United States
Environmental Protection
Agency

Industrial Environmental Research
Laboratory
Research Triangle Park NC 27711

EPA-600/7-78-197b
October 1978

EPA

Water-related Environmental Effects in Fuel Conversion: Volume II. Appendices

Interagency Energy/Environment R&D Program Report

RESEARCH REPORTING SERIES

Research reports of the Office of Research and Development, U.S. Environmental Protection Agency, have been grouped into nine series. These nine broad categories were established to facilitate further development and application of environmental technology. Elimination of traditional grouping was consciously planned to foster technology transfer and a maximum interface in related fields. The nine series are:

1. Environmental Health Effects Research
2. Environmental Protection Technology
3. Ecological Research
4. Environmental Monitoring
5. Socioeconomic Environmental Studies
6. Scientific and Technical Assessment Reports (STAR)
7. Interagency Energy-Environment Research and Development
8. "Special" Reports
9. Miscellaneous Reports

This report has been assigned to the INTERAGENCY ENERGY-ENVIRONMENT RESEARCH AND DEVELOPMENT series. Reports in this series result from the effort funded under the 17-agency Federal Energy/Environment Research and Development Program. These studies relate to EPA's mission to protect the public health and welfare from adverse effects of pollutants associated with energy systems. The goal of the Program is to assure the rapid development of domestic energy supplies in an environmentally-compatible manner by providing the necessary environmental data and control technology. Investigations include analyses of the transport of energy-related pollutants and their health and ecological effects; assessments of, and development of, control technologies for energy systems; and integrated assessments of a wide range of energy-related environmental issues.

EPA REVIEW NOTICE

This report has been reviewed by the participating Federal Agencies, and approved for publication. Approval does not signify that the contents necessarily reflect the views and policies of the Government, nor does mention of trade names or commercial products constitute endorsement or recommendation for use.

This document is available to the public through the National Technical Information Service, Springfield, Virginia 22161.

EPA-600/7-78-197b

October 1978

Water-related Environmental Effects in Fuel Conversion: Volume II. Appendices

by

Harris Gold and David J. Goldstein

Water Purification Associates
238 Main Street
Cambridge, Massachusetts 02142

Contract No. 68-03-2207
Program Element No. EHE623A

EPA Project Officer: Chester A. Vogel

Industrial Environmental Research Laboratory
Office of Energy, Minerals, and Industry
Research Triangle Park, NC 27711

Prepared for

U.S. ENVIRONMENTAL PROTECTION AGENCY
Office of Research and Development
Washington, DC 20460

PREFACE

The work presented in this report was supported by the U.S. Environmental Protection Agency (EPA) under Contract No. 68-03-2207 and the U.S. Department of Energy (DOE) under Contract No. EX-76-C-01-2445. The site specific studies of the Western states were supported principally by EPA, while those of the Eastern and Central states were supported by DOE. In addition the results of the Western site studies were synthesized into the DOE program in order to generalize the results to the United States as a whole. It seemed appropriate to incorporate all of the results into one document in order to increase the usefulness of the report rather than to fragment the study into separate reports. The report consists of a summary volume and an appendix volume and will be issued separately by each of the sponsoring agencies to receive as wide a distribution as possible.

The authors gratefully acknowledge the help and support of Mr. John A. Nardella, Program Manager, and Mr. James C. Johnson of DOE and Mr. Chester A. Vogel, Program Manager, and Mr. T. Kelly Janes of EPA. We are grateful to D. Morazzi, C. Morazzi, P. Gallagher and P. Qamoos for carrying out the detailed process-site calculations. We wish also to acknowledge Resource Analysis, Inc. and Richard L. Laramie, John H. Gerstle and David H. Marks in particular for supplying information on water resources developed under several joint programs with Water Purification Associates.

CONTENTS

Figures

Number **Page**

FIGURES (Cont.)

Tables

Number		Page

Number	Tables (Cont.)	Page

CONVERSION FACTORS

Conversion of American to International System (SI) Units

	Multiply	By	To Obtain
ACCELERATION	foot/second^2	3.048×10^{-1}	meter/second^2
	free fall, standard	9.807	meter/second^2
AREA	acre	4.047×10^{3}	meter^2
	feet^2	9.290×10^{-2}	meter^2
ENERGY	Btu (mean)	1.056×10^{3}	joule
	calorie (mean)	4.190	joule
	kilowatt-hours	3.60×10^{6}	joule
ENERGY/AREA-TIME	Btu/foot^2 hour	3.152×10^{-1}	watt/meter^2
	Btu/foot^2 minute	1.891×10^{2}	watt/meter^2
	Btu/foot^2 second	1.135×10^{4}	watt/meter^2
	calorie/cm^2 minute	6.973×10^{2}	watt/meter^2
FORCE	dyne	1.00×10^{-5}	newton
	kilogram force (Kg_f)	9.807	newton
	pound force (lb_f, avoirdupois)	4.448	newton
LENGTH	foot	3.048×10^{-1}	meter
	mile	1.609×10^{3}	meter
MASS	pound (avoirdupois)	4.536×10^{-1}	kilogram
	ton (metric)	1.00×10^{3}	kilogram
	ton (short, 2000 lb)	9.072×10^{2}	kilogram
MASS/TIME	pound/hour	1.260×10^{-4}	kilogram/second
	pound/minute	7.560×10^{-3}	kilogram/second
	ton (short)/hour	2.520×10^{-1}	kilogram/second
	ton (short)/day	1.050×10^{-2}	kilogram/second
MASS/VOLUME	gram/centimeter^3	1.00×10^{3}	kilogram/meter^3
	pound/foot^3	1.602×10^{1}	kilogram/meter^3
	pound/gallon (U.S. liquid)	1.198×10^{2}	kilogram/meter^3
MISCELLANEOUS	Btu/hr-ft^2-°F	5.674	joules/sec-m^2-°C
	Btu/kw-hr	2.929×10^{-1}	joules/kw-sec
	Btu/lb_m	2.324×10^{3}	joule/kg
	Btu/lb_m-°F	4.184×10^{3}	joule/kg-°C
	gal/10^6 Btu	3.585×10^{-12}	meter^3/joule
	kilocalorie/kilogram	4.184×10^{3}	joule/kg
POWER	Btu/hour	2.929×10^{-1}	watt
	Btu/minute	1.757×10^{1}	watt
	Btu/second	1.054×10^{3}	watt
	calorie/hour	1.162×10^{-3}	watt
	calorie/minute	6.973×10^{-2}	watt
	calorie/second	4.184	watt
	horsepower	7.457×10^{2}	watt
PRESSURE	atmosphere	1.013×10^{5}	pascal (= newton/m^2)
	foot of water (39.2°F)	2.989×10^{3}	pascal
	psi (lb_f/in^2)	6.895×10^{3}	pascal
	lb_f/foot^2	4.788×10^{1}	pascal
SPEED	foot/minute	5.08×10^{-3}	meter/second
	foot/second	3.048×10^{-1}	meter/second
	mile/hour	4.470×10^{-1}	meter/second
TEMPERATURE	°F	0.556 (°F + 459.7)	°K

(continued)

	Multiply	By	To Obtain
VOLUME	acre foot	1.590×10^{-1}	$meter^3$
	barrel (oil, 42 gal)	1.233×10^{3}	$meter^3$
	$foot^3$	2.832×10^{-2}	$meter^3$
	gallon (U.S. liquid)	3.785×10^{-3}	$meter^3$
VOLUME/TIME	ft^3/min	4.719×10^{-4}	$meter^3$/second
	ft^3/sec	2.832×10^{-2}	$meter^3$/second
	gal (U.S. liquid)/day	4.381×10^{-8}	$meter^3$/second
	gal (U.S. liquid)/min	6.309×10^{-5}	$meter^3$/second

Other Conversion Factors

The following table is based on a density of water of 62.3 pounds per cubic foot. This is the density of water at 68°F (20°C) and corresponds to 8.33 pounds of water per gallon.

acres	4.36×10^{4}	square feet
acres	1.56×10^{-3}	square miles
acre-feet	4.36×10^{4}	cubic feet
acre-feet	3.26×10^{5}	gallons
acre-feet/year	1.38×10^{-3}	cubic feet/second
acre-feet/year	3.91×10^{-5}	cubic meters/second
acre-feet/year	6.20×10^{-1}	gallons/minute
acre-feet/year	8.93×10^{-4}	million gallons/day
barrels, oil	4.2×10	gallons
Btu	2.52×10^{2}	calories
Btu	3.93×10^{-4}	horsepower-hours
cubic feet	2.30×10^{-5}	acre-feet
cubic feet	7.48	gallons
cubic feet of water	6.23×10^{1}	pounds of water
cubic feet/second	4.49×10^{2}	gallons/minute
cubic feet/second	6.46×10^{-1}	million gallons/day
gallons	3.07×10^{-6}	acre-feet
gallons	2.38×10^{-2}	barrels, oil
gallons	1.34×10^{-1}	cubic feet
gallons of water	8.33	pounds of water
gallons/minute	1.61	acre-feet/year
gallons/minute	2.23×10^{-3}	cubic feet/second
gallons/minute	1.44×10^{-3}	million gallons/day
gallons of water/minute	5.00×10^{-1}	thousand pounds of water/hr
horsepower	6.11×10^{4}	Btu/day
horsepower	2.55×10^{3}	Btu/hour
kilowatt-hours	3.41×10^{3}	Btu
milligrams/liter	1	parts/million
million gallons/day	1.12×10^{3}	acre-feet/year
million gallons/day	1.55	cubic feet/second
million gallons/day	6.94×10^{2}	gallons/minute
million gallons of water/day	3.47×10^{2}	thousand pounds of water/hr
pounds of water	1.20×10^{-1}	gallons of water
pounds of water	1.60×10^{-2}	cubic feet of water
pound moles of gas	3.80×10^{2}	standard cubic feet of gas
square feet	2.30×10^{-5}	acres
temperature, °C	1.8	32 °F
temperature, °F-32	5.56×10^{-1}	°C
thousand pounds/hour	1.2×10	tons/day
thousand pounds/hour	4.38×10^{3}	tons/year
thousand pounds of water/hour	2.00	gallons of water/minute
thousand pounds of water/hour	2.88×10^{-3}	millions gals of water/day
tons (short)	2×10^{3}	pounds
tons (short)	9.07×10^{-1}	metric tons
tons/day	8.33×10^{-2}	thousand pounds/hour
tons/year	2.28×10^{-4}	thousand pounds/hour
watts	3.41	Btu/hour

APPENDIX 1

CALCULATIONS ON SOLVENT REFINED COAL

BASIS OF ANALYSIS

Solvent refined coal (SRC) plant designs are required for bituminous coals at:

1. Bureau, Illinois
2. White, Illinois
3. Fulton, Illinois
4. Saline, Illinois
5. Rainbow, Wyoming

subbituminous coals at:

6. Gillette, Wyoming
7. Antelope Creek, Wyoming
8. Colstrip, Montana

and lignites at:

9. Marengo, Alabama
10. Dickinson, North Dakota
11. Bentley, North Dakota
12. Underwood, North Dakota
13. Otter Creek, Montana
14. Pumpkin Creek, Montana
15. Coalridge, Montana.

The experiments on solvent refining of coal are described in References 1-7. Most of the work has been done on bituminous coals from Pittsburgh, Kentucky and Illinois. On Table A1-1 are shown three coal analyses and three average SRC analyses derived from these coals. Very little work has been done on solvent refining of lignite and subbituminous coals. Some experiments on North Dakota lignite and Wyoming subbituminous[7] were done in a small laboratory bench reactor; the solvent was not in balance, and the analyses of the SRC are only suggestive of what might be obtained on a large scale. However, the SRC derived from the Western coals seems very similar to that derived from Eastern coals. We have assumed the analyses given on Table A1-2.

An alternative process is under study, particularly as "Project Lignite," at the University of North Dakota[8]. In this process carbon monoxide or synthesis gas ($CO + H_2$) is used to dissolve the coal instead of hydrogen. Water is used (with lignite this may be the coal moisture) and the shift gas reaction, $CO + H_2O \rightarrow H_2 + CO_2$, occurs in the dissolver, probably catalyzed by coal mineral. It is this process which was studied by Ralph M. Parsons Co.[9] and Jahnig[10]. This is not the process used here.

The dissolving section of the plant, based mostly on the pilot plant design[4,6], is shown in simplified form in Figures A1-1 and A1-2. To obtain the water requirements we have proceeded as follows:

1) From the pilot plant results a set of rules has been formulated which give the material balance around the dissolving section of the plant.

2) The carbonaceous filter residue and extra coal were gasified to produce hydrogen.

3) Approximate heat balances have been made around the gasification and dissolving sections.

4) The energy needed to drive the plant was estimated. This energy was supplied from waste heat recovery units and by burning the light oil and gaseous hydrocarbon made in the dissolving section.

5) Surplus light oil and gaseous hydrocarbon was sold. So much energy is needed to dry lignites as feed to the dissolving section that very little light fuel is available for sale. However, with bituminous coals quite a lot of light fuel is available for sale. With bituminous and subbituminous coals an alternative procedure (not considered here but detailed elsewhere[13]) is to not add coal to the gasifier but to reform some gaseous hydrocarbon to hydrogen instead.

6) The approximate plant conversion efficiencies were then stated.

7) Finally, the points of loss of unrecovered heat were tabulated.

MATERIAL BALANCE ON DISSOLVING SECTION

The yields of the various products are mostly reported as fractions of the moisture-and-ash-free coal. Because of the high oxygen contents of Western coals, this procedure has not been used to convert the yields from Eastern coal to those from Western coals. Instead, we have used yields of carbon. Based on the published experimental results, mostly the pilot plant results[6], we have formulated the following rules for material balances in the dissolving section of the plant:

1) 70 percent of the carbon in the coal appears as carbon in the SRC.

2) 14 percent of the carbon in the coal appears as carbon in light liquid hydrocarbon product of composition $CH_{1.6}$.

3) 5 percent of the carbon in the coal appears as gaseous hydrocarbon product of composition $CH_{3.7}$ (about 75 percent CH_4 and the balance higher hydrocarbons).

4) 1 percent of the carbon in the coal appears as CO_2.

5) 10 percent of the carbon in the coal appears as carbon in undissolved residue.

6) The ratio O/C in the undissolved residue is the same as in the coal. The balance of the oxygen appears as water.

7) A detailed description of the distribution of sulfur would be that all of the sulfate sulfur stays in the mineral residue; 50 percent of the pyritic sulfur is reduced to H_2S, and the balance appears in the ash; 60-70 percent of the organic sulfur is reduced to H_2S, and the balance is distributed between the SRC and undissolved residue. However, for lack of sulfur analyses a simpler rule has been adopted: of the sulfur in the coal which does not appear as SRC, 50 percent is converted to H_2S and 50 percent stays in the residue.

8) Nitrogen from the coal appears in the SRC and the undissolved residue with the balance appearing as ammonia. The ratio N/C is the same in the coal and in the undissolved residue.

9) The ratio H/C in the filter residue is the same as in the coal.

10) Hydrogen is supplied as required, and 10 percent of the feed hydrogen does not react. This in fact may be low based on some recent EPRI data[18-20].

11) The remainder of the ash all appears in the undissolved residue.

Application of these rules gives the material balances presented on Table A1-3. On these tables stream numbers from Figures A1-1 and A1-2 have been entered. It should be noted that for Stream 2 only the hydrogen content has been stated. In fact, the hydrogen streams produced by gasification and reforming contain only about 85 percent hydrogen with CO being the balance. These extra gases are assumed to leave the dissolving section with the gas of Stream 7. Not shown on Table A1-4 is 10,000 lb/hr steam needed for the vacuum ejectors in all plants. The condensate from this steam is rejected with the dirty condensate from the dissolving section.

PRODUCTION OF HYDROGEN BY GASIFICATION

The production train is shown on Figures A1-3 and A1-4. A Koppers-Totzek gasifier has been chosen because of the high ash content of the feed. The gasifier rules are[14-16]:

oxygen feed = 1.06 lb/lb (carbon + hydrogen);

boiler feed water = 0.223 lb/lb (carbon + hydrogen);

in the off-gas, the concentrations are given by;

$$\frac{(H_2)(CO_2)}{(CO)(H_2O)} = 0.47.$$

Methane is not produced.

The weight rates of flow are given on Table A1-4 and molar rates of flow on Table A1-5. They are found as follows.

1) The hydrogen required is shown on Table A1-3, Stream 2. Let this be m_H moles/hr. Also, we assume the gas actually produced is 85 percent H_2 and 15 percent CO. The total of H_2 + CO in the product and in all gas streams from the gasifier off-gas onwards is therefore $m_H/0.85$. The symbols and values used in the following calculations are given on Table A1-6. The first two equations are:

$$M_{H2} + M_{CO} = m_H/0.85 \qquad (1)$$

$$\frac{(M_{H2})(M_{CO2})}{(M_{CO})(M_{H2O})} = 0.47 \qquad (2)$$

2) The elemental balances around the gasifier can now be written. They are:

carbon

$$M_C + c.W_C/12 = M_{CO2} + M_{CO} = K_1 \text{ (say)} \quad (3)$$

hydrogen

$$M_H + h.W_C/2 + w.W_C/18 + \frac{0.233}{18}\left\{c.W_C + 12M_C + h.W_c + 2M_H\right\} = M_{H2} + M_{H2O}$$

$$= K_2 \text{ (say)} \quad (4)$$

oxygen

$$M_O + x.W_C/32 + w.W_C/36 + \left\{\frac{0.233}{36} + \frac{1.06}{32}\right\}\left\{c.W_C + 12M_C + h.W_C + 2M_H\right\}$$

$$= M_{CO}/2 + M_{CO2} + M_{H2O}/2 = K_3 \text{ (say)} \quad (5)$$

Equations (3), (4) and (5) can be rearranged to give

$$M_{H2} + M_{CO} = K_2 + 2K_1 - 2K_3$$

$$= \text{(from Eq. (1)) } m_H/0.85 \quad (5a)$$

Equation (5a) can be solved for W_C , the weight of coal. Knowing W_C , Equations (3), (4) and (5) give M_{CO2} ,M_{H2} and M_{H2O} in terms of M_{CO} and substitution into Equation (2) gives a quadratic in M_{CO}.

3) The gasifier off-gas is quenched to 130°F with condensation of water. The water in the gas after quench is very small and is treated as zero.

4) The shift reactor must have in its exit gas M_H moles/hr H_2 and $15m_H/85 = 0.176\ m_H$ moles/hr CO. Also, from the stoichiometry of the shift reaction, CO is converted to CO_2, so the moles/hr CO_2 in the exit case:

$$= M_{CO2} + M_{CO} - 0.176m_H \quad (6)$$

Finally, the shift reaction is in equilibrium at 50°F, so the moles/hr H_2O in the exit gas, M'_{H2O} is given by:

$$\frac{m_H(M_{CO2}+M_{CO}-0.176m_H)}{0.176m_H.M'_{H2O}} = 11.8 \qquad (7)$$

The steam in Stream 14, M_{ST}, is given by the hydrogen balance around the shift reactor:

$$M_{H2} + M_{ST} = M_H + M'_{H2O} \qquad (8)$$

5) The acid gas removal is, for simplicity, assumed to remove all the CO_2. All the water leaving the shift reactor appears in Stream 15 as condensate.

HEAT BALANCE ON DISSOLVING SECTION

Approximate heat balances on the dissolving section are given on Table A1-7. They are calculated as follows:

1) Coal feed is given on Table A1-3.

2) Hydrogen is given on Table A1-3 and this stream is 15 percent CO and 85 percent H_2. The higher heating value of H_2 is 123,000 Btu/mole, and of CO is 122,000 Btu/mole.

3) The dissolver preheater is designed to heat dried coal, hydrogen and solvent through 170°F. The specific heat of the hydrogen stream is taken as 4.1 Btu/(lb H_2)(°F) which includes the CO in the stream; the specific heat of coal is taken as 0.27 Btu/(lb)(°F) calculated by Kopp's Rule[17], and the specific heat of the solvent is taken as 0.5 Btu/(lb)(°F) with 2 lb of solvent pumped per lb of coal. Of the fired duty, 61 percent is used in the radiation section to heat the slurry, 27 percent is recovered as steam and 12 percent goes up the stack.

The vacuum preheater is calculated to heat the solvent refined coal (specific heat 0.27 Btu/(lb)(°F)) and solvent through 100°F, and vaporize all the oil assuming a latent heat of 141 Btu/lb. The fired duty is divided as for the solvent preheater.

4) The compositions of SRC, filter residue oil and gas are given on Table A1-3. The heating values of the nongaseous products are calculated from the formula:

$$14{,}540C + 62{,}000(H - X/8)$$

where C, H and X are the pounds of carbon, hydrogen and oxygen. The heating value of the gaseous hydrocarbon is taken to be 23,500 Btu/lb.

5) The steam recovered is the total from the two-fired heater plus the energy given out when the solvent is cooled through 160°F.

6) Stack losses are 12 percent of the fired preheater duties.

7) Cooling loads involve cooling the flashed gas, water and light oil from 550°F to 100°F and condensing the water and oil. Also, refluxed solvent to the vacuum tower must be condensed, but this stream, while not known, must certainly be very small because the separation requires very little reflux. The total cooling loads are calculated as:

1,500 x (condensed water, Stream 5)
+ 360 x (condensed light oil, Stream 6)
+ 220 x (gas, Stream 7)

These numbers are totals of sensible and latent heat. Condensing water is much the largest part of the load, and this is mostly done in the dry cooler. Of the total load, 80 percent is assigned to dry cooling and 20 percent to wet cooling. In addition to this load, the wet loading is arbitrarily increased to force a balance.

8) Around the filter the stream is assumed to cool 100°F by convection and radiation.

9) The SRC is assumed recovered as a liquid with a sensible heat of 130 Btu/lb.

10) The other losses are an arbitrary 0.5×10^9 Btu/hr. They are assumed to be radiant and convective losses.

HEAT BALANCE ON THE GASIFICATION SECTION

Approximate heat balances on the gasification sections are given on Table A1-8. They are calculated as follows.

1) The filter residue, Stream 4, is copied from Table A1-7. The coal, Stream 17, is given on Table A1-4. The steam, Stream 14, is also given on Table A1-4 and its enthalpy is 1120 Btu/lb. The hydrogen product, Stream 2, is copied from Table A1-7.

2) The heat in the ash and slag is the weight of ash in the total coal feed to the plant multiplied by 543 Btu/lb, which multiplier assumes a latent heat of slag of 63 Btu/lb and a sensible heat of ash of 0.2 Btu/(lb)(°F) over a range of 2400°F, i.e., 543 = (0.2)(2400) + 63.

3) The steam raised in the gasifier is found from a heat balance around the gasifier. All the gasifier feed streams have been entered, as has the slag stream leaving. The enthalpy of the off-gas is:

$$127{,}300 \times (\text{moles } H_2) + 126{,}200 \times (\text{moles CO}) + 6{,}460 \times (\text{moles } CO_2) + 24{,}140 \times (\text{moles } H_2O)$$

The gas composition is given on Table A1-5 (Stream 12).

Additional steam is raised after the shift converter. This energy is:

$$3{,}290 \times (\text{moles } H_2) + 3{,}380 \times (\text{moles CO}) + 5{,}130 \times (\text{moles } CO_2) + 4{,}000 \times (\text{moles } H_2O)$$

The gas composition is given on Table A1-5.

The steam calculated was found to be too high for a balance; to force the balance the result was reduced by 40-45 percent.

4) There are two dry cooling loads. The load on the off-gas scrubber is:

$$3{,}980 \times (\text{moles } H_2) + 4{,}060 \times (\text{moles CO}) + 5{,}980 \times (\text{moles } CO_2) + 1{,}040 \times (\text{lb } H_2 \text{ in Stream 13})$$

The load on the product gas air cooler is:

$$980 \times (\text{moles } H_2) + 1{,}000 \times (\text{moles CO}) + 1{,}470 \times (\text{moles } CO_2) + 18{,}900 \times (\text{moles } H_2O \text{ condensed})$$

Water is condensed to reduce its content in the vapor to 19 mole percent.

5) The wet cooling load is in the product gas cooler and is:

$$280 \times (\text{moles } H_2) + 290 \times (\text{moles CO}) + 240 \times (\text{moles } CO_2) + 18{,}900 \times (\text{moles } H_2O \text{ entering the wet cooler})$$

PLANT DRIVING ENERGY

The approximate plant driving energy is shown on Table A1-9. The moisture lost in drying is shown on Table A1-3. It is evaporated at 1,150 Btu/lb. The energy for acid gas removal is 28,400 Btu/mole CO_2 (a solvent type of system being assumed used). The CO_2 adsorbed is the total of that shown on Tables A1-3 and A1-5. The vacuum tower ejector stream contains 0.01×10^9 Btu/hr. Stream 8 is therefore 10×10^3 lb steam/hr at all plants and Stream 9 is the same. Stream 9 is shown on the worksheets added to the condensate from the dissolving section, Stream 5. The electricity is 15,000 kw. Oxygen production consumes 1,920 Btu/lb with the quantity of oxygen being shown on Table A1-4. The synthesis gas compressor requires 0.02×10^9 Btu/10^3 moles gas where the gas is listed on Table A1-5, entering shift. The hydrogen compressor requires 0.0126×10^9 Btu/10^3 moles gas. The gas is Stream 2 on Table A1-5. The slurry pump requires 0.0000733×10^9 Btu/10^3 lb dry coal. The dry coal rate is given on Table A1-3. The additional allowance is an arbitrary 0.2×10^9 Btu/hr.

PLANT EFFICIENCY AND UNRECOVERED HEAT

The plant efficiency calculation is given on Table A1-10. The coal rates are given on Tables A1-7 and A1-8. The SRC product is given on Table A1-7 as is the oil product and the gas product. The total steam recovered is the sum of that recovered in the dissolving section (Table A1-7) and in the gasification section (Table A1-8). Steam is consumed in the gasification section as shown on Table A1-8. The plant driving energy, for which gas and oil will be burnt, is shown taken from Table A1-9. In burning gas and oil to raise steam, there is some stack loss; this is 12 percent of the fuel or 13.6 percent of

(plant driving energy + steam required - steam recovered)

where all the terms are treated as positive no matter how entered on Table A1-10.

The fuel to dissolver and vacuum preheaters is shown on Table A1-7. All the plants have net gas or oil for sale.

ULTIMATE DISPOSITION OF UNRECOVERED HEAT

The ultimate disposition of unrecovered heat is shown on Table Al-11. The direct losses are the sum of:

from Table Al-7:	Stack losses
	Losses around filter
	Sensible heat in SRC
	Losses around dissolver and other
from Table Al-8:	Ash and slag
from Table Al-9:	Coal drying
	Vacuum tower ejector
	30% of energy to generate electricity
	30% of energy to drive the slurry pump
from Table Al-10:	Boiler stack losses

The dry cooling load is the sum of that entered on Tables Al-7 and Al-8.

The wet cooling load is the sum of that entered on Tables Al-7 and Al-8 plus the allowances on Table Al-9.

The gas purification system regenerator condenser load is the energy entered on Table Al-9.

The total steam turbine condenser load is 70 percent of the sum of:

electricity
oxygen production
synthesis gas compressor
hydrogen compressor
slurry pump

all from Table Al-9.

The total gas compressor interstage cooler load is 30 percent of the sum of:

oxygen production
synthesis gas compressor
hydrogen compressor

all from Table Al-9.

REFERENCES, APPENDIX 1

1. Hydrocarbon Research, Inc., "Solvent Refining Illinois No. 6 and Pittsburgh No. 8 Coals," Electric Power Research Institute, Palo Alto, Calif., Report No. EPRI 389, June 1975.

2. Southern Services, Inc., "Status of Wilsonville Solvent Refined Coal Pilot Plant," Electric Power Research Institute, Palo Alto, Calif., Report No. EPRI 1234, May 1975.

3. Anderson, R. P., and Wright, C. H., Pittsburgh and Midway Coal Mining Co., "Development of a Process for Producing an Ashless, Low-Sulfur Fuel from Coal, Vol. II; Laboratory Studies. Part 3; Continuous Reactor Experiments Using Petroleum Derived Solvent," May 1975. U.S. Energy Research and Development Administration, Research and Development Report No. 53, Interim Report No. 8 (NTIS Cat. No. FE-496-T1).

4. Schmid, B. K., "The Solvent Refined Coal Process," presented at Symp. on Coal Gasification and Liquefaction, University of Pittsburgh, August 1974.

5. Anderson, R. P., "Evolution of Steady State Process Solvent in the Pittsburgh and Midway Solvent Refined Coal Process," presented at Symp. on Coal Processing, AIChE, Salt Lake City, August 1974.

6. Catalytic, Inc. for Southern Services, Inc., "SRC Technical Report No. 5, Analysis of Runs 19 Through 40, 20 January to 8 August 1974, Wilsonville, Alabama," unpublished report.

7. Wright, C. H., et al, "Development of a Process for Producing an Ashless, Low-Sulfur Fuel from Coal, Vol. II; Laboratory Studies, Part 2; Continuous Reactor Studies Using Anthracene Oil Solvent," U.S. Energy Research and Development Administration, Research and Development Report No. 53, Interim Report No. 7, September 1975 (NTIS Cat. No. FE-496-T4).

8. University of North Dakota, "Project Lignite--Process Development for Solvent Refined Lignite," U.S. Energy Research and Development Administration, Report 106, Interim Report No. 1, 1974 (NTIS Cat. No. FE-1224-T1).

9. Ralph M. Parsons Co., "Demonstration Plant, Clean Boiler Fuels from Coal, Preliminary Design/Capital Cost Estimate," U.S. Dept. of the Interior, O.C.R., R&D Report No. 82, Interim Report No. 1, Volume II, 1975.

10. Jahnig, C. E., "Evaluation of Pollution Control in Fossil Fuel Conversion Processes: Liquefaction; Section 2, SRC Process," U.S. Environmental Protection Agency, Research Triangle Park, N.D., Report No. EPA-50/2-74-009-f, March 1975.

11. Pittsburgh and Midway Coal Mining Company, "Development of a Process for Producing an Ashless, Low-Sulfur Fuel from Coal, Vol. III; Pilot Plant Development Work, Part 2; Construction of Pilot Plant," May 1975, U.S. Energy Research and Development Administration, Research and Development Administration Report No. 53, Interim Report No. 9 (NTIS Cat. No. FE-496-T2).

12. Nelson, W. L., Petroleum Refinery Engineering, 4th Ed., pp. 252-262, McGraw-Hill, 1958.

13. Water Purification Associates, "Water Conservation and Pollution Control in Coal Conversion Processes," Report EPA 600/7-77-065, U.S. Environmental Protection Agency, June 1977.

14. Farnsworth, J. F., Mitsak, D. M., and Kamody, J. F., "Clean Environment with K-T Process," presented at EPA Symposium on Environmental Aspects of Fuel Conversion Technology, St. Louis, Mo., May 1974.

15. Farnsworth, J. F., Mitsak, D. M., Leonard, H. F., and Wintrell, R., "Production of Gas from Coal by the KOPPERS-TOTZEK Process," IGT Symposium on Clean Fuels from Coal, Institute of Gas Technology, Chicago, Ill., September 10-14, 1973.

16. Mitsak, D. M., and Kamody, J. F., "Koppers-Totzek: Take a Long, Hard Look," presented at 2nd Annual Symposium on Coal Gasification: Best Prospects for Commercialization, University of Pittsburgh, August 1975.

17. Lange, N. A., Handbook of Chemistry, 10th Ed., p. 1516, McGraw-Hill, 1961.

18. Nongbri, G., "Solvent Refining of West Kentucky 9-14 Coal," EPRI Report AF-499, Electric Power Research Institute, Palo Alto, Calif., May 1977.

19. Lewis, H.E., et al, "Operation of Solvent Refined Coal Pilot Plant at Wilsonville, Alabama," EPRI Report AF-585, Electric Power Research Institute, Palo Alto, Calif., November 1977.

20. Nongbri, G. and Ariadni, K., "Solvent Refining of Indiana V Coal and North Dakota Lignite," EPRI Report AF-666, Electric Power Research Institute, Palo Alto, Calif., January 1978.

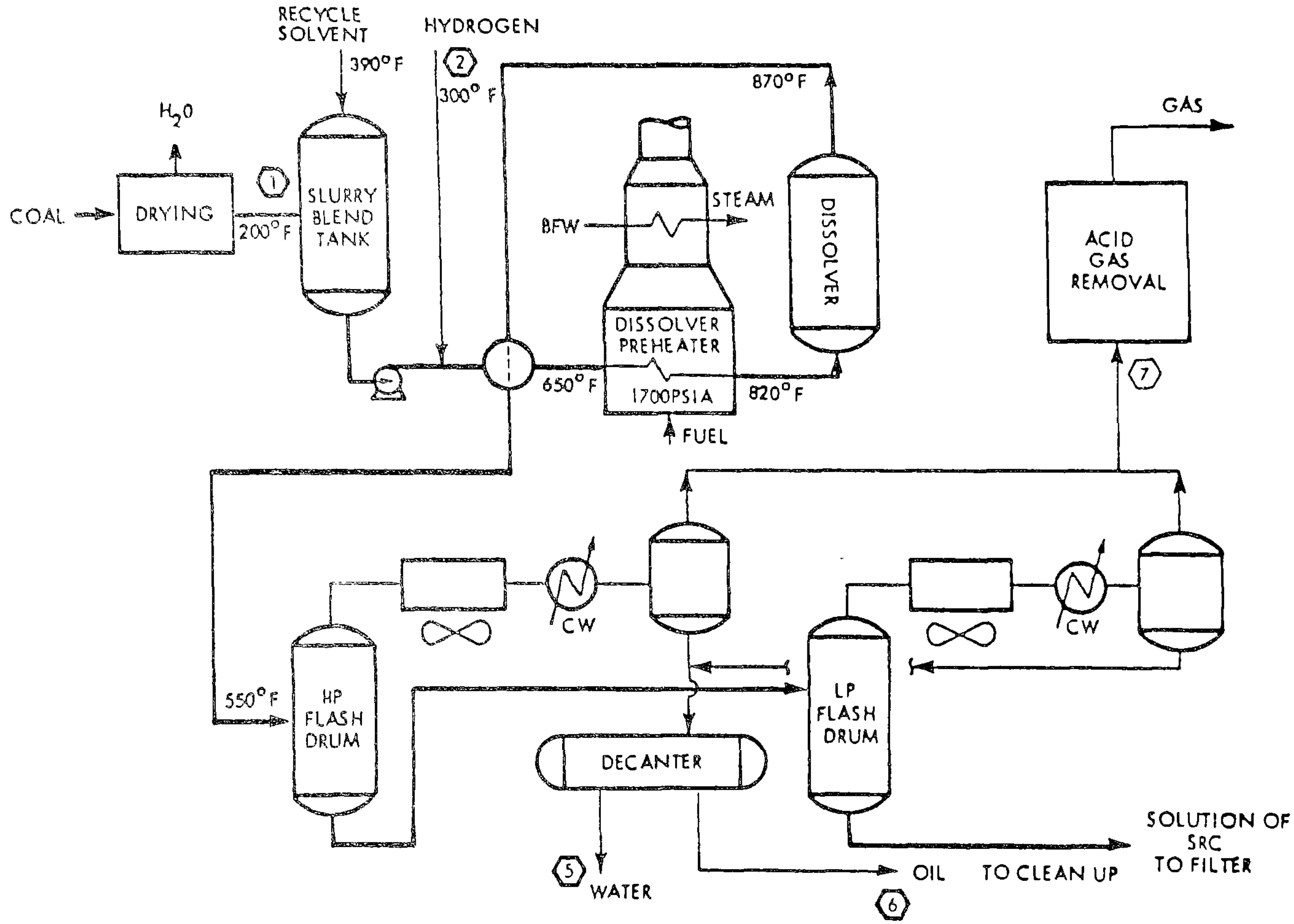


Figure A1-1. SRC dissolving section--A.

