= \frac{(6.7 \times 10^{-3} \text{ lb/ton}) (86.5 \times 10^3 \text{ tons})}{(2000 \text{ lb/tons})} \\
 &= 0.290 \text{ tons/yr}
 \end{aligned}$$

Tests at the outlet of mechanical collectors used as the first particulate control device of three other boilers indicated that POM emissions averaged less than 29×10^{-6} lb/10⁶ Btu for all three boilers.⁵ For this typical boiler, this would result in annual POM emissions of less than 0.019 tons/yr.

References

1. Hall, E. H., et al., "Comparison of Fossil and Wood Fuels," EPA-600/2-76-056, prepared by Battelle Columbus Laboratories for the U.S. Environmental Protection Agency, March 1976.
2. Steam, Its Generation and Use, 39th Edition, Babcock & Wilcox Company, New York, N. Y., 1978.
3. Shih, C. C. and A. M. Takata, "Emissions Assessment of Conventional Stationary Combustion Systems: Summary Report," prepared by TRW Environmental Engineering Division for the U.S. Environmental Protection Agency, July 1981.
4. Oglesby, H. S. and R. O. Blosser, "Information on the Sulfur Content of Bark and Its Contribution to SO₂ Emissions When Burned As A Fuel," Journal of the Air Pollution Control Association, Vol. 30, No. 7, pp. 769-772, July 1980.
5. U.S. Environmental Protection Agency, "Nonfossil Fuel Fired Industrial Boilers - Background Information, Draft EIS," EPA-450/3-82-007, Office of Air Quality Planning and Standards, Research Triangle Park, N. C., March 1982.

10 Boiler Makeup Water

The annual boiler makeup water requirement for the case where 30 percent of the process steam is consumed is 15.8×10^6 gal/yr.

The makeup water requirement for the boiler feedwater is calculated in Appendix B for the case where the condensate return is assumed to be approximately 30 percent of the steam delivered to the process and the boiler blowdown is assumed to be 20 cycles of concentration. For this case, the steam delivered to the process is calculated to be 78.4×10^3 lb/hr at 250 psig and 406°F or 206×10^3 tons/yr and the makeup water requirement at 50°F and atmospheric pressure is 25.1×10^3 lb/hr. The yearly water requirement is calculated as follows:

Makeup water requirement =

$$\frac{(\text{hourly water requirement}) (\text{hr/day}) (\text{days/yr}) (\text{capacity factor})}{(\text{water density @ } 50^\circ\text{F})}$$

$$= \frac{(25.1 \times 10^3 \text{ lb/hr}) (24 \text{ hr/day}) (365 \text{ days/yr}) (0.60)}{(8.34 \text{ lb/gal})}$$

$$= 15.8 \times 10^6 \text{ gal/yr}$$

The above value is for the case where the condensate return is 70 percent of the steam delivered to the industrial process. For the hypothetical extremes where the condensate return is 100 percent and 0 percent of the delivered steam, the makeup water requirements would be 0.0 gal/yr and 43.5×10^6 gal/yr, respectively.

11 Raw Water Treatment Chemicals

The annual sodium chloride requirement is estimated to be 13.9 tons/yr for regeneration of water softeners.

The makeup water supplied to the raw water treatment plant is treated to reduce contaminants to acceptable levels. The sequence of treatment depends on the type and concentration of contaminants found in the water supply and the desired quality of the finished water to avoid the major boiler system problems - deposits, corrosion and carryover.¹

Suspended solids are removed first from the incoming raw water by coagulation and filtration. Typical coagulant chemicals are alum and iron sulfate. After removal of the suspended materials, the hardness or scale-forming materials are still present in solution. One method of reducing hardness is the sodium zeolite softening process which uses resin materials to exchange the hardness constituents, calcium and magnesium, for sodium. The resin becomes exhausted when the sodium ions are depleted and is then regenerated by adding a sodium chloride (salt) solution.²

The raw water serving the boiler plant is assumed to have a total hardness of 100 mg/l as CaCO_3 . To calculate the sodium chloride requirement for water softening, a typical softener salt consumption of 6 lb NaCl /20,000 gr softener capacity is used.¹ The annual salt consumption is then calculated as follows.

Annual salt consumption =

$$\begin{aligned} & \frac{(\text{CaCO}_3, \text{ mg/l}) (\text{yearly makeup water}) (\text{NaCl/softener capacity}) (\text{ton/lb})}{(\text{mg/l})/(\text{gr/gal})} \\ &= \frac{(100 \text{ mg/l}) (15.8 \times 10^6 \text{ gal/yr}) (6 \text{ lb salt}/20,000 \text{ gr}) (1 \text{ ton}/2000 \text{ lb})}{(17.1 \text{ mg/l/gr/gal})} \\ &= 13.9 \text{ tons/yr} \end{aligned}$$

Therefore, 13.9 tons/yr of salt are required to regenerate the raw water softener at the boiler plant. Additional water will be required during the regeneration and backflushing of the resin bed of the softener, but this is quite small (less than 0.1 percent) of the total makeup water requirement.

Additional chemicals are required for the treatment of boilerwater, steam and returning condensate. Chemicals will include sulfites or hydrazine for oxygen scavenging, volatile and/or filming amines for condensate corrosion control, phosphates and caustic soda for boiler corrosion control, and chelants for limiting boiler fouling. However, these are very site and application specific and are not quantified here.

References

1. Nalco Chemical Company (Kemmer, F. N., ed.), The NALCO Water Handbook, McGraw-Hill Book Company, New York, N. Y., 1979.
2. The Babcock & Wilcox Company, Steam, Its Generation and Use, New York, N. Y., 1978.

12 Boiler Blowdown

The annual boiler blowdown is 790×10^3 gal/yr.

As noted in Appendix B, the boiler blowdown is assumed to be 20 cycles of concentration, or

$$\text{Blowdown} = (1/20) (\text{boiler makeup water})$$

The boiler makeup water requirement was calculated in item 10 for the case where the condensate return is 70 percent of the delivered process steam. Therefore, the annual blowdown is calculated as follows:

$$\begin{aligned}\text{Blowdown} &= (1/\text{cycles of concentration}) (\text{boiler makeup water}) \\ &= (1/20) (15.8 \times 10^6 \text{ gal/yr}) \\ &= 790 \times 10^3 \text{ gal/yr}\end{aligned}$$

13 Water Treatment Facility Discharge

The annual discharge from the water treatment facility is estimated to be 1.22×10^6 gal/yr.

total aqueous discharge from the water treatment facility is approximately the sum of the incoming boiler blowdown stream and the water removed from the solid waste handling facility. The boiler blowdown was calculated in item 12 and the water removed from the solid waste facility is assumed to be equal to the weight of total solid waste generated, noted in item 8. Therefore, the total annual liquid discharge is calculated as follows:

Annual effluent discharge =

(annual boiler blowdown) + [(annual solid waste) (lb/ton)

x (gal/lb)]

= $(790 \times 10^3 \text{ gal/yr}) + [(1.78 \times 10^3 \text{ tons/yr}) (2000 \text{ lb/ton})$

x (1 gal/8.34 lb)]

= $1.22 \times 10^6 \text{ gal/yr}$

Water effluent standards governing the quality of this discharge is discussed in Appendix A, Regulatory Considerations.

III. PHYSICAL REQUIREMENTS

The water and land requirements for an industrial wood-fired steam boiler are very specific to the site and the industrial process application served. Water requirements for a given size boiler are a function primarily of the percent of condensate returned from the industrial process, the boiler blowdown rate, inclusion or lack of a water scrubber for particulate control, the type of or dry ash handling facilities, and the degree of water recycling, if any. Land use is a function of land availability, configuration and cost, operating philosophy including desired on-site storage capacity, and on-site or off-site ash disposal selection. This section summarizes the water, land, and materials requirements for the typical boiler plant.

Water

The primary water needs for the typical plant include boiler makeup water requirements and water for wet handling of solid ash from the boiler and the particulate control equipment. The boiler makeup water requirement assuming a 70 percent condensate return was calculated in item (10). The water supply for the wet ash handling system is assumed to be roughly twice the weight of the ash generated with one-half of the water removed and delivered to the waste water treatment prior to ash disposal and the remainder acting as a compaction agent for the ash and landfilled with the ash. No water recycling is employed. Therefore, the annual water requirement is calculated as follows:

Annual water requirement =

(boiler makeup water) + [(ash solid waste) (2) (lb/ton)

÷ (water density)]

= (15.8 × 10⁶ gal/yr) + [(1.78 × 10³ tons/yr) (2) (2000 lb/ton)

÷ (8.34 lb/gal)]

= 16.7 × 10⁶ gal/yr

Land

The land requirement for a boiler plant varies considerably as noted earlier. To calculate the land requirement, a power plant land use factor of 1 × 10⁻⁶ mi²/kW is assumed for a power plant with a burn rate of 13,000 Btu/kWh.¹ Therefore, the land required for the typical boiler plant, excluding ash disposal needs, is calculated as follows:

Boiler plant land =

(boiler heat input) (1/burn rate) (land use factor) (acres/mi²)

= (150 x 10⁶ Btu/hr) (1/13,000 Btu/kWh) (1 x 10⁻⁶ mi²/kW)

x (640 acres/mi²)

= 7.4 acres

The annual land requirement for ash disposal was calculated to be 0.2 acres/yr in item (8), Solid Waste Handling and Disposal.

Construction Materials

Quantities of construction materials were estimated from equipment vendor catalogs and other sources. Estimated materials include 150 tons of steel and 140 tons of refractory materials. Approximately one-third of the steel is accounted for by the boiler itself.

References

1. Blake, D. and D. Salo, "Systems Descriptions and Engineering Costs for Solar Related Technologies, Volume IX, Biomass Fuels Production and Conversion Systems," The MITRE Corporation, prepared for the U.S. Energy Research and Development Administration, June 1977.

IV. PERSONNEL

The number of people required for the operation and planned maintenance of a steam boiler plant is dependent on the quality of fuel, the degree of automation of the fuel storage, feeding and burning equipment, the philosophy of the plant management, insurance requirements, and local codes. One factor large boilers burning "green" wood cites two people per shift plus one day supervisor.¹ For three shifts per day, a total of 7 people would therefore be required.

Construction labor was estimated using a labor factor of 10×10^{-3} man-yr/kW for a power plant with a burn rate of 13,000 Btu/kWh.² Therefore construction labor for the boiler plant is estimated as follows:

$$\begin{aligned}\text{Construction labor} &= \\ &(\text{boiler heat input}) (1/\text{burn rate}) \\ &\times (\text{construction labor factor}) \\ &= (150 \times 10^6 \text{ Btu/hr}) (1/13,000 \text{ Btu/kWh}) \\ &\times (10 \times 10^{-3} \text{ man-yr/kW}) \\ &= 115 \text{ man-yr}\end{aligned}$$

For a one-and-a-half year construction period, this equates to 77 man-yr per year.

References

1. Levi, M. P. and M. J. O'Grady, "Decisionmaker's Guide to Wood Fuel for Small Industrial Energy Users," SERI/TR-8234-1, prepared by North Carolina State University for the DOE Solar Energy Research Institute, February 1980.
2. Blake, D. and D. Salo, "Systems Descriptions and Engineering Costs for Solar-Related Technologies, Volume IX, Biomass Fuels Production and Conversion Systems," The MITRE Corporation, prepared for the U.S. Energy Research and Development Administration, June 1977.

V. OCCUPATIONAL SAFETY AND HEALTH

Actual death and injury statistics are not available for wood-fired industrial steam boilers. However, they are not likely to differ substantially from coal-fired plants. Estimates of deaths and injuries for coal-fired power plant boilers have been estimated to be 0 to 0.0095 deaths per 10^{12} Btu output and 0.16 to 0.19 injuries per 10^{12} Btu output. For the wood-fired boiler plant producing 0.495×10^{12} Btu per year, the projected deaths and injuries are as follows:

	<u>Annual</u>	<u>Per 10^{12} Btu Energy Produced</u>
Deaths	$0-4.7 \times 10^{-3}$	$0 - 9.5 \times 10^{-3}$
Injuries	$79 \times 10^{-3} - 94 \times 10^{-3}$	$0.16 - 0.19$

Reference

1. Morris, S. C., et al., "Health Effects of Coal in the National Energy Plan," BNL-51043, Brookhaven National Laboratory, April 1979.

APPENDIX A. REGULATORY CONSIDERATIONS

AIR EMISSIONS

As noted in Item ⑦, the typical wood-fired boiler is assumed to meet the draft EPA New Source Performance Standard (NSPS) of 0.1 lb/10⁶ Btu/hr heat input for particulate matter from nonfossil fuel-fired boilers with heat input in excess of 100 x 10⁶ Btu/hr.¹ The draft NSPS also establishes a maximum 20 percent opacity standard. No NSPSs are anticipated for oxides of nitrogen, carbon monoxide, sulfur dioxide or hydrocarbons. Additional Federal Standards may include Prevention of Significant Deterioration (PSD) standards if the boiler is located in an attainment area.

In addition to Federal standards, state and local regulations will apply to wood-fired boilers. These are directed at the control of particulate matter and are specified in terms of lb/10⁶ Btu heat input or as grains per dry standard cubic foot (gr/dscf).

WATER EFFLUENTS

There are no Federal standards governing the liquid discharge from the water treatment facility. However, the discharge stream must adhere to the water quality standards for the state in which it is located. Water quality parameters for which standards may exist include:

- o dissolved solids
- o dissolved oxygen
- o sulfates
- o chloride
- o acidity - alkalinity
- o arsenic
- o cadmium
- o chromium
- o mercury
- o zinc
- o pH

Solid Wastes

Solid waste from the boiler plant is composed of boiler bottom ash, sand classifier bottom ash, and ESP fly ash. At present, these wastes are not considered hazardous wastes under regulations promulgated under the Resource Conservation and Recovery Act (RCRA). However, they may be subject to state or local limitations regarding their disposal.

References

1. U.S. Environmental Protection Agency, "Draft Standards of Performance for New Stationary Sources, Industrial Boilers," Emission Standards and Engineering Division, Research Triangle Park, N. C., April 23, 1982.

APPENDIX B. BOILER MAKEUP WATER CALCULATION

The makeup water requirement is a function of both the quantity of condensate returned to the boiler and the blowdown rate from the boiler to control solids. In turn, the quantity of makeup water will determine the amount of usable steam delivered to the process. To envision this interdependency, consider Figure

Figure B-1. Steam/Water Material Balance

From the figure, the following relationships are drawn:

$$Q_{DF} = Q_{MW} + Q_{CR} \quad (1)$$

$$Q_{BF} = Q_S + Q_{LP} + Q_{BD} \quad (2)$$

$$Q_{BF} = Q_{DF} + Q_{LP} \quad (3)$$

$$\text{or } Q_S + Q_{LP} + Q_{BD} + Q_{MW} + Q_{CR} + Q_{LP} \quad (4)$$

Assumptions regarding the condition of the makeup water (Q_{MW}) received from the raw water treatment plant (item ⑩), the condensate returning from the industrial process (Q_{CR}), and the boiler feedwater (Q_{BF}) are as follows:

	Temperature, °F	Pressure, psig	Enthalpy, liquid, Btu/lb
Q_{MW}	50	0	18.1
Q_{CR}	170	0	138
Q_{BF}	240	10	208

Although the process steam consumption, if any, is not specified, the condensate return, Q_{CR} , is assumed to comprise 70 percent of Q_{DF} , and Q_{MW} 30 percent for illustrating the calculation procedure. Finally, a typical 20 cycles of concentration is assumed for blowdown from the boiler.

The enthalpy of Q_{DF} is computed as:

$$\begin{aligned} h_{1-DF} &= (0.3) (h_{1-MW}) + (0.7) (h_{1-CR}) \\ &= (0.3) (18 \text{ Btu/lb}) + (0.7) (138 \text{ Btu/lb}) \\ &= 102 \text{ Btu/lb} \end{aligned}$$

Therefore, in order to raise the enthalpy of the deaerator feedwater to the assumed value of the boiler feedwater, the following energy must be supplied:

$$\begin{aligned} h_{1-BF} - h_{1-DF} &= 208 \text{ Btu/lb} - 102 \text{ Btu/lb} \\ &= 106 \text{ Btu/lb} \end{aligned}$$

This energy is assumed to be supplied by low pressure steam (Q_{LP}) from the boiler and delivered to the deaerator at 10 psig. Since the latent heat of evaporation of Q_{LP} is 952 Btu/lb, the quantity of Q_{LP} required to raise the enthalpy of Q_{DF} is calculated as:

$$Q_{LP} (h_{\text{evap-LP}}) = Q_{DF} (h_{1-BF} - h_{1-DF})$$

$$\text{or } Q_{LP} (952 \text{ Btu/lb}) = Q_{DF} (106 \text{ Btu/lb})$$

$$\text{or } Q_{LP} = 0.111 Q_{DF}$$

Therefore, using equation (1):

$$Q_{LP} = 0.111 Q_{DF} = 0.111 (Q_{MW} + Q_{CR}) \quad (5)$$

In addition to assuming that Q_{CR} is 70 percent of Q_{DF} , it is also assumed that Q_{CR} is 70 percent of the steam supplied to the process, Q_S . (In practice, these two percentages will differ by a small percent to reflect relatively small steam losses). Therefore, equation (4) becomes:

$$Q_S + Q_{LP} + Q_{BD} = Q_{MW} + Q_{CR} + Q_{LP} \quad (4)$$

$$= Q_{MW} + 0.7 Q_S + Q_{LP}$$

$$\text{or } Q_S + Q_{BD} = Q_{MW} + 0.7 Q_S \quad (6)$$

Since the blowdown is assumed to be 20 cycles of concentration, by definition

$$Q_{BD} = 0.05 Q_{MW} \quad (7)$$

$$\text{or } Q_{MW} = 20 Q_{BD} \quad (8)$$

Substituting into equation (6),

$$Q_S + Q_{BD} = 20 Q_{BD} + 0.7 Q_S$$

$$\text{or } Q_{BD} = 0.016 Q_S \quad (9)$$

To calculate Q_S , from Figure B-1,

$$Q_S + Q_{LP} + Q_{BD} = \frac{(\text{heat input rate}) (\text{boiler efficiency})}{\Delta h}$$

$$\text{where } \Delta h = h_S - h_{1-DF}$$

Therefore,

$$Q_S + Q_{LP} + Q_{BD} = \frac{(150 \times 10^6 \text{ Btu/hr}) (0.65)}{(1202 \text{ Btu/lb} - 102 \text{ Btu/lb})}$$

$$= 88.6 \times 10^3 \text{ lb/hr}$$

Substituting equations (5) and (9),

$$88.6 \times 10^3 \text{ lb/hr} = Q_S + (0.111(Q_{MW} + Q_{CR})) + 0.016 Q_S \quad (10)$$

where $Q_{CR} = 0.7Q_S$. To compute Q_{MW} as a function of Q_S , combine equations (7) and (9) to obtain,

$$Q_{BD} = 0.05 Q_{MW} = 0.016 Q_S$$

$$\text{or } Q_{MW} = 0.32 Q_S$$

Therefore, equation (10) becomes

$$88.6 \times 10^3 \text{ lb/hr} = Q_S + (0.111 (0.32 Q_S + 0.7Q_S)) + 0.016 Q_S$$

$$= 1.13 Q_S$$

$$\text{or } Q_S = 78.4 \times 10^3 \text{ lb/hr}$$

and from equation (11),

$$Q_{MW} = 0.32 Q_S$$

$$= (0.32) (78.4 \times 10^3 \text{ lb/hr})$$

$$= 25.1 \times 10^3 \text{ lb/hr}$$

APPENDIX C. COST INFORMATION

The Environmental Protection Agency's NSPS background information document on nonfossil fuel fired industrial boilers provides cost information for wood-fired boilers of varying size and with different types and levels of control equipment.⁽¹⁾ The capital and annualized costs provided in the EPA document are reported in mid-1978 dollars. To adjust these to 1982 costs, material and building cost indices from a recent issue of Engineering News-Record were applied.² The adjusted costs are presented in Table C-1.

Table C-1. Capital and Annualized Cost for
150 x 10⁶ Btu/hr Boiler (1982 Dollars)

	<u>Capital Cost, \$</u>	<u>Annualized Cost, \$</u>
Boiler	7.54 x 10 ⁶	2.74 x 10 ⁶
Emission Control	<u>1.61 x 10⁶</u>	<u>0.42 x 10⁶</u>
TOTAL	9.15 x 10 ⁶	3.16 x 10 ⁶

The capital cost components include:

- o Equipment and Installation
- o Indirect Costs
 - engineering
 - construction and field expense
 - construction fees
 - startup costs
 - performance tests
- o Contingencies
- o Land
- o Working Capital

The annualized cost components include:

- o Direct Operating Costs
 - labor
 - materials and supplies
 - utilities
 - waste disposal

- o Indirect Operating Costs
 - plant and payroll overhead
- o Capital Charges
 - G & A, taxes and insurance
 - interest on working capital
 - capital recovery charges

No cost for the wood waste fuel or its transportation is assigned.

The emission control equipment includes mechanical collectors followed by an electrostatic precipitator. The control equipment adds 21.4 and 15.5 percent to the capital and annualized costs, respectively, of the boiler, while the electrostatic precipitator increases the capital and operating costs by 15.5 and 9 percent, respectively, over a boiler equipped with mechanical collectors only.

Figure C-1 illustrates the capital cost variations as a function of boiler size. Both total capital costs and unit total capital costs per 10^6 Btu/hr fuel input are illustrated for boilers equipped with mechanical collectors followed by an electrostatic precipitator.

Figure C-1. Total and Unit Total Capital Costs of Wood-Fired Boilers, 1982 \$ Basis (Source: Ref. 1)

References

1. U.S. Environmental Protection Agency, "Nonfossil Fuel Fired Industrial Boilers - Background Information, Draft EIS," EPA-450/3-82-007, Office of Air Quality Planning and Standards, Research Triangle Park, N. C., March 1982.
2. Engineering News-Record, Vol. 208, No. 11, March 18, 1982, McGraw-Hill, Inc., New York, N. Y.

GLOSSARY

Blowdown	Water that is periodically removed from the boiler to prevent excessive concentration of total dissolved solids.
Burn ash	Noncombustible residues of wood combustion that are collected and removed from the boiler.
Capacity factor	The actual plant output in a year divided by the output that would be achieved if the plant were to operate at 100 percent rated capacity for 365 days/year.
Carryover	Any contaminant that leaves the boiler steam drum with the steam.
Chelant	An agent which is soluble in water and can undergo reactions with metal ions to hold them in solution.
Coagulation	Process by which finely divided materials are combined by the use of chemicals to produce large particles capable of rapid settling.
Condensate return	Water from condensed steam recycled to the boiler as feedwater.
Electrostatic precipitator	A device which removes dust or other finely divided particles from a gas by charging the particles inductively with an electric field, then attracting them to highly charged collector plates.
Excess air	Additional air supplied above the theoretical air requirements to assure sufficient oxygen for complete combustion.
Flue gas	Gases generated from the combustion of the wood in the boiler.
Fly ash	Noncombustible residues of wood combustion that are carried out of the boiler in the flue gas.
Hog	A mechanical chipping machine used to reduce various wood chip sizes to a practically uniform size of chips or shreds.
Leachate	Liquid which has extracted and/or suspended constituents from a solid material.
Polycyclic organic matter	Organic molecules that contain two or more bound closed rings of atoms.
Sand classifier	A device used to separate combustible and noncombustible materials leaving the mechanical collectors.

Spreader
stoker

A solid fuel burning system where mechanical feeders and distributing devices form a thin fuel bed on a grate.

Water-tube
boiler

A steam boiler in which water circulates within tubes and heat is applied from outside the tubes to generate steam.

Zeolite

Any of various hydrous silicates that can act as ion exchangers.

ACRONYMS AND ABBREVIATIONS

Al	aluminum
As	arsenic
Ba	barium
Be	beryllium
Btu	British thermal unit
Ca	calcium
Cd	cadmium
Co	cobalt
CO	carbon monoxide
CO ₂	carbon dioxide
COD	chemical oxygen demand
Cr	chromium
Cu	copper
DOE	Department of Energy
dscf	dry standard cubic foot
ECIR	Environmental Characterization Information Report
EIS	Environmental Impact Statement
EPA	Environmental Protection Agency
ESP	electrostatic precipitator
F	fluorine
°F	degrees Fahrenheit
Fe	iron
ft	foot
ft ²	square feet
ft ³	cubic feet
gal	gallon
gr	grains (1 lb = 7000 grains)
h	enthalpy
H ₂	hydrogen
HC	hydrocarbons
H ₂ O	water
hr	hours
K	potassium
kjcl-N	total organic and ammonia nitrogen
l	liquid
lb	pound
Li	lithium
Mn	manganese
MW	megawatt

N ₂	nitrogen
Na	sodium
Ni	nickel
NSPS	New Source Performance Standard
O ₂	oxygen
P	phosphorous
Pb	lead
POM	polycyclic organic matter
PSD	Prevention of Significant Deterioration
psig	pounds per square inch, gauge
QBD	blowdown mass rate
QBF	boiler feedwater mass rate
QCR	condensate return mass rate
QDF	deaerator feedwater mass rate
QLP	low pressure steam mass rate
QMW	makeup water mass rate
QS	process steam mass rate
RCRA	Resource Conservation and Recovery Act
S	sulfur
Se	selenium
SERI	Solar Energy Research Institute
Si	silicon
SO ₂	sulfur dioxide
T-PO ₄	total phosphate
V	vanadium
wt	weight
yr	year

Geothermal Energy Plant

(Hydrothermal Flashed Steam)

Environmental Characterization Information Report

September 1981

**U.S. Department of Energy
Assistant Secretary for Environmental
Protection, Safety, and
Emergency Preparedness
Office of Environmental Analysis**

CONTENTS

	<u>Page</u>
I. SUMMARY	A.14-3
II. PROCESS DESCRIPTION AND ENVIRONMENTAL POINTS OF INTEREST	A.14-6
1. Drilling Muds to Bermed Containment Area	A.14-10
2. Fluid Flow to Flash Separator.	A.14-12
3. Flashed Steam: Directly to Turbine or Through the EIC Hydrogen Sulfide (H ₂ S) Abatement	A.14-15
3x. Geothermal Fluid to Fluid Treatment.	A.14-17
4. Flashed Steam to the Turbine	A.14-19
5. Treated Fluid to Injection Well.	A.14-20
6. Solid Wastes to Disposal (Optional).	A.14-24
7. Condensate to Cooling Tower.	A.14-26
8. Cooling Tower Emissions.	A.14-27
9. Cooled Water to Condenser.	A.14-29
10. Cooling Tower Blowdown to Treatment.	A.14-31
11. Noncondensable Gases to Stretford Process	A.14-32
12. Cleaned and Noncondensable Gases to Cooling Tower.	A.14-35
13. Make-up Water to the Cooling Tower	A.14-36
III. PHYSICAL REQUIREMENTS.	A.14-37
IV. PERSONNEL REQUIREMENTS	A.14-40
V. OCCUPATIONAL SAFETY AND HEALTH CONSIDERATIONS.	A.14-42
APPENDIX A: AIR EMISSION STANDARDS	A.14-48
APPENDIX B: COST INFORMATION	A.14-54
APPENDIX C: TRACE ELEMENTS AND GASEOUS EMISSION ANALYSIS	A.14-58
GLOSSARY.	A.14-64
ABBREVIATIONS & ACRONYMS.	A.14-65

I. SUMMARY

The power plant chosen to typify geothermal power systems in this Environmental Characterization Information Report (ECIR) is a 50-MWe single-flash hydrothermal plant. Hydrogen sulfide abatement and fluid injection serve as environmental controls. The 50-MWe size was chosen to be more representative of a practical, operating plant as opposed to a 5-12 MWe pilot or demonstration plant.

The most significant environmental concerns associated with geothermal development are gaseous emissions of hydrogen sulfide, solid wastes generated during well drilling, and sludges from optional geothermal fluid treatment. The solid wastes and sludges may eventually be regulated under the Resource Conservation and Recovery Act (RCRA) though regulations have not yet been developed. Geothermal plants tend to be water consumptive which is a problem since most geothermal resources in the United States are located in areas where water is not plentiful and where a great deal of water is needed for agricultural irrigation.

The withdrawal of geothermal fluid from a resource can also induce subsidence of the ground which can interfere with an existing agricultural irrigation system. Subsidence can be mitigated via injection of geothermal fluids after their use in the power plant.

The process, plant operating parameters, resources needed, environmental residuals and products associated with the power plant are shown in the summary table (Table 1). A capacity factor of 75% was assumed to account for shutdown periods for routine plant maintenance.

Section II describes each step of the plant's process flow with sample calculations for various quantities associated with these steps. Among the quantities calculated are environmental residuals, products, by-products and amounts of resources used.

The remaining sections include information on physical requirements, personnel requirements, and occupational safety and health considerations. The appendices describe air emissions, cost information, and trace element and gaseous emissions.

TABLE 1. SUMMARY SHEET

GEOTHERMAL ENERGY PLANT (HYDROTHERMAL FLASHED STEAM)

REFERENCE ENERGY SYSTEM

Hot Geothermal Fluid Is Withdrawn From the Geothermal Reservoir and Steam Is Flashed From the Fluid. Steam From This Flash Is Used To Power the Turbogenerators. Hydrogen Sulfide Emissions Are Abated by the Stretford or EIC Process. Residual Fluid Is Injected Into a Subsurface Aquifer.