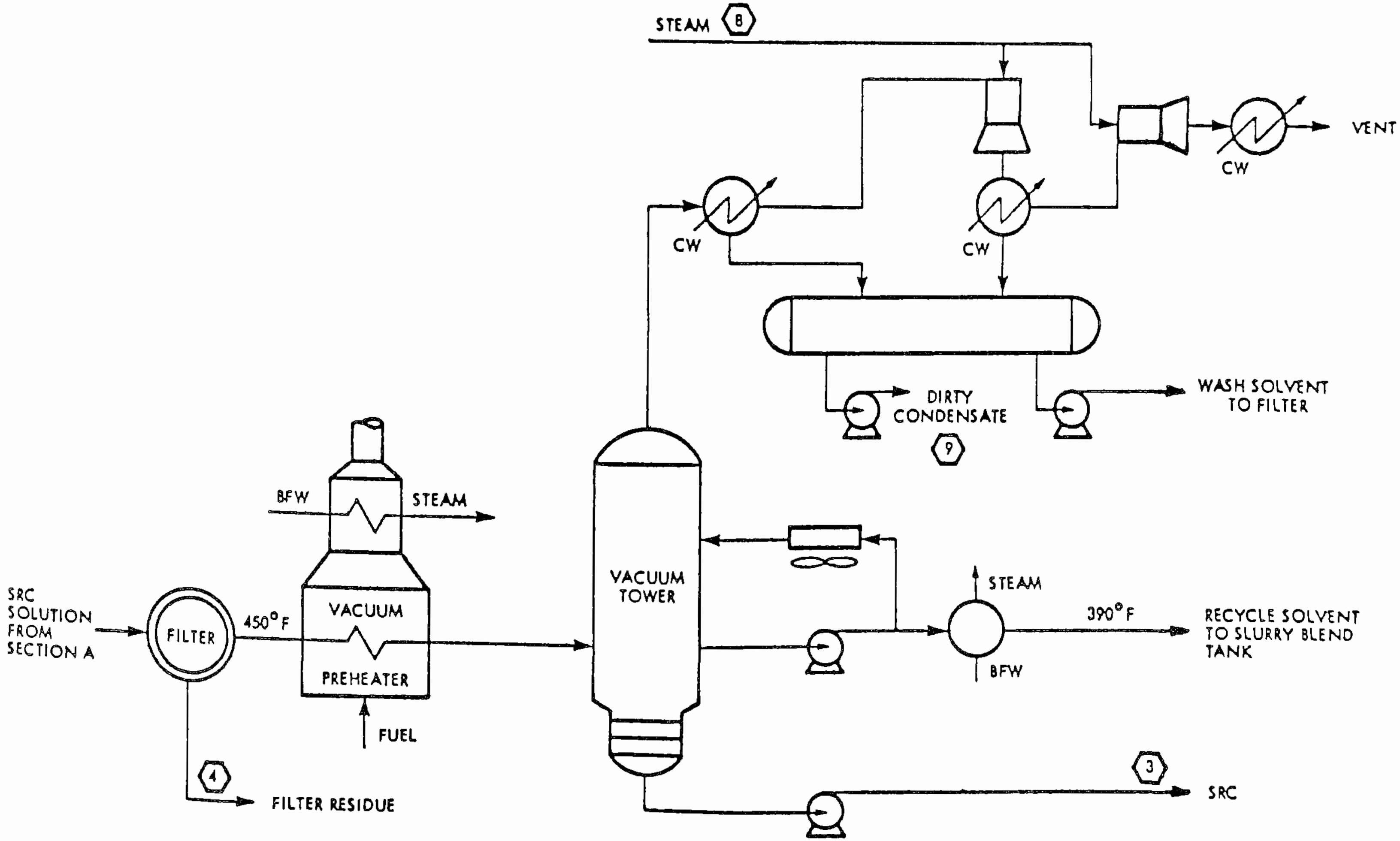


Figure A1-2. SRC dissolving section--B.

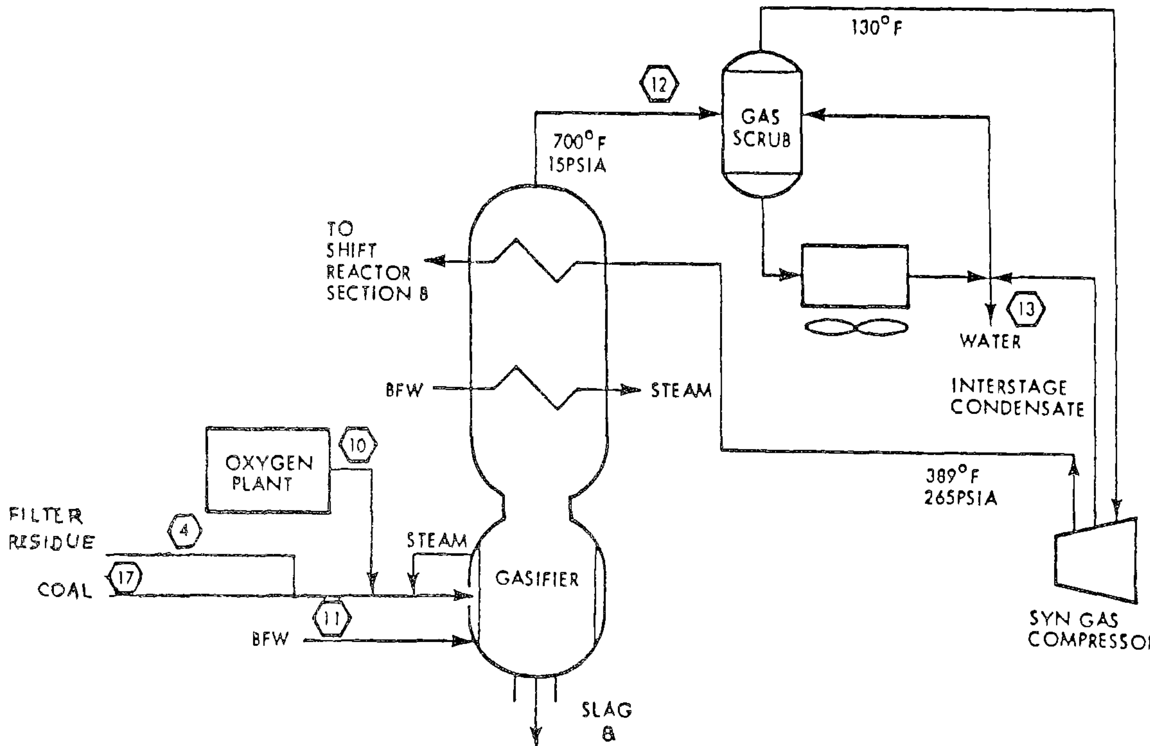


Figure A1-3. SRC hydrogen production by gasification--A.

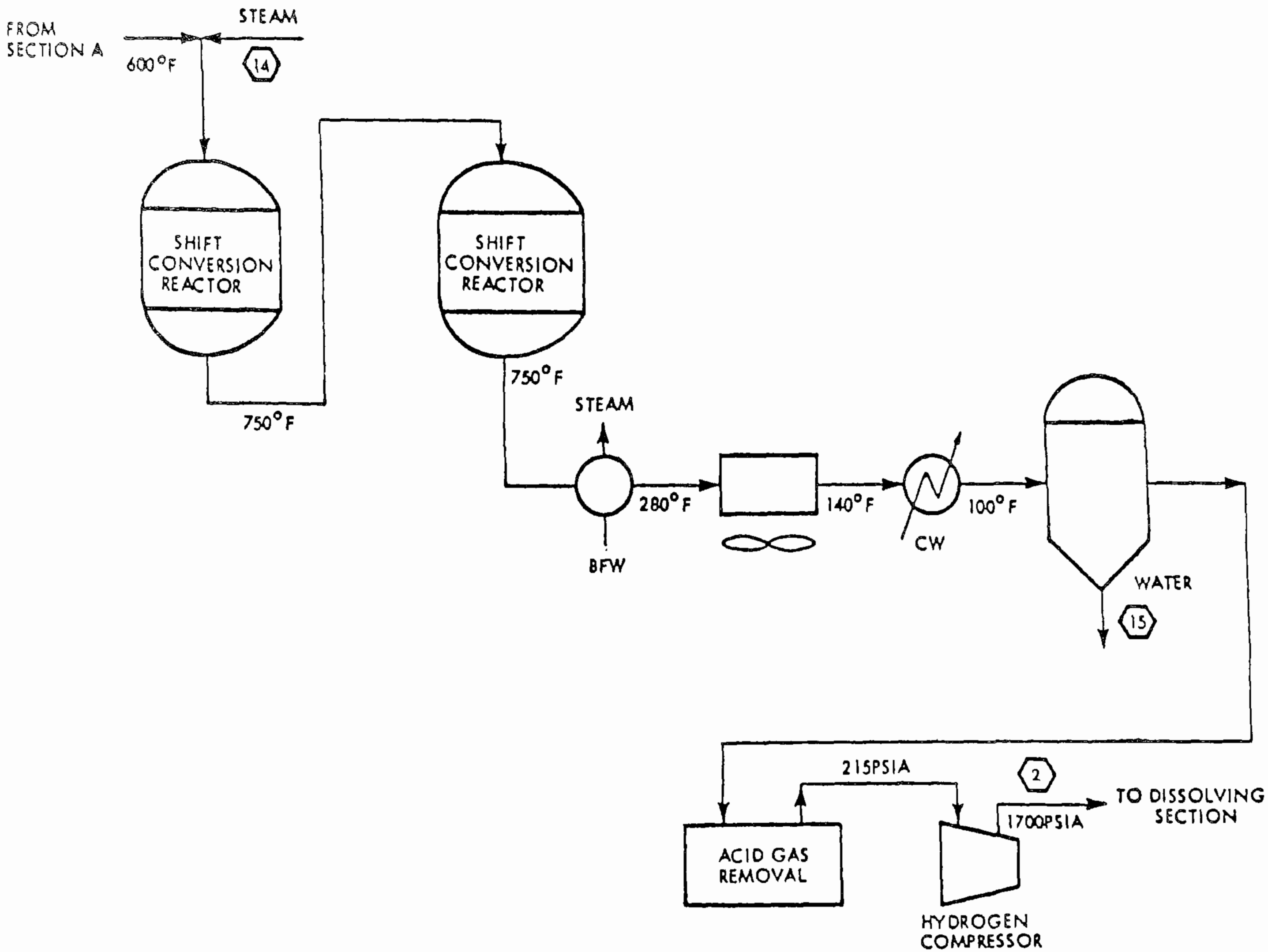


Figure A1-4. SRC hydrogen production by gasification--B.

TABLE A1-1. ANALYSES OF COAL AND SOLVENT REFINED COAL

In wt % for dry materials.

	Pittsburgh[6]		Illinois[6]		Kentucky[4]	
	Coal	SRC	Coal	SRC	Coal	SRC
C	75.1	88.4	70.8	87.1	72.9	88.5
H	5.1	5.5	5.1	5.6	4.8	5.1
N	1.3	1.7	1.3	1.6	1.2	1.8
O	7.6	3.3	8.7	4.6	10.3	3.7
S	2.6	0.9	3.2	0.9	3.5	0.8
Ash	8.2	0.1	10.8	0.1	7.3	0.1
HHV (Btu/lb)		16,000		16,000		16,000

TABLE A1-2. ASSUMED ANALYSES OF SOLVENT REFINED COAL (wt %)

	Bituminous	Subbituminous & Lignite
C	87.1	87.1
H	5.6	5.3
N	1.6	1.2
O	4.7	5.7
S	0.9	0.5
Ash	0.1	0.2
HHV (calculated)	15,820	15,540

TABLE A1-3. MATERIAL BALANCES FOR DISSOLVING SECTIONS OF 10,000 TONS/DAY SRC PLANTS

Units: 10^3 lb/hr.

LOCATION: Bureau, Illinois (bituminous)

	Total	C	H	N	O	S	Ash
As-received coal:	1,725	1,037	--	--	--	--	--
Moisture lost in drying:	277	--	--	--	--	--	--
INTO DISSOLVING SECTION							
1. Dry coal	1,448	1,037	71	19	143	50	128
2. Hydrogen	31	--	31	--	--	--	--
TOTAL:	1,479	1,037	102	19	143	50	128
OUT							
3. SRC	833	726	47	13	39	7	1
4. Filter residue	275	104	7	2	14	21	127
5. Water	71	--	8	--	63	--	--
H_2S	23	--	1	--	--	22	--
NH_3	5	--	1	4	--	--	--
6. Light oil	164	145	19	--	--	--	--
7. Gaseous hydrocarbons	68	52	16	--	--	--	--
CO_2	37	10	--	--	27	--	--
Unconsumed H_2	3	--	3	--	--	--	--
TOTAL:	1,479	1,037	102	19	143	50	128

LOCATION: White, Illinois (bituminous)

	Total	C	H	N	O	S	Ash
As-received coal:	1,557	1,037	--	--	--	--	--
Moisture lost in drying:	45	--	--	--	--	--	--
INTO DISSOLVING SECTION							
1. Dry coal	1,512	1,037	72	22	111	44	226
2. Hydrogen	24	--	24	--	--	--	--
TOTAL:	1,536	1,037	96	22	111	44	226
OUT							
3. SRC	833	726	47	13	39	7	1
4. Filter residue	368	104	7	2	11	18	225
5. Water	38	--	4	--	34	--	--
H_2S	19	--	1	--	--	19	--
NH_3	7	--	0	7	--	--	--
6. Light oil	164	145	19	--	--	--	--
7. Gaseous hydrocarbons	68	52	16	--	--	--	--
CO_2	37	10	--	--	27	--	--
Unconsumed H_2	2	--	2	--	--	--	--
TOTAL:	1,536	1,037	96	22	111	44	226

TABLE A1-3 (continued)

Units: 10^3 lb/hr.

LOCATION: Fulton, Illinois (bituminous)

	Total	C	H	N	O	S	Ash
As-received coal:	1,764	1,037	--	--	--	--	--
Moisture lost in drying:	276	--	--	--	--	--	--
INTO DISSOLVING SECTION							
1. Dry coal	1,488	1,037	72	19	129	55	176
2. Hydrogen	29	--	29	--	--	--	--
TOTAL:	1,517	1,037	101	19	129	55	176
OUT							
3. SRC	833	726	47	13	39	7	1
4. Filter residue	325	104	7	2	13	24	175
5. Water	56	--	6	--	50	--	--
H_2S	26	--	2	--	--	24	--
NH_3	5	--	1	4	--	--	--
6. Light oil	164	145	19	--	--	--	--
7. Gaseous hydrocarbons	68	52	16	--	--	--	--
CO_2	37	10	--	--	27	--	--
Unconsumed H_2	3	--	3	--	--	--	--
TOTAL:	1,517	1,037	101	19	129	55	176

LOCATION: Saline, Illinois (bituminous)

	Total	C	H	N	O	S	Ash
As-received coal:	1,527	1,037	--	--	--	--	--
Moisture lost in drying:	104	--	--	--	--	--	--
INTO DISSOLVING SECTION							
1. Dry coal	1,423	1,037	69	21	104	47	145
2. Hydrogen	29	--	29	--	--	--	--
TOTAL:	1,452	1,037	98	21	104	47	145
OUT							
3. SRC	833	726	47	13	39	7	1
4. Filter residue	287	104	7	2	10	20	144
5. Water	32	--	4	--	28	--	--
H_2S	21	--	1	--	--	20	--
NH_3	7	--	1	6	--	--	--
6. Light oil	164	145	19	--	--	--	--
7. Gaseous hydrocarbons	68	52	16	--	--	--	--
CO_2	37	10	--	--	27	--	--
Unconsumed H_2	3	--	3	--	--	--	--
TOTAL:	1,452	1,037	98	21	104	47	145

continued

Table A1-3 (continued)

Units: 10^3 lb/hr.

LOCATION: Rainbow, Wyoming (bituminous)

	Total	C	H	N	O	S	Ash
As-received coal:	1,569	1,037	--	--	--	--	--
Moisture lost in drying:	163	--	--	--	--	--	--
INTO DISSOLVING SECTION							
1. Dry coal	1,406	1,037	72	25	173	14	85
2. Hydrogen	33	--	33	--	--	--	--
TOTAL:	1,439	1,037	105	25	173	14	85
OUT							
3. SRC	833	726	47	13	39	7	1
4. Filter residue	218	104	7	3	17	3	84
5. Water	101	--	11	--	90	--	--
H_2S	4	--	0	--	--	4	--
NH_3	11	--	2	9	--	--	--
6. Light oil	164	145	19	--	--	--	--
7. Gaseous hydrocarbons	68	52	16	--	--	--	--
CO_2	37	10	--	--	27	--	--
Unconsumed H_2	3	--	3	--	--	--	--
TOTAL:	1,439	1,037	105	25	173	14	85

LOCATION: Gillette, Wyoming (subbituminous)

	Total	C	H	N	O	S	Ash
As-received coal:	2,264	1,037	--	--	--	--	--
Moisture lost in drying:	687	--	--	--	--	--	--
INTO DISSOLVING SECTION							
1. Dry coal	1,577	1,037	77	14	256	16	177
2. Hydrogen	34	--	34	--	--	--	--
TOTAL:	1,611	1,037	111	14	256	16	177
OUT							
3. SRC	833	726	44	10	47	4	2
4. Filter residue	320	104	8	1	26	6	175
5. Water	176	--	20	--	156	--	--
H_2S	6	--	0	--	--	6	--
NH_3	4	--	1	3	--	--	--
6. Light oil	164	145	19	--	--	--	--
7. Gaseous hydrocarbons	68	52	16	--	--	--	--
CO_2	37	10	--	--	27	--	--
Unconsumed H_2	3	--	3	--	--	--	--
TOTAL:	1,611	1,037	111	14	256	16	177

continued

TABLE A1-3 (continued)

Units: 10^3 lb/hr.

LOCATION: Antelope Creek, Wyoming (subbituminous)

	Total	C	H	N	O	S	Ash
As-received coal:	1,971	1,037	--	--	--	--	--
Moisture lost in drying:	515	--	--	--	--	--	--
INTO DISSOLVING SECTION							
1. Dry coal	1,456	1,037	71	12	237	10	89
2. Hydrogen	35	--	35	--	--	--	--
TOTAL:	1,491	1,037	106	12	237	10	89
OUT							
3. SRC	833	726	44	10	47	4	2
4. Filter residue	226	104	7	1	24	3	87
5. Water	156	--	17	--	139	--	--
H_2S	3	--	0	--	--	3	--
NH_3	1	--	0	1	--	--	--
6. Light oil	164	145	19	--	--	--	--
7. Gaseous hydrocarbons	68	52	16	--	--	--	--
CO_2	37	10	--	--	27	--	--
Unconsumed H_2	3	--	3	--	--	--	--
TOTAL:	1,491	1,037	106	12	237	10	89

LOCATION: Colstrip, Montana (subbituminous)

	Total	C	H	N	O	S	Ash
As-received coal:	1,979	1,037	--	--	--	--	--
Moisture lost in drying:	482	--	--	--	--	--	--
INTO DISSOLVING SECTION							
1. Dry coal	1,497	1,037	69	16	230	8	137
2. Hydrogen	39	--	39	--	--	--	--
TOTAL:	1,536	1,037	108	16	230	8	137
OUT							
3. SRC	833	726	44	10	47	4	2
4. Filter residue	273	104	7	2	23	2	135
5. Water	150	--	17	--	133	--	--
H_2S	2	--	0	--	--	2	--
NH_3	5	--	1	4	--	--	--
6. Light oil	164	145	19	--	--	--	--
7. Gaseous hydrocarbons	68	52	16	--	--	--	--
CO_2	37	10	--	--	27	--	--
Unconsumed H_2	4	--	4	--	--	--	--
TOTAL:	1,536	1,037	108	16	230	8	137

continued

TABLE A1-3 (continued)

Units: 10^3 lb/hr.

LOCATION: Marengo, Alabama (lignite)

	Total	C	H	N	O	S	Ash
As-received coal:	3,231	1,037	--	--	--	--	--
Moisture lost in drying:	1,574	--	--	--	--	--	--
INTO DISSOLVING SECTION							
1. Dry coal	1,657	1,037	71	19	317	58	155
2. Hydrogen	50	--	50	--	--	--	--
TOTAL:	1,707	1,037	121	19	317	58	155
OUT							
3. SRC	833	726	44	10	47	4	2
4. Filter residue	325	104	7	2	32	27	153
5. Water	237	--	26	--	211	--	--
H_2S	29	--	2	--	--	27	--
NH_3	9	--	2	7	--	--	--
6. Light oil	164	145	19	--	--	--	--
7. Gaseous hydrocarbons	68	52	16	--	--	--	--
CO_2	37	10	--	--	27	--	--
Unconsumed H_2	5	--	5	--	--	--	--
TOTAL:	1,707	1,037	121	19	317	58	155

LOCATION: Dickinson, North Dakota (lignite)

	Total	C	H	N	O	S	Ash
As-received coal:	2,758	1,037	--	--	--	--	--
Moisture lost in drying:	1,137	--	--	--	--	--	--
INTO DISSOLVING SECTION							
1. Dry coal	1,621	1,037	74	14	303	14	179
2. Hydrogen	42	--	42	--	--	--	--
TOTAL:	1,663	1,037	116	14	303	14	179
OUT							
3. SRC	833	726	44	10	47	4	2
4. Filter residue	324	104	7	1	30	5	177
5. Water	224	--	25	--	199	--	--
H_2S	5	--	0	--	--	5	--
NH_3	4	--	1	3	--	--	--
6. Light oil	164	145	19	--	--	--	--
7. Gaseous hydrocarbons	68	52	16	--	--	--	--
CO_2	37	10	--	--	27	--	--
Unconsumed H_2	4	--	4	--	--	--	--
TOTAL:	1,663	1,037	116	14	303	14	179

continued

TABLE A1-3 (continued)

Units: 10^3 lb/hr.

LOCATION: Bentley, North Dakota (lignite)

	Total	C	H	N	O	S	Ash
As-received coal:	2,493	1,037	--	--	--	--	--
Moisture lost in drying:	907	--	--	--	--	--	--
INTO DISSOLVING SECTION							
1. Dry coal	1,586	1,037	77	15	282	30	145
2. Hydrogen	39	--	39	--	--	--	--
TOTAL:	1,625	1,037	116	15	282	30	145
OUT							
3. SRC	833	726	44	10	47	4	2
4. Filter residue	298	104	8	2	28	13	143
5. Water	203	--	23	--	180	--	--
H_2S	14	--	1	--	--	13	--
NH_3	4	--	1	3	--	--	--
6. Light oil	164	145	19	--	--	--	--
7. Gaseous hydrocarbons	68	52	16	--	--	--	--
CO_2	37	10	--	--	27	--	--
Unconsumed H_2	4	--	4	--	--	--	--
TOTAL:	1,625	1,037	116	15	282	30	145

LOCATION: Underwood, North Dakota (lignite)

	Total	C	H	N	O	S	Ash
As-received coal:	2,429	1,037	--	--	--	--	--
Moisture lost in drying:	860	--	--	--	--	--	--
INTO DISSOLVING SECTION							
1. Dry coal	1,569	1,037	73	15	296	12	136
2. Hydrogen	42	--	42	--	--	--	--
TOTAL:	1,611	1,037	115	15	296	12	136
OUT							
3. SRC	833	726	44	10	47	4	2
4. Filter residue	281	104	7	2	30	4	134
5. Water	216	--	24	--	192	--	--
H_2S	4	--	0	--	--	4	--
NH_3	4	--	1	3	--	--	--
6. Light oil	164	145	19	--	--	--	--
7. Gaseous hydrocarbons	68	52	16	--	--	--	--
CO_2	37	10	--	--	27	--	--
Unconsumed H_2	4	--	4	--	--	--	--
TOTAL:	1,611	1,037	115	15	296	12	136

continued

TABLE A1-3 (continued)

Units: 10^3 lb/hr.

LOCATION: Otter Creek, Montana (lignite)

	Total	C	H	N	O	S	Ash
As-received coal:	2,062	1,037	--	--	--	--	--
Moisture lost in drying:	607	--	--	--	--	--	--
INTO DISSOLVING SECTION							
1. Dry coal	1,455	1,037	60	12	231	12	103
2. Hydrogen	47	--	47	--	--	--	--
TOTAL:	1,502	1,037	107	12	231	12	103
OUT							
3. SRC	833	726	44	10	47	4	2
4. Filter residue	239	104	6	1	23	4	101
5. Water	151	--	17	--	134	--	--
H_2S	4	--	0	--	--	4	--
NH_3	1	--	0	1	--	--	--
6. Light oil	164	145	19	--	--	--	--
7. Gaseous hydrocarbons	68	52	16	--	--	--	--
CO_2	37	10	--	--	27	--	--
Unconsumed H_2	5	--	5	--	--	--	--
TOTAL:	1,502	1,037	107	12	231	12	103

LOCATION: Pumpkin Creek, Montana (lignite)

	Total	C	H	N	O	S	Ash
As-received coal:	2,325	1,037	--	--	--	--	--
Moisture lost in drying:	713	--	--	--	--	--	--
INTO DISSOLVING SECTION							
1. Dry coal	1,612	1,037	72	16	291	12	184
2. Hydrogen	43	--	43	--	--	--	--
TOTAL:	1,655	1,037	115	--	291	12	184
OUT							
3. SRC	833	726	44	10	47	4	2
4. Filter residue	328	104	7	2	29	4	182
5. Water	212	--	24	--	188	--	--
H_2S	4	--	0	--	--	4	--
NH_3	5	--	1	4	--	--	--
6. Light oil	164	145	19	--	--	--	--
7. Gaseous hydrocarbons	68	52	16	--	--	--	--
CO_2	37	10	--	--	27	--	--
Unconsumed H_2	4	--	4	--	--	--	--
TOTAL:	1,655	1,037	115	16	291	12	184

continued

TABLE A1-3 (continued)

Units: 10^3 lb/hr.

LOCATION: Coalridge, Montana (lignite)

	Total	C	H	N	O	S	Ash
As-received coal:	2,946	1,037	--	--	--	--	--
Moisture lost in drying:	1,189	--	--	--	--	--	--
<u>INTO DISSOLVING SECTION</u>							
1. Dry coal	1,757	1,037	71	18	398	12	221
2. Hydrogen	58	--	58	--	--	--	--
TOTAL:	1,815	1,037	129	18	398	12	221
<u>OUT</u>							
3. SRC	833	726	44	10	47	4	2
4. Filter residue	376	104	7	2	40	4	219
5. Water	320	--	36	--	284	--	--
H_2S	4	--	0	--	--	4	--
NH_3	7	--	1	6	--	--	--
6. Light oil	164	145	19	--	--	--	--
7. Gaseous hydrocarbons	68	52	16	--	--	--	--
CO_2	37	10	--	--	27	--	--
Unconsumed H_2	6	--	6	--	--	--	--
TOTAL:	1,815	1,037	129	18	398	12	221

TABLE A1-4. FLOW RATES IN PRODUCTION OF HYDROGEN IN 10,000 TON/DAY SRC PLANTS

Units: 10^3 lb/hr.

Stream	Bureau, Illinois	White, Illinois	Fulton, Illinois	Saline, Illinois
17 Coal feed	77.00	16.00	60.00	50.50
10 Oxygen	17.00	129.7	157.6	156.4
11 Boiler feed water to gasifier	35.78	27.29	33.17	32.91
13 Condensate from off-gas	21.24	9.36	17.64	11.70
15 Condensate to aftershift	84.78	64.44	78.48	77.76
14 Steam to shift	243.9	190.4	227.9	229.1

Stream	Rainbow, Wyoming	Gillette, Wyoming	Antelope Creek, Wyoming	Colstrip, Montana	Marengo, Alabama	Dickinson, N. Dakota	Bentley, N. Dakota	Underwood, N. Dakota	Otter Creek, Montana	Pumpkin Creek, Montana	Coalridge, Montana
17 Coal feed	88.0	145.0	140.0	180.0	500.0	308.0	225.0	272.0	286.0	270.0	620.0
10 Oxygen	183.6	194.3	201.1	224.3	299.5	249.2	225.3	249.4	277.9	254.2	364.8
11 Boiler feed water to gasifier	38.63	40.88	42.30	47.19	63.00	52.43	47.40	52.47	58.46	53.47	76.74
13 Condensate from off-gas	23.4	57.4	48.96	55.26	222.8	126.5	90.72	103.5	83.88	93.60	251.3
15 Condensate to aftershift	91.98	97.2	101.7	113.6	152.8	126.7	113.0	127.1	143.1	129.3	188.5
14 Steam to shift	263.3	257.6	271.0	306.8	354.5	311.7	288.5	321.0	376.2	332.9	434.7

TABLE A1-5. GAS STREAMS IN PRODUCTION OF HYDROGEN IN 10,000 TONS/DAY SRC PLANTS

Units: 10^3 moles/hr.

Stream		Bureau, Illinois	White, Illinois	Fulton, Illinois	Saline, Illinois
12 Gasifier off-gas:	CO	11.56	9.10	10.80	10.98
	CO_2	0.96	0.45	0.80	0.54
	H_2	6.66	5.00	6.20	6.09
	H_2O	1.18	0.52	0.98	0.65
Entering shift:	CO	11.56	9.10	10.80	10.98
	CO_2	0.96	0.45	0.80	0.54
	H_2	6.66	5.00	6.20	6.09
	H_2O	0	0	0	0
Leaving shift:	CO	2.73	2.11	2.55	2.55
	CO_2	9.79	7.44	9.05	8.97
	H_2	15.5	12.0	14.5	14.5
	H_2O	4.71	3.58	4.36	4.32
2 To dissolving:	CO	2.73	2.11	2.55	2.55
	H_2	15.5	12.0	14.5	14.5

Stream		Rainbow, Wyoming	Gillette, Wyoming	Antelope Creek, Wyoming	Colstrip, Montana	Marengo, Alabama	Dickinson, N. Dakota	Bentley, N. Dakota	Underwood, N. Dakota	Otter Creek, Montana	Pumpkin Creek, Montana	Coalridge, Montana
12 Gasifier off-gas:	CO	12.43	11.98	12.72	14.19	15.50	14.00	13.25	14.51	17.10	15.09	18.79
	CO_2	1.08	2.22	2.09	2.34	6.54	4.31	3.22	3.84	3.55	3.61	8.06
	H_2	6.98	8.09	7.79	8.76	13.80	10.72	9.75	10.22	10.55	10.19	15.32
	H_2O	1.30	3.19	2.72	3.07	12.38	7.03	5.04	5.75	4.66	5.20	13.96
Entering shift:	CO	12.43	11.98	12.72	14.19	15.50	14.00	13.25	14.51	17.10	15.09	18.79
	CO_2	1.08	2.22	2.09	2.34	6.54	4.31	3.22	3.84	3.55	3.61	8.06
	H_2	6.98	8.09	7.79	8.76	13.80	10.72	9.75	10.22	10.55	10.19	15.32
	H_2O	0	0	0	0	0	0	0	0	0	0	0
Leaving shift:	CO	2.90	2.99	3.08	3.43	4.40	3.70	3.43	3.70	4.14	3.78	5.10
	CO_2	10.60	11.21	11.73	13.10	17.64	14.61	13.04	14.64	16.51	14.92	21.75
	H_2	16.5	17.0	17.5	19.5	25.0	21.0	19.5	21.0	23.5	21.5	29.0
	H_2O	5.11	5.40	5.65	6.31	8.49	7.04	6.28	7.06	7.95	7.18	10.47
2 To dissolving:	CO	2.90	2.99	3.08	3.43	4.40	3.70	3.43	3.70	4.14	3.78	5.10
	H_2	16.5	17.0	17.5	19.5	25.0	21.0	19.5	21.0	23.5	21.5	29.0

TABLE A1-6. SYMBOLS AND VALUES USED FOR CALCULATIONS AROUND GASIFIER IN 10,000 TON/DAY SRC PLANTS

	Flow Rates (moles/hr)
FEEDS	
Total coal	W_C (lb/hr)
Coal carbon	$c.W_C/12$*
Coal hydrogen	$h.W_C/2$*
Coal oxygen	$x.W_C/32$*
Coal moisture	$w.W_C/18$*
Filter Residue	
Carbon	M_C
Hydrogen	M_H
Oxygen	M_O
OFF-GAS	
H_2	M_{H2}
CO	M_{CO}
CO_2	M_{CO2}
H_2O	M_{H2O}

*c, h, x, w are weight fractions in as-received coal.

TABLE A1-7. APPROXIMATE HEAT BALANCES ON DISSOLVING SECTION OF 10,000 TONS/DAY SRC PLANTS

Units: 10^9 Btu/hr.