FACILITY OPERATING PARAMETERS

Size: 50 MWe; 1.12×10^{12} Btu
Annual Capacity Factor: 75%
Annual Energy Production: 1.2×10^{12} Btu
Efficiency: 5-8% overall
Lifetime: 30 Yr

PROCESS FLOW

RESOURCES USED

Code No.	Resource	Quantities Used			Remarks
		Reference Energy System Annual Usage		Per 10 ¹² Btu Energy Produced	
		English Units	Metric Units		
①	Feed Material				
	Geothermal fluid (230°C)	26.0 × 10 ⁶ tons	23.6 × 10 ⁶ tonnes	23.2 × 10 ⁶ tons	Assuming 70 kg/kWh
	Energy				
	Electricity	32.9 × 10 ⁶ kWh	32.9 × 10 ⁶ kWh	29.4 × 10 ⁶ kWh	10% of output
	Processing Materials				
3x	Caustic soda process				Data adapted from The Geysers
	• Sodium hydroxide	57.1 tons	51.8 tonnes	51.0 tons	
11a	Stretford Process				Chemicals used for secondary H ₂ S abatement processes. See Section II, (2).
	• Sodium ammonium polyanadate	4.82 tons	4.37 tonnes	4.30 tons	
	• Anthraquinone disulfonic acid (ADA)	1.34 tons	1.22 tonnes	1.20 tons	
3x	Iron catalyst (H ₂ O ₂ supplemented) process				
3x	• Hydrogen peroxide	302 tons	274 tonnes	270 tons	
	Iron catalyst process				
	• Ferrous sulfate and hydroxy acetic acid	84.0 tons	76.2 tonnes	75.0 tons	
3a	Copper sulfate				
	Water	Not Determined			For EIC process
13	Cooling tower make-up (10% cycle efficiency)	2.24 × 10 ³ acre-ft	2.76 × 10 ³ litres	2.00 × 10 ³ acre-ft	
		Total Usage			
	Construction Materials	Not Determined			
	Land				
	Wells (18 wells at 5 acres/well)	90.0 acres 5.00-20.0 acres	36.5 ha 2.03-8.10 ha	80.4 acres 4.46-17.9 acres	
	Personnel				
	Construction (2 yr)	233 workers (maximum)		208 workers	
	Operation and maintenance	67 workers		60 workers	

TABLE 1 (Continued)

GEOHERMAL ENERGY PLANT (HYDROTHERMAL FLASHED STEAM)

COSTS

	Reference Energy System	Per 10 ¹² Btu Energy Produced	Remarks
	(1980 \$)		
Construction costs	\$18.75 (10 ⁶) total	\$16.67 (10 ⁶) total	
Operation and maintenance	\$1.3 (10 ⁶)/yr	\$0.9-2.7 (10 ⁶)/yr	
Environmental Controls			
Stretford process (with surface condenser)	\$3.64 × 10 ⁶	\$3.25 × 10 ⁶	
EIC process	\$4.64 × 10 ⁶	\$4.14 × 10 ⁶	

ENVIRONMENTAL RESIDUALS & PRODUCTS

		Quantities Used		
		Reference Energy System Annual Levels (75% Capacity Factor)		
Code No.	Residuals or Products	English Units	Metric Units*	Per 10 ¹² Btu Energy Produced
⑧	<u>Air Pollutants**</u>			
	Hydrogen sulfide	4.41-44.1 tons	4.00-40.0 tonnes	3.94-39.4 tons
	Ammonia	165-17,000 tons	150-15,400 tonnes	147-15,200 tons
	Methane	108-4,520 tons	98.0-4,100 tonnes	96.4-4,040 tons
	Carbon dioxide	6,780-67,800 tons	6,150-61,500 tonnes	6,050-60,500 tons
	Arsenic	0.452-4.52 tons	0.410-4.10 tonnes	0.404-4.04 tons
	Boron	11.4-114 tons	10.3-103 tonnes	10.2-102 tons
	Mercury	0.2-26 tons	0.2-05 tonnes	0.2-02 tons
	Radon	10.5-16.1 Ci	10.5-16.1 Ci	9.38-14.4 Ci
	Benzene	22.0 tons	20.0 tonnes	19.6 tons
① ⑥ ③f ⑥	<u>Solid Wastes**</u>			
	Drilling mud	181-392 (10 ³) ft ³	5.13-11.1 (10 ³) m ³	162-350 (10 ³) ft ³
	Solid waste (from plant operation)			
	Solids separated from fluid	4300 tons	3900 tonnes	3840 tons
	Solids from H ₂ S abatement	176 tons	160 tonnes	157 tons
⑥	Solids from scale removal	231 tons	210 tonnes	206 tons
<u>Noise Pollution***</u>				
	Well drilling	75-85 dB at 50 ft		
	Operation of construction machinery	70-96 dB at 50 ft		
	Plant operation	70-100 dB at 50 ft		

*Basis of other calculations.

**Quantities indicated for air, water and solid wastes are based on a total flow of 23.6 × 10⁶ tonne/yr from 18 wells at 1.31 × 10⁶ tonne/yr per well. Fluid density is assumed to be 1.15 kg/l.

***Noise cannot be expressed in terms of energy produced.

PRODUCTS

	Reference Energy System Annual Production		Per 10 ¹² Btu Energy Produced
	English Units	Metric Units	
Primary			
Electricity (net)	329 × 10 ⁶ kWh	329 × 10 ⁶ kWh	294 × 10 ⁶ kWh
<u>Recoverables/Recyclables</u>			
(11a) Sulfur	378-3,780 tons	343-3,430 tonnes	338-3,380 tons

OCCUPATIONAL SAFETY AND HEALTH

	Reference Energy System	Per 10 ¹² Btu Energy Produced	Remarks
Injuries/Illnesses			
Based on data from Geysers (per 50 MW)	0.40 injuries/illnesses	0.36 injuries/illnesses	

II. PROCESS DESCRIPTION AND ENVIRONMENTAL POINTS OF INTEREST

There are three types of geothermal resources from which energy may be obtained: hydrothermal, hot igneous (dry rock), and geopressured. Of interest here are the hydrothermal resources which can be defined as convective systems of water and/or steam trapped in fractured rock or sediment beneath impermeable surface layers. These resources are characterized as either vapor-dominated or liquid- (hot fluid) dominated.

Vapor-dominated geothermal resources are characterized by high-temperature (i.e., 240°C), high-pressure steam. These systems are the easiest to develop since the steam is of high quality and can be used to drive conventional turbines without requiring steam/water separation processes. However, vapor-dominated resources are rare geological occurrences. In the United States, The Geysers in California is the only known vapor-dominated geothermal resource available for development as a power plant. Developed by Pacific Gas and Electric, The Geysers generates 908 MWe. Two other vapor-dominated resources are the Mud Volcano system in Yellowstone National Park (Old Faithful) and an unproven, but likely, system in Mt. Lassen National Park. These resources cannot be developed since they are contained in national parks.

Several liquid-dominated geothermal resources, or Known Geothermal Resource Areas* (KGRAs), have been identified in the United States, particularly in California, New Mexico, Idaho, Utah, Nevada and Hawaii. Moderate and low-temperature resources ($<150^{\circ}\text{C}$) can be developed for non-electric purposes such as industrial heating and residential space heating. Moderate-temperature resources (i.e., $\sim 150^{\circ}\text{C}$) can be used to produce electricity via a binary process in which geothermal fluid heats a second fluid such as isobutane that has a low boiling point. Vapors produced by the boiling of this second fluid are used to drive a turbine. A pilot 11.2-MWe binary plant has been built in East Mesa, California, in the Imperial Valley KGRA, and a 5-MWe binary plant is being designed for construction in Raft River, Idaho. A 45-MWe binary plant is planned for Heber, California.

*This term, KGRA, is used to describe any type of geothermal resource whether it be hydrothermal, hot igneous or geopressured.

High-temperature liquid-dominated geothermal resources can produce electricity via a flashed steam process. Resources at 150° to 350°C are often called "high temperature" resources, although temperatures on the upper end of this range are required for flashed steam plants. In this process, geothermal steam and fluid are introduced to a flash vessel where a portion of the fluid is converted to steam by a pressure reduction. If the fluid temperature is high enough, the fluid can be flashed more than once. Operating flash steam plants can be found in several other countries (i.e., Iceland, New Zealand, Mexico, El Salvador), though none are currently operating in the United States. A 48-MWe double flash plant (the fluid will be flashed twice) has been planned for East Mesa, California, and a 45-MWe double flash plant has been planned for construction in Heber, California. Single flash plants have been planned for Brawley, California; Niland, California; and Baca Ranch, New Mexico, which will produce 10, 5 and 50 MWe, respectively. A 10 MWe plant has been built in Puna, Hawaii. Another 50-MWe plant at Niland, California, is being planned; this plant will be either a single or double flash plant.

The plant described in this ECIR involves a high-temperature, liquid-dominated hydrothermal resource at a temperature between approximately 150°C and 350°C. It is a 50-MWe power facility with a single-flash power cycle, i.e., a 50-MWe hydrothermal (hot fluid) flash injection energy plant.

The tapped resource may emit considerable hydrogen sulfide (H_2S) so abatement could be mandatory. The Stretford downstream H_2S abatement technique is assumed since this technique has been used successfully in synthetic fuel plants and is planned for use at The Geysers. The state-of-the-art EIC upstream H_2S abatement process is also described as a possible alternative to the Stretford process, although the EIC process has not been tested on full-scale plants. It has operated successfully, however, at The Geysers and appears to be a promising technology for future application.

Regardless of whether H_2S abatement is accomplished upstream or downstream of the turbine/generator, disposition of the fluid from which it is released can present difficulties. Treatment of fluids before injection is not always required. The composition of the geothermal brine at each site and the characteristics of the geologic formation into which the fluid will be injected will determine whether or not treatment is needed before injection and, if so, what type of treatment is required.

Geothermal resources are characterized by a significant lack of uniformity which makes the quantification of a general case very difficult. For example, there may be wide variations in geothermal fluid compositions even within the same well field. This variation can affect the materials used in plant components (and hence the plant cost), the amount of hydrogen sulfide abatement, the amount of cooling tower make-up water, and many other factors. Due to these variations, ranges of figures have been presented instead of single figures that could be misleading.

The use of geothermal energy to produce electricity is shown in Figure 1. Items (1) through (4) concern the separation of steam from the geothermal fluid, (5) and (6) deal with fluid injection, (7) to (12) deal with treatment of steam after it has passed through the turbine.

FIGURE 1. PROCESS FLOWCHART WITH ENVIRONMENTAL POINTS OF INTEREST – GEOTHERMAL ENERGY PLANT (HYDROTHERMAL FLASHED STEAM) – 75% CAPACITY FACTOR

1 Drilling Muds to Bermed Containment Area

An estimated 181 to 392 thousand cubic feet of solid waste are produced during the drilling of 18 production wells of an average depth of 4920 feet.

The principal functions of drilling muds are:

- to cool and lubricate the well bit,
- to lift formation cuttings to the surface,
- to control reservoir pressure, and
- to prevent formation damage and caving of the wells. (1,2,3,4)

Cuttings are separated from the mud as the mixture is passed through a shaker screen. The mud passes through the screen and is recirculated into the well. The quantity of solid waste generated depends on the well bore diameter and the physical nature of the rock formation and the removed rock chips. Typically 19 m³ (cubic meters) to 41 m³ of solid waste are generated per 100 meters of well (based on estimates of contractors experienced in California's Imperial Valley). Table 2 projects these figures for an average well depth of 1,500 m (4920 feet).

Components of typical drilling mud are shown in Table 3. Proprietary components also may be included.

Since the drilling muds come in contact with geothermal fluids, the muds may contain barium, arsenic, lead and other substances that are considered toxic. Consequently, these muds may be defined as hazardous under the Resource Conservation and Recovery Act (RCRA) and may require special disposal. (3)

References

- (1) U.S. Environmental Protection Agency, 1977. Western Energy Resources the Environment. Washington, D.C., EPA-600/9-77-010.
- (2) Kestin, Joseph (ed), 1980. Sourcebook on the Production of Electricity from Geothermal Energy. U.S. Department of Energy, Washington, D.C., DOE/RA/4051-1.
- (3) Lawrence Livermore National Laboratory, 1980. An Assessment of Geothermal Development in the Imperial Valley of California. U.S. Department of Energy, Washington, D.C., DOE/EV-0092.
- (4) U.S. Department of Energy, 1980. "State-of-the-Art of Liquid Waste Disposal for Geothermal Energy Systems." Washington, D.C., DOE/EV-0083.

Therefore, given a resource temperature, well production rate, and desired electrical capacity, the total fluid requirement and the corresponding number of production wells to fulfill that requirement can be calculated. For example:

Given: Resource Temperature (T_r) = 230°C (446°F)
 Well Production Rate (W_p) = $2 \times 10^5 \text{ kg/h}$
 ($4.41 \times 10^5 \text{ lb/hr}$)
 Desired Capacity (C) = 50 MWe

Using Figure 2,

Fluid Requirements (B_{kWh}) = 70 kg/kWh
 or Total Fluid Requirements (B_T) = $B_{\text{kWh}} \times C$
 = $70 \text{ kg/kWh} \times 50,000 \text{ kW} = 3.5 \times 10^6 \text{ kg/h}$

Therefore, the minimum number of wells required

= $B_T \div W_p = 3.5 \times 10^6 \text{ kg/h} \div 2 \times 10^5 \text{ kg/h} = 17.5$
 = 18 production wells, excluding injection wells

The total geothermal fluid used would be the number of wells multiplied by the well production rate

(W_p)
 = $18 \times 2 \times 10^5 \text{ kg/h} = 36 \times 10^5 \text{ kg/h}$
 = $23.6 \times 10^6 \text{ tonnes/yr}$ ($26.0 \times 10^6 \text{ tons/yr}$)

To protect against subsidence (ground settling as the resource is depleted), injection of unused fluid and make-up fluid may be necessary. The required amount of fluid injection can vary from site to site and state to state.

The amount of extracted fluids required for each kWh of electricity produced is primarily a function of the resource temperature. Figure 2 is a plot of estimates of the fluid requirements of power plants using geothermal resources of different temperatures.

FIGURE 2. ESTIMATED FLUID REQUIREMENT AS A FUNCTION OF RESOURCE TEMPERATURE⁽³⁾

References

- (1) U.S. Environmental Protection Agency, 1977. Western Energy Resources and the Environmental Geothermal Energy. Washington, D.C., EPA-600/9-77-010
- (2) Kestin, Joseph (ed), 1980. Sourcebook on the Production of Electricity from Geothermal Energy. U.S. Department of Energy, Washington, D.C., DOE/RA/4501-1.
- (3) Lawrence Livermore National Laboratory, 1980. An Assessment of Geothermal Development in the Imperial Valley of California. U.S. Department of Energy, Washington, D.C., DOE/EV-0092.

TABLE 2. SOLID WASTES PRODUCED BY
WELL DRILLING ACTIVITY

m^3 (solid waste) per 100 m of well depth ⁽³⁾	m^3 (solid waste) per well (1500 m deep) ⁽³⁾	m^3 (solid waste) per 18 production wells
19 - 41 m^3	285 - 615 m^3	$5.13 \times 10^3 - 11.1 \times 10^3 \text{ m}^3$ ($181 \times 10^3 - 392 \times 10^3 \text{ ft}^3$)

TABLE 3. COMPONENTS OF A TYPICAL DRILLING MUD⁽³⁾
(LISTED IN ORDER OF DESCENDING QUANTITIES)

LIQUIDS

Water
WL-100 (sodium polyacrylate)
Drilling detergent

SOLIDS

Sepiolite (hydrous magnesium silicate)
Bentonite (porous clay)
Lignite (soft coal)
Caustic Soda (sodium hydroxide)
Soda Phosphate (sodium phosphate)
Soda Ash (sodium carbonate)
Barite (barium sulfate)
Bicarbonate of soda (sodium bicarbonate)

2

Fluid Flow to Flash Separator

For a desired electrical generating capacity of 50MWe, a minimum of 18 production wells are required, given a resource temperature of 446°F and a per well production rate of 4.41×10^5 lb/hr ($B_{kWh} = 70$ kg/kWh). Total fluid flow to the flash separator under these conditions is 26.0×10^6 tons/yr.