	Stream	Bureau, Illinois	White, Illinois	Fulton, Illinois	Saline, Illinois
1	Dry coal	18.56	18.84	18.79	18.72
2	Hydrogen & carbon monoxide	2.24	1.73	2.09	2.09
	Fuel to dissolver & vacuum preheater	1.49	1.55	1.53	1.46
	TOTAL IN:	22.29	22.12	22.41	22.27
3	SRC	13.16	13.16	13.16	13.16
4	Filter residue	1.83	1.86	1.85	1.87
6	Oil	3.29	3.29	3.29	3.29
7	Gas (hydrocarbon + H_2)	1.78	1.72	1.78	1.78
	Steam recovered	0.62	0.66	0.65	0.62
	Stack losses	0.18	0.19	0.18	0.18
	Dry cooling load	0.14	0.10	0.13	0.10
	Wet cooling load	0.5	0.35	0.56	0.48
	Losses around filter	0.18	0.18	0.19	0.18
	Sensible heat in SRC	0.11	0.11	0.11	0.11
	Losses around dissolver; other	0.5	0.5	0.5	0.5
	TOTAL OUT:	22.29	22.12	22.41	22.27

	Stream	Rainbow, Wyoming	Gillette, Wyoming	Antelope Creek, Wyoming	Colstrip, Montana	Marengo, Alabama	Dickinson, N. Dakota	Bentley, N. Dakota	Underwood, N. Dakota	Otter Creek, Montana	Pumpkin Creek, Montana	Coalridge, Montana
1	Dry coal	18.22	17.93	17.74	17.63	17.25	17.40	17.80	17.34	17.05	17.34	16.50
2	Hydrogen & carbon monoxide	2.38	2.46	2.53	2.82	3.6	3.04	2.81	3.04	3.40	3.11	4.19
	Fuel to dissolver & vacuum preheater	1.45	1.62	1.50	1.55	1.71	1.67	1.64	1.62	1.52	1.67	1.83
	TOTAL IN:	22.05	22.01	21.77	22.00	22.56	22.11	22.25	22.0	21.97	22.12	22.52
3	SRC	13.16	12.92	12.92	12.92	12.92	12.92	12.92	12.92	12.92	12.92	12.92
4	Filter residue	1.81	1.81	1.76	1.77	1.69	1.71	1.79	1.71	1.71	1.72	1.64
6	Oil	3.29	3.29	3.29	3.29	3.29	3.29	3.29	3.29	3.29	3.29	3.29
7	Gas (hydrocarbon + H_2)	1.78	1.78	1.78	1.84	1.91	1.84	1.84	1.84	1.91	1.84	1.97
	Steam recovered	0.62	0.69	0.64	0.66	0.73	0.71	0.70	0.69	0.64	0.71	0.77
	Stack losses	0.17	0.19	0.18	0.19	0.21	0.20	0.20	0.19	0.18	0.20	0.22
	Dry cooling load	0.18	0.27	0.25	0.24	0.34	0.33	0.30	0.32	0.24	0.31	0.44
	Wet cooling load	0.25	0.25	0.16	0.29	0.65	0.29	0.40	0.23	0.29	0.32	0.44
	Losses around filter	0.18	0.20	0.18	0.19	0.21	0.21	0.20	0.20	0.18	0.20	0.22
	Sensible heat in SRC	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11
	Losses around dissolver; other	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
	TOTAL OUT:	22.05	22.01	21.77	22.00	22.56	22.11	22.25	22.0	21.97	22.12	22.52

TABLE A1-8. APPROXIMATE HEAT BALANCES ON GASIFICATION SECTIONS OF 10,000 TONS/DAY SRC PLANTS

Units: 10^9 Btu/hr.

Stream	Bureau, Illinois	White, Illinois	Fulton, Illinois	Saline, Illinois
4 Filter residue	1.83	1.86	1.85	1.87
17 Coal	0.83	0.19	0.64	0.62
14 Steam	0.27	0.21	0.26	0.26
TOTAL IN:	2.93	2.26	2.75	2.75
16 Hydrogen product	2.24	1.73	2.09	2.09
Total steam generated	0.39	0.29	0.35	0.38
Ash and slag	0.07	0.08	0.10	0.08
Dry cooling load	0.13	0.09	0.12	0.11
Wet cooling load	0.10	0.07	0.09	0.09
TOTAL OUT:	2.93	2.26	2.75	2.75

Stream	Rainbow, Wyoming	Gillette, Wyoming	Antelope Creek, Wyoming	Colstrip, Montana	Marengo, Alabama	Dickinson, N. Dakota	Bentley, N. Dakota	Underwood, N. Dakota	Otter Creek, Montana	Pumpkin Creek, Montana	Coalridge, Montana
4 Filter residue	1.81	1.81	1.76	1.77	1.69	1.71	1.79	1.71	1.71	1.72	1.64
17 Coal	1.03	1.15	1.26	1.60	2.67	1.94	1.61	1.94	2.37	2.01	3.47
14 Steam	0.29	0.29	0.30	0.34	0.40	0.35	0.32	0.36	0.42	0.37	0.49
TOTAL IN:	3.13	3.25	3.32	3.71	4.76	4.00	3.72	4.01	4.50	4.10	5.60
16 Hydrogen product	2.38	2.46	2.53	2.82	3.60	3.04	2.81	3.04	3.40	3.11	4.19
Total steam generated	0.45	0.39	0.44	0.47	0.44	0.40	0.44	0.48	0.61	0.46	0.55
Ash and slag	0.05	0.10	0.05	0.08	0.10	0.11	0.09	0.08	0.06	0.11	0.14
Dry cooling load	0.14	0.19	0.18	0.21	0.44	0.30	0.25	0.26	0.27	0.27	0.51
Wet cooling load	0.11	0.11	0.12	0.13	0.18	0.15	0.13	0.15	0.16	0.15	0.21
TOTAL OUT:	3.13	3.25	3.32	3.71	4.76	4.00	3.72	4.01	4.50	4.10	5.60

TABLE A1-9. APPROXIMATE PLANT DRIVING ENERGY REQUIREMENTS FOR 10,000 TONS/DAY SRC PLANTS

Units: 10^9 Btu/hr.

	Bureau, Illinois	White, Illinois	Fulton, Illinois	Saline, Illinois
Coal drying	0.32	0.05	0.32	0.12
Acid gas removal (two places)	0.30	0.24	0.28	0.28
Vacuum tower ejector	0.01	0.01	0.01	0.01
Electricity	0.18	0.18	0.18	0.18
Oxygen production	0.33	0.25	0.30	0.30
Synthesis gas compressor	0.38	0.29	0.36	0.35
Hydrogen compressor	0.20	0.15	0.18	0.18
Slurry pump	0.11	0.11	0.11	0.10
Water treatment & allowance for other low-level uses	0.2	0.2	0.2	0.2
TOTAL:	2.03	1.48	1.94	1.72

	Rainbow, Wyoming	Gillette, Wyoming	Antelope Creek, Wyoming	Colstrip, Montana	Marengo, Alabama	Dickinson, N. Dakota	Bentley, N. Dakota	Underwood, N. Dakota	Otter Creek, Montana	Pumpkin Creek, Montana	Coalridge, Montana
Coal drying	0.19	0.79	0.59	0.55	1.81	1.31	1.04	0.99	0.70	0.82	1.37
Acid gas removal (two places)	0.32	0.34	0.36	0.40	0.52	0.49	0.39	0.44	0.49	0.45	0.64
Vacuum tower ejector	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Electricity	0.18	0.18	0.18	0.18	0.18	0.18	0.18	0.18	0.18	0.18	0.18
Oxygen production	0.35	0.37	0.39	0.43	0.58	0.48	0.43	0.48	0.53	0.49	0.70
Synthesis gas compressor	0.41	0.45	0.45	0.51	0.72	0.58	0.52	0.57	0.62	0.58	0.84
Hydrogen compressor	0.21	0.21	0.22	0.25	0.32	0.27	0.25	0.27	0.30	0.27	0.37
Slurry pump	0.10	0.12	0.11	0.11	0.12	0.12	0.12	0.12	0.11	0.12	0.13
Water treatment & allowance for other low-level uses	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
TOTAL:	1.97	2.75	2.51	2.64	4.46	3.64	3.14	3.26	3.14	3.12	4.44

TABLE A1-10. EFFICIENCY CALCULATION FOR 10,000 TON/DAY SRC PLANTS

Units: 10^9 Btu/hr.

	Bureau, Illinois	White, Illinois	Fulton, Illinois	Saline, Illinois
Coal to dissolving	18.56	18.84	18.79	18.72
Coal to gasifier	0.83	0.19	0.64	0.62
Total input energy	19.39	19.03	19.43	19.34
SRC product	13.16	13.16	13.16	13.16
Oil product	3.29	3.29	3.29	3.29
Gas product	1.78	1.72	1.78	1.78
Total steam recovered	1.01	0.95	1.00	1.00
Steam required in gasification	-0.27	-0.21	-0.26	-0.26
Plant driving energy	-2.03	-1.48	-1.94	-1.72
Boiler stack loss	-0.41	-0.29	-0.39	-0.36
Fuel to dissolver & vacuum preheater	-1.49	-1.55	-1.53	-1.46
Total output energy	15.04	15.59	15.11	15.43
Unrecovered heat	4.35	3.44	4.32	3.91
Conversion efficiency %	77.56	81.92	77.77	79.78

	Rainbow, Wyoming	Gillette, Wyoming	Antelope Creek, Wyoming	Colstrip, Montana	Marengo, Alabama	Dickinson, N. Dakota	Bentley, N. Dakota	Underwood, N. Dakota	Otter Creek, Montana	Pumpkin Creek, Montana	Coalridge, Montana
Coal to dissolving	18.22	17.93	17.74	17.63	17.25	17.40	17.80	17.34	17.05	17.34	16.50
Coal to gasifier	1.03	1.15	1.26	1.60	2.67	1.94	1.61	1.94	2.37	2.01	3.47
Total input energy	19.25	19.08	19.00	19.23	19.92	19.34	19.41	19.28	19.42	19.35	19.97
SRC product	13.16	12.92	12.92	12.92	12.92	12.92	12.92	12.92	12.92	12.92	12.92
Oil product	3.29	3.29	3.29	3.29	3.29	3.29	3.29	3.29	3.29	3.29	3.29
Gas product	1.78	1.78	1.78	1.84	1.91	1.84	1.84	1.84	1.91	1.84	1.97
Total steam recovered	1.07	1.08	1.08	1.13	1.17	1.11	1.14	1.17	1.25	1.17	1.32
Steam required in gasification	-0.29	-0.29	-0.30	-0.34	-0.40	-0.35	-0.32	-0.36	-0.42	-0.37	-0.49
Plant driving energy	-1.97	-2.75	-2.51	-2.64	-4.46	-3.64	-3.14	-3.26	-3.14	-3.12	-4.44
Boiler stack loss	-0.42	-0.53	-0.51	-0.55	-0.89	-0.71	-0.62	-0.66	-0.68	-0.65	-0.94
Fuel to dissolver & vacuum preheater	-1.45	-1.62	-1.50	-1.55	-1.71	-1.67	-1.64	-1.62	-1.52	-1.67	-1.83
Total output energy	15.19	13.88	14.25	14.10	11.83	12.79	13.47	13.32	13.61	13.11	11.80
Unrecovered heat	4.08	5.20	4.75	5.13	8.09	6.55	5.94	5.96	5.81	6.24	8.17
Conversion efficiency %	78.81	72.75	75.00	73.32	59.39	66.13	69.40	69.09	70.08	67.75	59.09

TABLE A1-11. ULTIMATE DISPOSITION OF UNRECOVERED HEAT IN 10,000 TONS/DAY SRC PLANTS

Units: 10^9 Btu/hr.

	Bureau, Illinois	White, Illinois	Fulton, Illinois	Saline, Illinois
Direct losses	1.86	1.49	1.89	1.63
Assigned to dry cooling	0.27	0.19	0.25	0.21
Assigned to wet cooling	0.8	0.62	0.85	0.77
Gas purification system regenerator condenser	0.30	0.24	0.28	0.28
Total steam turbine condenser	0.85	0.69	0.80	0.78
Total gas compressor interstage cooler	0.27	0.21	0.25	0.24
TOTAL:	4.35	3.44	4.32	3.91

	Rainbow, Wyoming	Gillette, Wyoming	Antelope Creek, Wyoming	Colstrip, Montana	Marengo, Alabama	Dickinson, N. Dakota	Bentley, N. Dakota	Underwood, N. Dakota	Otter Creek, Montana	Pumpkin Creek, Montana	Coalridge, Montana
Direct losses	1.72	2.60	2.21	2.27	3.92	3.25	2.86	2.83	2.51	2.70	3.60
Assigned to dry cooling	0.32	0.46	0.43	0.45	0.78	0.63	0.55	0.58	0.51	0.58	0.95
Assigned to wet cooling	0.56	0.56	0.48	0.62	1.03	0.64	0.73	0.58	0.65	0.67	0.85
Gas purification system regenerator condenser	0.32	0.34	0.36	0.40	0.52	0.49	0.39	0.44	0.49	0.45	0.64
Total steam turbine condenser	0.87	0.93	0.95	1.03	1.35	1.14	1.05	1.13	1.23	1.14	1.55
Total gas compressor interstage cooler	0.29	0.31	0.32	0.36	0.49	0.40	0.36	0.40	0.42	0.40	0.58
TOTAL:	4.08	5.20	4.75	5.13	8.09	6.55	5.94	5.96	5.81	6.24	8.17

APPENDIX 2

CALCULATIONS ON THE SYNTHOIL PROCESS

BASIS OF ANALYSIS

Calculations on the Synthoil process are required for bituminous coals at:

1. Jefferson, Alabama
2. Gibson, Indiana
3. Warrick, Indiana
4. Harlan, Kentucky
5. Pike, Kentucky
6. Tuscarawas, Ohio
7. Jefferson, Ohio
8. Somerset, Pennsylvania
9. Mingo, West Virginia

and subbituminous coals at:

10. Lake de Smet, Wyoming
11. Jim Bridger, Wyoming
12. Gallup, New Mexico

The only integrated plant design (including hydrogen production) which we have seen is that of the Bureau of Mines[1] made for a Wyoming coal and made specifically for cost estimating purposes. For the purpose of estimating water requirements we have chosen to make our own, somewhat simplified, design using the block diagram from Reference 1 reproduced as Figure A2-1 in a form suitable for present purposes. The overall material balances, not including hydrogen production, were made using the following rules.

OVERALL MATERIAL BALANCES

1) 50,000 bbl/stream day of dry oil equals 700 x 10^3 lb/stream hr (Reference 1) and the oil is assumed to be 90 wt % carbon, 8.5 wt % hydrogen, 1.0 wt % oxygen and 0.5 wt % nitrogen and other elements.

2) Five barrels of oil are produced from each ton of carbon in the coal. This is the average of published results:

Ref. No.	bbl oil/ton carbon in coal
1	4.7
2	5.3
3	5.0
used in this work	5.0

The feed to the reactors (Streams 2 and 5) must therefore contain 0.833 x 10^6 lb/stream hr of carbon. Coal is assumed dried to 0.5 wt % moisture. This moisture is assumed to remain in the product oil.

3) Hydrogen requirements have been given as:

Ref. No.	scf H_2/bbl oil
1	4830
2	4200
3	4730
used in this work	4700

The hydrogen in Stream 6 is therefore 2.58 x 10^4 moles/stream hr, or 51.6 x 10^3 lb/stream hr. Stream 6 is taken to be 97 mole % H_2 and 3 mole % CO.

4) The carbon in the char has been given as:

Ref. No.	Carbon in Char as % of Carbon in Coal
1	about 6.3
2	6
used in this work	6.2

so the char (Stream 9) contains 51.6×10^3 lb/stream hr of carbon; the hydrogen and oxygen are assumed to be negligible.

5) The oxygen in the coal is assumed converted as follows:

10 percent to gas and oil;

12.8×10^3 lb/stream hr reacts with CO in Stream 6 to yield CO_2 which remains in the gas;

the balance is converted to water, Stream 13.

6) The balance of the carbon and hydrogen appears in the gas. The overall material balance calculations resulting from the above rules are given on Table A2-1 for each site. The water from phase separation has been copied onto the summary table, Table A2-2. This stream is controlled by the oxygen content of the coal.

HYDROGEN PRODUCTION

There are many ways to make hydrogen: 1) The gas can be put through a steam reforming reaction (this is quite efficient but necessitates burning char and coal for plant energy, and both char and coal contain sulfur). 2) The char, with added coal, can be partially oxidized (gasified) to make synthesis gas which can be converted to H_2 by the shift reaction (this procedure yields the sulfur as H_2S which can be readily removed; the gas produced in the oil plant is also stripped of H_2S and is then burnt as a fuel). We have assumed that gasification is used, and the hydrogen production train is shown in Figure A2-2. Extrapolating from Reference 1, the following rules were used to calculate the various water streams of Figure A2-2.

1) The gasifier is pressurized and yields hydrogen at 450 psig which is compressed to 4000 psig for use in the Synthoil reactor.

2) The gasifier off-gas comes off at 1800°F. The mole ratio H_2:CO = 0.72. Since the hydrogen stream (No. 6) contains 2.58×10^4 moles H_2/hr and 0.08×10^4 moles CO/hr, or 2.66×10^4 total moles/hr, and since one mole CO yields one mole H_2 in a shift reaction, the total CO + H_2 in the off-gas must also be 2.66×10^4 moles/hr and must be 1.11×10^4 moles H_2/hr and 1.55×10^4 moles CO/hr.

At two locations, Lake de Smet, Wyoming and Jim Bridger Mine, Wyoming, the coal is particularly wet and there is not enough byproduct gas to drive the plant. At these two locations extra coal is gasified to produce extra gas which is burnt for fuel, as shown on Figure A2-2. At Lake de Smet 7.4 percent of the gasifier off-gas is burnt, and at Jim Bridger 16.7 percent of the gasifier off-gas is burnt.

3) In addition to char, steam, oxygen and coal are fed to the gasifier at rates determined by the simultaneous solutions of the carbon, hydrogen and oxygen elemental balances and the thermal balance. For this high temperature gasifier it is assumed that 80 percent of the steam feed is decomposed. Hydrogen in the coal is first used up making the oxygen in the coal into water; only the surplus is available for reaction. Moisture in the coal passes unchanged into the gas.

In deriving the equations and performing the calculations, the symbols and numerical values shown on Table A2-3 were used. The balances are:

Carbon

$$c.W_C/12 + 4,300 = M_{CO2} + 15,500 \qquad (1)$$

Hydrogen

$$h.W_C/2 - x.W_C/16 + 0.8\ M_{ST} = 11,100 \qquad (2)$$

Moisture

$$w.W_C/18 + 0.2\ M_{ST} + x.W_C/16 = M_{H2O} \qquad (3)$$

Oxygen

$$0.4\ M_{ST} + OX = 7,750 + M_{CO2} \qquad (4)$$

Thermal

$$H_C W_C + 0.748 \times 10^9 + 21,100\ M_{ST} = 3.598 \times 10^9 + 20,500\ M_{CO2} + 34,800\ M_{H2O} \qquad (5)$$

Equations (1) to (4) can be rewritten to give:

$$M_{CO2} = 0.0833\ c.W_C - 11,200 \quad (6)$$

$$M_{ST} = 13,875 - 0.625\ h.W_C + 0.0781\ x.W_C \quad (7)$$

$$M_{H2O} = 2,775 + 0.0556\ w.W_C - 0.125\ h.W_C + 0.0781\ x.W_C \quad (8)$$

$$OX = -9,000 + W_C(0.0833\ c + 0.25\ h - 0.0312\ x) \quad (9)$$

Equation (5) gives:

$$W_C(H_C - 1,708\ c - 8,838\ h - 1,935\ w - 1,070\ x) = 2.424 \times 10^9 \quad (10)$$

The coal feed, steam and oxygen have been calculated and entered on Table A2-2. Selected gas rates have been calculated and entered on Table A2-4.

Table A2-3 shows 11,100 moles H_2 and 15,500 moles CO in the gasifier off-gas (as calculated in Step 2 above) and Equations (1) to (10) use these quantities. At Lake de Smet and Jim Bridger, Wyoming, where extra gas is made for fuel, the gasifier off-gas composition must be that shown on Table A2-4 and Equations (1) to (10) must be modified accordingly.

4) Water is added to the gasifier off-gas to quench it. The quenched gas then goes to the first stage shift reaction which the gas leaves at 900°F and assumed to be in equilibrium at 950°F.

Let M' be the moles/hr leaving the first stage shift; let M be, as before, the moles/hr leaving the gasifier; and let M_W = moles quench water/hr. The equilibrium equation is:

$$\frac{M'_{CO2}\ M'_{H2}}{M'_{CO}\ M'_{H2O}} = 4.55 \quad (11)$$

The carbon balance is:

$$M'_{CO2} + M'_{CO} = M_{CO2} + 15{,}500$$

or

$$M'_{CO2} = M_{CO2} + 15{,}500 - M'_{CO} = \text{(say) } K_{12} - M'_{CO} \tag{12}$$

From the stoichiometry of the shift reaction:

$$M'_{H2} + M'_{CO} = 26{,}600$$

or

$$M'_{H2} = 26{,}600 - M'_{CO} \tag{13}$$

The thermal balance is:

Heat content leaving gasifier at 1800°F = heat content leaving 1st shift reactor at 900°F (because quench water is at base or zero enthalpy).

$$3.598 \times 10^9 + 20{,}500\ M_{CO2} + 34{,}800\ M_{H2O} = 8{,}800\ M'_{CO2}$$

$$+ 127{,}700\ M'_{CO} + 25{,}900\ M'_{H2O} + 128{,}700\ M'_{H2} \tag{14}$$

From Equations (12), (13) and (14):

$$M'_{H2O} = K_{14} + 0.378\ M'_{CO} \tag{15}$$

where

$$K_{14} = 1{,}474 + 1.344\ M_{H2O} + 0.452\ M_{CO2} \tag{16}$$

Substitution of Equations (12), (13) and (15) into Equation (11) gives a quadratic in M'_{CO} which can be solved allowing the determination of all other quantities. The quench water, M_W , can be found from the hydrogen balance:

$$11{,}100 + M_{H2O} + M_W = M'_{H2} + M'_{H2O} \tag{17}$$

The results of the calculations have been entered onto Tables A2-2 and A2-4.

5) When the gas is cooled to 300°F, assuming a pressure at this point of 430 psig, the water vapor is reduced to 15 mole % and all the rest of the water in the gas condenses. Total removal of CO_2 is assumed in the first acid gas removal system. In fact, the removal is over 95 percent and the assumption of total removal simplifies the calculations while introducing negligible error.

6) The gas leaving the second stage shift reactor is in equilibrium at 550°F. The compositions of the gas streams are (in moles/hr):

	IN	OUT
CO_2	0	m'_{CO2}
H_2O	m_{H2O}	m'_{H2O}
CO	m_{CO}	800
H_2	m_{H2}	25,800

Also, let m_W be the moles of steam added.

From the carbon balance:

$$m'_{CO2} = m_{CO} - 800 \tag{18}$$

the equilibrium equation is:

$$\frac{(m'_{CO2})(25,800)}{(800)(m'_{H2O})} = 46.7 \tag{19}$$

which gives m'_{H2O} having found m'_{CO2} from Equation (18). The steam added, m_W, can be found from the hydrogen balance:

$$m_W + m_{H2O} + m_{H2} = 25,800 + m'_{H2O} \tag{20}$$

7) It is sufficiently accurate to assume 100 percent removal of CO_2 in the second acid gas removal and to take the clean condensate, Stream 17, as

100 percent of the water vapor in the gas leaving the second stage shift, Stream 22.

PLANT ENERGY REQUIREMENTS

The approximate plant energy requirements are given on Table A2-5. Those listed are the principal requirements, but not all the energy loads in the plant. Since all the energy requirements may not have been found, the stated efficiencies may be high. This will not affect cooling water requirements, which is the sole reason for preparing Table A2-5. In preparing that table the following calculations were made:

1) Drying coal requires 1100 Btu/lb water evaporated plus 200 Btu/lb coal feed to heat the coal.

2) The slurry contains 2 lb oil per lb coal and the pumps require 146 Btu/lb dry coal.

3) The heat load on the dissolver-heat exchanger-phase separation section was taken from Reference 1. The heat load to char de-oiling was treated similarly.

4) Coal and char are assumed fed to the gasifier through lock hoppers and variations from coal to coal is too small a part of the total energy to be considered.

5) Acid gas removal requires 30,000 Btu per mole CO_2 removed. The rate of removal of CO_2 is given on Table A2-4.

6) The waste heat recovery in the hydrogen production plant was calculated from the heat capacities of the gases. Since at 300°F and 410 psig the water vapor will saturate the gas when it is 13 mole percent of the gas, there will be no condensation in the waste heat recovery unit. The heat recovered is:

$$1419\ M_{CO} + 1407\ M_{H2} + 2098\ M_{CO2} + 1672\ M_{H2O}$$

where M is the moles/hr in Stream 22 leaving the second stage shift. That is:

$$3.744 \times 10^{7} + 2098\ M_{CO2} + 1672\ M_{H2O}\ \text{Btu/hr}$$

The loads on the dry and wet coolers will also be needed and were calculated as follows. At 140°F after acid gas removal, water vapor is reduced to 1.25×10^3 moles/hr. The dry cooling load is:

$$2.984 \times 10^7 + 18{,}756\ M_{WT}\ \text{Btu/hr}$$

where M_{WT} is the moles of water condensed in the dry cooler.

The wet cooling load is 3.126×10^7 Btu/hr for all the plants.

7) The hydrogen compression load is the same for all the plants.

8) The energy for oxygen production is 2.03×10^6 Btu/thousand lbs oxygen.

9) Electricity generated is 15,000 kw at 11,700 Btu/kw-hr.

10) The low level requirements are arbitrary.

11) The boiler stack loss is 15 percent of the fuel burnt, which is the total heat load.

The approximate plant conversion efficiencies are shown on Table A2-6. All heating values are calculated from the formula:

$$H = 14{,}540\ W_C + 62{,}000(W_H - \frac{W_O}{8})$$

where W_C, W_H, and W_O are the weights of carbon, hydrogen and oxygen in the stream.

ULTIMATE DISPOSITION OF UNRECOVERED HEAT

The ultimate disposition of unrecovered heat is given on Table A2-7. The calculations were made as follows. The direct losses consist of the energy to dry coal for the Synthoil reactor (Table A2-5), the boiler stack loss (Table A2-5), char de-oiling energy, which is a stack loss (Table A2-5), 30 percent of the electricity generation energy, 30 percent of the slurry pump energy and an arbitrary allowance for convection losses. Other losses begin with the acid gas removal regenerator condenser which is taken as all the energy into the acid gas removal (Table A2-5). Air cooling consists of air cooling in the hydrogen plant (calculation is described above) plus 80 percent of the energy to condense the condensate out of phase separation (at 1040 Btu/lb condensate). The energy dissipated in the turbine drive condensers is taken as 70 percent of slurry pump energy plus 70 percent of the energy to feed solids to gasifier (i.e., the lock hopper compressor energy) plus 70 percent of hydrogen compression energy plus 70 percent of oxygen production energy plus 70 percent of electrical generation. Compressor interstage cooling is taken as 30 percent of lock hopper compressor energy plus 30 percent of hydrogen compression energy plus 30 percent of oxygen production energy. The wet cooling load is the balance.

In estimating solid residues these plants use no flue gas desulfurization. All the ash in the entering coal (fed to reactor plus gasifier) leaves the gasifier and is listed as bottom ash.

REFERENCES, APPENDIX 2

1. U.S. Dept. of the Interior, "SYNTHOIL Process Liquid Fuel from Coal Plant, 50,000 Barrels per Stream Day. An Economic Evaluation," Report No. ERDA 76-35, Bureau of Mines, Morgantown, W. Va., 1975; summarized in: Katell, S., and White, L. G., "Economic Comparison of Synthetic Fuels Gasification and Liquefaction," presented at ACS National Meeting, Division of I&EC, New York, April 1976.

2. Akhtar, S., Mazzocco, N. J., Weintraub, M., and Yavorsky, P. M., "SYNTHOIL Process for Converting Coal to Non-Polluting Fuel Oil," 4th Synthetic Fuels from Coal Conference, Oklahoma State University, Stillwater, Oklahoma, May 6-7, 1974.

3. Akhtar, S., Lacey, J. J., Weintraub, M., Rezik, A. A., and Yavorsky, P. M., "The SYNTHOIL Process--Material Balance and Thermal Efficiency," presented at 67th Annual Meeting, AIChE, Washington, D.C., Dec. 1-5, 1974.

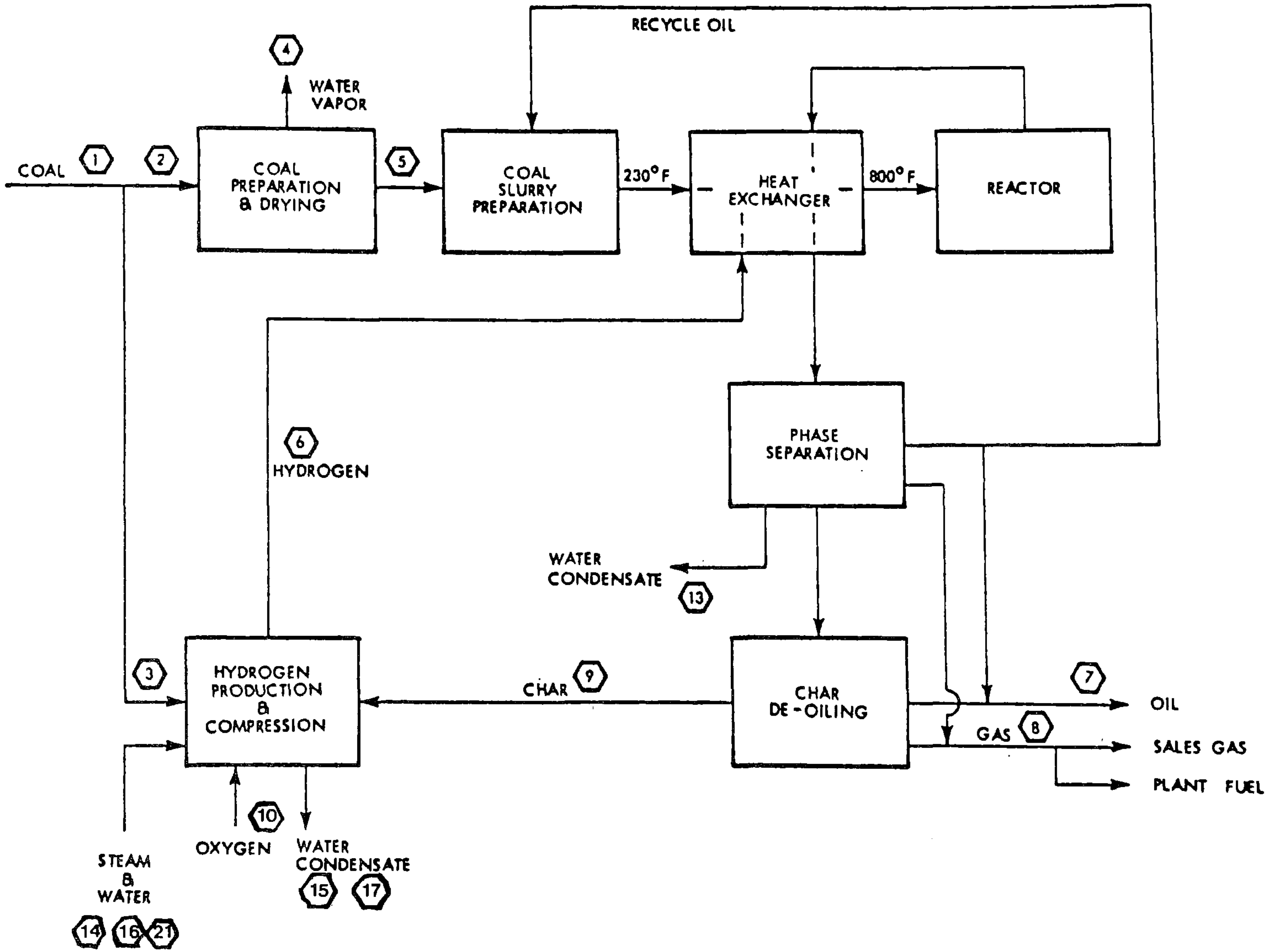


Figure A2-1. Flow diagram for process water streams in Synthoil process.

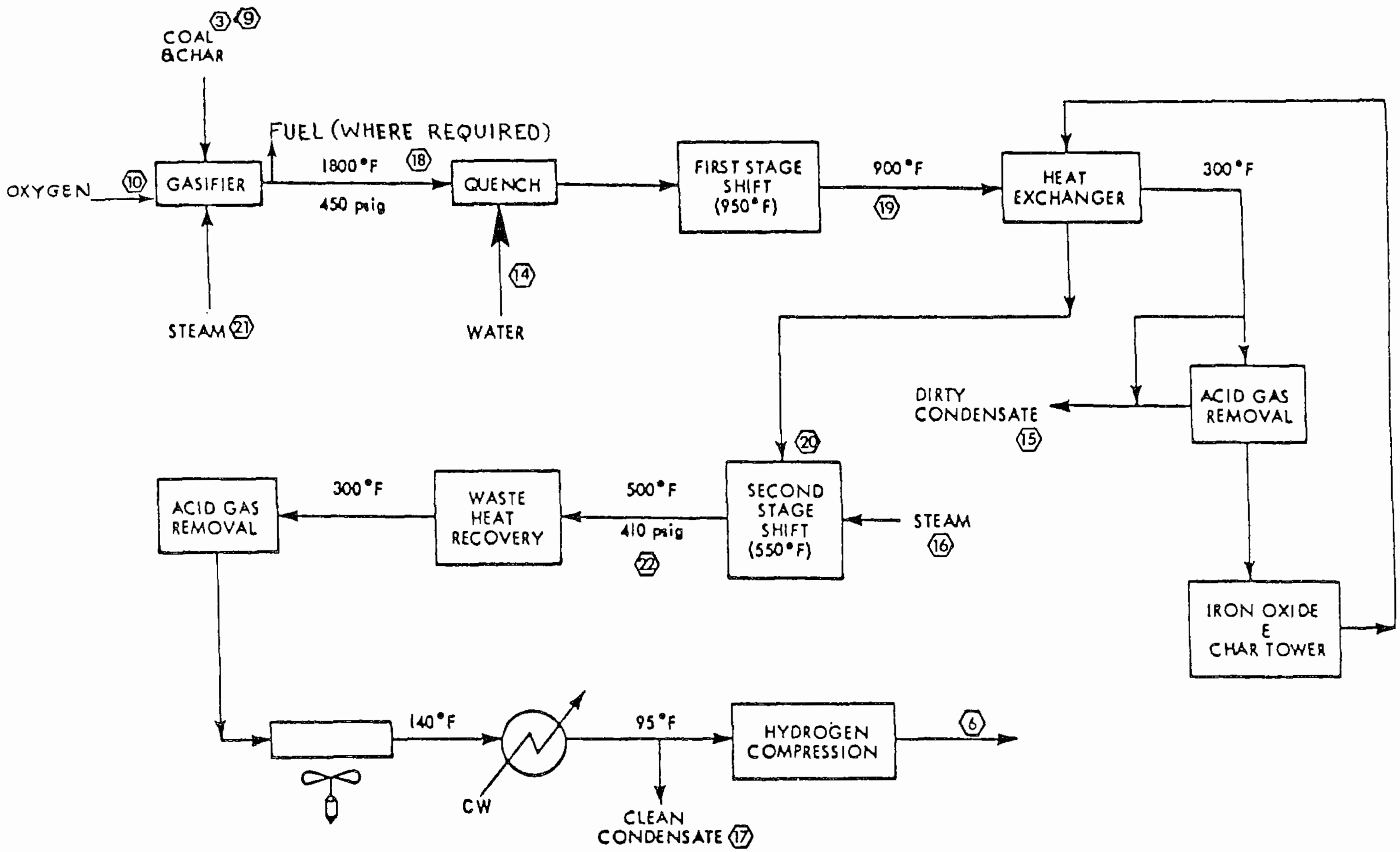


Figure A2-2. Flow diagram for hydrogen production in Synthoil process.

TABLE A2-1. MATERIAL BALANCE ON SYNTHOIL PLANT EXCLUSIVE OF HYDROGEN PRODUCTION

Units: 10^3 lb/stream hr.

LOCATION: Jefferson, Alabama

Stream		Total	Moisture	C	H	O	Ash	N&S
2	Coal, as-received	1173.3	27.0	833	51.6	44.6	188.9	28.2
4	Water lost in drier	21.2	21.2	--	--	--	--	--
5	Coal, dry	1152.1	5.8	833.0	51.6	44.6	188.9	28.2
6	Makeup hydrogen	74.0	--	9.6	51.6	12.8	--	--
	TOTAL 5,6	1226.1	--	842.6	103.2	57.4	188.9	28.2
7	Oil	705.8	5.8	630.0	59.5	7	--	3.5
8	Gas: CO_2 from CO in makeup hydrogen	257	--	9.6	--	25.6	--	--
	Other		--	151.4	41.2	4.5	--	24.7
9	Char	240.5	--	51.6	--	--	188.9	--
13	Water from phase separation	22.8	--	--	2.5	20.3	--	--
	TOTAL 7,8,9,13	1226.1	--	842.6	103.2	57.4	188.9	28.2

LOCATION: Gibson, Indiana

Stream		Total	Moisture	C	H	O	Ash	N&S
2	Coal, as-received	1221.3	122.1	833	56.2	92.8	78.2	39.0
4	Water lost in drier	116.0	116.0	--	--	--	--	--
5	Coal, dry	1105.3	6.1	833	56.2	92.8	78.2	39.0
6	Makeup hydrogen	74	--	9.6	51.6	12.8	--	--
	TOTAL 5,6	1179.3	--	842.6	107.8	105.6	78.2	39.0
7	Oil	706.1	6.1	630	59.5	7	--	3.5
8	Gas: CO_2 from CO in makeup hydrogen	272.6	--	9.6	--	25.6	--	--
	Other		--	151.4	41.2	9.3	--	35.5
9	Char	129.8	--	51.6	--	--	78.2	--
13	Water from phase separation	70.8	--	--	7.1	63.7	--	--
	TOTAL 7,8,9,13	--	--	842.6	107.8	105.6	78.2	39.0

(continued)

Table A2-1 (continued)

Units: 10^3 lb/stream hr.

LOCATION: Warrick, Indiana

Stream		Total	Moisture	C	H	O	Ash	N&S
2	Coal, as-received	1285.5	119.6	833	59.1	120.8	106.7	46.3
4	Water lost in drier	113.2	113.2	--	--	--	--	--
5	Coal, dry	1172.3	6.4	833	59.1	120.8	106.7	46.3
6	Makeup hydrogen	74	--	9.6	51.6	12.8	--	--
	TOTAL 5,6	1246.3	--	842.6	110.7	133.6	106.7	46.3
7	Oil	706.4	6.4	630	59.5	7	--	3.5
8	Gas: CO_2 from CO in makeup hydrogen	282.8	--	9.6	--	25.6	--	--
	Other		--	151.4	41.3	12.1	--	42.8
9	Char	158.3	--	51.6	--	--	106.7	--
13	Water from phase separation	98.8	--	--	9.9	88.9	--	--
	TOTAL 7,8,9,13	1246.3	--	842.6	110.7	133.6	106.7	46.3

LOCATION: Harlan, Kentucky

Stream		Total	Moisture	C	H	O	Ash	N&S
2	Coal, as-received	1070.7	38.5	833	54.6	81.4	40.7	22.5
4	Water lost in drier	33.1	33.1	--	--	--	--	--
5	Coal, dry	1037.6	5.4	833	54.6	81.4	40.7	22.5
6	Makeup hydrogen	74	--	9.6	51.6	12.8	--	--
	TOTAL 5,6	1111.6	--	842.6	106.2	94.2	40.7	22.5
7	Oil	705.4	5.4	630	59.5	7	--	3.5
8	Gas: CO_2 from CO in makeup hydrogen	254.5	--	9.6	--	25.6	--	--
	Other		--	151.4	40.8	8.1	--	19.0
9	Char	92.3	--	51.6	--	--	40.7	--
13	Water from phase separation	59.4	--	--	5.9	53.5	--	--
	TOTAL 7,8,9,13	1111.6	--	842.6	106.2	94.2	40.7	22.5

(continued)

Table A2-1 (continued)

Units: 10^3 lb/stream hr.

LOCATION: Pike, Kentucky

Stream		Total	Moisture	C	H	O	Ash	N&S
2	Coal, as-received	1046.5	31.4	833	53.4	55.5	50.2	23.0
4	Water lost in drier	26.2	26.2	--	--	--	--	--
5	Coal, dry	1020.3	5.2	833	53.4	55.5	50.2	23.0
6	Makeup hydrogen	74	--	9.6	51.6	12.8	--	--
	TOTAL 5,6	1094.3	--	842.6	105.0	68.3	50.2	23.0
7	Oil	705.2	5.2	630	59.5	7	--	3.5
8	Gas: CO_2 from CO in makeup hydrogen	253.9	--	9.6	--	25.6	--	--
	Other		--	151.4	42.2	5.6	--	19.5
9	Char	101.8	--	51.6	--	--	50.2	--
13	Water from phase separation	33.4	--	--	3.3	30.1	--	--
	TOTAL 7,8,9,13	1094.3	--	842.6	105.0	68.3	50.2	23.0

LOCATION: Tuscarawas, Ohio

Stream		Total	Moisture	C	H	O	Ash	N&S
2	Coal, as-received	1169.9	73.7	833	57.3	94.8	65.5	45.6
4	Water lost in drier	67.9	67.9	--	--	--	--	--
5	Coal, dry	1102.0	5.8	833	57.3	94.8	65.5	45.6
6	Makeup hydrogen	74	--	9.6	51.6	12.8	--	--
	TOTAL 5,6	1176.0	--	842.6	108.9	107.6	65.5	45.6
7	Oil	705.8	5.8	630	59.5	7	--	3.5
8	Gas: CO_2 from CO in makeup hydrogen	280.3	--	9.6	--	25.6	--	--
	Other		--	151.4	42.1	9.5	--	42.1
9	Char	117.1	--	51.6	--	--	65.5	--
13	Water from phase separation	72.8	--	--	7.3	65.5	--	--
	TOTAL 7,8,9,13	1176.0	--	842.6	108.9	107.6	65.5	45.6

(continued)

Table A2-1 (continued)

Units: 10^3 lb/stream hr.

LOCATION: Jefferson, Ohio

Stream		Total	Moisture	C	H	O	Ash	N&S
2	Coal, as-received	1171.5	28.1	833	57.4	62.1	118.3	72.6
4	Water lost in drier	22.2	22.2	--	--	--	--	--
5	Coal, dry	1149.3	5.9	833	57.4	62.1	118.3	72.6
6	Makeup hydrogen	74	--	9.6	51.6	12.8	--	--
	TOTAL 5,6	1223.3	--	842.6	109.0	74.9	118.3	72.6
7	Oil	705.9	5.9	630	59.5	7	--	3.5
8	Gas: CO_2 from CO in makeup hydrogen	307.4	--	9.6	--	25.6	--	--
	Other		--	151.4	45.5	6.2	--	69.1
9	Char	169.9	--	51.6	--	--	118.3	--
13	Water from phase separation	40.1	--	--	4.0	36.1	--	--
	TOTAL 7,8,9,13	1223.3	--	842.6	109.0	74.9	118.3	72.6

LOCATION: Somerset, Pennsylvania

Stream		Total	Moisture	C	H	O	Ash	N&S
2	Coal, as-received	1125.7	20.3	833	45.0	34.9	153.1	39.4
4	Water lost in drier	14.7	14.7	--	--	--	--	--
5	Coal, dry	1111.0	5.6	833	45.0	34.9	153.1	39.4
6	Makeup hydrogen	74	--	9.6	51.6	12.8	--	--
	TOTAL 5,6	1185.0	--	842.6	96.6	47.7	153.1	39.4
7	Oil	705.6	5.6	630	59.5	7	--	3.5
8	Gas: CO_2 from CO in makeup hydrogen	261.8	--	9.6	--	25.6	--	--
	Other		--	151.4	35.8	3.5	--	35.9
9	Char	204.7	--	51.6	--	--	153.1	--
13	Water from phase separation	12.9	--	--	1.3	11.6	--	--
	TOTAL 7,8,9,13	1185.0	--	842.6	96.6	47.7	153.1	39.4

(continued)

Table A2-1 (continued)

Units: 10^3 lb/stream hr.

LOCATION: Mingo, West Virginia

Stream		Total	Moisture	C	H	O	Ash	N&S
2	Coal, as-received	1047.8	23.1	833	54.5	61.8	51.3	24.1
4	Water lost in drier	17.9	17.9	--	--	--	--	--
5	Coal, dry	1029.9	5.2	833	54.5	61.8	51.3	24.1
6	Makeup hydrogen	74	--	9.6	51.6	12.8	--	--
	TOTAL 5,6	1103.9	--	842.6	106.1	74.6	51.3	24.1
7	Oil	705.2	5.2	630	59.5	7	--	3.5
8	Gas: CO_2 from CO in makeup hydrogen	256.0	--	9.6	--	25.6	--	--
	Other		--	151.4	42.6	6.2	--	20.6
9	Char	102.9	--	51.6	--	--	51.3	--
13	Water from phase separation	39.8	--	--	4.0	35.8	--	--
	TOTAL 7,8,9,13	1103.9	--	842.6	106.1	74.6	51.3	24.1

LOCATION: Lake de Smet, Wyoming

Stream		Total	Moisture	C	H	O	Ash	N&S
2	Coal, as-received	1724.7	407.0	833	60.4	227.7	167.3	29.3
4	Water lost in drier	398.4	398.4	--	--	--	--	--
5	Coal, dry	1326.3	8.6	833	60.4	227.7	167.3	29.3
6	Makeup hydrogen	74	--	9.6	51.6	12.8	--	--
	TOTAL 5,6	1400.3	--	842.6	112.0	240.5	167.3	29.3
7	Oil	708.6	8.6	630	59.5	7	--	3.5
8	Gas: CO_2 from CO in makeup hydrogen	267.1	--	9.6	--	25.6	--	--
	Other		--	151.4	31.9	22.8	--	25.8
9	Char	218.9	--	51.6	--	--	167.3	--
13	Water from phase separation	205.7	--	00	20.6	185.1	--	--
	TOTAL 7,8,9,13	1400.3	--	842.6	112.0	240.5	167.3	29.3

(continued)

Table A2-1 (continued)

Units: 10^3 lb/stream hr.

LOCATION: Jim Bridger, Wyoming

Stream		Total	Moisture	C	H	O	Ash	N&S
2	Coal, as-received	1605.1	340.3	833	51.4	223.1	131.6	25.7
4	Water lost in drier	332.3	332.3	--	--	--	--	--
5	Coal, dry	1272.8	8.0	833	51.4	223.1	131.6	25.7
6	Makeup hydrogen	74	--	9.6	51.6	12.8	--	--
	TOTAL 5,6	1346.8	--	842.6	103.0	235.9	131.6	25.7
7	Oil	708.0	8.0	630	59.5	7	--	3.5
8	Gas: CO_2 from CO in makeup hydrogen	254.5	--	9.6	--	25.6	--	--
	Other		--	151.4	23.4	22.3	--	22.2
9	Char	183.2	--	51.6	--	--	131.6	--
13	Water from phase separation	201.1	--	--	20.1	181.0	--	--
	TOTAL 7,8,9,13	1346.8	--	842.6	103.0	235.9	131.6	25.7

LOCATION: Gallup, New Mexico

Stream		Total	Moisture	C	H	O	Ash	N&S
2	Coal, as-received	1318.0	199.0	833	61.9	137.1	67.2	19.8
4	Water lost in drier	192.4	192.4	--	--	--	--	--
5	Coal, dry	1125.6	6.6	833	61.9	137.1	67.2	19.8
6	Makeup hydrogen	74	--	9.6	51.6	12.8	--	--
	TOTAL 5,6	1199.6	--	842.6	113.5	149.9	67.2	19.8
7	Oil	706.6	6.6	630	59.5	7	--	3.5
8	Gas: CO_2 from CO in makeup hydrogen	259.1	--	9.6	--	25.6	--	--
	Other		--	151.4	42.5	13.7	--	16.3
9	Char	118.8	--	51.6	--	--	67.2	--
13	Water from phase separation	115.1	--	--	11.5	103.6	--	--
	TOTAL 7,8,9,13	1199.6	--	842.6	113.5	149.9	67.2	19.8

TABLE A2-2. SUMMARY OF FLOWS FOR HYDROGEN PRODUCTION AND OTHER WATER STREAMS IN 50,000 BBL/DAY SYNTHOIL PLANTS

Units: 10^3 lb/hr

Stream		Jefferson, Alabama	Gibson, Indiana	Warrick, Indiana	Harlan, Kentucky	Pike, Kentucky	Tuscarawas, Ohio	Jefferson, Ohio	Somerset, Pennsylvania	Mingo, West Virginia	Lake de Smet, Wyoming	Jim Bridger, Wyoming	Gallup, New Mexico
3	Coal to gasifier	218	234	246	203	196	220	214	213	196	413	449	258
10	Oxygen to gasifier	194	206	204	199	197	197	189	193	197	271	322	216
21	Steam to gasifier	153	154	155	155	152	154	148	163	151	183	196	151
14	Water to gas quench	266	286	289	274	268	278	265	266	267	352	351	302
15	Medium quality condensate from hydrogen	59	95	103	73	63	83	59	59	62	243	234	130
16	Steam to second stage shift	79	61	56	73	77	65	77	82	77	25	22	46
17	Clean condensate	67	59	57	64	66	61	66	68	66	45	43	53
13	Water from phase separation	23	71	99	59	33	73	40	13	40	206	201	115

TABLE A2-3. SYMBOLS AND VALUES USED TO CALCULATE BALANCES AROUND GASIFIER IN 50,000 bbl/day SYNTHOIL PLANTS

	Flow Rates	Enthalpies	
TOTAL COAL:	W_C (lb/hr)	H_C (Btu/lb)	$H_C \cdot W_C$
	(moles/hr)	(Btu/mole)	(Btu/hr)
Coal carbon	$c.W_C/12$*	--	--
Coal hydrogen	$h.W_C/2$*	--	--
Coal oxygen	$x.W_C/32$*	--	--
Coal moisture	$w.W_C/18$*	--	--
Char carbon	4,300	174,000	0.748×10^9
Steam	M_{ST}	21,100	21,100 M_{ST}
Oxygen	OX	0	0
Off-gas:			
H_2	11,100	135,300	1.502×10^9
CO	15,500	135,200	2.096×10^9
CO_2	M_{CO2}	20,500	20,500 M_{CO2}
H_2O	M_{H2O}	34,800	34,800 M_{H2O}

*c, h, x, w are weight fractions in as-received coal.

TABLE A2-4. SUMMARY OF GAS STREAMS FOR HYDROGEN PRODUCTION IN 50,000 BBL/DAY SYNTHOIL PLANTS

Units: 10^3 mole/hr.

Stream	Jefferson, Alabama	Gibson, Indiana	Warrick, Indiana	Harlan, Kentucky	Pike, Kentucky	Tuscarawas, Ohio	Jefferson, Ohio	Somerset, Pennsylvania	Mingo, West Virginia	Lake de Smet, Wyoming	Jim Bridger, Wyoming	Gallup, New Mexico
18 Gasifier off-gas:												
CO	15.5	15.5	15.5	15.5	15.5	15.5	15.5	15.5	15.5	16.74	18.6	15.5
H_2	11.1	11.1	11.1	11.1	11.1	11.1	11.1	11.1	11.1	11.99	13.32	11.1
CO_2	1.71	2.10	2.08	1.92	1.79	1.82	1.45	1.91	1.77	4.19	5.12	2.37
H_2O	2.50	4.12	4.44	3.09	2.66	3.59	2.64	2.44	2.64	10.71	11.34	5.52
19 Exit first shift reactor:												
CO	6.2	5.55	5.42	5.95	6.14	5.73	6.11	6.25	6.14	4.4	4.28	5.06
H_2	20.4	21.0	21.2	20.6	20.5	20.9	20.5	20.3	20.5	22.2	22.3	21.5
CO_2	11.0	12.0	12.2	11.5	11.2	11.6	10.8	11.2	11.1	15.2	15.5	12.8
H_2O	7.95	10.0	10.4	8.74	8.18	9.29	7.99	7.98	8.14	18.2	17.7	11.9
20 Entry to second shift reactor:												
CO	6.2	5.55	5.42	5.95	6.14	5.73	6.11	6.25	6.14	4.4	4.28	5.06
H_2	20.4	21.0	21.2	20.6	20.5	20.9	20.5	20.3	20.5	22.2	22.3	21.5
CO_2	0	0	0	0	0	0	0	0	0	0	0	0
H_2O	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7
22 Exit second shift reactor:												
CO	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8
H_2	25.8	25.8	25.8	25.8	25.8	25.8	25.8	25.8	25.8	25.8	25.8	25.8
CO_2	5.4	4.75	4.62	5.15	5.34	4.93	5.31	5.45	5.34	3.6	3.48	4.26
H_2O	3.7	3.28	3.19	3.55	3.69	3.4	3.67	3.76	3.69	2.5	2.4	2.94

TABLE A2-5. PLANT ENERGY REQUIREMENTS IN 50,000 BBL/DAY SYNTHOIL PLANTS

Units: 10^9 Btu/hr.

	Jefferson, Alabama	Gibson, Indiana	Warrick, Indiana	Harlan, Kentucky	Pike, Kentucky	Tuscarawas, Ohio	Jefferson, Ohio	Somerset, Pennsylvania	Mingo, West Virginia	Lake de Smet, Wyoming	Jim Bridger, Wyoming	Gallup, New Mexico
Drying coal to liquefaction	0.26	0.37	0.38	0.25	0.24	0.30	0.30	0.24	0.23	0.78	0.69	0.47
Slurry pumps	0.17	0.18	0.19	0.16	0.15	0.17	0.17	0.16	0.15	0.25	0.23	0.19
Heat exchanger of phase separation	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
Char de-oiling	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23
Solids feed to hydrogen gasifier	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
Acid gas removal in hydrogen production	0.49	0.50	0.50	0.50	0.50	0.50	0.48	0.50	0.49	0.56	0.57	0.51
Waste heat recovery in hydrogen production	-.05	-.05	-.05	-.05	-.05	-.05	-.05	-.06	-.05	-.05	-.05	-.05
Hydrogen compression	0.49	0.49	0.49	0.49	0.49	0.49	0.49	0.49	0.49	0.49	0.49	0.49
Oxygen production	0.39	0.42	0.41	0.40	0.40	0.40	0.38	0.39	0.40	0.51	0.51	0.44
Electrical generation	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17
Water treatment & other low-level uses	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50
Boiler stack loss	0.50	0.53	0.53	0.50	0.49	0.51	0.50	0.49	0.49	0.64	0.62	0.55
Approximate total heat load	3.57	3.76	3.77	3.57	3.54	3.64	3.59	3.53	3.52	4.5	4.38	3.92

TABLE A2-6. APPROXIMATE THERMAL EFFICIENCIES OF 50,000 BBL/DAY SYNTHOIL PLANTS

Units: 10^9 Btu/hr.

	Jefferson, Alabama	Gibson, Indiana	Warrick, Indiana	Harlan, Kentucky	Pike, Kentucky	Tuscarawas, Ohio	Jefferson, Ohio	Somerset, Pennsylvania	Mingo, West Virginia	Lake de Smet, Wyoming	Jim Bridger, Wyoming	Gallup, New Mexico
Coal to synthoil reactor	15	14.9	14.97	14.88	14.96	15.09	15.35	14.72	14.98	14.14	13.64	14.89
Coal to gasifier	2.79	2.85	2.87	2.82	2.80	2.84	2.80	2.79	2.80	3.39	3.81	2.92
Total coal	17.79	17.74	17.84	17.7	17.76	17.93	18.15	17.51	17.78	17.53	17.45	17.81
Heating value of product oil	12.7	12.7	12.7	12.7	12.7	12.7	12.7	12.7	12.7	12.7	12.7	12.7
Heating value of gas produced	4.72	4.68	4.69	4.69	4.77	4.74	4.97	4.39	4.79	4.0	3.48	4.73
Heating value of gasifier off-gas burnt for fuel	0	0	0	0	0	0	0	0	0	0.5	0.9	0
Plant driving energy	-3.57	-3.76	-3.77	-3.57	-3.54	-3.64	-3.59	-3.53	-3.52	-4.5	-4.38	-3.92
Total output energy	13.9	13.6	13.6	13.8	13.9	13.8	14.1	13.6	14.0	12.7	12.7	13.5
Unrecovered heat	3.94	4.12	4.22	3.88	3.83	4.13	4.07	3.95	3.81	4.83	4.75	4.3
Approximate conversion efficiency %	77.9	76.8	76.3	78.1	78.4	77.0	77.6	77.4	78.6	72.4	72.8	75.9

TABLE A2-7. DISPOSITION OF UNRECOVERED HEAT IN 50,000 BBL/DAY SYNTHOIL PLANTS

Units: 10^9 Btu/hr.

	Jefferson, Alabama	Gibson, Indiana	Warrick, Indiana	Harlan, Kentucky	Pike, Kentucky	Tuscarawas, Ohio	Jefferson, Ohio	Somerset, Pennsylvania	Mingo, West Virginia	Lake de Smet, Wyoming	Jim Bridger, Wyoming	Gallup, New Mexico
Coal drying	0.26	0.37	0.38	0.25	0.24	0.30	0.30	0.24	0.23	0.78	0.69	0.47
Boiler stack loss	0.5	0.53	0.53	0.50	0.49	0.51	0.5	0.49	0.49	0.64	0.62	0.55
Char de-oiling	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23
Electricity used	0.051	0.051	0.051	0.051	0.051	0.051	0.051	0.051	0.051	0.051	0.051	0.051
Slurry pump loss	0.051	0.054	0.057	0.048	0.045	0.051	0.051	0.048	0.051	0.075	0.069	0.057
Other direct loss	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10
Subtotal direct losses	1.192	1.335	1.348	1.179	1.156	1.242	1.232	1.159	1.152	1.876	1.76	1.458
Acid gas removal regenerator condenser	0.49	0.50	0.50	0.50	0.50	0.50	0.48	0.50	0.49	0.56	0.57	0.51
Air cooling in phase separation & hydrogen plant	0.12	0.15	0.15	0.13	0.13	0.14	0.12	0.13	0.13	0.26	0.25	0.17
Turbine drive condensers	0.87	0.90	0.90	0.87	0.86	0.88	0.86	0.86	0.86	1.01	0.99	0.92
Compressor interstage cooling	0.27	0.28	0.28	0.27	0.27	0.27	0.28	0.27	0.27	0.31	0.31	0.29
Wet cooling load	1.00	0.96	1.04	0.93	0.91	1.10	1.10	1.03	0.91	0.81	0.87	0.95
Grand Total	3.94	4.12	4.22	3.88	3.83	4.13	4.07	3.95	3.81	4.83	4.75	4.3

APPENDIX 3

CALCULATIONS ON THE HYGAS PROCESS

Calculations on the Hygas process are needed for bituminous coals at:

1. Jefferson, Alabama
2. Gibson, Indiana
3. Warrick, Indiana
4. Tuscarawas, Ohio
5. Jefferson, Ohio
6. Armstrong, Pennsylvania
7. Fayette, West Virginia
8. Monongalia, West Virginia
9. Mingo, West Virginia

for subbituminous coals at:

10. Gillette, Wyoming
11. Antelope Creek, Wyoming
12. Belle Ayr, Wyoming
13. Hanna Coal Field, Wyoming
14. Decker, Montana
15. Colstrip, Montana
16. El Paso, New Mexico
17. Gallup, New Mexico

and for lignites at:

18. Marengo, Alabama
19. East Moorhead, Montana

Gasifier and pretreatment balances have been provided by the Institute of Gas Technology for the Hygas-oxygen process operating on two coals shown on Table A3-1. Complete calculations of material and energy have been made for two reference plants, one in West Virginia and one in Wyoming. The required information for plants consuming bituminous coals has been taken from the West Virginia reference plant. The required information for plants consuming subbituminous coals and lignites has been taken from the Wyoming reference plant.

First the two reference plants will be described. The flow diagram is shown on Figure A3-1. Wyoming coal is dried to 2 percent moisture before feeding to the gasifier. West Virginia coal is pretreated in air to prevent caking. Pretreatment material rates are given on Table A3-2. The pretreatment balance was made by assuming a 1.1 wt % loss as fines and 1.08 wt % loss as tar and oil. The coal incurs about a 10 percent weight loss during treatment. The pretreatment energy information is given on Table A3-3. The imbalance on the pretreater is assumed lost to the atmosphere.

The coal is slurried to 50 percent solid concentration (by weight) with recycle slurry oil from downstream in the process. The char-oil slurry is then pumped to the gasifier operating pressure of 1200 psig and heated in an external heater to 200°F. Gasifier flow rates are given on Table A3-4, and energy rates are given on Table A3-5. The gasifier is in thermal balance, and the only energy rates listed are those needed to define the plant unrecovered heat and cooling load. The raw off-gas contains the slurry oil as vapor. The oil made about equals the oil lost in purification or left in the product gas.

According to most process flow sheets, the gasifier product gas is quenched with oil to about 400°F to cool the gas and recover a portion of the slurry oil without condensation of water. The steam is left in the feed gas so that the amount of steam required for shift conversion is minimized.

A portion of the gas next undergoes shift reaction at an equilibrium temperature of 750°F to adjust the ratio of hydrogen to CO for the downstream methanation reaction. The shifted gas is cooled to 100°F to ensure condensation of the oil. Water also condenses at this point. A circulating water scrub may be used to ensure that all the ammonia, phenol and other soluble species are removed from the gas. It has been assumed that these species can be adequately removed by the quantity of water which condenses. Circulating water has not been shown on Figure A3-1.

A physical-solvent based system is used for acid-gas removal to recover the remainder of the BTX stream, dehydrate the gas, generate an H_2S-rich gas for sulfur recovery, discharge a CO_2-rich gas with minimum H_2S concentration and provide a treated gas of sufficient purity that only a nominal sulfur guard is required prior to methanation. Based on the recommendation of IGT, the following losses are assumed to occur in gas purification: 0.5% loss of H_2 and CO, 1% loss of CH_4 and 25% loss of C_2H_6. The process is assumed capable of reducing CO_2 to one percent. All other acid gases were completely absorbed.

Gas and water streams for the two reference plants are shown on Table A3-6. The calculations are illustrated by the Wyoming case. In the raw gas, Stream 6, there is:

CO	20.55
H_2	25.21
Total:	45.76

After shift, in Stream 10, one wants $H_2/CO = 3.1$, so in Stream 10 one must have:

CO	11.16
H_2	34.60
Total:	45.76

The moles of gas shifted are 20.55 - 11.66 = 9.39, so CO_2 in Stream 10 = 19.32 + 9.39, and the H_2O in Stream 11 = 25.81 - 9.39 (assuming complete condensation at 100°F). Most of the "other gases" are assumed to leave with the condensate. A little N_2 will be left in the gas as shown. (For the West Virginia plant the ratio after shift was $H_2/CO = 3.05$, because there is less ethane to hydrogenate in the methanator.)

Streams 8 and 9, which are needed for heat calculations, can now be found. Let x be the fraction of gas in Stream 6 which enters the shift reactor. Since 9.39 thousand moles/hr are shifted, the composition of Stream 9 is:

CO	$20.55x - 9.39$
H_2	$25.21x + 9.39$
CO_2	$19.32x + 9.39$
H_2O	$25.81x - 9.39$

and since Stream 9 is in equilibrium at 750°F:

$$\frac{(CO_2)(H_2)}{(CO)(H_2O)} = 11.8$$

so, x = 0.827.

Stream 12 reflects the losses after gas purification, as stated above. In methanation all of the CO is assumed reacted to methane and water, and the ethane is assumed hydrogenated to methane.

The heat balance and additional energy information for the gasifier trains are given on Table A3-7. The heat loads were calculated from the enthalpies of the streams listed on Table A3-6. For a solvent type acid gas removal process, 28,400 Btu are consumed to remove 1 lb mole of CO_2.

On Table A3-8 is tabulated the total plant driving energy (most of which is taken from preceding tables, the rest of which is arbitrary) and the calculation of unrecovered heat and conversion efficiency. Table A3-8 suggests that for Wyoming, all the net driving energy goes to produce steam for the gasifier and that all the steam used for other uses could be raised in waste heat recovery units. At West Virginia even some of the steam for the gasifier is shown raised in waste heat recovery units. This is not practical. Waste heat is not available to raise steam at much over 700 psi. Steam for the gasifiers must be raised in a boiler and, in addition, some of the 700 psi steam from waste heat recovery must be superheated in a boiler for use to drive turbines. In fact, the plants have surplus low temperature steam. Unless this steam is used, the theoretical plant conversion efficiencies given overstate the practical efficiency. This does not affect the cooling water requirements as the surplus waste heat will be lost through air coolers, not by evaporative cooling.

The ultimate disposition of unrecovered heat, needed for estimation of cooling water, is presented on Table A3-9 and was calculated as follows. The direct losses are taken from preceding tables, except electricity used which is 30,000 kw and slurry pump loss which is 30 percent of the driving energy. The dry cooling load is from Table A3-7. The wet cooling load is from Table A3-7 plus the "allowance" on Table A3-8. The turbine condenser load is 100 percent of pretreatment air compressor, plus 70 percent of slurry pump, plus 70 percent of oxygen production compressors, plus 70 percent of energy to produce electricity. The gas compressor interstage cooling load is 30 percent of the oxygen production compressors.

From the reference plants the necessary information has been scaled for all the desired plants and entered on Table A3-10 in weight flow units and on

Table A3-11 in energy flow units. First the energy in the coal to pretreatment was taken to be that of the reference plants and the weight of coal is as determined.

All coals are dried to 2 percent. If W lb coal/hr containing w fraction moisture are dried to 2 percent, then the water evaporated is:

$$w.W - (1-w)W \times 2/98 = W(1.0204w - 0.0204)$$

The weight of water evaporated in the dryer is entered on Table A3-10. The weight of steam to the gasifier is taken from the reference plants (Stream 5) as are the effluent water streams (Streams 11 and 14); all water streams are entered on Table A3-10.

The energy to dry coal is 1150 Btu/lb water evaporated, and the total energy is entered on Table A3-11. Next on Table A3-11 is the other driving energy from Table A3-8, the net driving energy, the boiler stack loss which is 12 percent of the boiler fuel, and the boiler fuel. The coal to the boiler is copied, in weight units, on Table A3-10.

The energy table is then completed by entering fines, tar and oil, and product gas from Table A3-8, and calculating the unrecovered heat and conversion efficiency. Since the only changes in the ultimate disposition of unrecovered heat were in the direct losses, these were not entered on Table A3-11 but taken directly from Table A3-9 onto the work sheets in a later appendix.

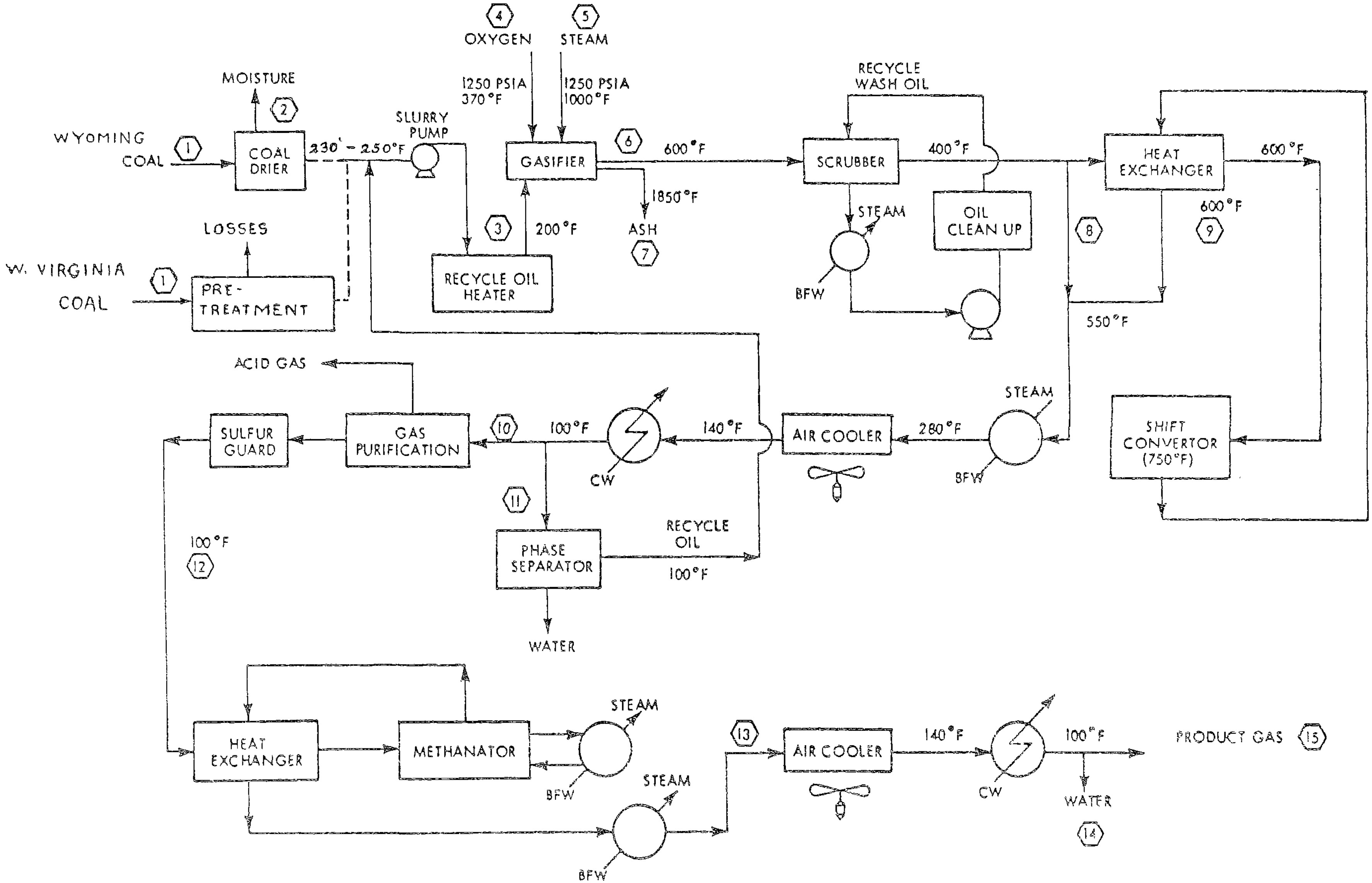


Figure A3-1. Flow diagram for Hygas process.