(2a) Some fluid is extracted during the testing and development stages of a geothermal plant. A reserve pit approximately 1,000 ft and 8 feet deep ($8,000 \text{ ft}^3$ or 226 m^3) is prepared to store waste fluids. (1) The release of geothermal fluid will be accompanied by the unabatement temporary release of air pollutants such as hydrogen sulfide, ammonia, methane and carbon dioxide.

The use of a surface impoundment to contain geothermal fluid may come under control of the Resource Conservation and Recovery Act (RCRA) though regulations have not yet been developed. (2) The presence of sufficient quantities of toxic substances such as zinc, lead, copper, arsenic and mercury in geothermal fluids may cause the fluids to be defined as hazardous waste under RCRA standards. If this were the case, then the fluids would require special disposal as hazardous wastes.

(2b) Geothermal resources are characterized by a significant lack of uniformity, even within the same well field over distances of a few kilometers. These factors are among those that may vary:

- fluid composition,
- fluid temperature,
- resource depth, and
- well production rate.

The exact fluid requirement will vary from plant to plant since the plant design is based on the conditions at each geothermal resource.

The resource characteristics of a geothermal site capable of providing a desired electrical capacity (MW) will be dependent primarily on the resource temperature (°C) and the unit well production rate (kg/h). The typical range of values for these parameters for a liquid-dominated resource are:

- 150° to 350°C (3) ($302 - 466^\circ\text{F}$), and
- 4×10^4 to 4×10^5 kg/h (2)

respectively.

3

Flashed Steam: Directly To Turbine or Through the EIC Hydrogen Sulfide (H₂S) Abatement

Flashed steam goes directly to the turbine if the Stretford process, a downstream system, is used. Otherwise, the EIC process, an upstream system, is used to abate hydrogen sulfide.

If the EIC Process is not used and the steam passes directly to the turbine, see step **4**.

Though it is still in the testing stage, the EIC Process for hydrogen sulfide (H₂S) abatement is an important alternative to the Stretford system by virtue of its being an upstream process; that is, H₂S is removed before the steam enters the power plant. The Stretford system, a downstream process, removes H₂S after the steam has passed through the power plant. Some of the advantages of an upstream process are listed below.^(1,2)

- When the plant is down (i.e., for maintenance), the steam bypasses the power plant but is nevertheless treated for H₂S emissions. A plant with downstream abatement cannot treat H₂S emissions of bypassed steam.
- Less expensive direct-contact condensers can be used instead of surface condensers. Direct-contact condensers cannot be used with downstream abatement processes since the contact of geothermal steam and a large amount of water spray would cause a significant portion of the H₂S to dissolve into the condensate and to therefore bypass the downstream abatement process.
- Removal of H₂S upstream of the plant reduces the corrosion on power plant components.

EIC Process Flow

3a

Scrubber Solution Start-up or Make-up Requirements

A certain amount of copper sulfate solution is required for the initial start-up of the EIC Process. During normal plant operation, it may be necessary to add make-up solution occasionally.

(3b)

In the scrubber, H_2S is removed when the steam is scrubbed with a dilute solution of copper sulfate:

Then:

Ammonia (NH_3) is removed by the reaction:

Boron (B) is also removed:

(3c)

Slurry Recirculation

Precipitates contained in the slurry include Cu_2S (cuprous sulfide), CuS (cupric sulfide), and elemental sulfur.^(1,2,3)

(3d)

Regenerated Copper Sulfate ($CuSO_4$) to Scrubber

The net reaction for $CuSO_4$ regeneration is:

(3e)

Cleaned Steam to Turbine

Table 4 summarizes the removal efficiencies of the EIC Process.

TABLE 4. EIC PROCESS ABATEMENT EFFICIENCIES^(1,2,3,4)

Component	Percent Removal
H_2S (hydrogen sulfide)	90-99%
NH_3 (ammonia)	80-90
H_3BO_3 (boric acid)	80-90
Particulates	Significant amounts

3f EIC Residuals

The primary constituent of EIC Process residue is ammonium sulfate ($(\text{NH}_4)_2\text{SO}_4$) which is produced in amounts proportional to the amount of H_2S in the geothermal fluid. It is estimated that a 50MWe plant in the Salton Sea area with 95% H_2S control would produce approximately $\times 10^5$ kg of aluminum sulfate annually. (5) Although pure aluminum sulfate can be used as a fertilizer, the residue from the EIC Process is contaminated with undetermined amounts of pollutants such as boric acid. (5)

References

- (1) U.S. Department of Energy, 1980. "State-of-the-Art Hydrogen Sulfide Control for Geothermal Energy Systems: 1979." Washington, D.C., DOE/EV-0068
- (2) EIC Corporation, 1978. "Control of Hydrogen Sulfide Emission from Geothermal Power Plants," U.S. Department of Energy, Washington, D.C., COO-2730-3.
- (3) Allen, G.W. and F.C. Brown, 1980. "Highlights of Test Results from the Operation of a 5MW Pilot Plant Demonstration of the EIC Process at the Geysers," Proceedings of the Second U.S. Department of Energy Environmental Control Symposium, March 17-19, 1980. Reston, Virginia, CONF-800334/2 (Available from NTIS, Springfield, Va).
- (4) Pacific Gas and Electric Company (for EIC Corporation), 1980. "Demonstration of EIC's Copper Sulfate Process for Removal of Hydrogen Sulfide and other Trace Contaminants from Geothermal Steam at Turbine Inlet Temperatures and Pressures." U.S. Department of Energy, Washington, D.C., DOE/RA/27181-01.
- (5) Layton, D.W. and W.F. Morris (Lawrence Livermore National Laboratory), 1981. "Geothermal Power: Accidental Fluid Releases and Waste Disposal," Chemical Engineering Progress, Vol. 77, No. 4.

3x Geothermal Fluid to Fluid Treatment

Geothermal fluid is often treated prior to reinjection to prevent clogging of the receiving aquifer.

Fluid that remains in the aqueous phase and does not flash into steam can be sent to optional fluid treatment. (1,2) Treatment of the fluid may be required to remove solids that were in suspension at high temperatures, but precipitate when the fluid cools to ambient temperatures. If not removed, these solids could clog the receiving aquifer during injection. Composition of the liquid effluent is discussed in (5).

A secondary H_2S abatement process can be used to remove H_2S from this fluid. Several available processes that are available are listed below: (3)

1. Caustic Soda Process - H_2S is contacted with sodium hydroxide (NaOH) in a countercurrent packed tower. H_2S and CO_2 are removed.
2. Iron Catalyst Process - The hydrogen peroxide-supplemented process uses a ferrous sulfate catalyst to convert H_2S to elemental sulfur and water.
3. Hydrogen Peroxide Process - H_2O_2 (hydrogen peroxide) reacts with H_2S to form elemental sulfur and water.

References

- (1) Lawrence Livermore National Laboratory, 1980. An Assessment of Geothermal Development in the Imperial Valley of California. U.S. Department of Energy, Washington, D.C., DOE/EV-0092.
- (2) Kestin, Joseph (ed), 1980. Sourcebook on the Production of Electricity from Geothermal Energy. U.S. Department of Energy, Washington, D.C., DOE/RA/4051-1.
- (3) U.S. Department of Energy, 1980. "State-of-the-Art Hydrogen Sulfide Control for Geothermal Energy Systems: 1979." Washington, D.C., DOE/EV-0068.

4

Flashed Steam to the Turbine

Between 10 and 30 percent (by weight) of the geothermal fluid is flashed to the gaseous stream and sent to the turbine.

Geothermal fluid/steam from the well is partitioned between the gaseous and aqueous phases at the flash separator. Each component of the fluid is partitioned depending on its own physical properties and the operating conditions of the separator. The partitioning of the various components at this point is not well understood.⁽¹⁾ The steam either passes through the EIC Process if this process is employed or passes directly to the turbine.

Steam yields from a liquid-dominated reservoir are approximately 10 to 30 percent by weight of the fluids from the well bore.^(1,2) Some estimates of steam yields are shown in Table 5.

TABLE 5. STEAM YIELD ESTIMATES⁽²⁾
(SEPARATOR PRESSURE = 4.46 BARS*)

<u>Separator Temperature</u>	<u>Steam Percentage</u>	<u>Aqueous Percentage</u>
200°C	11	89
300°C	33	67

*Lower pressures would increase the steam percentage.

References

- (1) Lawrence Livermore National Laboratory, 1980. An Assessment of Geothermal Development in the Imperial Valley of California. U.S. Department of Energy, Washington, D.C., DOE/EV-0092.
- (2) U.S. Department of Energy, 1980. "State-of-the-Art of Liquid Waste Disposal for Geothermal Energy Systems: 1979." Washington, D.C., DOE/EV-0083.

5 Treated Fluid to Injection Well

Liquid waste from the geothermal facility is injected into a deep well to prevent introduction to surface or ground waters. Pollutants contained in this liquid waste are as follows:

Total dissolved solids	22.6-226 (10^3) tons
Chloride	2.26-22.6 (10^3) tons
Calcium	226-2,260 tons
Magnesium	22.6-226 tons
Potassium	1.14-11.4 (10^3) tons
Aluminum	11.4-114 tons
Iron	22.6-226 tons
Bromide	11.4-114 tons
Manganese	22.6-226 tons
Strontium	11.4-114 tons
Lithium	22.6-226 tons
Cesium	2.26-22.6 tons
Fluoride	22.6-226 tons
Rubidium	11.4-114 tons
Iodine	2.26-22.6 tons
Copper	0-11.4 tons
Sulfur	4.52-45.2 tons
Sulfate	1.14-11.4 (10^3) tons
Silica	1.14-11.4 (10^3) tons
Sodium	2.26-22.6 (10^3) tons

Massive amounts of liquid wastes are produced by liquid-dominated geothermal power conversions. In the example below, assume a fluid consumption rate of 3.5×10^6 kg/h and a steam percentage of 20% (aqueous, 80%).

Liquid waste produced:

$$3.5 \times 10^6 \text{ kg/h} \times 0.80 = 2.80 \times 10^6 \text{ kg/h} (6.17 \times 10^6 \text{ lb/h}).$$

Then the production over a year is:

$$2.80 \times 10^6 \text{ kg/h} \times 24 \text{ h/day} \times 365 \text{ day/yr} \times 0.75 =$$

$$1.84 \times 10^{10} \text{ kg/yr} (4.05 \times 10^{10} \text{ lb/yr})$$

$$\text{or } 1.29 \times 10^4 \text{ acre-ft/yr}$$

where 75% is the power plant capacity factor.

Estimated amounts of various constituents in geothermal fluid are given in Table 6. The ranges of these components were obtained from several references (references 1 and 2) which derived their data from many different geothermal resources (including Salton Sea). A sample calculation is shown below:

Range of calcium in geothermal fluid is approximately .

$$10 \frac{\text{mg}}{\ell} \times \frac{\ell}{1.15 \text{ kg}} \times \frac{10^3 \text{ kg}}{\text{tonne}} \times 23.6 \times 10^6 \frac{\text{tonnes}}{\text{yr}} \times \frac{\text{tonne}}{10^9 \text{ mg}} = 205 \frac{\text{tonnes}}{\text{yr}}$$

where $1.15 \frac{\text{kg}}{\ell}$ = fluid density

$23.6 \times 10^6 \frac{\text{tonnes}}{\text{yr}}$ = fluid flow rate

Likewise,

$$100 \frac{\text{mg}}{\ell} = 2050 \frac{\text{tonnes}}{\text{yr}}$$

The amount of each constituent that can be removed from this fluid prior to injection is difficult to estimate with current data. Removal of solids, particularly silica, heavy metal sulfides and calcium, is important in order to prevent clogging of the injection well or receiving aquifer. ^(3,4)

Clarification has been shown to remove at least 80% on the injectable solids contained in geothermal fluid. ⁽⁵⁾ As much as 95%, can be removed via the

use of reaction-clarification coupled with granular media filtration. ⁽⁶⁾

Clogging can also be prevented by the addition of chemicals to the fluid to keep the dissolved and suspended solids in solution. ⁽⁴⁾ The extent of treatment required is a site-specific decision, depending at least in part on fluid composition and aquifer characteristics.

TABLE 6
CONSTITUENTS OF GEOTHERMAL LIQUID WASTE

Constituents	English Units	Metric Units
Total dissolved solids	22.6-226 (10^3) tons	20.5-205 (10^3) tonnes
Chloride	2.26-22.6 (10^3) tons	2.05-20.5 (10^3) tonnes
Calcium	226-2,260 tons	205-2,050 tonnes
Magnesium	22.6-226 tons	20.5-205 tonnes
Potassium	1.14-11.4 (10^3) tons	1.03-10.3 (10^3) tonnes
Aluminum	11.4-114 tons	10.3-103 tonnes
Iron	22.6-226 tons	20.5-205 tonnes
Bromide	11.4-114 tons	10.3-103 tonnes
Manganese	22.6-226 tons	20.5-205 tonnes
Strontium	11.4-114 tons	10.3-103 tonnes
Lithium	22.6-226 tons	20.5-205 tonnes
Cesium	2.26-22.6 tons	2.05-20.5 tonnes
Fluoride	22.6-226 tons	20.5-205 tonnes
Rubidium	11.4-114 tons	10.3-103 tonnes
Iodine	2.26-22.6 tons	2.05-20.5 tonnes
Copper	0-11.4 tons	0-10.3 tonnes
Sulfur	4.52-45.2 tons	4.10-41.0 tonnes
Sulfate	1.14-11.4 (10^3) tons	1.03-10.3 (10^3) tonnes
Silica	1.14-11.4 (10^3) tons	1.03-10.3 (10^3) tonnes
Sodium	2.26-22.6 (10^3) tons	2.05-20.5 (10^3) tonnes

Disposal of these wastes must be addressed in the design of a geothermal plant. Deep-well injection seems to be one of the most promising types of liquid waste disposal when compared to the alternatives of ponding or discharge to surface waters. Ponding of liquid wastes would require extensive amounts of land due to the large volume of fluid. Due to the presence of metals and other pollutants, geothermal liquid wastes are not suitable for release to surface or ground waters. The fluids would require extensive and costly treatment in order to meet environmental standards. The advantages and disadvantages of deep-well injection are listed below. (1,2,3,4)

Advantages

- More environmentally acceptable than most other alternatives (i.e., release to surface waters).
 - Effective mitigation measure for land subsidence caused by withdrawal of fluid from producing wells.
 - Source of fluid recharge for geothermal aquifer.
- (1,2,3,4)

Disadvantages

- Can lower the temperature and hence the energy potential of subsurface geothermal sources.
- In highly fractured reservoirs, the injected fluid may seep into and contaminate potable aquifers.
- Can induce seismicity.
- Cost of injection can reduce economic feasibility of the plant.

Many potential adverse effects of injection can be avoided through careful planning and proper placement of the injection wells.