TABLE A3-1. ANALYSIS OF COAL USED IN REFERENCE HYGAS PLANTS (wt %)

	West Virginia	Wyoming
Moisture	2.5	19.9
C	74.6	54.2
H	4.7	4.0
O	3.3	14.5
N	1.5	0.8
S	2.7	0.6
Ash	10.7	6.0
	100	100

TABLE A3-2. PRETREATMENT MATERIAL RATES FOR REFERENCE HYGAS PLANTS

TABLE A3-2. PRETREATMENT MATERIAL RATES FOR REFERENCE HYGAS PLANTS

WYOMING:

	Coal IN (10^3 lb/hr)	Coal OUT (10^3 lb/hr)
Moisture	262	22
C	713	713
H	53	53
O	191	191
N	10	10
S	8	8
Ash	78	78
	1,315	1,075

Water Vapor OUT
240

	Air IN (803×10^3 lb/hr) (10^3 moles/hr)	Gas OUT (10^3 moles/hr)
N_2	22.0	21.0
O_2	5.8	0
CO	--	0.7
CO_2	--	2.8
H_2O	--	6.3
SO_2	--	0.2
CH_4	--	0.5
C_2H_6	--	0.1
C_3H_8	--	0.2

WEST VIRGINIA:

	Coal IN (10^3 lb/hr)	Coal OUT (10^3 lb/hr)	Fines OUT (10^3 lb/hr)	Tar & Oil OUT (10^3 lb/hr)
C	809	737	7.7	9.4
H	51	36	0.6	0.8
O	36	29	0.7	0.9
N	16	15	0.2	0.1
S	30	21	0.4	0.4
Ash	116	113	2.2	--
Moisture	26	--	--	--
	1,084	951	11.8	11.6

TABLE A3-3. PRETREATMENT ENERGY RATES FOR REFERENCE HYGAS PLANTS

Units: 10^9 Btu/hr

	Wyoming	West Virginia
IN		
Coal	12.18	14.70
OUT		
Coal	12.18	12.79
Steam	0.26	--
Fines, tar & oil (HHV)	--	0.32
Sensible heat of effluent solids at 800°F	--	0.14
Total heat of effluent gases at 800°F	--	0.82
Radiation & convective losses	--	0.63
Heat to dry coal	0.26	0
Energy to compress air to 10 psig	--	0.09

TABLE A3-4. GASIFIER FLOW RATES FOR REFERENCE HYGAS PLANTS

Stream		Wyoming	West Virginia
		(10^3 lb/hr)	(10^3 lb/hr)
3	Pretreated coal	1,075	951
3	Slurry oil	1,075	951
4	Oxygen	249	295
5	Steam	1,015	1,434
7	Ash residue*	99	132
		(10^3 moles/hr)	(10^3 moles/hr)
6	Raw gas:		
	CO	20.55	14.41
	H_2	25.21	26.61
	CO_2	19.32	25.68
	H_2O	25.81	34.10
	CH_4	13.77	15.82
	C_2H_6	1.04	0.37
	Other**	0.76	1.44

*Composition of ash residue: Wyoming C wt % 17.80, H wt % 0.19; West Virginia C wt % 9.56, H wt % 1.09.

**N_2, NH_3, H_2S, HCN, COS.

TABLE A3-5. GASIFIER ENERGY INFORMATION FOR REFERENCE HYGAS PLANTS

Units: 10^9 Btu/hr.

	Wyoming	West Virginia
Steam (1250 psia, 1000°F)	1.48	2.09
Energy to produce oxygen	0.57	0.68
Slurry pump	0.04	0.04
Recycle oil heater	0.06	0*
Sensible & chemical heat in ash residue at 1850°F	0.32	0.31

*The coal is not from the pretreatment and the slurry heater is not needed.

TABLE A3-6. GAS AND WATER STREAMS FOR REFERENCE HYGAS PLANTS

Units: 10^3 moles/hr.

Stream numbers from Figure A3-1.

		Wyoming	West Virginia
Stream 8:	CO	3.56	7.98
	H_2	4.36	14.75
	CO_2	3.34	14.23
	H_2O	4.47	18.89
	CH_4	2.38	8.49
	C_2H_6	0.18	0.21
	Other	0.13	0.80
Stream 9:	CO	7.60	2.14
	H_2	30.24	16.14
	CO_2	25.37	15.74
	H_2O	11.95	10.92
	CH_4	11.39	7.33
	C_2H_6	0.86	0.16
	Other	0.63	0.64
Stream 10:	CO	11.16	10.12
	H_2	34.60	30.89
	CO_2	28.71	29.97
	H_2O	0	0
	CH_4	13.77	15.82
	C_2H_6	1.04	0.37
	Other	0.09	0.09

		Wyoming	West Virginia
Stream 11:	H_2O	16.42	29.81
	Other	0.67	1.35
Stream 12:	CO	11.10	10.12
	H_2	34.43	30.89
	CO_2	0.60	0.56
	CH_4	13.63	15.82
	C_2H_6	0.78	0.37
	N_2	0.09	0.09
Stream 13:	H_2	0.35	0.65
	CO_2	0.60	0.56
	CH_4	26.29	26.68
	C_2H_6	0	0
	H_2O	11.10	10.00
	N_2	0.09	0.09
Stream 14:	H_2O	11.10	10.00
Stream 15:	H_2	0.35	0.16
	CO_2	0.60	0.56
	CH_4	26.29	26.68
	N_2	0.09	0.09
Stream 15, scf/day:		250×10^6	250×10^6
	Btu/hr:	10.11×10^9	10.34×10^9

TABLE A3-7. APPROXIMATE HEAT BALANCE AND ENERGY INFORMATION ON GASIFIER TRAIN FOR REFERENCE HYGAS PLANTS

Units: 10^9 Btu/hr

	Wyoming	West Virginia
IN		
Pretreated coal	12.18	12.79
Steam	1.48	2.09
Recycle oil heater	0.06	--
	13.72	14.88
OUT		
Product gas	10.11	10.34
Steam produced	2.38	3.10
Combustibles lost in gas purification	0.26	0.25
Dry cooling of process streams	0.55	0.78
Wet cooling of process streams	0.10	0.10
Sensible & chemical heat in ash residue	0.32	0.31
	13.72	14.88
Energy consumed in gas purification	0.80	0.84

TABLE A3-8. DRIVING ENERGY FOR REFERENCE HYGAS PLANTS, FUEL REQUIRED IN BOILER, EFFICIENCY, AND UNRECOVERED HEAT

Units: 10^9 Btu/hr

	Wyoming	West Virginia
Driving Energy		
Coal drying	0.26	--
Pretreatment air compression	--	0.09
Slurry pump	0.04	0.04
Recycle oil heater	0.06	0
Oxygen production	0.57	0.68
Gas purification	0.80	0.84
Gasifier steam	1.48	2.09
Electrical production (30,000 kw)	0.35	0.35
Steam raised in process	(-2.38)	(-3.10)
Allowance for water treatment & other low-level uses	0.30	0.30
Net driving energy required	1.48	1.29
Boiler stack losses	0.20	0.18
Coal to boiler	1.68	1.47
Coal to pretreatment	12.18	14.70
Fines, tar & oil	--	0.32
Product gas	10.11	10.34
Unrecovered heat	3.75	5.51
Conversion efficiency	72.9%	65.9%

TABLE A3-9. ULTIMATE DISPOSITION OF UNRECOVERED HEAT FOR REFERENCE HYGAS PLANTS

Units: 10^9 Btu/hr

	Wyoming	West Virginia
Coal drying	0.26	--
Boiler stack losses	0.20	0.18
Pretreatment losses	--	1.59
Slurry pump	0.01	0.01
Hot ash residue	0.32	0.31
Electricity used	0.11	0.11
Combustibles lost in purification	0.26	0.25
Subtotal Direct Losses	1.16	2.45
Assigned to dry cooling	0.55	0.78
Assigned to wet cooling	0.40	0.40
Acid gas removal regenerator condenser	0.80	0.84
Total turbine condensers	0.67	0.84
Total gas compressor interstage cooling	0.17	0.20
Total	3.75	5.51

TABLE A3-10. FLOW RATES IN 250 x 10^6 SCF/DAY HYGAS PLANTS

Units: 10^3 lb/hr

	Jefferson, Alabama	Gibson, Indiana	Warrick, Indiana	Tuscarawas, Ohio	Jefferson, Ohio	Armstrong, Pennsylvania	Fayette, West Virginia	Monongalia, West Virginia	Mingo, West Virginia	Gillette, Wyoming
Coal to pretreatment	1149.3	1204.9	1261.8	1139.5	1122.1	1097.0	1050.0	1035.2	1028.0	1537.9
Water evaporated in drying	0*	92.73	88.05	44.46	0*	0*	5.43	6.41	0*	445.69
Steam to gasifier	1,434	1,434	1,434	1,434	1,434	1,434	1,434	1,434	1,434	1,015
Dirty condensate	537	537	537	537	537	537	537	537	537	296
Methanation water	180	180	180	180	180	180	180	180	180	200
Coal to boiler	114.93	130.33	135.62	117.83	112.21	109.70	105.71	104.23	102.80	248.74

	Antelope Creek, Wyoming	Belle Ayr, Wyoming	Hanna Coal Field, Wyo.	Decker, Montana	Colstrip, Montana	El Paso, New Mexico	Gallup, New Mexico	Marengo, Alabama	East Moorhead, Montana
Coal to pretreatment	1353.3	1308.3	1142.6	1284.8	1367.0	1413.0	1077.9	2280.9	1730.1
Water evaporated in drying	334.19	263.00	114.27	287.12	312.47	206.19	144.09	1086.93	602.01
Steam to gasifier	1,015	1,015	1,015	1,015	1,015	1,015	1,015	1,015	1,015
Dirty condensate	296	296	296	296	296	296	296	296	296
Methanation water	200	200	200	200	200	200	200	200	200
Coal to boiler	202.22	185.82	143.53	185.65	202.02	192.58	139.82	147.79	308.24

*Coal moisture content is below 2.5%.

TABLE A3-11. ENERGY FLOWS IN 250 x 10^6 SCF/DAY HYGAS PLANTS

Units: 10^9 Btu/hr

	Jefferson, Alabama	Gibson, Indiana	Warrick, Indiana	Tuscarawas, Ohio	Jefferson, Ohio	Armstrong, Pennsylvania	Fayette, West Virginia	Monongalia, West Virginia	Mingo, West Virginia	Gillette, Wyoming
Coal to pretreatment	14.70	14.70	14.70	14.70	14.70	14.70	14.70	14.70	14.70	12.18
Coal drying	0	0.11	0.10	0.05	0	0	0.01	0.01	0	0.51
Other driving energy	1.29	1.29	1.29	1.29	1.29	1.29	1.29	1.29	1.29	1.22
Net driving energy	1.29	1.40	1.39	1.34	1.29	1.29	1.30	1.30	1.29	1.73
Boiler stack loss	0.18	0.19	0.19	0.18	0.18	0.18	0.18	0.18	0.18	0.24
Coal to boiler	1.47	1.59	1.58	1.52	1.47	1.47	1.48	1.48	1.47	1.97
Fines, tar & oil	0.32	0.32	0.32	0.32	0.32	0.32	0.32	0.32	0.32	0
Product gas	10.34	10.34	10.34	10.34	10.34	10.34	10.34	10.34	10.34	10.11
Unrecovered heat	5.51	5.63	5.62	5.56	5.51	5.51	5.52	5.52	5.51	4.04
Conversion efficiency (%)	65.92	65.44	65.48	65.72	65.92	65.92	65.88	65.88	65.92	71.45

	Antelope Creek, Wyoming	Belle Ayr, Wyoming	Hanna Coal Field, Wyo.	Decker, Montana	Colstrip, Montana	El Paso, New Mexico	Gallup, New Mexico	Marengo, Alabama	East Moorhead, Montana
Coal to pretreatment	12.18	12.18	12.18	12.18	12.18	12.18	12.18	12.18	12.18
Coal drying	0.38	0.30	0.13	0.33	0.36	0.24	0.17	1.25	0.69
Other driving energy	1.22	1.22	1.22	1.22	1.22	1.22	1.22	1.22	1.22
Net driving energy	1.60	1.52	1.35	1.55	1.58	1.46	1.39	1.47	1.91
Boiler stack loss	0.22	0.21	0.18	0.21	0.22	0.20	0.19	0.20	0.26
Coal to boiler	1.82	1.73	1.53	1.76	1.80	1.66	1.58	1.67	2.17
Fines, tar & oil	0	0	0	0	0	0	0	0	0
Product gas	10.11	10.11	10.11	10.11	10.11	10.11	10.11	10.11	10.11
Unrecovered heat	3.89	3.80	3.60	3.83	3.87	3.73	3.65	3.74	4.24
Conversion efficiency (%)	72.21	72.68	73.74	72.53	72.32	73.05	73.47	73.00	70.45

APPENDIX 4

CALCULATIONS ON THE BIGAS PROCESS

Calculations for the Bigas process are required for bituminous coals at:

1. Bureau, Illinois
2. Shelby, Illinois
3. Vigo, Indiana
4. Kemmerer, Wyoming

and for lignites at:

5. Slope, North Dakota
6. Center, North Dakota
7. Scranton, North Dakota
8. Chupp Mine, Montana

Two designs (for economic analysis) are available from the Bureau of Mines[1]. We have extracted all necessary information from these reference designs, one for a Montana subbituminous coal and one for a Kentucky bituminous coal, and used the reference designs as models from which to determine the required information by extrapolation to the chosen coals. It should be noted that at this time representative steady state operation of the Bigas plant has not been achieved. First, details of the reference designs will be given.

The process flow diagram is Figure A4-1. Coal is fed, as a 50 percent slurry in water, to a spray dryer as shown in the upper center of the figure. The main flow streams, taken from Reference 1, are entered on Table A4-1 as are the gas stream analyses at five points labeled in Figure A4-1. The elemental balances are reasonably closed. The Bigas process yields negligible hydrocarbon byproducts. The hydrogen balances, expressed as equivalent weights of water, are shown on Table A4-2.

On Table A4-3 are presented the analyses of the chosen coals calculated after drying to 1.3 percent moisture as is done in the reference plants.

Also shown on Table A4-3 are: 1) calculated higher heating values; 2) lb/hr dried coal fed assuming 12.5×10^9 Btu/hr for bituminous coals and 12.1×10^9 Btu/hr for lignites; 3) lb/hr water evaporated to dry the coal to 1.3 percent calculated as 0.987wx/(100-w) where x = lb/hr dried coal and w = % moisture in as-received coal; 4) lb/hr as-received coal which equals moisture plus dried coal.

On Table A4-4 are given water equivalent hydrogen balances for the chosen Bigas plants. Most of the quantities come from Tables A4-2 and A4-3. It is assumed that if steam heat is needed in the spray dryer, the heat can be transferred through a wall so that water is not consumed. Live steam, as shown in the Kentucky reference plant, has not been assumed. The balances on Table A4-4 are forced to close because the condensate is varied to ensure this.

To determine the cooling water requirement, an estimate is made of the auxiliary energy required to drive the plants. The estimate is given on Table A4-5 as well as the plant thermal efficiency. The energy needed to vaporize water in the feed coal is calculated for each coal. This energy is lost up the stack.

The slurry feed pump for the western Kentucky reference plant[1] consumes about 4,000 hp, that is about 0.035×10^9 Btu/hr assuming a steam turbine drive requiring 11,700 Btu/kw-hr. The energy for other plants has been scaled by the rate of dry coal feed. Of this energy 70 percent is lost in the turbine condenser and 30 percent is lost through heating the slurry or through pipe walls.

The gas purification system is assumed to be hot potassium carbonate requiring 30,000 Btu/mole CO_2 removed with 34×10^3 moles CO_2 removed per hour on the average (the average difference between Streams 2 and 3 on Table A4-1). This energy is dissipated in the condenser of the acid gas removal regenerator.

The gasifier steam is given in Table A4-4.

The production of 495×10^3 lb/hr of oxygen at 1,250 psig requires 93,000 kw or 1.09×10^9 Btu/hr. The energy input is for steam to compressor drives for compressing air and oxygen. The energy content of the compressed oxygen is very small; 70 percent of the input energy is lost in the turbine condensers and 30 percent is lost in the compressor interstage coolers.

Enough electricity is generated to run the plant (particularly the cooling water circulation pumps and the acid gas removal liquor circulation pumps). 42,000 kw are generated requiring 0.5×10^9 Btu/hr with 70 percent of this (0.35×10^9 Btu/hr) being lost in the turbine condensers.

An additional allowance is made, based on experience, for energy consumed in water treatment and for other losses.

According to the Bureau of Mines[1], 2.2×10^9 Btu/hr will be recovered in the two waste heat recovery units. This is quite a conservative recovery.

The balance of the energy required is produced by raising steam in a coal fired boiler assumed to operate at 85 percent efficiency with 15 percent stack loss.

The overall thermal efficiency is calculated from the formula:

$$\frac{\text{HHV product fuel}}{\text{HHV coal to gasifier + boiler}}$$

The energy not recovered as product fuel is also listed on Table A4-5. It is obtained by burning coal in a boiler. It remains to find how this energy is dissipated to the atmosphere and how much cooling water is needed. Part of this information is presented on Table A4-6. On this table the stack losses are the sum of drying energy and boiler stack losses. The electricity generated and slurry pump transmitted energy is next listed. The carbon losses have been entered so as to force total unrecovered heat to equal the values on Table A4-5. A loss of 0.4×10^9 Btu/hr for bituminous coals and nearly zero for lignites occurs simply because 12.5×10^9 Btu/hr are fed as bituminous coals and only 12.1×10^9 Btu/hr as lignites. When the losses for bituminous coals are converted to weight units by taking 14,500 Btu/lb for carbon, the apparent loss is 4 percent of the carbon in the feed coal for all cases, and this is problably too high. However, for the purpose of studying water quantities all that matters is that this energy loss has been assigned to "direct losses" which cannot require cooling water.

The coal ash leaves the gasifier as slag with a heat content of about 560 Btu/lb which is used to evaporate quench water.

The energy to the acid gas removal system is listed next. The condensers are frequently air cooled. Reference 2 shows that air cooling is preferable if cooling water costs more than about $0.46/thousand gallons. A lot of heat is dissipated through the condensers on the turbine drives for oxygen production, electrical generation and the slurry pumps. Dry cooling is expensive here, but a wet/dry combination will be used at some sites. Interstage cooling on air and oxygen compressors will be wet cooling, unless cooling water is severely restricted or very expensive (Reference 2).

The remaining unrecovered heat is lost by cooling process streams in the gas production train and is also the auxiliary energy added for water treatment and allowances in Table A4-5. It is shown[2] that air, or dry cooling, is more economical on process streams down to about 140°F, with wet cooling below this temperature. Much the largest part of the load, which is condensing water out of gas streams, occurs above 140°F. Most of the auxiliary energy will go to ammonia recovery stills which are likely to require wet, low-temperature condensers. On Table A4-6 the balance of the unrecovered heat has been arbitrarily distributed 50 percent to wet cooling and 50 percent to dry cooling.

In copying the water quantities from Table A4-4 onto the work sheets, the quantity of dirty water input was taken as the sum of water to char quench and water to slurry coal.

REFERENCES, APPENDIX 4

1. Bureau of Mines, "Preliminary Economic Analysis of BCR Bi-Gas Plant Producing 250 million SCFD High-Btu Gas from Two Coal Seams: Montana and Western Kentucky," Report ERDA 76-48, FE-2083-2, UC-90-C, March 1976.

2. "Water Conservation and Pollution Control in Coal Conversion Process," Report EPA 600/7-77-065, U.S. Environmental Protection Agency, June 1977.

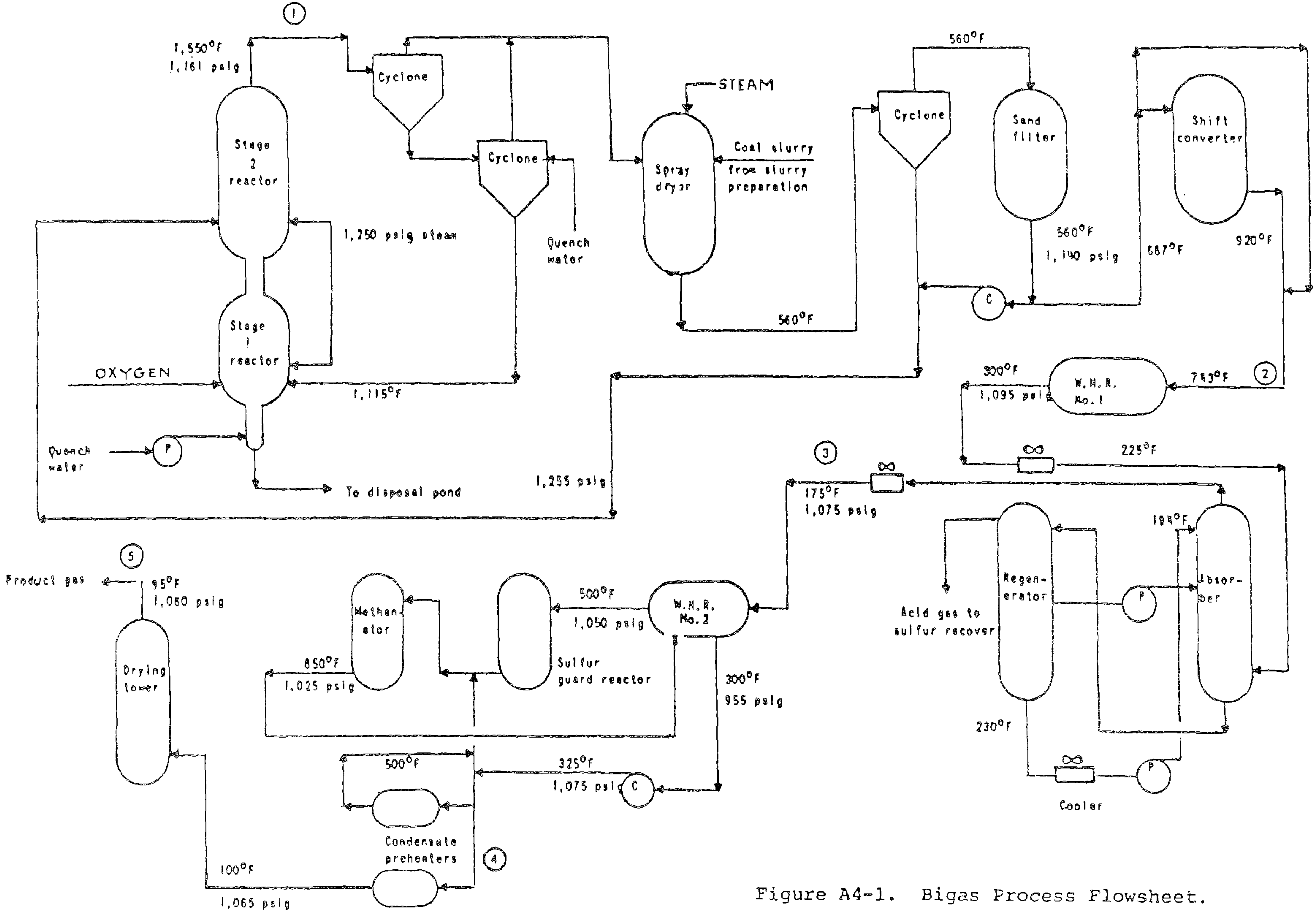


Figure A4-1. Bigas Process Flowsheet.

TABLE A4-1. FLOW RATES IN REFERENCE BIGAS PROCESSES[1]

	Western Kentucky	Montana
Feed to Gasifier		
Coal (1.3% moisture)	946×10^3 lb/hr	1089×10^3 lb/hr
	12.5×10^9 Btu/hr	12.1×10^9 Btu/hr
Oxygen	499×10^3 lb/hr	488×10^3 lb/hr
Steam	410×10^3 lb/hr	691×10^3 lb/hr
Water Feeds		
Steam to dryer	201×10^3 lb/hr	0
Water vaporized to quench char	214×10^3 lb/hr	214×10^3 lb/hr
Product Gas	250×10^6 scf/day	250×10^6 scf/day
	9.90×10^9 Btu/hr	9.90×10^9 Btu/hr

Gas Streams (10^3 moles/hr)	Western Kentucky						Montana					
	CO_2	CO	CH_4	H_2	H_2O	Other	CO_2	CO	CH_4	H_2	H_2O	Other
1, Gasifier off-gas	11.6	36.5	12.9	20.2	7.3	1.8	18.6	30.6	12.7	23.8	17.7	0.6
2, Aftershift	32.3	13.0	12.2	40.5	56.9	1.8	35.1	13.0	12.4	40.2	70.9	0.6
3, Into methanation	0.3	13.0	12.2	40.5	0.4	0.5	0.3	13.0	12.4	40.2	0.4	0.4
4, Out of methanation	0.3	0	25.1	1.5	13.0	0.5	0.3	0	25.3	1.2	13.0	0.4
5, Product	0.3	0	25.1	1.5	0	0.5	0.3	0	25.3	1.2	0	0.4

TABLE A4-2. WATER EQUIVALENT HYDROGEN BALANCES FOR TWO BIGAS PLANTS FROM REFERENCE 1

	Water Equivalent to Hydrogen (10^3 lb/hr)	
	Western Kentucky	Montana
IN		
Water equivalent of hydrogen in coal	428	446
1.3% moisture in coal	13	14
Steam to gasifier	410	691
Water vaporized to quench char	214	214
Live steam to spray drier	201	0
Water vaporized from coal slurry (equals weight of coal fed)	946	1,089
	2,212	2,454
OUT		
Condensate (Stream 2-3)	1,017	1,269
Water from methanation (Stream 4)	234	234
Water equivalent of hydrogen in product gas (Stream 5)	931	932
	2,182	2,435
Error in balance:	1.4%	0.8%

TABLE A4-3. ANALYSES OF VARIOUS COALS DRIED TO 1.3% MOISTURE FOR FEED TO BIGAS PROCESS

	W. Kentucky (Ref. 1)	Bureau, Ill.	Shelby, Ill.	Vigo, Ind.	Kemmerer, Wyo.
Type	Bituminous				
Moisture	1.3	1.3	1.3	1.3	1.3
C	73.4	70.6	64.2	74.9	73.0
H	5.0	4.9	4.7	5.2	5.1
O	7.9	9.7	8.2	9.5	9.1
N	1.4	1.4	1.5	1.6	1.2
S	3.8	3.4	3.5	0.7	1.0
Ash	7.2	8.7	16.6	7.7	9.3
HHV calculated*	13.3	12.7	11.8	13.4	13.1
Dried coal feed**	946	984	1059	933	954
As-received coal feed**	--	1170	1228	1111	981
Water removed on drying**	--	186	169	178	27

	Montana (Ref. 1)	Slope, N.D.	Center, N.D.	Scranton, N.D.	Chupp Mine, Mont.
Type	sub-bit.	Lignite			
Moisture	1.3	1.3	1.3	1.3	1.3
C	66.8	58.4	61.8	62.7	64.5
H	4.6	4.7	4.3	4.3	4.0
O	18.2	19.4	17.0	16.2	17.0
N	0.8	1.1	0.9	1.0	1.0
S	0.7	3.2	1.4	2.1	0.5
Ash	7.6	11.9	13.3	12.4	11.7
HHV calculated*	11.1	10.0	10.4	10.6	10.6
Dried coal feed**	1089	1210	1163	1141	1141
As-received coal feed**	--	2164	1814	1898	1840
Water removed on drying**	--	954	651	757	696

*10^3 Btu/lb.

**10^3 lb/hr.

TABLE A4-4. WATER EQUIVALENT HYDROGEN BALANCES FOR BIGAS PLANTS

Units: 10^3 lb/hr as H_2O.

	Bureau, Ill.	Shelby, Ill.	Vigo, Ind.	Kemmerer, Wyo.	Slope, N.D.	Center, N.D.	Scranton, N.D.	Chupp Mine, Mont.
IN								
Water equivalent of hydrogen in coal	434	448	437	438	512	450	442	411
Moisture in coal	13	14	12	12	16	15	15	15
Steam to gasifier	410	410	410	410	691	691	691	691
Water vaporized to quench char	214	214	214	214	214	214	214	214
Water to slurry coal	984	1059	933	954	1210	1163	1141	1141
TOTAL	2055	2145	2006	2028	2643	2533	2503	2472
OUT								
Condensate	890	980	841	863	1478	1368	1338	1307
Water from methanation	234	234	234	234	234	234	234	234
Water equivalent of hydrogen in product gas	931	931	931	931	931	931	931	931
TOTAL	2055	2145	2006	2028	2643	2533	2503	2472

TABLE A4-5. REQUIREMENTS FOR AUXILIARY ENERGY IN BIGAS PLANTS

Units: 10^9 Btu/hr.

	Bureau, Ill.	Shelby, Ill.	Vigo, Ind.	Kemmerer, Wyo.	Slope, N.D.	Center, N.D.	Scranton, N.D.	Chupp Mine, Mont.
Coal drying	0.19	0.17	0.18	0.03	0.95	0.65	0.76	0.70
Slurry pump	0.04	0.04	0.04	0.04	0.05	0.04	0.04	0.04
Gas purification	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02
Gasifier steam	0.45	0.45	0.45	0.45	0.76	0.76	0.76	0.76
Oxygen production	1.09	1.09	1.09	1.09	1.09	1.09	1.09	1.09
Electrical production	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50
Water treatment & allowances	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30
TOTAL	3.59	3.57	3.58	3.43	4.67	4.36	4.47	4.41
Less energy recovered	(2.20)	(2.20)	(2.20)	(2.20)	(2.20)	(2.20)	(2.20)	(2.20)
Energy out of boilers	1.39	1.37	1.38	1.24	2.47	2.16	2.27	2.21
Boiler stack losses	0.24	0.24	0.24	0.22	0.43	0.38	0.40	0.39
Net coal to boilers	1.63	1.61	1.62	1.46	2.90	2.54	2.67	2.60
Plant overall thermal efficiency %	70.1	70.2	70.2	71.0	66.0	67.6	67.0	67.3
Unrecovered energy	4.23	4.21	4.22	4.06	5.10	4.74	4.87	4.80
As-received coal feed to boiler (10^3 lb/hr)	151	158	143	113	514	378	415	394

TABLE A4-6. ULTIMATE DISPOSITION OF UNRECOVERED HEAT IN BIGAS PLANTS

Units: 10^9 Btu/hr.

	Bureau, Ill.	Shelby, Ill.	Vigo, Ind.	Kemmerer, Wyo.	Slope, N.D.	Center, N.D.	Scranton, N.D.	Chupp Mine, Mont.
Stack losses	0.43	0.41	0.42	0.25	1.38	1.03	1.16	1.09
Electricity used & pump losses	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16
Carbon loss	0.41	0.41	0.40	0.40	0.01	0.01	0.01	0.02
SUBTOTAL, Direct Losses	1.00	0.98	0.98	0.81	1.55	1.20	1.33	1.27
Slag quench	0.04	0.10	0.04	0.04	0.08	0.08	0.08	0.08
Acid gas removal regenerator condenser	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02
Turbine steam condensers	1.14	1.14	1.14	1.14	1.14	1.14	1.14	1.14
Compressor interstage cooling	0.33	0.33	0.33	0.33	0.33	0.33	0.33	0.33
Air cooling in the process	0.35	0.32	0.36	0.36	0.49	0.49	0.49	0.48
Water cooling in the process	0.35	0.32	0.35	0.35	0.48	0.48	0.48	0.48
GRAND TOTAL, Unrecovered Heat	4.23	4.21	4.22	4.05	5.09	4.74	4.87	4.80
Carbon lost as % of feed coal	4.1	4.1	3.9	3.9	0.1	0.1	0.1	0.2

APPENDIX 5

CALCULATIONS ON THE SYNTHANE PROCESS

Synthane plant designs are required for bituminous coals at:

1. Jefferson, Alabama
2. Gibson, Indiana
3. Sullivan, Indiana
4. Floyd, Kentucky
5. Gallia, Ohio
6. Jefferson, Ohio
7. Armstrong, Pennsylvania
8. Kanawha, West Virginia
9. Preston, West Virginia

and for subbituminous coals at:

10. Antelope Creek, Wyoming
11. Spotted Horse, Wyoming
12. Colstrip, Montana

Designs for economic analysis have been given by the Bureau of Mines[1] for a Wyoming subbituminous and a Pittsburgh seam bituminous coal. We have taken the gasifier details from Reference 1, and an ash quench design from Reference 2, and made the calculations for the rest of the plant. The design using the Wyoming coal has been presented in great detail[3], and the design using the Pittsburgh coal follows the same procedure. Both the Wyoming and the Pittsburgh designs are given below. The water streams and heat loads for all the bituminous coals have been extrapolated from the Pittsburgh design. The water streams and heat loads for all the subbituminous coals have been extrapolated from the Wyoming design.

Figure A5-1 is the flow diagram. The coal analyses, after drying to 4.3 percent moisture where drying is required, are given on Table A5-1. Flow and energy rates for the two reference designs are given on Table A5-2. The stream numbers on Table A5-2 correspond to those on Figure A5-1. The coal feed, oxygen feed, steam feed, gasifier off-gas and product gas (Streams 1, 2, 3, 4 and 13) come from Reference 1. The char compositions, and hence the heating value, were estimated from Reference 2 and are presented in Table A5-11 (details will be found in Reference 3). The heating value of the tar was calculated from the composition which is the residue of carbon and hydrogen to close the elemental balances around the gasifier. There is no need here to distinguish tar and char, and the distinction is approximate.