References

- (1) Kestin, Joseph (ed), 1980. Sourcebook on the Production of Electricity from Geothermal Energy. U.S. Department of Energy, Washington, D.C.,
- (2) U.S. Department of Energy, 1980. "State-of-the-Art of Liquid Waste Disposal for Geothermal Energy Systems: 1979." Washington, D.C., DOE/EV-0083.
- (3) Lawrence Livermore National Laboratory, 1980. An Assessment of Geothermal Development in the Imperial Valley of California. U.S. Department of Energy, Washington, D.C., DOE/EV-0092.
- (4) U.S. Environmental Protection Agency, 1977. Western Energy Resources and the Environmental Geothermal Energy. Washington, D.C., EPA-600/9-77-010.
- (5) Quong, R. et. al. (Lawrence Livermore National Laboratory), July 1978. "Principles of Geothermal Brine Effluents for Injection," Transactions of the Geothermal Resources Council, pp. 551-554.
- (6) Layton, D.W. and W.F. Morris (Lawrence Livermore National Laboratory), 1981. "Geothermal Power: Accidental Fluid Releases and Waste Disposal," Chemical Engineering Progress, Vol. 77, No. 4.

⑥ Solid Wastes to Disposal (Optional)

Solid wastes from fluid treatment are generated at an approximate rate of 3.9×10^6 kg/yr, requiring an area of about 488 m^2 for disposal annually.

Optional fluid treatment may be required in order to remove suspended and dissolved solids that might either clog the injection wells and the receiving aquifer or contaminate adjacent aquifers.^(1,2,3) Removal rates and efficiencies are, of course, dependent on the type of treatment equipment used as well as the form and concentration of constituents in the waste stream. Sedimentation, chemical coagulation, and filtration may be used since these techniques are not energy intensive and have been used successfully for many years in wastewater treatment plants. The exact treatment processes chosen must be tailored to the specific composition of the resulting fluid and the applicable environmental standards and regulations.

An estimated 3.9×10^6 kg/yr of solids would be produced from the separation of solids from geothermal fluid by a 50 MWe plant (0.75 capacity factor) in the Salton Sea resource area.⁽⁴⁾ This quantity of solids can be considered as an upper limit since the Salton Sea resource contains extremely high levels of solids. Total dissolved solids (TDS) of Salton Sea geothermal fluids average about 250,000 mg/l whereas the TDS for East Mesa fluids range from 2000 to 25,000 mg/l.⁽⁴⁾

The precipitates from the Salton Sea fluid consisted mostly of silica (as SiO_2) which comprised up to 75% of the precipitate. Approximately 10% of the precipitates were iron (Fe) while the remaining percentage contained minor amounts of other elements.⁽²⁾ Another reference also listed SiO_2 and iron as important elements of geothermal fluids and additionally listed sodium (Na), chlorine (Cl) and sulfate (SO_4) as significant components.⁽⁴⁾ Metals other than lead that can be found in significant amounts (>1000 ppm) in geothermal fluid precipitates are antimony (Sb), arsenic (As), thallium (Tl) and mercury (Hg).⁽⁵⁾

The volume required for this can be calculated assuming a filtered and pressed density of 1600 kg/m^3 .⁽²⁾

$$\begin{aligned} &3.9 \times 10^3 \text{ tonnes/yr} \times \text{m}^3/1600 \text{ kg} \\ &= 2440 \text{ m}^3/\text{yr of solid waste} \end{aligned}$$

Assuming a depth of 5 meters, disposal of this solid waste would require an area of 488 m^2 or 0.121 acres annually.

$$2440 \text{ m}^3 \div 5\text{m} = 488 \text{ m}^2 \text{ (0.121 acres)}$$

This area, when multiplied by the lifetime of the plant (30 years), becomes 3.63 acres.

The solids separated from geothermal fluids may be classified as hazardous due to the presence of metal sulfides (i.e., lead sulfide).⁽¹⁾ If this is the case, then the solids will require special disposal.

An estimated 231 tons per year (210 tonnes/yr) of scale is removed from a 50 MWe plant.⁽⁴⁾ Scale is formed when solids adhere to components in the power plant such as pipes and cooling louvers.

References

- (1) Kestin, Joseph (ed.) 1980. Sourcebook on the Production of Electricity from Geothermal Energy. U.S. Department of Energy, Washington, D.C., DOE/RA/4051-1.
- (2) Lawrence Livermore National Laboratory, 1980. An Assessment of Geothermal Development in the Imperial Valley of California. U.S. Department of Energy, Washington, D.C., DOE/EV-0092.
- (3) U.S. Department of Energy, 1980. "State-of-the-Art of Liquid Waste Disposal for Geothermal Energy Systems: 1979," Washington, D.C., DOE/EV-0083.
- (4) Layton, D.W. and W.F. Morris (Lawrence Livermore National Laboratory), 1981. "Geothermal Power: Accidental Fluid Releases and Waste Disposal," Chemical Engineering Progress, Vol. 77, No. 4.
- (5) Ellis, A.J. and W.A. Mahon, 1977. Chemistry and Geothermal Systems, Academic Press, New York.

7 Condensate to Cooling Tower

Condensate from the spent turbine steam is sent to the cooling tower.⁽¹⁾ In some cases, the amount of condensate is greater than the amount of water needed for the cooling tower and thus a net gain of water may occur.⁽²⁾

References

- (1) Lawrence Livermore National Laboratory, 1980. An Assessment of Geothermal Development in the Imperial Valley of California. U.S. Department of Energy, Washington, D.C., DOE/EV-0092.
- (2) Armstead, H. Christopher H., 1978. Geothermal Energy, John Wiley & Sons, New York.

8 Cooling Tower Emissions

Air pollutants emitted from the cooling tower are as follows:

<i>Hydrogen sulfide</i>	<i>4.41-44.1 tons</i>
<i>Ammonia</i>	<i>165-17,000 tons</i>
<i>Methane</i>	<i>108-4,520 tons</i>
<i>Carbon dioxide</i>	<i>6,780-67,800 tons</i>
<i>Arsenic</i>	<i>0.452-4.52 tons</i>
<i>Boron</i>	<i>11.4-114 tons</i>
<i>Mercury</i>	<i>0-2.26 tons</i>
<i>Radon</i>	<i>10.5-16.1 Ci</i>
<i>Benzene</i>	<i>22.0 tons</i>

The constituents of cooling tower drift are largely determined by (1) the composition of the make-up water, (2) the design of the cooling system, and (3) the composition of the geothermal fluid condensate. When condensed steam is used as make-up water, dissolved salts and suspended particles circulate in the cooling tower and are emitted with the water droplets that are emitted as cooling tower drift.⁽¹⁾ When other sources of make-up water are used, the resultant emissions depend on the constituents of this water.

The principal noncondensable gases that may be emitted from the cooling tower include carbon dioxide (CO_2), hydrogen sulfide (H_2S), ammonia (NH_3), mercury (Hg), and radon (Rn).^(1,2,) The Stretford process effectively removes 99% of the H_2S contained in the input to the Stretford unit. Assuming that 90% of the H_2S is partitioned into the gaseous phase, then approximately 1% of this 90% may pass through the Stretford process and be emitted as cooling tower drift. The portion of H_2S that is not partitioned into the gaseous phase remains in the condensate. Some substances emitted from the cooling tower (i.e., H_2S , NH_3) have the potential to be malodorous.

Ranges of pollutants emitted from geothermal plants are listed in several sources (references 1,2,3) and are shown in Table 7. The lower values are generally from data from the East Mesa resource from reference 1, and upper values are generally from references 2 and 3. Values were converted from their original units (i.e. mg/l or g/MWh) to the units used in Table 7. A sample calculation is shown below.

Ammonia contained in geothermal fluid:

low - 455 g/MWh (reference 1)

high - 750 mg/l (reference 2)

$$455 \frac{\text{g}}{\text{MWh}} \times \frac{\text{tonne}}{10^6 \text{ g}} \times 50 \text{ MW} \times 24 \frac{\text{hr}}{\text{day}} \times 365 \frac{\text{day}}{\text{yr}} \times 0.75 =$$

$$750 \frac{\text{mg}}{\text{l}} \times \frac{\text{l}}{1.15 \text{ kg}} \times \frac{10^3 \text{ kg}}{\text{tonne}} \times 23.6 \times 10^6 \frac{\text{tonnes}}{\text{yr}} \times \frac{\text{tonne}}{10^9 \text{ mg}} =$$

$$1.54 \times 10^4 \frac{\text{tonnes}}{\text{yr}} \quad (17,000 \frac{\text{tons}}{\text{yr}})$$

where 0.75 = capacity factor

$1.15 \frac{\text{kg}}{\text{l}}$ = geothermal fluid density

$23.6 \times 10^6 \frac{\text{tonnes}}{\text{yr}}$ = fluid flow rate.

Values for other pollutants were calculated in the same manner. Abatement efficiencies were included in the calculations for hydrogen sulfide.

The EIC abatement process can remove significant portions of hydrogen sulfide, ammonia, boric acid, and particulates (see (3e)). (1,2,4,5,6)

Cooling tower losses include losses due to evaporation, blowdown, and drift. Drift losses comprise 0.05-0.3% of cooling tower water recirculation. The amount of drift is not a strong function of water loading, but depends on air flow rates, velocities, and temperatures. (3,7)

Maximum deposition rates from drift tend to be within about 1.6 km (1 mile) of mechanical draft towers and can amount to 10 or more $\text{g/m}^2\text{-yr}$. (3)

TABLE 7
ANNUAL RELEASE OF AIR POLLUTANTS

	English Units	Metric Units
Hydrogen sulfide	4.41-44.1 tons	4.00-40.0 tonnes
Ammonia	165-17,000 tons	150-15,400 tonnes
Methane	108-4,520 tons	98.0-4,100 tonnes
Carbon dioxide	6,780-67,800 tons	6,150-61,500 tonnes
Arsenic	0.452-4.52 tons	0.410-4.10 tonnes
Boron	11.4-114 tons	10.3-103 tonnes
Mercury	0-2.26 tons	0-2.05 tonnes
Radon	10.5-16.1 Ci	10.5-16.1 Ci
Benzene	22.0 tons	20.0 tonnes

References

- (1) Lawrence Livermore National Laboratory, 1980. An Assessment of Geothermal Development in the Imperial Valley of California. U.S. Department of Energy, Washington, D.C., DOE/EV-0092.
- (2) U.S. Department of Energy, 1980. "State-of-the-Art of Liquid Waste Disposal for Geothermal Energy Systems: 1979." Washington, D.C., DOE/EV-0083.
- (3) Kestin, Joseph (ed), 1980. Sourcebook on the Production of Electricity from Geothermal Energy. U.S. Department of Energy, Washington, D.C., DOE/RA/4051-1.
- (4) Allen, G.W. and F.C. Brown, 1980. "Highlights of Test Results from the Operation of a 5MW Pilot Plant Demonstration of the EIC Process at the Geysers." Proceedings of the Second U.S. Department of Energy Environmental Control Symposium, March 17-19, 1980, Reston, Virginia. CONF-800334/2 (Available from NTIS).
- (5) EIC Corporation, 1978. "Control of Hydrogen Sulfide Emissions from Geothermal Power Plants." U.S. Department of Energy, Washington, D.C., COO-2730-3.
- (6) EIC Corporation, 1980. "Demonstration of EIC's Copper Sulfate Process for Removal of Hydrogen Sulfide and other Trace Contaminants from Geothermal Steam at Turbine Inlet Temperatures and Pressures." U.S. Department of Energy, Washington, D.C., DOE/RA/27181-01.
- (7) The Marley Company, 1968. Cooling Tower Fundamentals and Application Principles, Kansas City, Missouri.

9 Cooled Water to Condenser

Water is cooled in the cooling tower for use in the condenser.

The flowrate of circulating water in the cooling tower is a function of the temperature difference between the incoming and outgoing water and the particular design selected to achieve this temperature differential. The design will be a function of many variables including site specific meteorological conditions, land area requirements, quality and availability of makeup water, environmental considerations and other factors. Large cooling tower cells, or modules, can cool up to $1 \text{ m}^3/\text{sec}$ (16,000 gpm) of circulating water; intermediate sizes can handle capacities of 0.02 to $0.4 \text{ m}^3/\text{sec}$ (300-6000 gpm).⁽¹⁾

Existing and planned geothermal plants with capacities of 50-55 MW output utilize mechanical-draft cooling towers with circulating water flow rates of approximately 60,000 gpm⁽²⁾. Thus, to accommodate this rate, at least four (4) large cells or ten (10) intermediate cells would be required.

References

- (1) Kestin, Joseph (ed.), 1980. Sourcebook on the Production of Electricity from Geothermal Energy. U.S. Department of Energy, Washington, D.C., DOE/RA/4051-1.
- (2) Di Pippo, Ronald, 1980. Geothermal Energy as a Source of Electricity. U.S. Department of Energy, Washington, D.C.

10 Cooling Tower Blowdown to Treatment

Circulating water of a high dissolved solids content is removed from the cooling tower and sent to fluid treatment.

Circulating water is periodically removed as blowdown for treatment and disposal in order to control the concentration of salts and dissolved solids in the circulating water.⁽¹⁾ The blowdown water contains dissolved gases, some heavy metals, and other dissolved solids.⁽²⁾ Blowdown is discharged when it reaches the prescribed "cycles of concentration," the ratio of total dissolved solids (TDS) in the blowdown to the TDS in the make-up water. A concentration factor of 2 would imply that the circulating water is discharged as blowdown when it has a TDS concentration that is twice that of make-up water. Where make-up water is scarce, the concentration factor may be as high as 7.⁽²⁾

$$\text{Concentration Factor} = \frac{\text{TDS in blowdown}}{\text{TDS in make-up water}} = 2 \text{ to } 7$$

The actual amount of blowdown will depend on:

- (1) steam flow rate (which affects the rate at which condensate enters the tower),
- (2) cooling tower design, and
- (3) local meteorology, particularly humidity (which affects evaporation of cooling tower circulating water).

Typical blowdown rates are 0.4-3.0% of the water circulation rate,^(2,3) in comparison to non-geothermal processes where many blowdown rates exceed 5-8%.

References

- (1) Ellis, A.J., 1978. "Geothermal Fluid Chemistry and Human Health," *Geothermics*, Vol. 6, pp. 175-182.
- (2) Kestin, Joseph (ed), 1980. Sourcebook on the Production of Electricity from Geothermal Energy. U.S. Department of Energy, Washington, D.C., DOE/RA/4051-1.
- (3) The Marley Company, 1968. Cooling Tower Fundamentals and Application Principles, Kansas City, Missouri.

11 Noncondensable Gases to Stretford Process

The Stretford abatement process is used to remove hydrogen sulfide.

Noncondensable gases (i.e., CO_2 , H_2S , NH_3 , CH_4 , H_3BO_3) comprise approximately 0.3-5.0% of the flashed steam.⁽¹⁾ The total amount of gases passing through plant depends of course on the steam flow. Figure C-1 in Appendix C gives ranges of noncondensable gas concentration in geothermal fluids.

Stretford Abatement Process (1,2,3,4,5)

11a A certain amount of the scrubber solution is required for the initial start-up of the plant. During normal plant operation some make-up solution may need to be added.

11b In the scrubber, the off-gases are scrubbed in a countercurrent flow of a solution containing sodium carbonate (Na_2CO_3), sodium metavanadate (NaHVO_3) and anthraquinone disulfonic acid (ADA). The H_2S is dissolved forming hydrosulfide ion:

The hydrosulfide ion then reacts with the vanadium ion and oxygen to form elemental sulfur and water:

The reduced vanadium is regenerated to its +5 valence state by a mechanism involving oxygen transfer by ADA:

11c Air passed through the above solution in an oxidizer tank not only oxidizes the ADA, but bubbles also bring the elemental sulfur to the surface as a froth. This sulfur froth is then skimmed from the solution and is sent to a centrifugation and heating process. The remaining absorber solution is recycled back to the scrubber.

(11d) The sodium carbonate is regenerated and recycled by reacting the sodium bicarbonate with caustic soda:

(11e) Sulfur is centrifuged and heated to form high quality sulfur. The amount of sulfur produced is directly proportional to the amount of H_2S in the flashed geothermal steam. The amount of H_2S depends on (1) the composition of the fluid, (2) the percentage of H_2S partitioned into the gas stream during flashing, and (3) the amount of H_2S removed from the partitioned gas stream by the abatement process.

Assume:

1. 20 mg/l of H_2S in geothermal fluid
2. 2×10^5 kg/h fluid flow
3. 90% H_2S partitioning efficiency
4. 99% H_2S abatement efficiency
5. 1.15 kg/l geothermal fluid density
6. 18 wells

Then the amount of H_2S that enters the plant is:

$$\begin{aligned} S_p &= S_b \times b \times 1/\rho_b \quad (\text{From Appendix C, Step 1}) \\ S_p &= 20 \text{ mg/l} \times 2 \times 10^5 \text{ kg/h} \times 1/1.15 \text{ kg} \times \text{kg}/10^6 \text{ mg} \times 18 \\ &= 62.6 \text{ kg/h.} \end{aligned}$$

Ninety percent of the H_2S is partitioned into the gas stream:

$$62.6 \text{ kg/h} \times 0.90 = 56.3 \text{ kg/h } \text{H}_2\text{S} \text{ in steam}$$

The Stretford process removes 99% of the H_2S in the gas stream that enters the Stretford unit:

$$56.3 \text{ kg/h} \times .99 = 55.7 \text{ kg/h } \text{H}_2\text{S} \text{ removed}$$

Sulfur comprises 94% of H_2S :

$$\begin{aligned} 55.7 \text{ kg/h} \times 0.94 &= \boxed{52.4 \text{ kg/h}} \text{ sulfur produced} \\ &= 344 \times 10^3 \text{ kg/yr} \quad (758 \times 10^3 \text{ lb/yr}) \\ &= 344 \text{ tonnes/yr} \quad (379 \text{ tons/yr}). \end{aligned}$$

References

- (1) Kestin, Joseph (ed), 1980. Sourcebook on the Production of Electricity from Geothermal Energy. U.S. Department of Energy, Washington, D.C. DOE/RA/4051-1.
- (2) Institute of Gas Technology, 1980. "Preparation of a Coal Conversion Systems Technical Data Book". U.S. Department of Energy, Washington, D.C., FE-2286-48.
- (3) Lawrence Livermore National Laboratory, 1980. An Assessment of Geothermal Development in the Imperial Valley of California. U.S. Department of Energy, Washington, D.C., DOE/EV-0092.
- (4) Laszlo, J., 1976. "Application of the Stretford Process for H₂S Abatement at the Geysers Geothermal Power Plant." Proceedings of the Eleventh Intersociety Energy Conversion Engineering Conference, September 12-17, 1976, State Line, Nevada.
- (5) U.S. Department of Energy, 1980. "State-of-the-Art Hydrogen Sulfide Control for Geothermal Energy Systems: 1979." Washington, D.C., DOE/EV-0068.

12 Cleaned & Noncondensable Gases to Cooling Tower

The gases remaining after the abatement process are sent to the cooling tower.

A Stretford unit is over 99% efficient so that most of the H_2S delivered to the unit is removed. (1,2,3,4,5) The overall abatement efficiency for the geothermal facility is 78-92% depending on the partitioning of H_2S between gaseous and aqueous phases. (1,2) Table 8 illustrates the amount of H_2S remaining after abatement for several H_2S concentrations and overall abatement efficiencies.

TABLE 8. AMOUNT OF H_2S REMAINING AFTER ABATEMENT

Amount of H_2S (3) In Fluid (mg/l)	Amount Entering The Plant* (kg/h)	Overall (3,4) Abatement Efficiency (%)	Amount of H_2S Passed to Cooling Tower (kg/h)
120	376	78	86.5
120	376	92	30.1
85	266	78	61.2
85	266	92	21.3
5	15.6	78	3.59
5	15.6	92	1.25

*Fluid Consumption Rate assumed to be 2×10^5 kg/h for each of 18 wells.

References

- (1) Laszlo, J., 1976. "Application of the Stretford Process for H_2S Abatement at the Geysers Geothermal Power Plant". Proceedings of the Eleventh Inter-society Energy Conversion Engineering Conference, September 12-17, 1976, State Line, Nevada.
- (2) Lawrence Livermore National Laboratory, 1980. An Assessment of Geothermal Development in the Imperial Valley of California. U.S. Department of Energy, Washington, D.C., DOE/EV-0092.
- (3) Kestin, Joseph (ed), 1980. Sourcebook on the Production of Electricity from Geothermal Energy. U.S. Department of Energy, Washington, D.C., DOE/RA/4051-1.
- (4) Institute of Gas Technology, 1980. "Preparation of a Coal Conversion Systems Technical Data Book". U.S. Department of Energy, Washington, D.C., FE-2286-48.
- (5) U.S. Department of Energy, 1980. "State-of-the-Art Hydrogen Sulfide Control for Geothermal Energy Systems: 1979." Washington, D.C., DOE/EV-0068.

13 Make-up Water to the Cooling Tower

Approximately 2.24×10^3 acre-ft of make-up water per year are required by the cooling tower.

Make-up water is required to replace water that has either evaporated or been withdrawn as cooling tower blowdown. Circulating fluids are withdrawn as blowdown when the solids concentration reaches a set limit, unless the fluid is required for injection for mitigation of subsidence.⁽¹⁾ In this case blowdown is withdrawn at a faster pace and larger amounts of make-up water are required to offset the loss. If no blowdown is required for mitigation, then make-up water requirements may be relatively low. An estimated 1850 gpm (2.24×10^3 acre-ft) make-up water requirement is discussed in Section III, Physical Requirements.

Reference

- (1) Kestin, Joseph (ed), 1980. Sourcebook on the Production of Electricity from Geothermal Energy. U.S. Department of Energy, Washington, D.C., DOE/RA/4051-1.

III. PHYSICAL REQUIREMENTS

Water Requirements

Wet, mechanical-draft cooling towers are the most frequently used cooling process for hydrothermal facilities in the Western U.S. They are enclosed structures which provide an intimate mixing of water and air that results in accelerated cooling effect. This effect is provided mostly by an exchange of latent heat (heat of vaporization) resulting from the evaporation of a small amount of water, and partly by a transfer of sensible heat from the water to the air. Cooling towers can be designed to minimize use of water and, hence, are appropriate for water-conservative areas.⁽¹⁾

After start-up, the cooling water make-up requirement for this type of tower is equal to the amount lost to evaporation, the amount discharged as blowdown, and the amount lost to the atmosphere by the action of wind (drift loss). The number of times that the dissolved solids of the make-up water can be concentrated by evaporative losses from the cooling tower (cycles of concentration) directly controls the amount of blowdown water.⁽²⁾ Water is blown down from the tower as the concentration of solids reaches a particular saturation. Make-up water then is simultaneously added to dilute the cooling water and thus prevent mineral deposition from forming on heat transfer surfaces.

Typically, condensate from steam turbines is fairly low in dissolved solids. As a consequence, high cycles of concentration (i.e., 9 to 11) can be employed in a cooling tower in which the make-up stream is comprised exclusively of low solids content condensate.⁽³⁾

Estimated requirements for make-up water to the cooling towers of a 50-MWe geothermal plant are

Assumptions

Cooling Water Flow ⁽³⁾	-	60,000 gpm
Temperature Drop	-	26°F
Cycles of Concentration	-	7
Drift Loss Rate ⁽¹⁾	-	.05% Cooling Water Flow
Evaporative Loss Rate ⁽¹⁾	-	2.6% Cooling Water Flow
Blowdown Loss Rate ⁽¹⁾	-	.43% Cooling Water Flow

Drift Losses	=	(.0005) x (60,000 gpm)	=	30 gpm
Evaporative Losses	=	(.026) x (60,000 gpm)	=	1,560 gpm
Blowdown Losses	=	(.0043) x (60,000 gpm)	=	260 gpm
Make-up Water Req't	=	(.0308) x (60,000 gpm)	=	1,850 gpm

As long as the amount of condensate available for use in the cooling towers exceeds the various cooling losses, then no make-up water to the geothermal plant from external water supplies will be required. However, local mitigation measures to control subsidence and/or seismicity may be mandated requiring the injection of volumes of fluids equal to extracted fluids. Under such a scenario, the following formula presents the necessary calculation for determining the external water demand for the 50-MWe facility:

$$\begin{aligned} \text{Water Requirement} &= \text{Drift Losses} + \text{Evaporative Losses} \\ &+ \text{Blowdown Losses} \\ &- \text{Condensate Added to Make-up} \end{aligned}$$

Land Requirements

Land requirements for a given geothermal site intended to provide a specified electrical capacity will depend primarily on land requirements for the power production facility, well fields, and power transmission lines.

The major components affecting land requirements for the power production facility include turbine generators⁽⁴⁾ and condensers, cooling towers and transformers.⁽⁴⁾ The number and size of components and physical plant configuration will vary significantly from site to site and depend primarily on economic considerations and site topography. Estimates of land requirements for these components are on the order of 5 to 20 acres,⁽³⁾ based on existing and planned facilities.

The land required for the well field is primarily a function of the number and density of supply (and injection, if any) wells. Factors affecting these parameters include:

- Electrical Capacity - Higher capacities require more supply wells.
- Resource Characteristics - Wells must be drilled into zones of subsurface fractures where heat reservoirs are located.

- Site Topography - As the slope of the land increases, the land requirements increases due to stabilization requirements.
- Field Development Policy - A fast-paced policy results in a more clustered well arrangement requiring fewer acres per well.

Estimates of well densities (well spacing) of existing, developed geothermal sites range from 2 acres/well to as much as 240 acres/well.⁽³⁾

to accommodate roads and pipelines are normally contained on the well fields. The land between the wells can be used for activities such as agriculture or grazing.⁽⁴⁾ When the well density is low (e.g., 240 acres/well), land allocations for access roads and pipelines are included in the estimate; however, when the well density is high (e.g., 2 acres/well) land allocations for access roads (e.g., about 2 acres/well) and pipeline space become significant. The amount of land required for transmission lines depends on the plant's proximity to existing power grids.

In general:

$$\begin{aligned} \text{Land Requirement} = & (\text{Well density}) (\text{Number of Wells}) \\ & + (\text{Turbine Generator, Condenser,} \\ & \text{Cooling Tower, and Transformer Area}) \\ & + (\text{Access Roads}) + (\text{Pipeline Area}) \\ & + (\text{Power Lines Clearance}) \end{aligned}$$

References

- (1) The Marley Company, 1968. Cooling Tower Fundamentals and Application Principles, Kansas City, Missouri.
- (2) BETZ Laboratories, 1976. Handbook of Industrial Water Conditioning, 2nd ed., Trevose, Pennsylvania.
- (3) Kestin, Joseph (ed), 1980. Sourcebook on the Production of Electricity from Geothermal Energy. U.S. Department of Energy, Washington, D.C., DOE/RA/4051-1.
- (4) U.S. Environmental Protection Agency, 1977. Western Energy Resources and the Environmental Geothermal Energy. Washington, D.C., EPA-600/9-77-010.

IV. PERSONNEL REQUIREMENTS

The personnel required to operate a geothermal plant will depend in part on the power capacity of the plant, the complexity of the conversion and pollution abatement systems, and the individual plant design and management philosophy. Approximately 50 persons are required to operate and maintain the 660-MWe Geysers facility in California.⁽¹⁾ This vapor-dominated plant is less complex and requires less manpower than would a typical liquid-dominated facility.

Personnel estimates for the 50-MWe Baca geothermal plant in New Mexico are listed in Table 9.

TABLE 9
BACA PERSONNEL ESTIMATES⁽²⁾

Phase	Construction Craftsmen*	Supervisory	Total
		Staff	
Construction, 1st year	79 (maximum)	12	91
Construction, 2nd year	221 (maximum)	12	233
<u>Operation & Maintenance</u>			
Plant Operation	55	12	67

*i.e., pipe fitters, drill crewmen, electricians, operating engineers.

The staff required for routine operation of the 192.6-MW plant in Wairakei, New Zealand is listed in Table 10. The number of employees at Wairakei varies with the workload; an average for a four-year period was 150 employees.

TABLE 10
WAIRAKEI PERSONNEL REQUIREMENTS⁽³⁾

	<u>Persons/192.6 MW</u>	<u>Persons/50 MW* (est.)</u>
Administration	8	2
Operation & Maintenance	141	37
Services	12	3
Total	161	42

*These values were calculated using a linear interpolation between the 192.6-MWe and 50-MWe personnel requirements.

References

- (1) Lawrence Livermore National Laboratory, 1980. An Assessment of Geothermal Development in the Imperial Valley of California. U.S. Department of Energy, Washington, D.C., DOE/EV-0092.
- (2) U.S. Department of Energy, 1980. "Geothermal Demonstration Program, Final Environmental Impact Statement." Washington, D.C., DOE/EIS-0049.
- (3) Goodman, Louis J. and Ralph N. Love (ed.), 1980. "Geothermal Energy Projects." Pergamon Press, New York.

V. OCCUPATIONAL SAFETY AND HEALTH CONSIDERATIONS

Well blowouts and exposure to steam, hot water, and possibly hydrogen sulfide and noise are the most significant occupational hazards associated with geothermal energy. Although a detailed evaluation of these hazards is difficult since little operational data exist, some analogies to similar technologies can be made.

Well Blowouts

Blowouts, which can occur during drilling operations or during normal plant operations, cause the release of hot fluid, steam and gases. During drilling operations, a blowout may occur when pressurized brine forces its way to the surface via a path other than the well bore. Structural failure of cement and casing materials in the well or an instability in a land formation can cause a blowout during normal plant operation. Fortunately, this type of occurrence is very infrequent since modern drilling techniques can significantly reduce the risk of a blowout.⁽¹⁾ The National Petroleum Council reported 106 blowouts during the drilling of 273,000 petroleum wells in the 1960-1970 decade.⁽²⁾ Natural gas accident data show that onshore extraction involved 0.00008 fatalities per 10^{12} Btu and 0.004 injuries per 10^{12} Btu.⁽³⁾ Analogous rates for geothermal extraction may actually be less than these due to the significantly lower pressures of liquid-dominated geothermal resources relative to high pressure oil/gas wells. However, the forces acting in a geothermal well are quite different from those of an oil/gas well. Oil and gas wells are not subjected to the effects of deposition and fouling, nor do they have problems with separation of casings from the surrounding soils due to large thermal gradients imparted by geothermal sources.⁽⁴⁾

Hydrogen Sulfide

Exposure to hydrogen sulfide (H_2S) is probably the most significant health hazard associated with geothermal energy plants. Although other airborne contaminants, such as ammonia, mercury, radon, and benzene, are known to be present, they do not appear to pose either an occupational or public health problem.