The total condensate (Stream 5 plus Stream 6) results when the gasifier off-gas is cooled to 273°F as shown in Figure A5-1. The steam raised by quenching char (Stream 6) will vary with the ash content of the coal and has been estimated for each case.

The shift gas reaction is taken to be in equilibrium at 750°F, so that in Stream 8:

$$\frac{(CO_2)(H_2)}{(H_2O)(CO)} = 11.8$$

Also in Stream 8:

$$(H_2)/(CO) \text{ is set equal to } 3.18$$

These two equations, with the carbon, hydrogen and oxygen elemental balances around the shift reactor, fix both Streams 7 and 8.

The water left in the gas after shift is mostly condensed when the gas is cooled to 225°F, as shown on Figure A5-1, and the balance is condensed at 100°F after acid gas removal. Water made in the methanator is equivalent to the CO reacted as shown on Table A5-2.

Overall hydrogen balances for the two reference plants, with hydrogen expressed in units of H_2O equivalent, are given in Table A5-3. Hydrogen balances for the chosen sites are given in Table A5-4. On Table A5-4 the moisture and hydrogen in the coal are taken from Table A5-1 when the coal feed rate is 15.91×10^9 Btu/hr for bituminous coals and 17.08×10^9 Btu/hr for subbituminous coals. The rate of ash production varies with the coals. This results in variations in the small quantity of steam raised by quenching ash. This further results in small variations in the steam added for the shift reaction and in the condensate recovered after the scrub. All the remaining streams are unchanged from the reference plants. This procedure gives the biggest errors when the ash content of the coal is most different from the reference coal.

Heat balances around the gasifiers at the two reference locations are shown on Table A5-5. An "unaccounted loss" has been introduced to force a balance. This is assumed lost directly to the atmosphere. By calculating the duty of the various heat exchangers and waste heat recovery units, the heat balance has been extended to the complete gasifier train as shown on Table A5-6. An additional unaccounted loss has been found which is arbitrarily assumed 50 percent lost to cooling water and 50 percent lost directly to the atmosphere.

Some of the char from the gasifier is burnt in a boiler to provide energy to drive the plant. The amount of char burnt is calculated in Table A5-7. Wyoming coal is dried from 20 percent to 4.3 percent moisture and the coal is heated to 220°F. Pittsburgh coal requires no drying. The lock hopper compressors use 6,800 kw[1]. Gas purification is by the hot potassium carbonate process consuming 30,000 Btu/mole CO_2. The energy for oxygen production is that required to compress air to 90 psia and oxygen from 15 psia to 1015 psia, which is 2.17×10^3 Btu/lb oxygen. The electricity produced is more than enough for pumping the circulating cooling water and gas purification liquor[3]. The other uses listed are arbitrary. The steam raised in the process can all be used, and so it is subtracted from the need.

The overall plant heat balances can now be calculated and are presented in Table A5-8. It remains to find how the unrecovered heat is dissipated to the atmosphere and how much cooling water is needed. Part of this information is presented on Table A5-9. Most of the entries come directly from preceding tables. The electricity used is 31,000 kw. The unaccounted losses in the gasifier train have been assumed 50 percent lost to the atmosphere and 50 percent lost to cooling water. The first group of losses has been called "direct losses" because the loss is directly to the atmosphere and water cannot be used.

In the list of driving energy requirements, 0.3 x 10^9 Btu/hr was added for water treatment and other uses. A lot of this energy is used in ammonia recovery stills which are likely to need wet cooling to a low temperature. All of this energy is assumed lost to cooling water. The steam turbines driving the electric generator, the lock hopper compressors, and the air and oxygen compressors are taken to be condensing steam turbines with 70 percent of the energy lost in the condensers. For gas compressors the other 30 percent of the energy is lost in interstage cooling because the energy stored in a compressed gas is very small. Whether or not the turbine condensers and interstage coolers will be wet cooled or combined wet and dry will depend on cost and will vary from site to site[3]. The energy put into acid gas removal is mostly lost in the regenerator condenser. It is quite feasible for this to be a dry condenser[3], but the decision will vary with the site.

The ultimate disposition of unrecovered heat has been extended to the desired sites on Table A5-10. Coal drying requirements have been calculated for each site. In all other respects the plants follow the reference plants. The plant thermal efficiencies vary, but this is reflected in variations in direct losses and not in cooling requirements.

In evaluating solid residues account had to be taken of ash leaving the plant in char. The quantities of char sold, or not fired to the boiler, and of char fired are given on Table A5-10 in energy units. The ash in the entering coal is distributed between sold and fired in the ratio of the char energies. Of the ash in the char fired, 80 percent is fly ash and 20 percent is bottom ash.

In estimating water for flue gas desulfurization the char composition of the reference plants was assumed and the char weight fired was estimated from the char energy fired.

REFERENCES, APPENDIX 5

1. Bureau of Mines, "Preliminary Economic Analysis of Synthane Plant Producing 250 million SCFD High-Btu Gas from Two Coal Seams: Wyodak and Pittsburgh," ERDA-76-59, March 1976 (available from NTIS).

2. Strakey, J.P., Jr., Forney, A.J., and Haynes, W.P., "Effluent Treatment and its Cost for the Coal-to-SNG Process," presented at American Chemical Society 168th National Meeting, Atlantic City,

N.J., September 1974, Div. of Fuel Chemistry reprint Vol. 19, No. 5, p. 94.

3. Water Purification Associates, "Water Conservation and Pollution Control in Coal Conversion Processes," Report EPA 600/7-77-065, U.S. Environmental Protection Agency, June 1977.

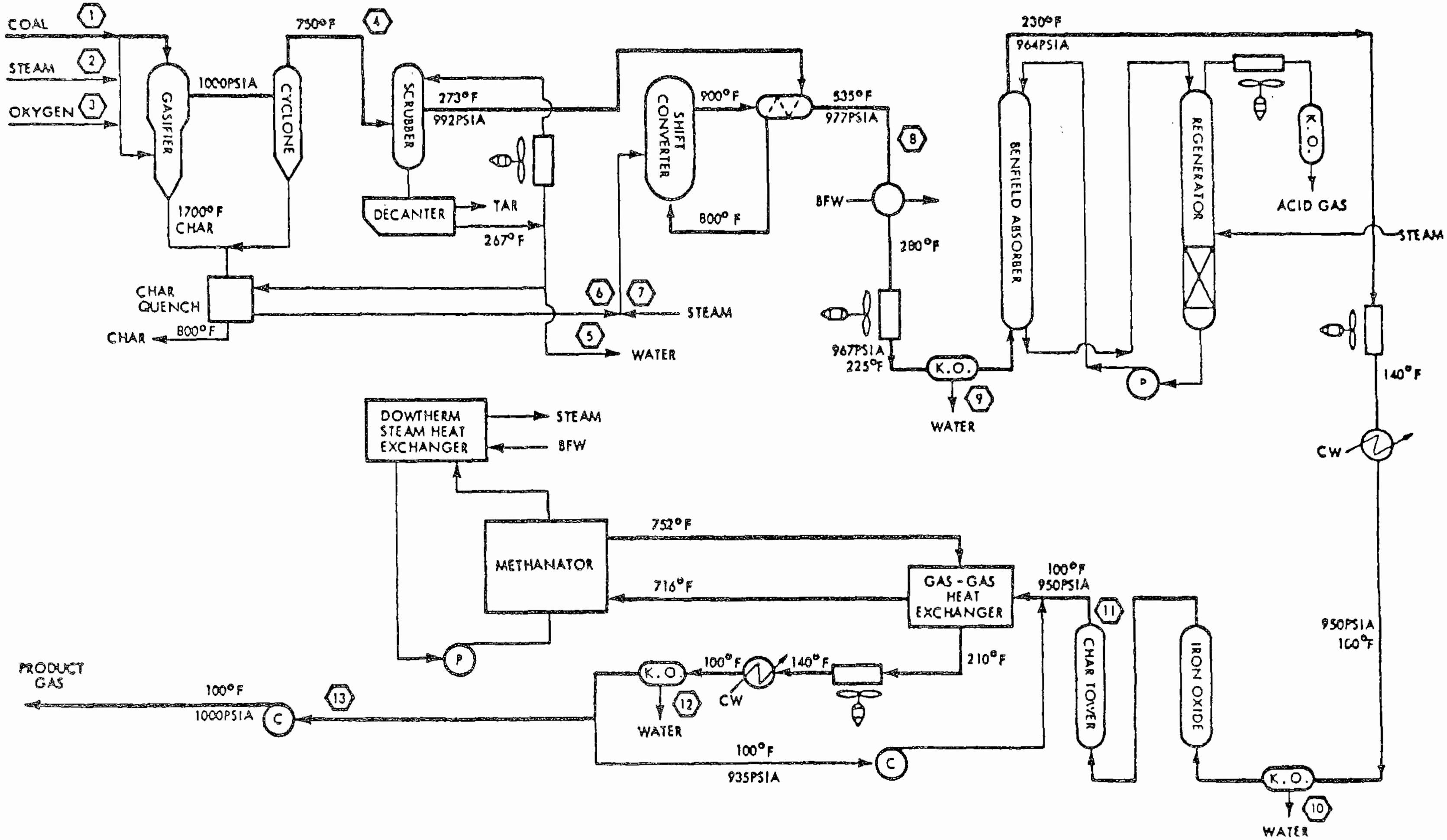


Figure A5-1. Flow diagram for Synthane processes.

TABLE A5-1. ANALYSES OF VARIOUS COALS DRIED TO 4.3% MOISTURE* FOR FEED TO SYNTHANE PROCESS

	Wyodak, Wyo.(Ref. 1)	Pittsburgh Seam (Ref. 1)	Jefferson, Ala.	Gibson, Ind.	Sullivan Ind.	Floyd, Ky.	Gallia, Ohio
Moisture	4.3	2.5	2.3	4.3	4.3	3.4	4.3
C	64.5	73.8	71.0	72.5	70.7	79.8	67.0
H	4.1	5.2	4.4	4.9	5.0	5.2	4.8
O	16.8	8.0	3.8	8.1	7.9	6.5	9.4
N	1.0	1.5	1.5	1.2	1.5	1.6	1.1
S	0.8	1.6	0.9	2.2	2.4	0.6	3.3
Ash	8.5	7.4	16.1	6.8	8.2	2.9	10.1
Type	Sub-bit.	Bituminous					
Calculated HHV	10,600	13,400	12,800	13,000	12,800	14,300	12,100

	Jefferson, Ohio	Armstrong Pa.	Kanawha, W. Va.	Preston, W. Va.	Antelope Creek Wyo.	Spotted-Horse Strip, Wyo.	Colstrip, Mont.
Moisture	2.4	2.3	1.9	2.5	4.3	4.3	4.3
C	71.1	73.6	75.1	74.6	68.2	62.2	66.4
H	4.9	4.9	4.9	4.7	4.7	4.7	4.4
O	5.3	5.3	6.7	3.3	15.6	16.3	14.7
N	1.2	1.4	1.4	1.5	0.8	0.9	1.0
S	5.0	2.8	0.7	2.7	0.6	1.2	0.5
Ash	10.1	9.7	9.3	10.7	5.8	10.4	8.7
Type	Bituminous				Subbituminous		
Calculated HHV	13,100	13,400	13,400	13,600	11,600	10,700	11,200

*Coals with less than 4.3% moisture listed "as-received."

TABLE A5-2. FLOW AND ENERGY RATES FOR REFERENCE SYNTHANE PLANTS

	PITTSBURGH	WYOMING
Coal feed (1)	1187×10^3 lb/hr	1605×10^3 lb/hr
	15.91×10^9 Btu/hr	17.08×10^9 Btu/hr
Oxygen feed (2)	304×10^3 lb/hr	482×10^3 lb/hr
Steam feed (3)	1170×10^3 lb/hr	978×10^3 lb/hr
Product gas (13)	9.79×10^9 Btu/hr	9.79×10^9 Btu/hr
Char	362×10^3 lb/hr	410×10^3 lb/hr
	3.55×10^9 Btu/hr	4.02×10^9 Btu/hr
Tar	0.6×10^9 Btu/hr	0.8×10^9 Btu/hr

	PITTSBURGH						WYOMING					
Gas Streams (10^3 moles/hr)	CO_2	CO	CH_4	H_2	H_2O	C_2H_6	CO_2	CO	CH_4	H_2	H_2O	C_2H_6
Gasifier off-gas (4)	19.66	11.34	16.63	18.91	40.08	0.54	25.89	16.70	15.24	16.03	36.43	1.12
Dirty Condensate (5)					33.23						28.68	
Char quench (6)					3.76						4.27	
Steam for Shift (7)					3.68						10.51	
After Shift (8)	23.77	7.22	16.63	23.02	6.42	0.54	34.77	7.82	15.24	24.91	9.38	1.12
Condensate after Shift (9)					5.02						7.68	
Condensate after Acid Gas Removal (10)					1.4						1.7	
Methanation Water (12)					7.22						7.82	

TABLE A5-3. WATER EQUIVALENT HYDROGEN BALANCES FOR SYNTHANE REFERENCE PLANTS

	10^3 lb/hr	
	PITTSBURGH	WYOMING
IN		
Moisture in coal	30	69
Water equiv. to hydrogen in coal	556	592
Steam to gasifier and shift converter	1236	1167
TOTAL	1890	1828
OUT		
Condensate after scrubbing	598	516
Condensate after shift reactor	90	138
Condensate after acid gas removal	25	31
Methanation water	130	141
Water equiv. to hydrogen in byproducts	87	87
Water equiv. to hydrogen in product gas	920	920
TOTAL	1850	1833
Error	2.1%	0.3%

TABLE A5-4. WATER EQUIVALENT HYDROGEN BALANCES AND FEED COAL RATES FOR SYNTHANE PLANTS

Units: 10^3 lb/hr

	Antelope Creek, Wyo.	Spotted Horse, Wyo.	Colstrip, Montana	Jefferson, Alabama	Gibson, Indiana	Sullivan, Indiana	Floyd, Ky.	Jallia, Ohio	Jefferson, Ohio	Armstrong, Pa.	Kanawha, W. Va.	Preston, W. Va.
As-received coal to drying	1472	1596	1525	1243	1224	1243	1113	1315	1215	1187	1187	1170
Dried coal to gasifier	1409	1527	1459	1214	1171	1190	1075	1258	1186	1160	1164	1141
HYDROGEN BALANCE												
IN												
Moisture in coal	63	69	66	29	53	53	38	57	29	27	23	29
Water equiv. to hydrogen in coal	623	675	604	492	540	559	521	568	536	523	523	495
Steam to gasifier and shift converter	1177	1162	1168	1215	1237	1234	1247	1228	1229	1231	1232	1229
	1863	1906	1838	1736	1830	1846	1806	1853	1794	1781	1778	1753
OUT												
Condensate after scrub	526	511	518	578	599	595	609	590	591	593	594	591
Condensate after shift reactor	138	138	138	90	90	90	90	90	90	90	90	90
Condensate after acid gas removal	31	31	31	25	25	25	25	25	25	25	25	25
Methanation water	141	141	141	130	130	130	130	130	130	130	130	130
Water equiv. to hydrogen in byproducts	87	87	87	87	87	87	87	87	87	87	87	87
Water equiv. to hydrogen in product gas	920	920	920	920	920	920	920	920	920	920	920	920
	1843	1828	1835	1830	1851	1847	1861	1842	1843	1845	1846	1843
Error	1.1%	4.1%	0.2%	5.4%	1.1%	0	3.0%	0.6%	2.7%	3.6%	3.8%	5.1%

TABLE A5-5. SYNTHANE GASIFIER HEAT BALANCES FOR REFERENCE LOCATIONS

	10^9 Btu/hr	
	PITTSBURGH	WYOMING
IN		
Coal	15.91	17.08
Steam	1.34	1.12
	17.25	18.20
OUT		
Gas	12.46	12.14
Steam raised in jacket	0.38	0.61
Char heating value	3.67	4.16
Char sensible energy	0.08	0.09
Tar heating value	0.60	0.80
Unaccounted losses	0.06	0.40
	17.25	18.20

TABLE A5-6. HEAT BALANCE AROUND THE SYNTHANE GASIFIER TRAIN FOR REFERENCE PLANTS

	10^9 Btu/hr	
	PITTSBURGH	WYOMING
IN		
Coal	15.91	17.08
Steam	1.51	1.43
	17.42	18.51
OUT		
Product gas	9.79	9.79
Char	3.67	4.16
Tar	0.60	0.80
Losses around gasifier	0.06	0.40
Combustibles lost in gas purification	0.10	0.10
Sensible heat of condensate	0.15	0.14
Steam produced in waste heat recovery (stream 8) and methanation	1.40	1.61
Dry cooling of process streams	1.38	1.33
Wet cooling of process streams	0.07	0.07
Unaccounted losses	0.20	0.11
	17.42	18.51

TABLE A5-7. DRIVING ENERGY FOR REFERENCE SYNTHANE PLANTS

	10^9 Btu/hr	
	PITTSBURGH	WYOMING
Coal drying	0	0.42
Lock hoppercompressors	0.08	0.08
Gas purification	0.69	1.01
Process steam	1.51	1.43
Oxygen production	0.66	1.05
Electrical production (31,000 kw)	0.36	0.36
For water treatment and other uses	0.30	0.30
Driving energy required	3.60	4.65
Less steam raised in process	(1.40)	(1.61)
Net heat required from fuel	2.20	3.04
CHAR FIRED BOILER		
Heat yield	2.20	3.04
Stack loss	0.30	0.41
Hot bottom ash	0.02	0.02
	2.52	3.47

TABLE A5-8. OVERALL PLANT HEAT BALANCES FOR REFERENCE SYNTHANE PLANTS

	10^9 Btu/hr	
	PITTSBURGH	WYOMING
IN		
Coal	15.91	17.08
OUT		
Product gas	9.79	9.79
Char not burnt in boiler	1.15	0.69
Tar	0.60	0.80
Unrecovered heat	4.37	5.80
	15.91	17.08
Plant thermal efficiency	72.5%	66.0%

TABLE A5-9. ULTIMATE DISPOSITION OF UNRECOVERED HEAT IN REFERENCE SYNTHANE PLANTS

	10^9 Btu/hr	
	PITTSBURGH	WYOMING
Coal drying	0	0.42
Heat lost in hot condensate	0.15	0.14
Losses around gasifier	0.06	0.40
Electricity used	0.11	0.11
Char boiler stack losses	0.30	0.41
Combustibles lost in gas purification	0.10	0.10
50% of gasifier train unaccounted losses	0.10	0.05
Subtotal direct losses	0.82	1.63
Air cooling of plant process streams	1.38	1.33
Wet cooling of plant process streams + 50% of gasifier train unaccounted losses + other uses of driving energy	0.47	0.43
Bottom ash quench from char boiler	0.02	0.02
Total turbine condenser losses	0.77	1.04
Total compressor interstage cooling	0.22	0.34
Acid gas removal regenerator condenser	0.69	1.01
	4.37	5.80

TABLE A5-10. DRIVING ENERGY, THERMAL EFFICIENCY AND ULTIMATE DISPOSITION OF UNRECOVERED HEAT FOR SYNTHANE PLANTS

Units: 10^9 Btu/hr	Jefferson, Ala.	Gibson, Ind.	Sullivan, Ind.	Floyd, Ky.	Gallia, Ohio	Jefferson, Ohio	Armstrong, Pa.	Kanawha, W. Va.	Preston, W. Va.
Coal drying	0	0.07	0.11	0	0.04	0	0	0	0
Other driving energy from Table A5-7	3.60	3.60	3.60	3.60	3.60	3.60	3.60	3.60	3.60
Total driving energy	3.60	3.67	3.71	3.60	3.64	3.60	3.60	3.60	3.60
Net heat required from fuel	2.20	2.27	2.31	2.20	2.24	2.20	2.20	2.20	2.20
Char fired to boiler	2.52	2.59	2.64	2.52	2.56	2.52	2.52	2.52	2.52
Char not fired in boiler	1.15	1.08	1.03	1.15	1.11	1.15	1.15	1.15	1.15
Unrecovered heat	4.37	4.44	4.49	4.37	4.41	4.37	4.37	4.37	4.37
Plant thermal efficiency	72.5%	72.1%	71.8%	72.5%	72.3%	72.5%	72.5%	72.5%	72.5%
Direct losses	0.82	0.89	0.94	0.82	0.86	0.82	0.82	0.82	0.82
Air cooling of plant process streams (Table A5-9)	1.38	1.38	1.38	1.38	1.38	1.38	1.38	1.38	1.38
Wet cooling (Table A5-9)	0.47	0.47	0.47	0.47	0.47	0.47	0.47	0.47	0.47
Bottom ash quench from boiler (Table A5-9)	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
Turbine condenser loss (Table A5-9)	0.77	0.77	0.77	0.77	0.77	0.77	0.77	0.77	0.77
Compressor interstage (Table A5-9)	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22
Acid gas system (Table A5-9)	0.69	0.69	0.69	0.69	0.69	0.69	0.69	0.69	0.69
	4.37	4.44	4.49	4.37	4.41	4.37	4.37	4.37	4.37

	Antelope Creek Wyo.	Spotted-Horse Strip, Wyo.	Colstrip, Mont.
Coal drying	0.54	0.63	0.51
Other driving energy from Table A5-7	4.23	4.23	4.23
Total driving energy	4.77	4.86	4.74
Net heat required from fuel	3.16	3.25	3.13
Char fired to boiler	3.61	3.71	3.57
Char not fired in boiler	0.55	0.45	0.59
Unrecovered heat	5.94	6.04	5.90
Plant thermal efficiency	65.2%	64.6%	65.5%
Direct losses	1.77	1.87	1.73
Air cooling of plant process streams (Table A5-9)	1.33	1.33	1.33
Wet cooling (Table A5-9)	0.43	0.43	0.43
Bottom ash quench from boiler (Table A5-9)	0.02	0.02	0.02
Turbine condenser loss (Table A5-9)	1.04	1.04	1.04
Compressor interstage (Table A5-9)	0.34	0.34	1.04
Acid gas system (Table A5-9)	1.01	1.01	1.01
	5.94	6.04	5.90

TABLE A5-11. CHAR COMPOSITIONS IN REFERENCE SYNTHANE PLANTS

	PITTSBURGH	WYOMING
C	71.4%	63.6%
H	0.9	1.0
N	0.5	1.4
O	1.8	0.4
S	1.5	0.3
Ash	23.9	33.3
	100	100
HHV (calc'd.)	10,900 Btu/lb.	9,700 Btu/lb.

APPENDIX 6

CALCULATIONS ON THE LURGI PROCESS

BASIS OF ANALYSIS

Calculations for the Lurgi process are required for bituminous coals at:

1. Bureau, Illinois
2. St. Clair, Illinois
3. Fulton, Illinois
4. Muhlenberg, Kentucky
5. Kemmerer, Wyoming

for subbituminous coals at:

6. El Paso, New Mexico
7. Gallup, New Mexico
8. Jim Bridger Mine, Wyoming
9. Decker, Montana
10. Foster Creek Montana
11. Wesco, New Mexico

and for lignites at:

12. Knife River, North Dakota
13. Williston, North Dakota
14. Marengo, Alabama

For bituminous coals, process water streams have been calculated using the rules given below which were taken from Fluor Engineers and Constructors[1]. A detailed analysis of a Lurgi SNG plant using Navajo subbituminous coal has been presented by El Paso[2]. From this reference we have abstracted a set of rules, also shown below, and used them for subbituminous coals. These rules give the reported water streams for El Paso[2,3] within 4 percent. When these rules are applied to Wesco, the calculated steam feed and dirty condensate are lower than the reported values[4-7] by 22-30 percent. The water consumed is the same, but more steam goes into the gasifier and is recovered unchanged than is calculated. The process water streams for El Paso and Wesco are those reported in References 2 to 6; they were calculated by us. The use of El Paso instead of Wesco as a model makes no difference to net water consumption but yields lower inlet and outlet streams with less cost for water treatment.

Judging from Reference 7, a lignite feed requires more steam to the gasifier than does a subbituminous feed. Lignite rules are also given below.

Bituminous Coals

1. Steam fed to the gasifier equals 2.58 lb per lb of dry, ash-free coal.

2. Of the steam fed to the gasifier, 72.3 percent passes through unchanged. This unchanged steam plus all the moisture in the feed coal appears as moisture in the gasifier off-gas.

3. Fourteen percent of the carbon in the coal is converted to methane and 1.05 percent is converted to C_2H_4 plus C_2H_6, which is taken here to be entirely C_2H_6.

4. Solid and oil products are assumed to contain zero oxygen. Because phenol is produced this is not strictly accurate, but it is a very good approximation. All of the oxygen in total feed streams appears as H_2O, CO and CO_2. The H_2O was calculated in Step 2. The molar ratio of $CO:CO_2$ in the off-gas is 0.49, so the weight ratio of oxygen in CO to oxygen in CO_2 is 0.245. With this information the oxygen balance can be closed and the weights of CO and CO_2 determined.

5. The balance of the carbon appears in the oil and solid residue.

6. All of the sulfur in the coal is converted to H_2S. All of the ammonia in the coal is converted to NH_3.

7. The molar ratio $H_2:CO$ in the off-gas is 2.79. The weight ratio is therefore 0.20. This gives the H_2 in the off-gas.

8. Any remaining hydrogen appears in the oil and solid product.

This completes the gasifier rules. To calculate the gas reactions, the off-gas composition is first retabulated in moles.

9. Enough gas is passed through a shift reactor to produce a molar ratio $H_2:CO$ of 3.05. If the moles of hydrogen and the moles of CO in the

off-gas are M_H and M_{CO}, and if the amount of shift reaction is:

$$xH_2O + xCO = xCO_2 + xH_2$$

then

$$\frac{M_H + x}{M_{CO} - x} = 3.05$$

$$4.05x = 3.05\ M_{CO} - M_H$$

All of the water remaining in the gas after shift reaction is recovered as dirty condensate.

10. A perfect acid gas removal is temporarily assumed (this is adjusted later). All of the CO is converted to methane by the reaction:

$$CO + 3H_2 = CH_4 + H_2O$$

The water obtained from this reaction, "methanation water", is clean enough to recycle to the boiler feed.

11. The dried product gas is assumed to contain some CO_2 and/or N_2 and to have a heating value of 950 Btu/scf (or 3.61×10^5 Btu/mole). The heating value of the product gas for a standard size plant is:

$$950 \text{ Btu/scf} \times 250 \times 10^6/24 \text{ scf/hr} = 9.90 \times 10^9 \text{ Btu/hr}$$

If, for the basis of the preceding calculations which is 1,000 lb as-received coal, the dried product gas is found to have a heating value of HHV Btu, then the actual plant streams equal the streams calculated multiplied by:

$$9.90 \times 10^9/\text{HHV in lb/hr}$$

The heating value of the gas is calculated as:

$$123{,}000 \times (\text{moles } H_2) + 382{,}000 \times (\text{moles } CH_4) = 668{,}000 \times (\text{moles}/C_2H_6) \text{ in Btu}$$

Subbituminous Coals

1. The carbon in the coal is distributed 14 percent to CH_4, 1.4 percent to C_2H_6, 15 percent to ash residue, oil, phenol and other byproducts, 40.8 percent to CO_2 and 28.7 percent to CO. The molar ratio $CO:CO_2 = 0.7$.

2. Oxygen appears in the off-gas only as H_2O, CO and CO_2. Oxygen in the residues is ignored. The ratio feed steam/feed oxygen is 4 lb/lb (7.1 moles/mole) and 45 percent of the feed steam decomposes. Let:

W_{H2O} be steam fed; it contains 0.889 W_{H2O} oxygen

W_C be the coal moisture; it contains 0.889 W_C oxygen

W_O be the coal oxygen

0.25 W_{H2O} is the oxygen feed

Let:

W_{CO} be the off-gas CO; it contains 0.571 W_{CO} oxygen

W_{CO2} be the off-gas CO_2; it contains 0.727 W_{CO2} oxygen

0.55 W_{H2O} + W_C is the off-gas H_2O

The oxygen balance is:

$$0.889\ W_{H2O} + 0.889\ W_C + W_O + 0.25\ W_{H2O} =$$
$$0.571\ W_{CO} + 0.727\ W_{CO2} + 0.889(0.55\ WH_{2O} + W_C)$$

or,

$$0.650\ W_{H2O} = 0.571\ W_{CO} + 0.727\ W_{CO2} - W_O$$

This gives all the oxygen streams and the steam feed.

3. All the sulfur in the coal is converted to H_2S. All the nitrogen in the coal is converted to NH_3. Effluents other than gas contain 0.0833 lb hydrogen/lb carbon (1 mole/mole). The balance of the hydrogen appears as molecular hydrogen in the off-gas.

4. The gas reaction rules and the scaling to size are as Rules 9, 10 and 11 for bituminous coals.

Lignites

For lignite the rules for subbituminous coals were used, with the exception of Step 2. The ratio of steam to oxygen in the feed for lignite was taken to be 8.5 moles/mole (4.78 lb/lb). The equation for the steam feed rate becomes:

$$0.585\ W_{H2O} = 0.571\ W_{CO} + 0.727\ W_{CO2} - W_O$$

PROCESS WATER

The gasifier material balances are given on Table A6-1. The gas train balances and scale factors are given on Table A6-2. Process water and other streams are summarized on Table A6-3, on which is shown:

Coal to gasification = Scale factor x 10^3 lb/hr

Steam to gasifier = Scale factor x steam on Table A6-1 lb/hr

Dirty condensate = Moles H_2O after shift x 18 x scale factor lb/hr

Methanation water = Moles H_2O after methanation x 18 x scale factor lb/hr

COOLING WATER

Lurgi plants use rectisol gas purification and other proprietary subsystems for which information is not published, and the plant driving energy and efficiencies have not been calculated. Instead the overall plant efficiency is taken to be 67 percent for bituminous and subbituminous coals[2,7] and 65 percent for lignites[8]. The calculations then proceeded as follows, with the results shown on Table A6-3.

1. The product gas energy is 9.9×10^9 Btu/hr by design.

2. Byproduct energy is:

$$(14{,}500\ C + 62{,}000\ H)(\text{scale factor})$$

were C and H are lb carbon and hydrogen in "other products" on Table A6-1.

3. The plant efficiency which is given above is equal to:

$$(\text{product energy} + \text{byproduct energy})/(\text{total coal energy})$$

From this is calculated the total coal energy.

4. Since the coal to gasifier is known, the coal to the boiler is the extra coal to make the correct total.

Note that for El Paso and Wesco the coal streams and unrecovered heat are calculated as for the other sites.

The load on wet cooling at each site has been assumed to be a fraction of the unrecovered heat which, to facilitate comparison, has been taken to be the same as for Synthane plants on the same site or in the same area. The fractions used are shown on worksheets in Appendix 10.

REFERENCES, APPENDIX 6

1. Fluor Engineers and Constructors, Inc., "Economics of Current and Advanced Gasification Processes for Fuel Gas Production," p. 85, Report EPRI-AF-244, Electric Power Research Institute, Palo Alto, Calif., 1976.

2. El Paso Natural Gas Company, "Second Supplement to Application of El Paso Natural Gas Company for a Certificate of Public Convenience and Necessity," Federal Power Commission Docket CP73-131, 1973.

3. Milios, Paul, "Water Reuse at El Paso Company's Proposed Burnham I Coal Gasification Plant," presented at AIChE 67th Annual Meeting, Washington, D.C., Dec. 1-5, 1974.

4. Moe, J. M., "SNG from Coal via the LURGI Gasification Process," IGT Symposium on Clean Fuels from Coal, Institute of Gas Technology, Chicago, Ill., Sept. 10-14, 1973.

5. Strasser, J. D., "General Facilities Offsite, and Utilites for Coal Gasification Plants," IGT Symposium on Clean Fuels from Coal, Institute of Gas Technology, Chicago, Ill., Sept. 10-14, 1973.

6. Berty, T. E., and Moe, J. M., "Environmental Aspects of the Wesco Gasification Plant," Symposium Proceedings: Environmental Aspects of Fuel Conversion Technology (May 1974, St. Louis, Mo.), U.S. Environmental Protection Agency, EPA-650/2-74-118, 1974.

7. Batelle Columbus Laboratories, "Detailed Environmental Analysis Concerning a Proposed Gasification Plant for Transwestern Coal Gasification Co., Pacific Coal Gasification Co., Western Gasification Co., and the Expansion of a Strip Mine Operation Near Burnham, New Mexico, Owned and Operated by Utah International Inc.," Federal Power Commission, Feb. 1, 1973.

8. Michigan-Wisconsin Pipeline Co. and American Natural Gas Coal Gasification Co., "Application for Certificates of Public Convenience and Necessity before the Federal Power Commission," Docket CP75-27B.