Hydrogen sulfide is a toxic gas that is released from geothermal fluid during well drilling and routine plant operations. Although H_2S is detectable at concentrations as low as 0.002 parts per million (ppm), health manifestations do not occur until levels reach a few ppm. For example, local inflammation of moist membranes of the eyes and lungs will occur at exposure levels of 10-20 ppm (see Table 11). Experience at The Geysers in California results of air quality modeling studies prepared for other principally hydrothermal sites indicate that ambient levels of H_2S should pose no chronic health problems, but rather a safety problem. This is due to the fact that H_2S can accumulate in certain areas (such as geothermal well-head pits and underground cableways)⁽⁵⁾ and can reach concentrations that are lethal but not detectable by smell due to olfactory paralysis as is shown in Table 11. Concentrations may be sufficiently high to constitute an odor nuisance to operators as well as visitors within a short distance of the plant.

Control of hydrogen sulfide is being accomplished by various abatement processes, but these processes expose workers to hazardous chemicals and waste products. Occupational illness information from The Geysers in California, Table 12 and Figure 3, includes both exposure to hydrogen sulfide and exposure to the by-products of hydrogen sulfide abatement. The increase in illnesses in early 1976 shown in Figure 3 is due at least in part to the installation of an unfamiliar abatement process. As familiarity with the process increased, the injuries began to decrease.⁽⁶⁾

The standards and recommendations for occupational exposure to hydrogen sulfide are listed in Table 13.

Noise

Exposure to high levels of noise is also an occupational hazard of the geothermal industry. The possible effects of noise exposure are hearing loss, interference with communication, sleep disturbance, and stress reactions that can have long term health implications.⁽¹⁾

The most significant noise associated with hot fluid wells is that emitted during production testing for power generation, when 20 to 25 percent of the hot fluid is flashed to steam. If unmuffled, the noise of the expanding steam could reach a level as high as 100 dB at 50 feet. Other noise levels are listed in Table 14.⁽⁷⁾

The Occupational Safety and Health Administration regulations specify that no workers be subjected to 115 dB for more than 15 minutes or to 90

TABLE 11
EFFECTS OF HYDROGEN SULFIDE ABATEMENT^(1,4,5,6,8)

<u>H₂S Concentration</u> <u>(parts per million, ppm)</u>	<u>Effects on Humans</u>
0.002-0.003	Odor threshold; detectable as "rotten egg" smell
0.33	Distinct odor; can cause nausea, headache
10-20	Local inflammation of moist membranes of eyes and lungs
50-100	Threshold for serious eye injury
150-250	Olfactory paralysis (prevents detection of H ₂ S by smell)
>300	Production of pulmonary edema (accumulation of fluid) which can occur with exposures of a few hours
>500	Strong stimulation of nervous system and apnea (transient cessation of respiration)
600	Has been fatal with exposures of 30 minutes
>800	Lethal immediately

TABLE 12
REPORTS OF OCCUPATIONAL ILLNESS AT THE GEYSERS,
CALIFORNIA FROM 1974 TO MID-1977⁽⁶⁾

<u>Operation</u>	<u>Type of Exposure</u>	<u>Number of Reports/ 50 Employees</u>
Drilling	H ₂ S, NH ₃	2
Power Production	H ₂ S	3
	H ₂ S and H ₂ S abatement sludges	10
	Hazardous chemicals	3

FIGURE 3
NUMBER OF DOCTOR'S FIRST REPORTS OF OCCUPATIONAL ILLNESS
PER SIX-MONTH PERIOD AT THE GEYSERS IN CALIFORNIA⁽⁶⁾
 (approximately fifty workers)

TABLE 13
STANDARDS AND RECOMMENDATIONS FOR H₂S

<u>Agency or Group</u>	<u>Standard or Recommendation</u>
Occupational Safety and Health Administration (1,7,9)	20 ppm acceptable ceiling concentration for an 8 hour shift 50 ppm maximum peak for 10 minutes of exposure once per 8 hour shift if no other measurable exposure occurs
National Institute of Occupational Safety and Health ^(9,12)	10 ppm peak for 10 minutes for up to a 10 hour shift in a 40 hour work week ≥ 47 ppm (70 mg/m ³) evacuation recommended
American Conference of Governmental Industrial Hygienists ^(1,10)	10 ppm time-weighted average limit over work day in a week 15 ppm maximum peak for 15 minutes

TABLE 14
TYPICAL NOISE LEVELS (7)

<u>Operation</u>	<u>Noise Level</u>	<u>Distance</u>
Well Drilling	75-85 dB	50 feet
Operation of Construction Machinery	70-95	50
Plant Operation	70-100	50
Familiar Noises (for comparison):		
Garbage Disposal	80	3
Motorcycle	90	25
Boeing 707 Before Landing	110	6000

dB for more than 8 hours. Noise limitations imposed on geothermal operations on Federal lands list a maximum level of 65 dB at the lease boundary or a distance of 1/2 mile from the source, whichever is greater.

Occupational Illnesses and Injuries at The Geysers

Occupational illnesses and injuries at The Geysers have numbered 19 over a period of 3 1/2 years⁽⁶⁾ or 5.43 illnesses and injuries per year. Assuming that complexity of plant operation is proportional to plant size and a power production of 660 MW⁽¹³⁾ for The Geysers over the 3 1/2 year period this number can be extrapolated for a 50MW plant.

$$5.43 \frac{\text{illnesses/injuries}}{\text{yr}} \times \frac{50\text{MW}}{660\text{MW}} = 0.4 \frac{\text{illnesses/injuries}}{\text{yr}}$$

The number of illnesses and injuries may be higher since plants for a liquid-dominated resource are more complex than those for a vapor-dominated resource.

References

- (1) Kestin, Joseph (ed.), 1980. Sourcebook on the Production of Electricity from Geothermal Energy. U.S. Department of Energy, Washington, D.C., DOE/RA/4051-1.
- (2) U.S. Department of Commerce, 1978. Statistical Abstract of the United States. Washington, D.C.
- (3) U.S. Environmental Protection Agency, 1977. A Summary of Accidents Related to Non-nuclear Energy." Washington, D.C., EPA-600/9-77-012.
- (4) Ellis, A.J. and W.A. Mahon, 1977. Chemistry and Geothermal Systems, Academic Press, New York.
- (5) Ellis, A.J., 1978. "Geothermal Fluid Chemistry and Human Health." Geothermics 6, pp. 175-182.
- (6) Lawrence Livermore National Laboratory, 1980. An Assessment of Geothermal Development in the Imperial Valley of California. U.S. Department of Energy, Washington, D.C., DOE/EV-0092.
- (7) U.S. Environmental Protection Agency, 1977. "Western Energy Resources and the Environment: Geothermal Energy." Washington, D.C., EPA/600/9-77-010.
- (8) Valland, A. and Damel, R., 1971. "L'hygiène et la sécurité dans la grande industrie chimique," Inst. nat. de recherche et de sécurité pour la prévention des accidents du travail et des maladies professionnelles, 9 avenue Montaigne, Paris 8.^e
- (9) Personal Communication with Joanne Linhard of OSHA, April 15, 1981.
- (10) American Conference of Governmental Industrial Hygienists, 1980. Industrial Ventilation: A Manual of Recommended Practice (16th Edition), Washington, D.C.
- (11) U.S. Department of Labor/Occupational Safety and Health Administration, 1977. Occupational Safety and Health Standards, Vol. 42, No. 239, Washington, D.C.
- (12) U.S. Department of Health, Education and Welfare/National Institute of Occupational Safety and Health/Public Health Service, 1977. Criteria for a Recommended Standard ... Occupational Exposure to Hydrogen Sulfide. Washington, D.C., DHEW No. 77-158.

APPENDIX A. AIR EMISSION STANDARDS

No Federal New Source Performance Standards (NSPS) exist for geothermal energy plants and it will be several years before any are drafted. ⁽¹⁾ However, individual facilities may be subject to state and/or local standards that are directed at ambient air quality or source specific emissions. Tables A-1 and A-2 list standards for air quality and emissions (respectively) that may be associated with geothermal energy facilities. Hydrogen sulfide (H_2S) is of particular interest since it is malodorous at very low concentrations and undetectable, yet highly toxic, at higher concentrations. It is unlikely that H_2S or any other emission would reach a level that would cause concern regarding toxicity. However, H_2S odor probably is a potential problem and care must be taken to insure that state and local standards are not violated.

The Federal prevention of significant deterioration (PSD) of air quality regulations established "de minimis" values of 10 tons/year for total reduced sulfur (including H_2S), reduced sulfur (including H_2S), and hydrogen sulfide. ⁽¹⁾ New or modified sources in attainment areas would be exempt from PSD review requirements if net emission increases would be below the "de minimus" values. Also, if net emission increases would cause air quality impacts of less than $0.04 \mu g/m^3$ (1 hour average) of H_2S , they would be exempt from the PSD requirements. These pollutant classes are included in the PSD regulations to avoid nuisance odor problems rather than for health impact reasons. ⁽³⁾

Since California has experienced significant geothermal development, its laws have begun to address geothermal utilities. Air emissions standards have been established by the local Air Pollution Districts of Northern Sonoma and Lake Counties. These standards, as shown in Table A-3, have been set for each utility for existing and proposed plants. Consideration was given to each plant's ability to meet a particular standard. For example, Units #14, 15 and 17 of The Geysers are able to meet a lower standard than some other units due to their use of surface condensers. In many cases, a standard was set for a geothermal plant to meet at the present time, with another more stringent standard to be met by June 1, 1985. The Air Pollution Districts have given geothermal developers the option of meeting a stringent standard of 5 pounds of hydrogen sulfide per million pounds of steam flow in order to hasten the permitting process. ⁽⁴⁾

TABLE A-1
 AMBIENT AIR QUALITY STANDARDS OF THE
 UNITED STATES
 FOR SELECTED SUBSTANCES (2)

Substance	Location		Long Term (>3 hrs.)			Short Term (<3 hrs.)			Foot- notes
	State	City or County	mg/m ³	ppm	Averaging Time	mg/m ³	ppm	Averaging Time	
Ammonia	Oregon	Mid-Willamette (Benton, Linn, Marion, Polk, Yamhill)	2.0	3.0	30 days	10.5	15.0	30 mins.	1
			5.0	7.0	8 hrs				2
Heavy Metals (total)	New Mexico		10.0		30 days				
Hydrogen Sulfide	California					0.042		1 hr.	
Hydrogen Sulfide	Kentucky					0.014	0.01	1 hr.	3
Hydrogen Sulfide	Minnesota					0.042	0.03	30 mins.	4
						0.07	0.05	30 mins.	5
Hydrogen Sulfide	Montana					0.042	0.03	30 mins.	4
						0.07		30 mins.	5
Hydrogen Sulfide	New Mexico					0.0042	0.003	30 mins.	6
						0.0042	0.003	30 mins.	7
Hydrogen Sulfide	New York					0.014	0.01	30 mins.	
Hydrogen Sulfide	North Dakota					0.045	0.032	30 mins.	4
Hydrogen Sulfide	Oklahoma	Tulsa City & Co.				0.042	0.03	30 mins.	8
						0.07	0.05	30 mins.	1
Hydrogen Sulfide	Pennsylvania			0.005	24 hrs.	0.14	0.1	1 hr.	
Hydrogen Sulfide	Tennessee	Nashville & Davidson Co.				0.042	0.03	30 mins.	8
						0.07	0.05	30 mins.	1
Hydrogen Sulfide	Texas					0.112	0.08	30 mins.	9
						0.168	0.12	30 mins.	10
Htdrogen Sulfide	Wyoming					0.04	0.029	30 mins.	4
						0.07	0.05	30 mins.	5

A.14-49

TABLE A-1
 AMBIENT AIR QUALITY STANDARDS OF THE
 UNITED STATES
 FOR SELECTED SUBSTANCES⁽²⁾
 (continued)

Substance	Location		Long Term (>3 hrs.)			Short Term (<3 hrs.)			Foot- notes
	State	City or County	mg/m ³	ppm	Averaging Time	mg/m ³	ppm	Averaging Time	
Suspended Particulate Matter	Federal	Primary	0.075		ACM [*]				1
			0.26		24 hrs.				
Suspended Particulate Matter	Federal	Secondary	0.06		ACM [*]				1
			0.15		24 hrs.				

FOOTNOTES

1. 24-hr. average not to be exceeded more than once a year.
 2. Not to be exceeded more than once in 24 hr.
 3. Secondary standard.
 4. Not to be exceeded more than twice in any five consecutive days.
 5. Not to be exceeded more than twice a year.
 6. Only H₂S.
 7. Total reduced sulfur.
 8. Not to be exceeded more than once in any five consecutive days.
 9. Residential & recreational area.
 10. Industrial area.
- * Annual geometric mean

TABLE A-2
EMISSION STANDARDS FOR SPECIFIC POLLUTANTS IN
EFFLUENT AIR OR GAS FROM STATIONARY SOURCES
OF THE UNITED STATES⁽²⁾
FOR SELECTED SUBSTANCES

Substance	Sources	Location		Standard	Foot- notes
		State	County or City		
Ammonia	Any source	Connecticut	Norwalk	--	1
Ammonia	Any source	Connecticut	Stamford	--	1
Hydrogen Sulfide	Any source	California	Ventura Co.	10 ppm	-
Hydrogen Sulfide	After 1/1/75	California	5 counties	10 ppm	2
Hydrogen Sulfide	Any source	Connecticut	--	10 grains/100 ft ³	-
Hydrogen Sulfide	Any source	Connecticut	Norwalk	--	1
Hydrogen Sulfide	Any source	Connecticut	Stamford	--	1
Hydrogen Sulfide	Any source	Indiana	East Chicago	160 ppm	3
Hydrogen Sulfide	Any source	Kansas	--	10 grains/100 ft ³	-
Hydrogen Sulfide	Any source	Mississippi	--	1 grain/100 ft ³	4
Hydrogen Sulfide	Any source	Montana	--	50 grains/100 ft ³	5
Hydrogen Sulfide	Any source	New Hampshire	--	5 grains/100 ft ³	-
Hydrogen Sulfide	Any source	Ohio	--	100 grains/100 ft ³	-
Hydrogen Sulfide	Any source	Oklahoma	Tulsa	100 ppm	-
Hydrogen Sulfide	Any source	Texas	--	--	6
Hydrogen Sulfide	Any source	Virginia	--	15 grains/100 ft ³	-
Hydrogen Sulfide	After 6/30/75	West Virginia	--	50 grains/100 ft ³	-

FOOTNOTES:

1. Allowable emission rate (lb/hr) is calculated as a function of the process weight.
2. Los Angeles, Orange, Riverside, San Bernardino, Santa Barbara, and Ventura Counties.
3. For two minutes.
4. Or incinerate at 1600°F for 0.5 sec.
5. Burning prohibited.
6. Ground-level concentration not to exceed 0.08 ppm (30-min. average) for residential, business or commercial property, or 0.12 ppm (30-min. average) for other property (0.3 ppm during shut-down or start-up).