TABLE A6-1. LURGI GASIFIER MATERIAL BALANCE

Location: Bureau, Illinois   Coal: Bituminous

Basis: 1000 lb As Received coal

All units: lb

		Total	C	H	O	N	S	Ash
Coal:	MAF	765	601	41	83	11	29	
	Moisture	161		17.8	143.2			
	Ash	74						74
Steam		1974		219	1755			
Oxygen		414			414			
	TOTAL IN	3388	601	278	2395	11	29	74
Gas:	H_2O	1588		176	1412			
	CH_4	112	84	28				
	C_2H_6	8	6.4	1.3				
	NH_3	13		2.4		11		
	H_2S	31		1.8			29	
	CO	338	145		193			
	CO_2	1086	296		790			
	H_2	68		67.6				
Other		144	69.6	0.9	0			74
TOTAL OUT		3388	601	278	2395	11	29	74

Location: St. Clair, Illinois   Coal: Bituminous

Basis: 1000 lb As Received coal

All units: lb

		Total	C	H	O	N	S	Ash
Coal:	MAF	776	611	42	74	12	37	
	Moisture	113		13	100			
	Ash	111						111
Steam		2002		222	1780			
Oxygen		420			420			
	TOTAL IN	3422	611	277	2374	12	37	111
Gas:	H_2O	1560		173	1387			
	CH_4	114	86	28				
	C_2H_6	8	6.4	1.6				
	NH_3	15		2.6		12		
	H_2S	39		2			37	
	CO	340	146		194			
	CO_2	1090	297		793			
	H_2	68		68				
Other		188	76	0.8	0			111
TOTAL OUT		3422	611	277	2374	12	37	111

(continued)

TABLE A6-1. Continued

Location: Fulton, Illinois   Coal: Bituminous

Basis: 1000 lb As Received coal

All units: lb

		Total	C	H	O	N	S	Ash
Coal:	MAF	744	588	41	73	11	31	
	Moisture	156		17	139			
	Ash	100						100
Steam		1920		213	1707			
Oxygen		403			403			
	TOTAL IN	3323	588	271	2322	11	31	100
Gas:	H_2O	1544		172	1372			
	CH_4	109	82	27				
	C_2H_6	8	6	1.5				
	NH_3	13		2		11		
	H_2S	33		2			31	
	CO	327	140		187			
	CO_2	1049	286		763			
	H_2	65		65				
Other		175	74	1.5	0			100
TOTAL OUT		3323	588	271	2322	11	31	100

Location: Muhlenberg, Kentucky   Coal: Bituminous

Basis: 1000 lb As Received coal

All units: lb

		Total	C	H	O	N	S	Ash
Coal:	MAF	818	648	47	83	14	26	
	Moisture	110		12	98			
	Ash	72						72
Steam		2110		234	1876			
Oxygen		443			443			
	TOTAL IN	3553	648	293	2500	14	26	72
Gas:	H_2O	1636		182	1454			
	CH_4	121	91	30				
	C_2H_6	9	7	2				
	NH_3	17		3		14		
	H_2S	28		2			26	
	CO	360	154		206			
	CO_2	1155	315		840			
	H_2	72		72				
Other		155	81	2	0			72
TOTAL OUT		3553	648	293	2500	14	26	72

(continued)

TABLE A6-1. Continued

Location: Kemmerer, Wyoming   Coal: Bituminous

Basis: 1000 lb As Received coal

All units: lb

		Total	C	H	O	N	S	Ash
Coal:	MAF	880	718	50	90	12	10	
	Moisture	28		3	25			
	Ash	92						92
Steam		2270		252	2018			
Oxygen		476			476			
	TOTAL IN	3746	718	305	2609	12	10	92
Gas:	H_2O	1669		185	1484			
	CH_4	135	101	34				
	C_2H_6	10	7.5	2				
	NH_3	15		3		12		
	H_2S	11		0.6			10	
	CO	387	166		221			
	CO_2	1243	339		904			
	H_2	77		77				
Other		199	104	3	0			92
TOTAL OUT		3746	718	305	2609	12	10	92

Location: Gallup, New Mexico   Coal: Subbituminous

Basis: 1000 lb As Received coal

All units: lb

		Total	C	H	O	N	S	Ash
Coal:	MAF	798	632	47	104	11	4	
	Moisture	151		17	134			
	Ash	51						51
Steam		1269		141	1128			
Oxygen		317			317			
	TOTAL IN	2586	632	205	1683	11	4	51
Gas:	H_2O	848		94	754			
	CH_4	119	89	30				
	C_2H_6	11	9	2				
	NH_3	13		2		11		
	H_2S	4		0			4	
	CO	422	181		241			
	CO_2	946	258		688			
	H_2	69		69				
Other		154	95	8				51
TOTAL OUT		2586	632	205	1683	11	4	51

(continued)

TABLE A6-1. Continued

Location: Jim Bridger Mine, Wyoming Coal: Subbituminous

Basis: 1000 lb As Received coal

All units: lb

		Total	C	H	O	N	S	Ash
Coal:	MAF	706	519	32	139	11	5	
	Moisture	212		24	188			
	Ash	82						82
Steam		961		107	854			
Oxygen		240			240			
	TOTAL IN	2201	519	163	1421	11	5	82
Gas:	H_2O	739		82	657			
	CH_4	97	73	24				
	C_2H_6	9	7	2				
	NH_3	13		2		11		
	H_2S	5		0			5	
	CO	348	149		199			
	CO_2	777	212		565			
	H_2	47		47				
Other		166	78	6	0			82
TOTAL OUT		2201	519	163	1421	11	5	82

Location: Decker, Montana Coal: Subbituminous

Basis: 1000 lb As Received coal

All units: lb

		Total	C	H	O	N	S	Ash
Coal:	MAF	724	572	32	109	6	5	
	Moisture	239		27	212			
	Ash	37						37
Steam		1128		125	1003			
Oxygen		282			282			
	TOTAL IN	2410	572	184	1606	6	5	37
Gas:	H_2O	858		95	763			
	CH_4	107	80	27				
	C_2H_6	10	8	2				
	NH_3	7		1		6		
	H_2S	5		0			5	
	CO	383	164		219			
	CO_2	858	234		624			
	H_2	52		52				
Other		130	86	7				37
TOTAL OUT		2410	572	184	1606	6	5	37

(continued)

TABLE A6-1. Continued

Location: Foster Creek, Montana Coal: Subbituminous

Basis: 1000 lb As Received Coal

All units: lb

		Total	C	H	O	N	S	Ash
Coal:	MAF	616	457	29	118	7	5	
	Moisture	307		34	273			
	Ash	77						77
Steam		853		95	758			
Oxygen		213			213			
	TOTAL IN	2066	457	158	1362	7	5	77
Gas:	H_2O	775		86	689			
	CH_4	85	64	21				
	C_2H_6	8	6	2				
	NH_3	9		2		7		
	H_2S	5		0			5	
	CO	306	131		175			
	CO_2	685	187		498			
	H_3	41		41				
Other		152	69	6				77
TOTAL OUT		2066	457	158	1362	7	5	77

Location: Knife River, North Dakota Coal: Lignite

Basis: 1000 lb As Received Coal

All units: lb

		Total	C	H	O	N	S	Ash
Coal:	MAF	589	425	28	123	6	7	
	Moisture	350		39	311			
	Ash	61						61
Steam		861		96	765			
Oxygen		215			215			
	TOTAL IN	2076	425	163	1414	6	7	61
Gas:	H_2O	885		98	787			
	CH_4	80	60	20				
	C_2H_6	7	6	1				
	NH_3	7		1		6		
	H_2S	7		0			7	
	CO	285	122		163			
	CO_2	638	174		464			
	H_2	38		38				
Other		129	63	5				61
TOTAL OUT		2076	425	163	1414	6	7	61

(continued)

TABLE A6-1. Continued

<u>Location</u>: Williston, North Dakota   <u>Coal</u>: Lignite

<u>Basis</u>: 1000 lb As Received Coal

<u>All units</u>: lb

		Total	C	H	O	N	S	Ash
Coal:	MAF	544	391	28	112	7	6	
	Moisture	400		44	356			
	Ash	56						56
Steam		793		88	705			
Oxygen		198			198			
	TOTAL IN	1991	391	160	1371	7	6	56
Gas:	H_2O	894		99	795			
	CH_4	73	55	18				
	C_2H_6	6	5	1				
	NH_3	9		2		7		
	H_2S	6		0			6	
	CO	262	112		150			
	CO_2	586	160		426			
	H_2	35		35				
Other		120	59	5				56
TOTAL OUT		1991	391	160	1371	7	6	56

<u>Location</u>: Marengo, Alabama   <u>Coal</u>: Lignite

<u>Basis</u>: 1000 lb As Received coal

<u>All units</u>: lb

		Total	C	H	O	N	S	Ash
Coal:	MAF	465	321	22	98	6	18	
	Moisture	487		54	433			
	Ash	48						48
Steam		639		71	568			
Oxygen		160			160			
	TOTAL IN	1799	321	147	1259	6	18	48
Gas:	H_2O	885		98	787			
	CH_4	60	45	15				
	C_2H_6	5	4	1				
	NH_3	7		1		6		
	H_2S	19		1			18	
	CO	215	92		123			
	CO_2	480	131		349			
	H_2	27		27				
Other		101	49	4				48
TOTAL OUT		1799	321	147	1259	6	18	48

TABLE A6-2. LURGI GAS TRAIN BALANCE

Location: Bureau, Illinois   Coal: Bituminous

Basis: 1000 lb As Received Coal

All Units: Moles

	Gasifier Off-Gas	After Shift	After Clean-up	After Methanation
H_2O	88.22	87.53	0	11.38
CH_4	7	7	7	18.38
C_2H_6	0.27	0.27	0.27	0.27
CO	12.07	11.38	11.38	0
CO_2	24.68	25.37	0	0
H_2	34	34.69	34.64	0.50

Product HHV, 7.26×10^6 Btu

Scale Factor = 9.9×10^9/HHV = 1364 hr^{-1}

Location: St. Clair, Illinois   Coal: Bituminous

Basis: 1000 lb As Received Coal

All Units: Moles

	Gasifier Off-Gas	After Shift	After Clean-up	After Methanation
H_2O	86.67	85.92	0	11.39
CH_4	7.13	7.13	7.13	18.52
C_2H_6	0.27	0.27	0.27	0.27
CO	12.14	11.39	11.39	0
CO_2	24.77	25.52	0	0
H_2	34	34.75	34.75	0.58

Product HHV, 7.33×10^6 Btu

Scale Factor = 9.9×10^9/HHV = 1351 hr^{-1}

Location: Fulton, Illinois   Coal: Bituminous

Basis: 1000 lb As Received Coal

All Units: Moles

	Gasifier Off-Gas	After Shift	After Clean-up	After Methanation
H_2O	85.78	85.01	0	10.91
CH_4	6.81	6.81	6.81	17.72
C_2H_6	0.27	0.27	0.27	0.27
CO	11.68	10.91	10.91	0
CO_2	23.84	24.61	0	0
H_2	32.5	33.27	33.27	0.54

Product HHV, 7.02×10^6 Btu

Scale Factor = 9.9×10^9/HHV = 1410 hr^{-1}

Location: Muhlenberg, Kentucky   Coal: Bituminous

Basis: 1000 lb As Received Coal

All Units: Moles

	Gasifier Off-Gas	After Shift	After Clean-up	After Methanation
H_2O	90.89	90.09	0	13.66
CH_4	7.56	7.56	7.56	21.22
C_2H_6	0.30	0.30	0.30	0.30
CO	12.86	12.09	12.09	0
CO_2	26.25	25.45	0	0
H_2	36	36.80	36.80	0.53

Product HHV, 8.37×10^6 Btu

Scale Factor = 9.9×10^9/HHV = 1183 hr^{-1}

(continued)

TABLE A6-2. LURGI GAS TRAIN BALANCE

Location: Kemmerer, Wyoming   Coal: Bituminous

Basis: 1000 lb As Received Coal

All Units: Moles

	Gasifier Off-Gas	After Shift	After Clean-up	After Methanation
H_2O	92.72	91.82	0	12.92
CH_4	8.44	8.44	8.44	21.36
C_2H_6	0.33	0.33	0.33	0.33
CO	13.82	12.92	12.92	0
CO_2	28.25	29.15	0	0
H_2	38.5	39.40	39.40	0.64

Product HHV, 8.46×10^6 Btu

Scale Factor = 9.9×10^9/HHV = 1170 hr^{-1}

Location: Jim Bridger Mine, Wyoming   Coal: Subbituminous

Basis: 1000 lb As Received Coal

All Units: Moles

	Gasifier Off-Gas	After Shift	After Clean-up	After Methanation
H_2O	41.06	37.50	0	8.87
CH_4	6.06	6.06	6.06	14.93
C_2H_6	0.30	0.30	0.30	0.30
CO	12.43	8.87	8.87	0
CO_2	17.66	21.22	0	0
H_2	23.5	27.06	27.06	0.45

Product HHV, 5.96×10^6 Btu

Scale Factor = 9.9×10^9/HHV = 1661 hr^{-1}

Location: Gallup, New Mexico   Coal: Subbituminous

Basis: 1000 lb As Received Coal

All Units: Moles

	Gasifier Off-Gas	After Shift	After Clean-up	After Methanation
H_2O	47.11	44.28	0	12.24
CH_4	7.44	7.44	7.44	19.68
C_2H_6	0.37	0.37	0.37	0.37
CO	15.07	12.24	12.24	0
CO_2	21.5	24.33	0	0
H_2	34.5	37.33	37.33	0.61

Product HHV, 7.84×10^6 Btu

Scale Factor = 9.9×10^9/HHV = 1263 hr^{-1}

Location: Decker, Montana   Coal: Subbituminous

Basis: 1000 lb As Received Coal

All Units: Moles

	Gasifier Off-Gas	After Shift	After Clean-up	After Methanation
H_2O	47.67	43.79	0	9.80
CH_4	6.69	6.69	6.69	16.49
C_2H_6	0.33	0.33	0.33	0.33
CO	13.68	9.80	9.80	0
CO_2	19.5	23.38	0	0
H_2	26	29.88	29.88	0.48

Product HHV, 6.58×10^6 Btu

Scale Factor = 9.9×10^9/HHV = 1505 hr^{-1}

(continued)

TABLE A6-2. Continued

Location: Foster Creek, Montana   Coal: Subbituminous

Basis: 1000 lb As Received Coal

All Units: Moles

	Gasifier Off-Gas	After Shift	After Clean-up	After Methanation
H_2O	43.05	39.88	0	7.76
CH_4	5.31	5.31	5.31	13.07
C_2H_6	0.27	0.27	0.27	0.27
CO	10.93	7.76	7.76	0
CO_2	15.57	18.74	0	0
H_2	20.5	23.67	23.67	0.39

Product HHV, 5.22×10^6 Btu

Scale Factor = 9.9×10^9/HHV = 1897 hr^{-1}

Location: Williston, North Dakota   Coal: Lignite

Basis: 1000 lb As Received Coal

All Units: Moles

	Gasifier Off-Gas	After Shift	After Clean-up	After Methanation
H_2O	49.67	46.94	0	6.63
CH_4	4.56	4.56	4.56	11.19
C_2H_6	0.20	0.20	0.20	0.20
CO	9.36	6.63	6.63	0
CO_2	13.32	16.05	0	0
H_2	17.5	20.23	20.23	0.34

Product HHV, 4.41×10^6 Btu

Scale Factor = 9.9×10^9/HHV = 2245 hr^{-1}

Location: Knife River, North Dakota   Coal: Lignite

Basis: 1000 lb As Received Coal

All Units: Moles

	Gasifier Off-Gas	After Shift	After Clean-up	After Methanation
H_2O	49.17	46.19	0	7.20
CH_4	5.00	5.00	5.00	12.20
C_2H_6	0.23	0.23	0.23	0.23
CO	10.18	7.20	7.20	0
CO_2	14.5	17.48	0	0
H_2	19	21.98	21.98	0.38

Product HHV, 4.86×10^6 Btu

Scale Factor = 9.9×10^9/HHV = 2037 hr^{-1}

Location: Marengo, Alabama   Coal: Lignite

Basis: 1000 lb As Received Coal

All Units: Moles

	Gasifier Off-Gas	After Shift	After Clean-up	After Methanation
H_2O	49.17	46.72	0	5.23
CH_4	3.75	3.75	3.75	8.98
C_2H_6	0.17	0.17	0.17	0.17
CO	7.68	5.23	5.23	0
CO_2	10.90	13.35	0	0
H_2	13.5	15.95	15.95	0.26

Product HHV, 3.58×10^6 Btu

Scale Factor = 9.9×10^9/HHV = 2765 hr^{-1}

TABLE A6-3. PROCESS WATER AND OTHER STREAMS IN 250 x 10^6 SCF/DAY LURGI PLANTS

	Bureau, Illinois	St. Clair, Illinois	Fulton, Illinois	Muhlenberg, Kentucky	Kemmerer, Wyoming	El Paso, New Mexico	Gallup, New Mexico	Jim Bridger Mine, Wyoming	Decker, Montana	Foster Creek, Montana	Wesco, New Mexico	Knife River, North Dakota	Williston, North Dakota	Marengo, Alabama
Units: 10^3 lb/hr														
Coal to gasification	1364	1351	1410	1183	1170	1672	1263	1661	1505	1897	1689	2037	2245	2765
Coal to boiler	204	199	207	269	220	463	355	519	448	574	475	589	678	845
Steam to gasifier	2693	2705	2707	2496	2656	1640	1603	1596	1698	1618	1990	1754	1780	1767
Dirty condensate	2149	2089	2158	1918	1934	1080	1007	1121	1186	1362	1490	1694	1897	2325
Methanation water	279	277	277	291	272	270	278	265	265	265	310	264	268	260
Units: 10^9 Btu/hr														
Product gas	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9
Byproducts	1.5	1.6	1.6	1.5	2.0	2.4	2.4	2.5	2.5	2.6	2.4	2.1	2.6	2.7
Efficiency, %	67	67	67	67	67	67	67	67	67	67	67	65	65	65
Total coal feed	16.9	17.1	17.2	17.1	17.7	18.4	18.3	18.5	18.6	18.7	18.3	18.4	19.3	19.3
Coal to gasifier	14.7	14.9	15.0	13.9	14.9	14.4	14.3	14.1	14.3	14.3	14.3	14.3	14.8	14.8
Coal to boiler	2.2	2.2	2.2	3.2	2.8	4.0	4.0	4.4	4.3	4.3	4.0	4.1	4.5	4.5
Unrecovered heat	5.6	5.6	5.8	5.6	5.9	6.1	6.0	6.1	6.1	6.2	6.0	6.5	6.7	6.8

APPENDIX 7

COOLING WATER REQUIREMENTS

INTRODUCTION

Throughout this report the terms wet or evaporative cooling and dry or air cooling have been used. Detailed discussion has been given in Reference 1. It is sufficient to say that a heat exchanger can be directly cooled by a stream of air, or cooled by circulating water which is itself cooled by evaporation and convection in a cooling tower.

In conformity with the discussion of Reference 1, all the cooling loads in the plants have been assigned to the categories given on Table A7-1. As has been shown[1], process streams are cooled to 140°F by dry cooling and below this by wet cooling. The acid gas removal regenerator condenser can be economically dry cooled at all plants when the hot potassium carbonate process is used and 90 percent dry-10 percent wet cooled when a physical solvent process is used[1]. The gas purification system of choice has been assigned to each process by the original designers. It is somewhat arbitrary and has only a small effect on the cumulative water consumption.

The cooling of steam turbine condensers and of gas compressor interstage coolers will depend on the cost of water and, therefore, on the site[1]. On Table A7-2 sites have been given a numerical classification for water cost and availability. The numerical classification determines whether turbine condensers are all wet cooled or whether parallel wet and dry condensers are used, and whether gas compressor interstage coolers are all wet cooled or whether series dry and wet coolers are used. The decision depends in part on the economics of cooling, which is discussed below. The approximate economics are shown graphically on Figures A7-1 to A7-5 for turbine condensers and Figures A7-6 to A7-10 for interstage cooling.

The numerical classification of sites is:

Water Cost & Availability No.*	% Turbine Condenser Cooling Load Wet Cooled	% Gas Compressor Interstage Cooling Load Wet Cooled
1	100	100
2	10	100
3	10	50

*No. 1 indicates plenty of water available within about 10 miles. No. 2 indicates limited local supply or a plentiful supply 25 to 30 miles away. Number 3 indicates substantial pumping costs and the need for a reservoir.

Also shown on Table A7-2 is the appropriate annual average evaporation rate. This number is only very slightly dependent on site.

Calculations of cooling water evaporated have been made for each site/process on the worksheets in a following appendix.

COOLING STEAM TURBINE CONDENSERS

On Figure A7-11 is shown a parallel dry/wet cooling system for a turbine condenser. The following calculations are intended to determine what fraction of the cooling load should be designed wet and what fraction should be designed dry; also, the water consumption is to be determined. Dry cooling has the advantage over wet cooling in that water is not used. It has the disadvantage of a higher capital investment and a higher condenser temperature. The higher condenser temperature means a lower efficiency for the turbine; that is, more energy as steam is consumed by the turbine for each kw-hr of shaft work performed.

Before an economic analysis can be made, a physical analysis is necessary To obtain the desired information the cooling system is first designed and then its operation is analyzed, month by month, for a year. Finally the economic analysis is made, and this depends on the cost of water.

Turbine Characteristics

In a steam turbine drive system the steam rate required by the turbine to produce a certain shaft power output depends on the inlet steam condition, the condenser pressure and the turbine efficiency. Usually the higher the inlet steam pressure and temperature, the higher will be the thermal efficiency of the system. In the present application where the steam is partially produced by waste heat recovery, the usual steam pressure is in the range of 715 to 915 psia, and the superheated temperature in the range of 600°F to 900°F. Also, in the present application where the steam turbine drive is used mainly for gas compression purposes, the type of turbine drive used usually has a maximum efficiency of about 80 percent when the condenser pressure is in the range of 3 to 5 in. Hg absolute. The corresponding steam saturation temperatures for the two condenser pressures are 115°F and 134°F respectively. Above 134°F, efficiency falls. We have assumed that below 115°F, the efficiency also falls. This is a function of the exhaust losses and may not be true for all turbines. However, usually there is no positive advantage in cooling below 115°F, so the procedure adopted in this study, which is never to cool below 115°F, is reasonably generally applicable when cooling water is scarce.

The heat rates required when the condenser temperature is in the range of 115°F to 134°F have been calculated for the various inlet steam conditions mentioned and are plotted in Figure A7-12. The calculations were made using an overall turbine efficiency of 80 percent including the bearing efficiency. The results in Figure A7-12 show that the steam rates for the four inlet steam conditions are quite close and that they can be represented by a single straight line going from a steam rate value of 11,700 Btu/kw-hr at the condenser temperature of 115°F to a value of 12,200 Btu/kw-hr at the condenser temperature of 134°F.

The increase in steam rate with condenser temperature indicates that there is a certain fuel penalty to be considered in evaluating the cost of various cooling systems.

The condenser cooling loads when the condenser temperature is in the range of 115°F to 134°F have also been calculated for the four inlet steam conditions mentioned and are plotted in Figure A7-13. The results indicate that the condenser loads for the four inlet steam conditions are also quite close and that they can be represented by a single straight line, going from a value of 8,200 Btu/kw-hr at the condenser temperature of 115°F to a value of 8,700 Btu/kw-hr at the condenser temperature of 134°F. This typical line will be used for condenser load calculations when the economics of condenser cooling systems are evaluated.

In analytical form the turbine heat rate is

$$Q_H \text{ (Btu/kw-hr)} = 11{,}700 + 500 \left[\frac{T_C - 115}{134 - 115}\right]$$

$$= 8{,}674 + 26.32\ T_C, \text{ for } 115 \leq T_C \leq 134 \tag{1}$$

and the condenser cooling load is

$$Q \text{ (Btu/kw-hr)} = 5{,}174 + 26.32\ T_C, \text{ for } 115 \leq T_C \leq 134 \tag{2}$$

The nomenclature is shown on Table A7-3.

Design Conditions

Design ambient conditions are given on Table A7-4 with complete monthly average ambient conditions. The condenser design condition is a condensing temperature of 134°F. This is a high design temperature chosen because the design ambient conditions are, on the average, not exceeded more than ten hours in a year. The design conditions for circulating cooling water are a hot water temperature, t_h, of 119°F which is a reasonable and usual 15°F below the design condensing temperature, and cold water temperature, t_c, of 94°F. The cold water temperature means that the circulating pumps must be sized for a 25°F rise which is usually found to be economical.

If x is the fraction of condenser load which is dry at design condition,

$$Q_{D,d} = 8{,}700x \tag{3}$$

The dry condenser area, A_D is given by

$$Q_{D,d} = U_D A_D \text{ (LMTD)}_D \tag{4}$$

where

$$LMTD_D = \frac{(T_C - T_{D,c}) - (T_C - T_{D,h})}{\ln\left\{\frac{T_C - T_{D,c}}{T_C - T_{D,h}}\right\}} \tag{5}$$

The temperature of the heated air leaving the dry condenser is found from the empirical equation

$$T_{D,h} - T_{D,c} = 0.005\ U_D(T_C - T_{D,c}) \tag{6}$$

from which

$$(T_C - T_{D,c}) - (T_C - T_{D,h}) = 0.005\ U_D(T_C - T_{D,c}) \tag{7}$$

$$T_C - T_{D,h} = (T_C - T_{D,c})(1 - 0.005\ U_D) \tag{8}$$

so,

$$LMTD_D = \frac{0.005\ U_D(T_C - T_{D,c})}{\ln\left\{\frac{T_C - T_{D,c}}{(T_C - T_{D,c})(1-0.005\ U_D)}\right\}}$$

$$= 0.005\ U_D(T_C - T_{D,c})/\left\{-\ln(1 - 0.005\ U_D\right\} \tag{9}$$

Values of U_D are given on Table A7-5. Since the design condenser temperature

$$T_{C,d} = 134 \tag{10}$$

the design log mean temperature difference, $LMTD_{D,d}$, can be found from Equation (9) and the area from Equations (3) and (4).

DESIGN OF WET CONDENSER AND COOLING TOWER

To design the cooling tower, information on the efficiency of the packing is needed. It must be remembered that our objective in designing a tower is not to build a tower but to determine its operation at off-design conditions. The choice of tower type and fill pattern is therefore not very important. For this study we have used the comprehensive graphical data given in Kelley's Handbook[2] based on 18 ft of air travel and 30 ft height of fill type H. The tower design parameter, which is given the symbol K_aY/L and is called "characteristic," is taken from Reference 2 for the condition

$$\text{"Wet Bulb"} = T_{W,d}$$

$$\text{"Range"} = t_h - t_c = 25°F \tag{11}$$

$$\text{"Approach"} = t_c - T_{W,d} = 94 - T_{W,d} \tag{12}$$

$T_{W,d}$ is the design air wet bulb temperature.

The equations which give the wet condenser area are

$$Q_{W,d} = 8700(1 - x) = U_W A_W (LMTD)_{W,d} \tag{13}$$

$$(LMTD)_{W,d} = \frac{(T_C - t_c) - (T_C - t_h)}{\ln\left\{\dfrac{T_C - t_c}{T_C - t_h}\right\}} \quad \text{(all design)}$$

$$= \frac{(134 - 94) - (134 - 119)}{\ln\left\{\dfrac{134 - 94}{134 - 119}\right\}}$$

$$= 25.5 \tag{14}$$

The equations which give the rate of circulation of cooling water are

$$R_L\,(\text{lb/kw-hr}) = Q_{W,d}/25 \tag{15}$$

$$R_G\,(\text{gal/min})/\text{kw}) = R_L/(8.33)(60) = 0.002\ R_L \tag{16}$$

Off-Design Conditions, General

Calculations were made using monthly average ambient conditions for each month of a year beginning with the hottest and ending with the coldest. This is more convenient than considering the months in chronological order. The condenser temperature is first determined. If this is apparently below 115°F, then it is controlled at 115°F using the following control philosophy. First, the heat rejection load of the cooling tower is reduced by altering the pitch of the fans or by turning the fans off. When the ambient air temperature is sufficiently low, the evaporative tower is shut down and the heat load is carried by the dry cooler which controls the turbine back pressure by altering the fan blade pitch. When the cooling tower is shut down, the circulation of water is stopped. Water circulation is either full on or off. Throttling the circulation pumps leads to stagnation, fouling and scaling and is not practiced.

Determination of Condenser Temperature--

Determination of the condenser temperature is a trial-and-error calculation made as follows.

1) A condenser temperature, T_C, is assumed.

2) The total cooling load, Q, is calculated from Equation (2).

3) The dry log mean temperature difference is calculated from Equation (5).

4) The dry cooling load is calculated from the equation

$$Q_D = U_D A_D (\text{LMTD})_D \tag{17}$$

5) The wet cooling load is calculated from the equation

$$Q_W = Q - Q_D \tag{18}$$

6) The cooling water temperatures are calculated from the wet cooling load. The "range" is given by the equation

$$t_h - t_c = Q_W/R_L \tag{19}$$

so,

$$t_c = t_h - Q_W/R_L \tag{20}$$

The rate of heat transfer in the wet condenser is given by

$$Q_W = U_W A_W (\mathrm{LMTD})_W \tag{21}$$

where

$$(\mathrm{LMTD})_W = (t_h - t_c)/\left\{\ln \frac{T_C - t_c}{T_C - t_h}\right\} \tag{22}$$

Algebraic manipulation of the above four equations gives

$$U_W A_W = Q_W/(\mathrm{LMTD})_W = R_L \ln \left\{\frac{T_C - t_c}{T_C - t_h}\right\} \tag{23}$$

or

$$\ln \left\{\frac{T_C - t_h + Q_W/R_L}{T_C - t_h}\right\} = U_W A_W/R_L \tag{24}$$

so,

$$t_h \left\{1 - \exp(U_W A_W/R_L)\right\} = T_C \left\{1 - \exp(U_W A_W/R_L)\right\} + Q_W/R_L \tag{25}$$

Equation (25) can be solved for t_h and Equation (20) for t_c.

7) Reference 2 is used to find whether, in fact, the cooling tower will give the water temperatures found for the prevailing wet bulb temperature T_w. Reference 2 gives the approach, $t_c - T_w$, when the wet bulb temperature, T_w, the range, $t_h - t_c$, and the tower characteristics are known. If t_c, calculated from the approach, is too high then the tower cannot do the job and a higher condenser temperature must be tried.

8) The fan and pump energy needs are calculated from the equations

$$\text{Dry condenser fan energy } E_D = 0.0149\ A_D \tag{26}$$

$$\text{Cooling tower fan energy } E_W = 0.0089\ R_G \tag{27}$$

$$\text{Cooling water circulation pump energy } E_C = 0.0246\ R_G \tag{28}$$

These equations are used only when the condenser temperature is above 115°F. When the condenser temperature is controlled at 115°F, the equation given in later steps should be used.

9) To calculate the water consumption, the rate of air flow through the tower must be known. The ratio of water flow to air flow, R_L/R_A, is part of the design of the tower (see Reference 2) and is known. Since the water flow, R_L, is known, the air flow, R_A, is also known. Knowing the dry bulb and wet bulb temperatures the absolute humidity of the entering air, H_i lb water/lb dry air, can be read from a standard psychometric chart. When the dry and wet bulb temperatures are below 30°F, the absolute humidity of the entering air is taken to be zero. It is also possible to calculate the enthalpy of the entering air, i_i. Enthalpies of humid air are normally measured above 0°F for dry air and liquid water at 32°F

$$i_i = 0.24\ T_D + H_i[1075 + 0.45(T_D - 32)] \tag{29}$$

In Equation (29), 0.24 is the specific heat of dry air, 0.45 is the specific heat of water vapor and 1075 is the latent heat of vaporization of water at 32°F.

Next, the condition of the air exiting the tower can be found. The enthalpy of the exit air is

$$i_e = i_i + Q_W/R_A \tag{30}$$

because the circulating water transfers the wet cooling load to the air. Experience shows that the leaving air is within a few percentage points of saturation and it is sufficiently accurate to assume it to be saturated. In Reference 2 is given a table of saturated air enthalpies against temperature from which the temperature of the air leaving the tower can be read. The psychometric chart gives the humidity of the leaving air, H_e. The rate of water evaporation is

$$R_A(H_e - H_i) \text{ lb/kw-hr} \tag{31}$$

Equation (31) applies when the tower is not bypassed. When the tower is bypassed the modification given in Step 18 is used.

Operation with 115°F Condenser Temperature--

When the condenser temperature is known, the calculation is as follows.

10) The total cooling load is 8,200 Btu/kw-hr.

11) The dry log mean temperature difference is given by the equation

$$LMTD_D = 0.005\ U_D(115 - T_{D,c}) / \left\{-\ln(1 - 0.005\ U_D)\right\} \tag{32}$$

12) The dry cooling load is given by Equation (17).

13) The wet cooling load is given by the equation

$$Q_W = 8{,}200 - Q_D \tag{33}$$

14) The hot temperature of the circulating cooling water, t_h, is given by Equation (25) and the cold temperature, t_c, by Equation (20). The cold temperature is the temperature of blended water entering the condenser, not the temperature at the bottom of the cooling tower. The tower is bypassed.

15) The temperature at the bottom of the cooling tower, t_r, is found from Reference 2. It is that temperature which makes both the range, $t_h - t_r$, and approach, $t_r - T_W$, correct at the same time. When the wet bulb temperature is very low such that it is no longer on the graphs, an arbitrary 37°F approach is chosen. This makes the tower bottom temperature 37° higher than the wet bulb temperature.

16) The fraction of the flow which bypasses the tower, y, is given by

$$yR_L t_h + (1 - y)R_L t_r = R_L t_c \tag{34}$$

$$y = \frac{t_c - t_r}{t_h - t_r} \tag{35}$$

If $y \geq 1$, we skip to Step 19.

17) The dry condenser fan energy is given by Equation (26). The cooling water circulation pump energy is given by Equation (28). The cooling tower fan energy is

$$E_W = 0.0089(1 - y)R_G \tag{36}$$

18) The water evaporation is calculated as in Step 9, except that the air rate is now $(1 - y)R_A$, where R_A is the design air rate.

19) If the ambient conditions are so cold that the cooling tower is completely bypassed, the rate of water evaporated is zero, the cooling tower fan energy is zero and the cooling water circulation pump energy is zero. The only quantity to be calculated is the dry condenser fan energy. To do this we first need to know the air temperature, T_D', at which the dry condenser will carry the whole load. This is given by

$$8200 = U_D A_D \times 0.005\ U_D(115 - T_D') / \left\{-\ln(1 - 0.005\ U_D)\right\} \tag{37}$$

$$115 - T_D' = \frac{-8200\ \ln(1 - 0.005\ U_D)}{0.005\ U_D^2\ A_D} \tag{38}$$

The fan factor, F, is read from the vertical scale of Figure A7-14 when the horizontal scale point is $(T_D' - T_D)$. The dry condenser fan energy is

$$E_D = 0.0149\ FA_D \tag{39}$$

Results

The results of the month-by-month calculations are given for 0, 25, 50, 75 and 95 percent dry cooling at each of the four sites on Table A7-7 to A7-10. Summaries are given on Table A7-11. To make the summaries, equal weight was given to each month: for example, the fan and pump energies from Tables A7-7 to A7-10 were totaled and divided by 12 to obtain the value entered on Table A7-11. The fuel penalty is that part of the turbine heat rate in excess of the minimum value, 11,700 Btu/kw-hr.

Costs

Unit costs are given on Table A7-6. The annual average costs, tabulated on Table A7-12, were calculated according to the following examples:

$$\text{Dry condenser cost } (\text{¢/kw-hr}) = (\text{area, ft}^2/\text{kw})(\text{cost, ¢/ft}^2)(\%/\text{yr})(1/7000 \text{ hrs/yr})$$

$$\text{Electrical energy } (\text{¢/kw-hr}) = (\text{energy, kw-hr/kw-hr})(\text{cost, ¢/kw-hr})$$

$$\text{Fuel penalty } (\text{¢/kw-hr}) = (\text{fuel penalty, Btu/kw-hr})(\text{steam, ¢/Btu})$$

Please note that "total costs" (¢/kw-hr) refers only to those costs dependent on the choice of cooling system. Other components of production cost are not included.

Various water costs were assumed, and the results are shown graphically in Figures A7-1 to A7-4 and summarized on Figure A7-5. It is clear that at all sites there is a cost of water above which it is economical to use parallel wet/dry condensers. It is also clear that when parallel wet/dry condensers are used, the load on wet cooling is reduced to a small percentage of the load with all wet cooling. Accurate generalization of actual numerical values is not possible. Not only do the numerical values depend on the climate, as shown on Figure A7-5, but they depend on the way the calculations were made and, particularly, on the relative costs of wet and dry condenser surface and the cost of cooling towers. Capital costs are always changing. The costs used here are late 1977; wet condenser surface and cooling towers have had recent cost increases, while dry condensers have not. This will change.