Control measures for hydrogen sulfide have been proposed that would eliminate the need for case-by-case analysis of air quality. The measures, listed below, would apply to new power plants, existing power plants, and steam stacking (steam venting during power plant outages).⁽⁵⁾

<u>Plant Size</u>	<u>Date of Plant Approval</u>	<u>H₂S Emissions Limit</u>
50 MW or more	on or after July 1, 1985	5 lbs/hour
50 MW or more	after June 30, 1981, but before July 1, 1985	5 lbs/hour or 40 grams/MWh (gross), whichever is greater
less than 50 MW	after June 30, 1981	50 grams/MWh (gross)

TABLE A-3
AIR EMISSION STANDARDS FOR EXISTING
AND PROPOSED PLANTS IN CALIFORNIA⁽⁴⁾

<u>Utility</u>	<u>Compliance Date</u>	<u>Standard</u>
EXISTING:		
Geysers Units #3,4,11	present	10% of H ₂ S in supply steam at full load
Geysers Units #5,6,11	present	200 grams/MWh (gross)
Geysers Units #3,5,6,11,12	June 1, 1985	200 grams/MWh (gross)
Geysers Units #1,2,7,9,10	June 1, 1985	200 grams/MWh (gross)
Geysers Unit #3	1986	200 grams/MWh (gross)
Geysers Units #14,15,17	June 1, 1985	50 grams/MWh (gross)
Geysers Unit #17	present	100 grams/MWh (gross)
UNDER CONSTRUCTION:		
Geysers Unit #18	present	44 grams/MWh (gross)
Department of Water Resources (DWR)		
Bottlerock	present	5 lbs/hour
DWR South Geysers	present	50 grams/MWh (gross)
Sacramento Municipal Utility District (SMUD)		
#1	present	5 lbs/hour (may emit up to 8 lbs/hr depending on ambient air quality)
Northern California Power Agency #1	present	100 grams/MWh (gross)
Northern California Power Agency #1	June 1, 1985	50 grams/MWh (gross)
Occidental Petroleum OXY #1	present	5 lbs/10 ⁶ lbs of steam flow

References

- (1) Personal Communication with Bob Walsh, EPA (Research Triangle Park, North Carolina), April 24, 1981.
- (2) U.S. Environmental Protection Agency, 1974. "The World's Air Quality Management Standards, Vol. 2." Washington, D.C., EPA-650/9-75-001-b.
- (3) Code of Federal Regulations Title 40, Section 52.21. Federal Register, Vol. 45, No. 154, (52675) August 7, 1980.
- (4) Personal Communication with George Lew, State of California Air Resources Board (Sacramento, CA), August 14, 1981.
- (5) State of California Air Resources Board, 1981. "Suggested Control Measure for the Geothermal Resources Area," Sacramento, California.

APPENDIX B. COST INFORMATION

Factors that influence the cost estimate of a geothermal facility include: (1)

- (1) brine temperature and composition,
- (2) field location,
- (3) well flow rates,
- (4) well spacing,
- (5) drilling costs,
- (6) well replacement rates, and
- (7) pollution control equipment.

Three major segments of the total cost are field development costs, plant capital costs, and operation and maintenance costs.

Development Costs

One of the most significant expenses of the development stage is the cost of well drilling. This cost varies with the well depth and the hardness of the overlying material as shown in Figure B-1. Field surface equipment costs (i.e., drills, well heads) are a function of resource temperature as shown in Figure B-2. A realistic range of total field development costs is \$240-400/kw^(1,2,3) or \$12-20 million for a 50-MW geothermal facility.

Capital Costs (Power Plant Costs)

The exact specifications for equipment and their material composition vary with the conditions at each plant.⁽⁴⁾ Estimates of capital cost range from \$350 to 1500/kw^(1,2,3,5) or \$17.5-75 million for a 50-MW plant. The dependence of capital cost on reservoir temperature is shown in Figure B-3.

The capital costs of hydrogen sulfide abatement systems vary with plant size and the H₂S concentration in the steam. Prices for the Stretford system are approximately \$3.64 million and, for the EIC Process, approximately \$4.64 million.⁽⁶⁾ Though the EIC Process is more expensive, it removes corrosive H₂S from the steam before it passes through the power plant. This causes less corrosion or makes it possible for the power plant components to be composed of less expensive materials. Other advantages of upstream abatement are discussed in Step 3 of the process flow.

FIGURE B-1. COST OF WELL DRILLING (PER FOOT) VS. WELL DEPTH⁽²⁾

FIGURE B-2. FIELD EQUIPMENT COST⁽²⁾

FIGURE B-3. PLANT CAPITAL COST⁽²⁾

Operation and Maintenance

Operation and maintenance costs for a 50-MWe geothermal facility range from \$1-3 million/year⁽²⁾ as shown in Figure B-4. In addition to this basic cost, the operation and maintenance costs for the Stretford H₂S abatement system are \$42,000-560,000.⁽⁷⁾ These costs for the EIC Process are \$290,000-9,900,000.

Fluid injection is another significant addition to operation and maintenance costs. These costs can range from \$2.6-6.6 million for a 50-MWe plant.^(1,7,8,9,10)

FIGURE B-4. PLANT OPERATING AND MAINTENANCE COST⁽²⁾

References

- (1) Larson, Todd, 1977. "The Costs of Geothermal Energy Development," Geothermal World Directory. Geothermal World Publications, Reseda, California.
- (2) U.S. Department of Energy, 1980. "Market Shares Estimation Task Force Report: Projections for Hydrothermal Electric Systems Market Shares." Washington, D.C.
- (3) Wahl, Edward F., 1977. Geothermal Energy Utilization. John Wiley & Sons, New York.
- (4) Ellis, Peter F., II and Marshall F. Conover, 1981. Materials Selection Guidelines for Geothermal Energy Utilization Systems, DOE/RA/27026-1.
- (5) Walsh, T.E., et al., 1980. "Tapping Geothermal Resources," Consulting Engineer, Nov. 1980, pp. 103-107.
- (6) EIC Corporation, 1980. "Demonstration of EIC's Copper Sulfate Process for Removal of Hydrogen Sulfide and other Trace Contaminants from Geothermal Steam at Turbine Inlet Temperatures and Pressures." U.S. Department of Energy, Washington, D.C., DOE/RA/27181-01.
- (7) U.S. Department of Energy, 1980. "State-of-the-Art Hydrogen Sulfide Control for Geothermal Energy Systems: 1979." Washington, D.C., DOE/EV-0068.
- (8) Laszlo, J., 1976. "Application of the Stretford Process for H₂S Abatement at The Geysers Geothermal Plant." Proceedings of the Eleventh Intersociety Energy Conversion Engineering Conference, Sept. 12-17, 1976, State Line, Nevada.
- (9) Pacific Northwest Laboratory, 1981. "An Exploratory Benefit-Cost Analysis for Environmental Controls on Hydrothermal Energy." U.S. Department of Energy, Washington, D.C., PNL-3527.
- (10) U.S. Department of Energy, 1980. "State-of-the-Art of Liquid Waste Disposal for Geothermal Energy Systems: 1979." Washington, D.C., DOE/EV-0083.

APPENDIX C. TRACE ELEMENTS AND GASEOUS EMISSION ANALYSIS

Emissions from a geothermal plant are highly dependent on the composition of the geothermal fluid that powers the plant. Fluid compositions vary (a) between well fields, (b) between wells in the same field, or (c) even within the same well over time.^(1,2,3) Thus, it can be expected that plant emissions will change with time also. This variability prevents an accurate quantification of a general case, but estimates of possible ranges of emissions can be made. Ranges of concentrations of trace elements and gases in geothermal fluid are shown in Figure C-1. These ranges can be narrowed for a particular source if fluid composition data are available for wells in the same general area.

The flow chart depicted in Figure C-2 (derived by the authors) can be used to conceptually follow a procedure, i.e., to calculate the quantity of a constituent at various points within the process and the quantity ultimately discharged as a non-condensable gas. The calculations are primarily a function of the geothermal fluid composition and consumption rate by the plant. The numbers in parentheses on the flow chart correspond to the following calculation steps.

1. Find the amount of substance "X" entering the plant:

Concentration of X in the fluid,

$$X_b \frac{[\text{mg}]}{\ell} \times \frac{\text{kg}}{10^6 \text{ mg}} (\text{conversion factor}) \times$$

Rate of fluid flow into the plant,

$$\dot{b} \left[\frac{\text{kg}}{\text{h}} \right] \times$$

1/brine density,

$$1/\rho_b \left[1.15 \frac{\text{kg}}{\ell}, \text{ assumed density of geothermal fluid} \right] =$$

Rate of flow of X into the plant,

$$X_p \text{ [kg/h]:}$$

$$X_p = X_b \times \dot{b} \times 1/\rho_b$$

*This notation indicates the units of each coefficient.

FIGURE C-1. RANGES OF CHEMICAL AND GASEOUS CONSTITUENTS
IN GEOTHERMAL FLUIDS (1, 3)

FIGURE C-2. CALCULATION FLOWCHART

- Determine the amount of X that partitions into the gaseous phase at the flash separator.

Each substance will be partitioned between the gaseous and liquid streams depending on its own physical properties and the operating conditions of the flash separator of the liquid-dominated plant. The partitioning of various substances is not well understood at this time. (2) Partitioning efficiencies of H_2S at The Geysers have varied between 75% and 92% depending on the pH. (3) One may want to assume that partitioning is complete and that if X is gaseous at the flash separator, then all of X enters the plant in the flashed steam.

Amount of X flowing into the plant,

$$X_p \left[\frac{kg}{h} \right] \quad x$$

Percent of X that partitions into the gaseous stream at the flash separator,

$$X_g [\%] \quad =$$

Amount of X in steam flashed at the flash separator, $X_{fs} \left[\frac{kg}{h} \right]$:

$$X_{fs} = X_p \times X_g$$

If X is noncondensable, then it goes to the hydrogen sulfide abatement process.

If X is condensable, then it is directed to the cooling tower.

- Determine the amount of X that remains in the liquid phase and is sent to fluid treatment.

Amount of X in liquid phase and sent to fluid treatment, $X_{tmt} \left[\frac{kg}{h} \right]$:

$$X_{tmt} = X_p - X_{fs}$$

- The amount of X (noncondensable) remaining after hydrogen sulfide (H_2S) abatement is directed to the cooling tower:

When X is H_2S , the calculation (a) below is used. For all other substances, see (b) below.

(a) When X is H_2S ,

Amount of X directed to the cooling tower after H_2S abatement, $X_{ct} =$

$$X_t - [(X_t) \times (H_2S \text{ abatement efficiency, } \eta_{hs})],$$

which reduces to

$$X_{ct} = X_t (1 - \eta_{hs})$$

For the Stretford H_2S abatement process, removal efficiencies exceeding 99% have been reported. It should be noted that overall plant H_2S emissions are dependent also on the preceding gas/liquid partitioning efficiencies, as well as miscellaneous "fugitive" emissions of H_2S during well development and plant operation.

(b) When X is not H_2S ,

$$X_{ct} = X_t$$

For both $X = H_2S$ and $X \neq H_2S$, the amount X_{ct} will be discharged to the atmosphere via the cooling tower except for small amounts that may condense or that adhere to components of the tower (i.e., louvers).

5. When X is condensable, it goes to the cooling tower to be used as make-up water. This amount X_t is concentrated as the cooling water evaporates. The actual loading of X will not change though its concentration in the cooling water does change. Minor amounts of some substances may adhere to components of the tower or may be discharged in cooling tower drift. Except for these losses, X_t will eventually be discharged as cooling tower blowdown.

Find the amount of X in the blowdown to be injected.

Amount of X in blowdown to be injected,

$$X'_{rnj} = X_m - [(X_m * \text{fluid treatment efficiency, } \eta_{ft})]$$

which reduces to:

$$X'_{rnj} = X_m (1 - \eta_{ft})$$

6. Determine the amount of X that is injected.

Amount of X that is injected, X_{rnj} [kg/h] =

Total amount of X to reach fluid treatment

- amount removed by fluid treatment,

which is:

$$X_{rnj} = (X_m + X_{tmt}) - ((X_m + X_{tmt}) \times \eta_{ft})$$

where η_{ft} is the fluid treatment efficiency.

This reduces to:

$$X_{rnj} = (X_m + X_{tmt}) (1 - \eta_{ft})$$

X_m is equivalent to X_t if X is condensable. If X is noncondensable, then X_m is calculated as the amount that is not emitted from the cooling tower (see Step 4).

ABBREVIATIONS & ACRONYMS

Btu	British thermal unit
dB	decibels
EIC	Department of Energy EIC Corporation, developers of the EIC H ₂ S Abatement Process
ft	foot (ft ² = square feet, ft ³ = cubic feet)
gal	gallon
gpm	gallons per minute
h	hour
ha	hectare
H ₂ S	hydrogen sulfide
kg	kilogram
kW	kilowatt
kWh	kilowatt-hour
l	liter
lb	pound
m	meter (m ² = square meters, m ³ = cubic meters)
min	minute
MW	megawatt
MWe	megawatt of electricity
ppm	parts per million
sec	second
S _t , S _{tmt} , etc.	Substance symbolism (See Appendix C)
TDS	Total Dissolved Solids
yr	year

A.14-65

7. Determine the amount of X that becomes solid waste.

Amount of X that becomes a solid waste, X_{sw} , is the amount removed by the fluid treatment process.

$$X_{sw} = (X_m + X_{tmt}) \eta_{ft}$$

References

- (1) Kestin, Joseph (ed.), 1980. Sourcebook on the Production of Electricity from Geothermal Energy. U.S. Department of Energy, Washington, D.C. DOE/RA/4051-1.
- (2) Lawrence Livermore National Laboratory, 1980. An Assessment of Geothermal Development in the Imperial Valley of California. U.S. Department of Energy, Washington, D.C., DOE/EV-0092.
- (3) U.S. Department of Energy, 1980. "State-of-the-Art of Liquid Waste Disposal for Geothermal Energy Systems: 1979." Washington, D.C., DOE/EV-0083.

GLOSSARY

Berm	An earthen wall enclosure used to contain geothermal fluid spills and other material.
Blowdown	Water discharged from the cooling tower basin to control concentrations of salts and other impurities in the circulating water.
Circulating Water	Water that is cooled in the cooling tower for use in the condenser.
Concentration Factor	The ratio of total dissolved solids (TDS) in the cooling tower blowdown to TDS in the make-up water.
Cooling Tower	A structure used to cool water for use in the condenser.
Cooling Tower Drift	The portion of cooling water that becomes entrained in the moving airstreams of the cooling tower and is carried out of the tower in droplet or particulate form.
Downstream	A term used to describe events in the process flow that occur after the turbine/generator.
Flash	A process whereby steam is derived from a fluid by a reduction in the pressure of the fluid (isenthalpic expansion).
Flash Chamber	A chamber where pressure is decreased and steam is flashed and separated from fluid.
Geothermal Resource	A reserve of heat relatively near the earth's surface, created by the underlying geologic structure of the earth. This heat can be converted into useful energy by a hydrothermal plant with geothermal fluid acting as the heat transfer mechanism.
Hydrogen Sulfide (H_2S)	A colorless, toxic, flammable gas with the odor (at very low concentration) of rotten eggs.
Injection	Disposal of geothermal fluid and/or condensate into wells that are not being used as production wells (though an old production well that is no longer in use may become an injection well). This practice is an alternative to the release of fluid to surface.
Production Well	A well from which geothermal fluid is produced for use in the power plant.
Single-flash Geothermal System	A geothermal power cycle in which steam is flashed once above ground in a flash chamber.
Upstream	A term used to describe events in the process flow that occur before the turbine/generator.