We have adopted the policy of using wet/dry cooling at many sites where water is less than freely available, but not at all sites. If the cost of

20¢/1000 gallons shown on Figure A7-5 were totally and permanently trustworthy, parallel wet/dry condensers would be used everywhere, always. When wet/dry cooling is used, we have dropped the load on wet cooling to 10 percent of the case for all wet cooling. Figure A7-5 suggests a value as low as 2 percent, so our choice is conservative for the cost year and basis used.

Because of the way the calculations were made, the hot and cold circulating water temperatures are both changed to control the system. Now, the cooling system may have other connections such as to process coolers, and the hot water returning to the tower may have a temperature derived from mixing all the returning streams. However, there is no other way of making calculations. If the cooling tower is not reserved exclusively for turbine condensers, then the calculations made are indicative but not a precise representation of reality. Fortunately the chosen configuration, when not all wet, is 90 percent dry and only 10 percent wet. The wet condensers will only be turned on for a few months of the year, and even then they will carry such a small fraction of the load that control may not be required.

INTERSTAGE COOLING OF GAS COMPRESSORS

To study the effect of series dry-wet coolers on interstage gas compressors, an air compressor has been chosen as the example. Air is compressed from ambient temperature and 15 psia to 90 psia and 104°F (or cooler), in which condition air enters the separation plant to be separated into nitrogen and oxygen. Air compressors are used in all plants, and they are the biggest compressors in the gas plants.

The compressor is shown on Figure A7-15. It is a three-stage compressor with a compression ratio of 1.817 per stage. The temperatures T_X and T_i = 109°F are design conditions. The stage outlet temperatures are calculated from the equation

$$T_o = T_i \, r^{(n-1)/n} \qquad (40)$$

where

T_o, T_i are outlet and inlet temperatures, °R, (°R = 460 + °F)

r is the compression ratio

$(n-1)/n = 0.371$ for air

The only number which must be chosen is T_x, the temperature between the air cooler and the wet cooler. The following calculations are intended to determine what T_x should be.

To begin, it is necessary to know the power consumed by a gas compressor.

The general equations for the horsepower needed to drive a gas compressor are[3]:

$$HP = WH/33{,}000e \tag{41}$$

$$H = \left(\frac{Z_s + Z_d}{2}\right)\left(\frac{1{,}545}{M_w}\right) T_s \left[\frac{r^{(n-1)/n} - 1}{(n-1)/n}\right] \tag{42}$$

$$(n-1)/n = (k-1)/ke \tag{43}$$

HP is horsepower

W is gas flow in lb/min

H is polytrophic head (ft-lb)/lb

e is polytrophic efficiency

Z_s, Z_d are compressibility factors for suction and discharge

M_w is molecular weight

T_s is suction temperature, °R(°R = 460 + °F)

r is the compression ratio

k is ratio of specific heats

For air, the appropriate values of the parameters are:

W	-	16.67
e	-	0.77
Z_s	-	1.0
Z_d	-	1.0
k	-	1.40
M_w	-	29
$(n-1)/n$	-	0.371

The choice of W means that all calculations are based on 1,000 lb/hr of gas. Note that 1,000 lb/hr of air is equivalent to 233 lb/hr of oxygen.

The short equation, where P is the power in kw (= 1.341 HP), is:

$$P = 0.0702\ T_i (r^{0.371} - 1) \tag{44}$$

Design

Monthly average and design ambient conditions are as previously given for turbine condenser calculations. Hot and cold water design temperatures are 119°F and 94°F as above, and the tower characteristics are as previously found. For interstage cooling the tower is assumed independent of the tower for the turbine condensers. This means a segregated cooling loop which is acceptable practice but not always done. The two cooling loops are assumed segregated in this study to limit the calculation and to aid in understanding the theory.

T_X is chosen and the areas of the various wet and dry coolers determined. The heat transfer coefficient varies with the gas pressure as shown on Table A7-5. The load on the cooler, Btu/hr, is

$$(\text{gas rate, lb/hr})(T_{in} - T_{out})c_p \tag{45}$$

The gas rate is 1,000 lb/hr. The specific heat is sufficiently independent of temperature and pressure to be taken as constant. We have used

$$c_p(\text{air}) = 0.241 \tag{46}$$

so, the load

$$Q = 241(T_{in} - T_{out}) \tag{47}$$

The wet and dry cooler areas following each stage are calculated and tabulated. The calculation proceeds as follows.

1) For the design ambient temperature, calculate the first stage outflow temperature $T_{1,0}$ from Equation (40) which, for this compressor, is

$$T_{out} = 1.248\ T_{in} \tag{48}$$

2) Calculate the area of the air cooler from the equations

$$Q_D = U_D A_D (LMTD)_D = 241(T_o - T_X) \tag{49}$$

$$LMTD_D = \frac{GTD - LTD}{\ln \frac{GTD}{LTD}} \tag{50}$$

where GTD is the greater of the temperature differences

$$(T_o - T_{D,h}) \text{ and } (T_X - T_{D,d})$$

and LTD is the lesser temperature differences. The nomenclature is given on Figure A7-15 and Table A7-3.

The hot temperature on the ambient side of the cooler is given by

$$T_{D,h} - T_{D,d} = 0.005\ U_D \left(\frac{T_o + T_X}{2} - T_{D,d} \right) \tag{51}$$

All four temperatures are known and A_D can be found for each stage.

3) Calculate the area of the wet cooler from the equation

$$Q_W = U_W A_W (LMTD)_W = 241\ (T_X - T_i) \tag{52}$$

where $LMTD_w$ is given by an equation similar to Equation (50) in which the temperature differences are

$$(T_X - t_h) \text{ and } (T_i - t_c)$$

The design conditions are: T_X as chosen, t_h = 119°F, T_i = 109°F, t_c= 94°F. The wet area is calculated for all stages.

4) The water circulation rates for each wet cooler are calculated from Equations (15) and (16). The total flow is the sum of the individual flows.

Off-Design Conditions

When turbine condensers were studied, there was actually a penalty for cooling too low. In this case there is a benefit for cooling to a lower, and still lower temperature--namely, the compression energy is decreased. At first sight the optimum strategy is not apparent: whether to control the inlet temperature to each stage or let it go as cold as possible. However, calculations show that maximum cooling is always preferable. An example can be given to show this. With the temperature between dry and wet cooling equal to 160°F in Farmington, New Mexico, the maximum cooling calculations show a cost of 65.54 ¢/1000 lb and a water evaporation rate of 1.929 gal/1000 lb (Table A7-20). If water is turned off for months 1, 2, 3, 11 and 12, the cost goes up by 0.65 ¢/1000 lb and the water consumption goes down by 0.562 gal/1000 lb (Tables A7-13 and A7-14). This cost of water is $11.57/thousand gallons, which is too high.

Operation with Maximum Cooling

5) The calculation must begin at the entry to the first stage and proceed through each piece of equipment in series. First the exit temperature from Stage 1 is calculated.

6) Next, $T_{X,1}$ is calculated by simultaneous solution of Equations (49), (50) and (51). A trial-and-error solution is used. A value is assumed for T_X, $T_{D,h}$ is calculated from Equation (51) and $LMTD_D$ is calculated from Equation (50). The assumed value for T_X is correct if Equation (49) is true. If

$$U_D A_D (LMTD)_D < 241 \ (T_o - T_X)$$

then T_X has been chosen too low and a larger value must be tried.

7) Next, $T_{2,i}$ is calculated (also be trial and error). A value for $T_{2,i}$ is assumed and Q_W calculated from Equation (52). The hot and cold water temperatures are then calculated from the equations

$$Q_W = R_L(t_h - t_c) = U_W A_W \frac{\left(T_X - t_h - T_i + t_c\right)}{\ln \dfrac{T_X - t_h}{T_i - t_c}} \tag{53}$$

that is,

$$t_c = t_h - Q_W/R_L \tag{54}$$

and

$$Q_W = U_W Q_W \frac{\left(T_X - T_i - Q_W/R_L\right)}{\ln \dfrac{T_X - t_h}{T_i - t_h + Q_W/R_L}} \tag{55}$$

so,

$$t_h(e^k - 1) = e^k(T_i + Q_W/R_L) - T_X \tag{56}$$

where

$$k = \frac{U_W A_W}{Q_W}\,(T_X - T_i - Q_W/R_L) \tag{57}$$

If the cold water temperature calculated this way is colder than the value given by the cooling tower curves[2] at the prevailing wet bulb temperature and hot water temperature, then $T_{2,i}$ has been chosen too low and a higher temperature must be tried.

8) Steps 5, 6 and 7 are then repeated for Stage 2. This will result in a hot and cold water temperature different from those calculated in Step 7. However, the cold water to both wet coolers must have the same temperature because it all comes from the same cooling tower basin. The hot water temperature to the tower is the temperature resulting from mixing the two streams.

It is necessary, therefore, to determine those hot and cold water temperatures which satisfy the calculations for both stages. In fact, only one repeat calculation is needed using an average of the water temperatures found for Stages 1 and 2 separately.

9) For air separation there is little benefit to having $T_{air} < 95°F$ so the third stage water cooler is turned off when $T_{X,3} \leq 95°F$.

10) The calculations of all the temperatures are made month by month beginning with the hottest month and continuing through successively cooler months. In the colder months little benefit is obtained from the wet cooler. The purpose of the wet cooler is to decrease the energy consumed in compression. When $(T_X - T_i) \leq 5°F$, the wet cooler gives less than one percent reduction in compression energy and we considered turning off the wet coolers, circulating water and tower. However, we found no cases where $T_X - T_i < 5°F$.

11) From the above calculations the grand total wet load each month is known, and so the water evaporated can now be calculated using the procedure previously given.

12) The fan and pump energies are calculated as previously described.

13) The compression energy is calculated from Equation (41).

Results

The results are shown on Tables A7-15 to A7-18, with summaries on Table A7-19 and costs on Table A7-20. The cost of compression energy is calculated from steam at $\$1.80/10^6$ Btu and a heat rate of 11,700 Btu/kw-hr, making ¢2.106/kw-hr. As with turbine condensers, please note that the "total costs" (¢/1000 lb) refer only to those costs dependent on the choice of cooling system. Other cost components such as purchase of the compressors are omitted.

As a result of these calculations, it is clear that there is a price of water above which the use of series dry/wet interstage cooling is the economic choice. This price of water is about $\$1.50/10^3$ gal, and dry cooling will only be introduced into interstage cooling of air compressors when water is scarce. Once the decision has been made to use partial dry cooling, the fraction of the load to be carried by the dry cooler is found to vary significantly with the cost of water. The effect of the cost of water is more gradual than was found from the calculations on turbine condensers. Also, the fraction of the load carried by the dry cooler depends on how the cooling system is operated. Finally, the calculations were made on air compressors and there are other compressors.

For estimation on a large number of plants, we have assumed that when water is sufficiently scarce, dry cooling is used; then dry cooling will carry 50 percent of the load of all interstage compressors in all plants in all locations. This is the best that we can do at this time, but please recognize that it is quite a rough approximation.

REFERENCES, APPENDIX 7

1. Water Purification Associates, "Water Conservation and Pollution Control in Coal Conversion Processes," U.S. Environmental Protection Agency, Report EPA 600/7-77, June 1977.

2. Kelly's Handbook of Crossflow Cooling Tower Performance, Neil W. Kelly and Associates, Kansas City, Missouri.

3. Neerken, R.F., "Compressor Selection for the Chemical Process Industries," Chemical Engineering 78-94, January 20, 1975.

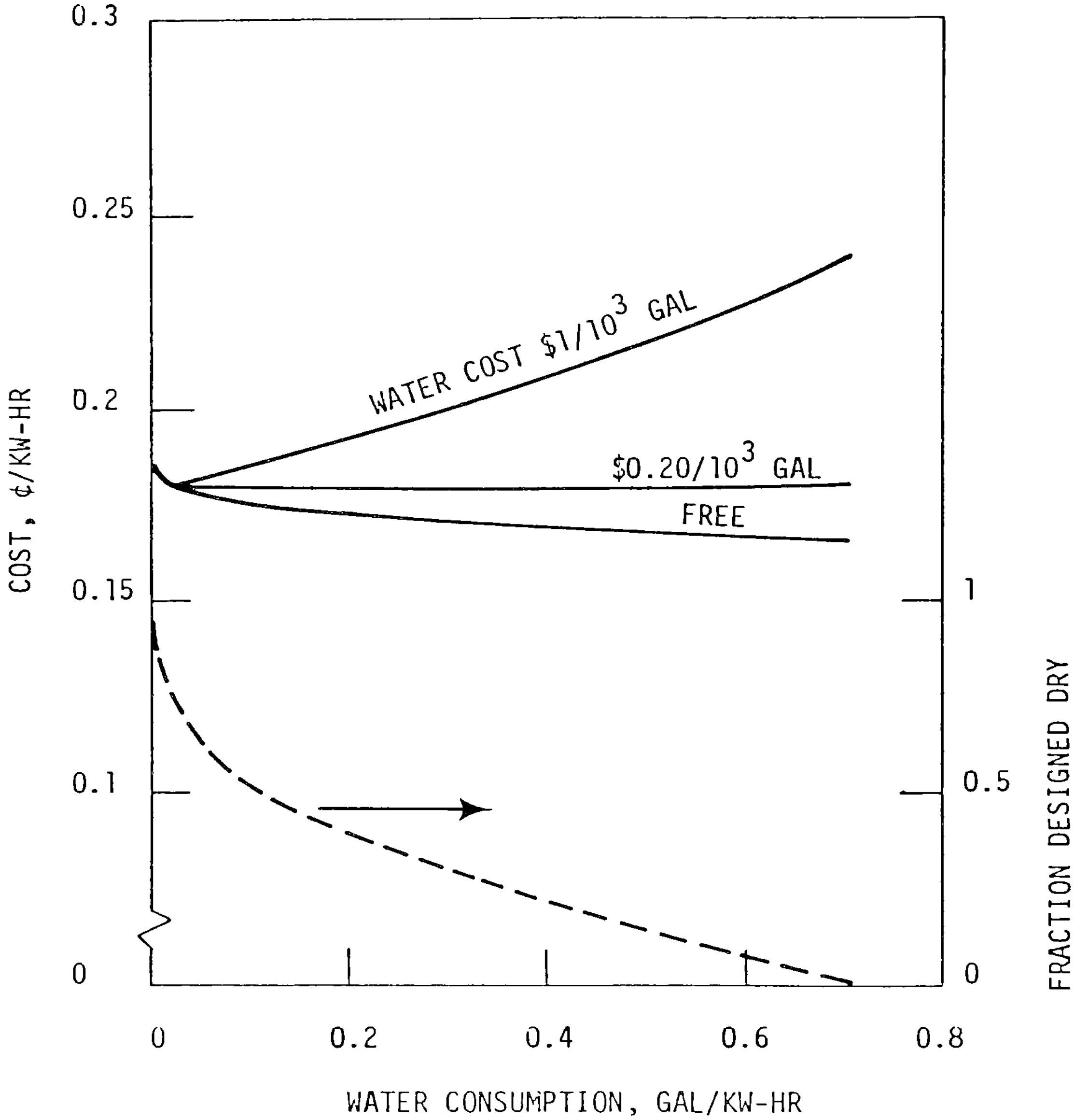


Figure A7-1. Cost of steam turbine condenser cooling in Farmington, New Mexico.

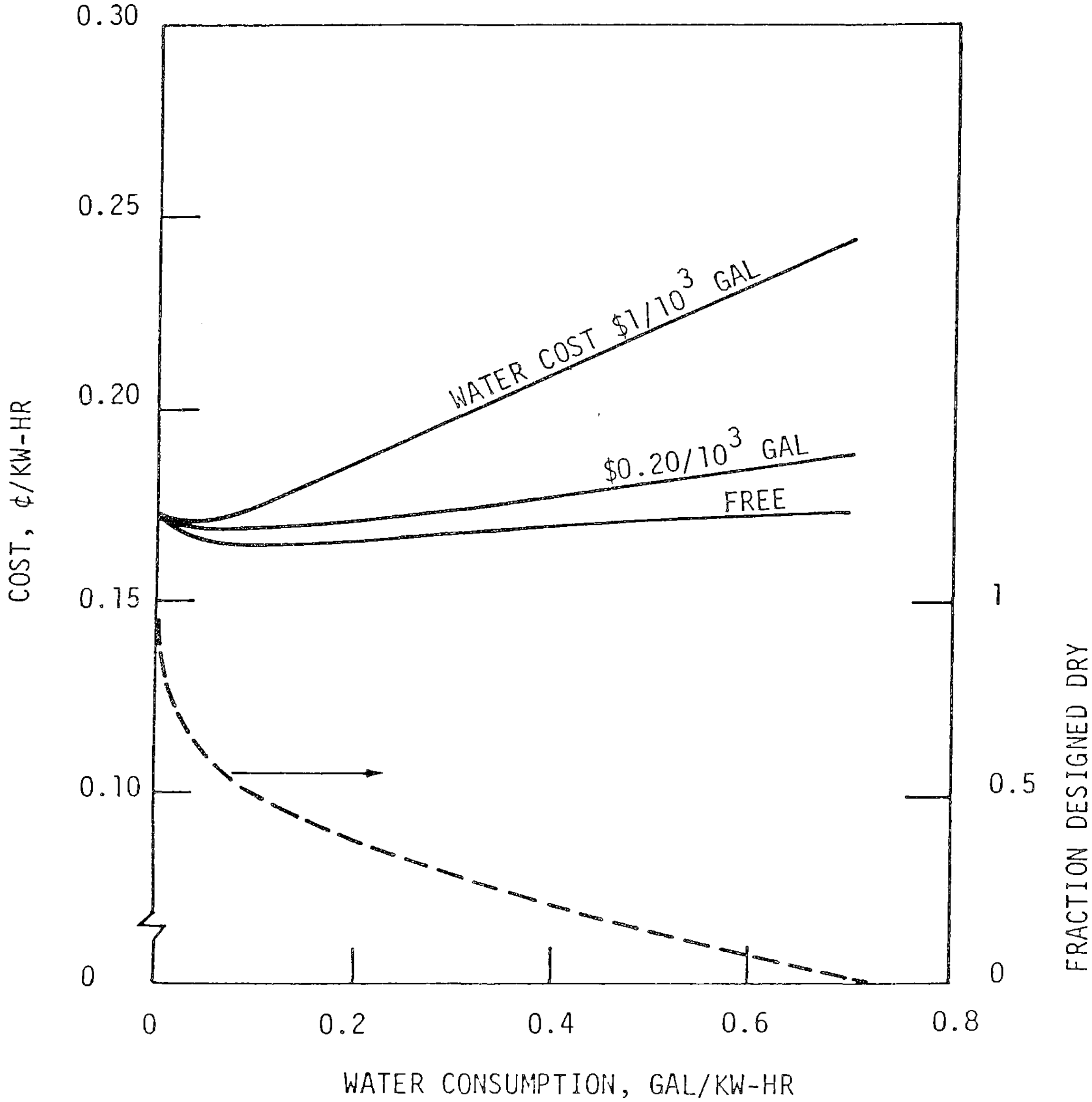


Figure A7-2. Cost of steam turbine condenser cooling in Casper, Wyoming

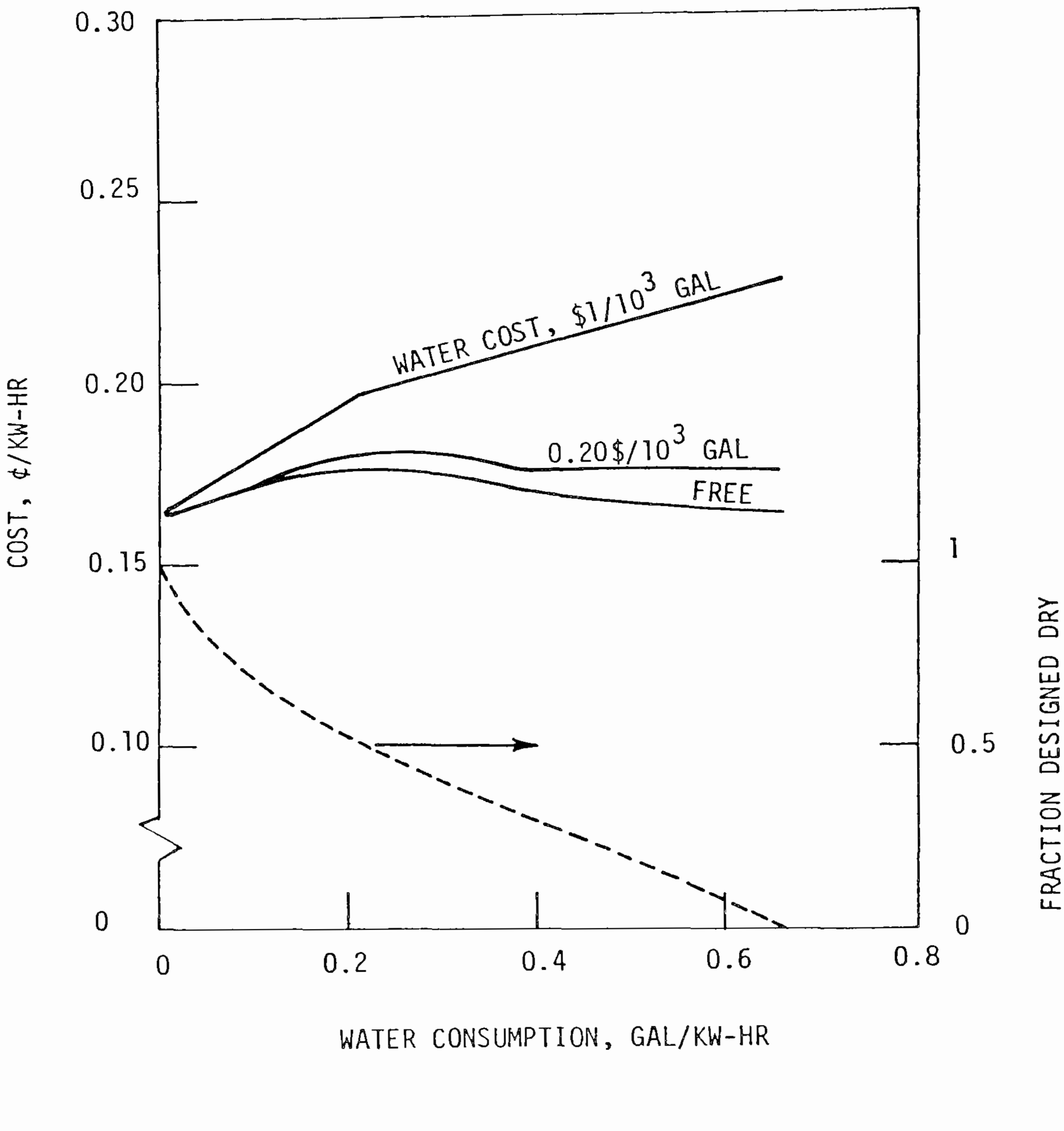


Figure A7-3. Cost of steam turbine condenser cooling in Charleston, W. Virginia.

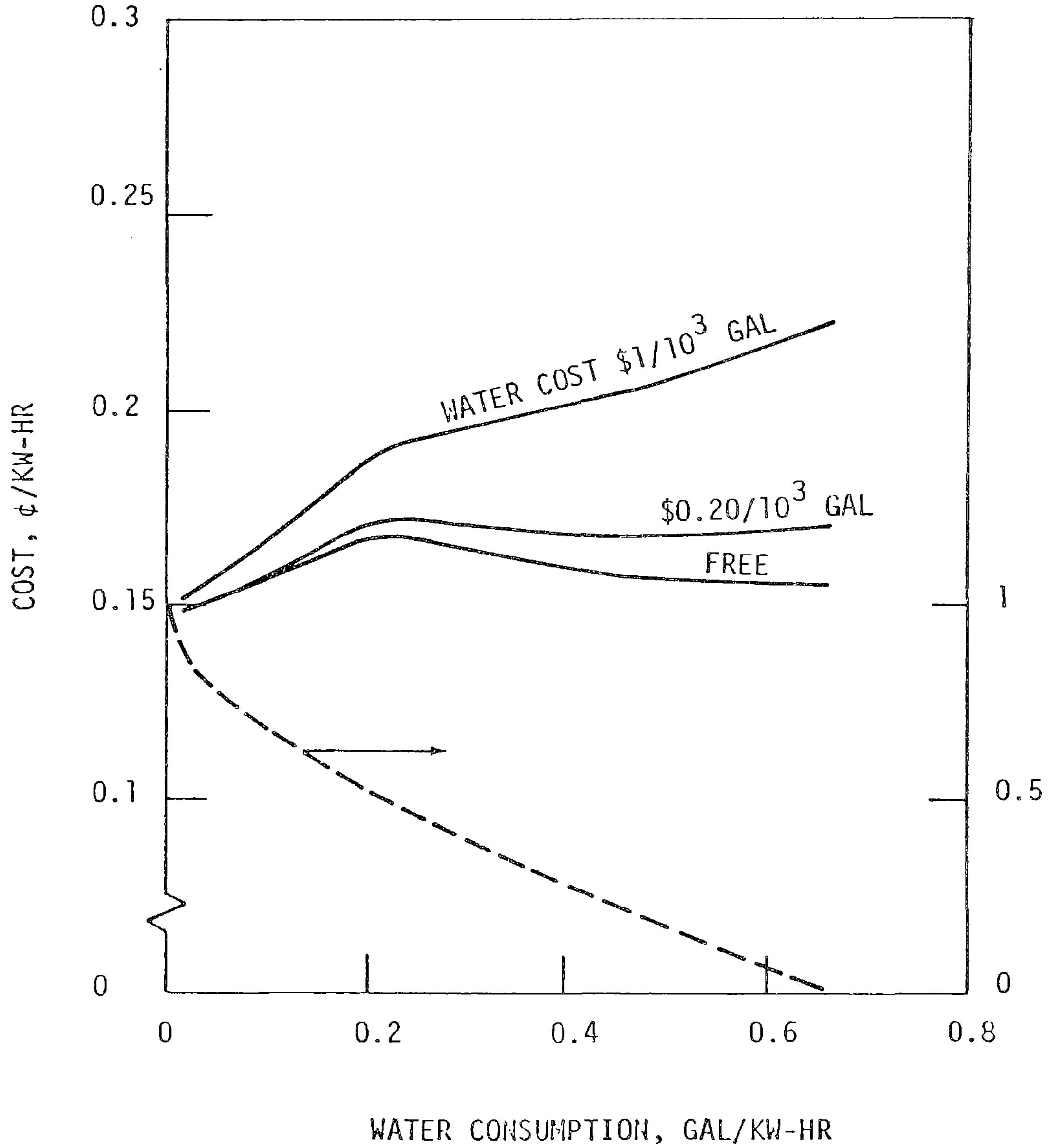


Figure A7-4. Cost of steam turbine condenser cooling in Akron, Ohio.

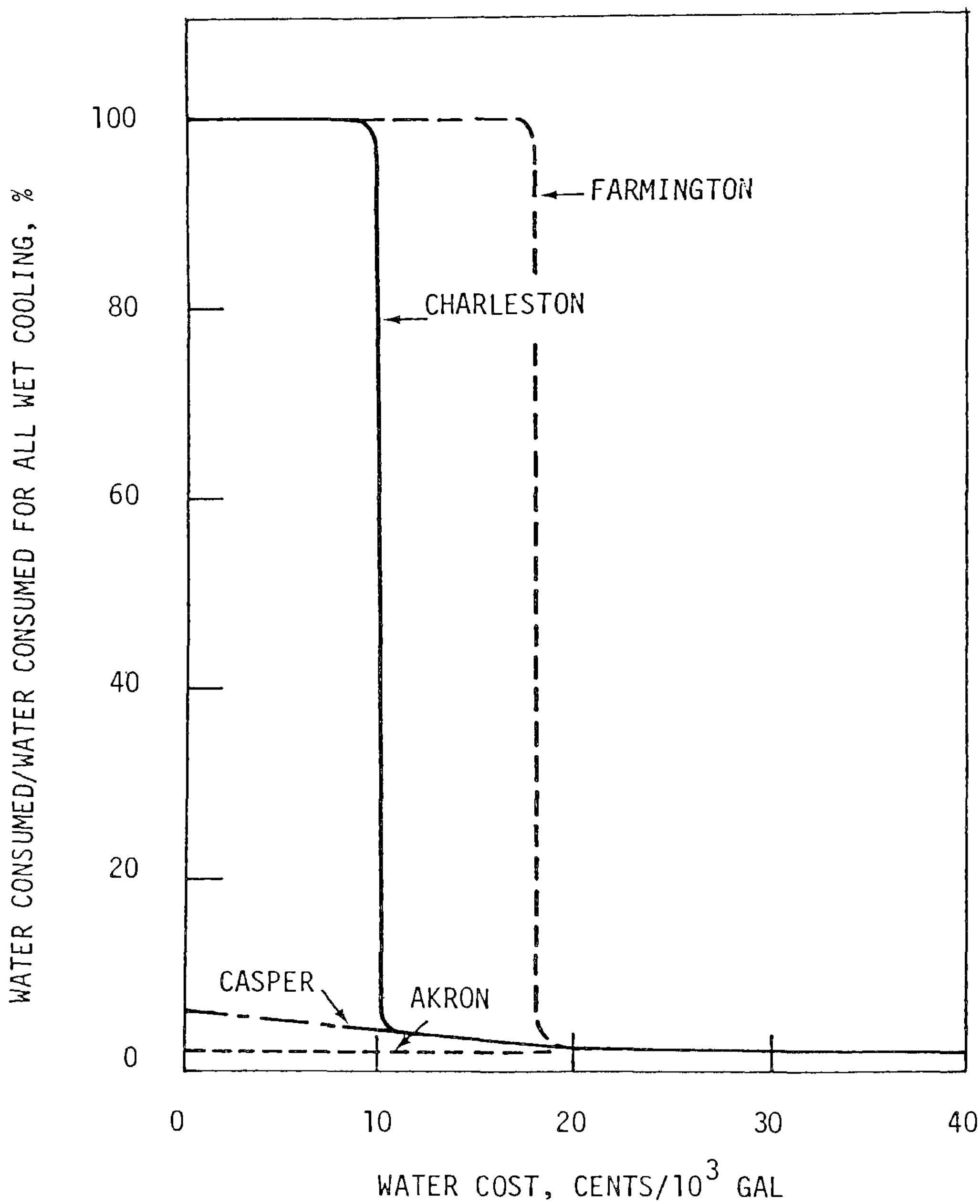


Figure A7-5. The effect of water cost on water consumed for cooling turbine condensers.

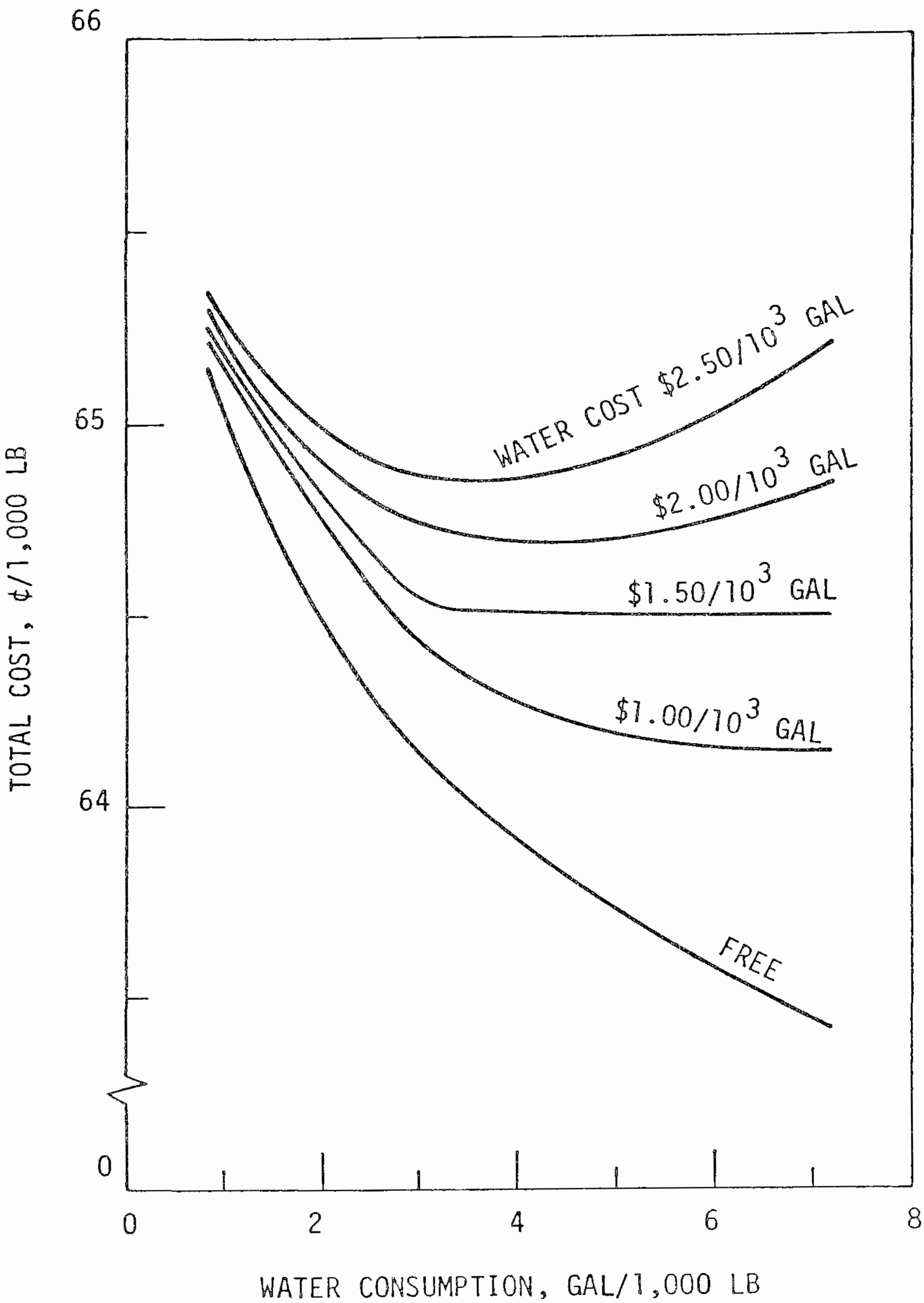


Figure A7-6. Cost of interstage cooling for compressing 1,000 lb air at Farmington, New Mexico.

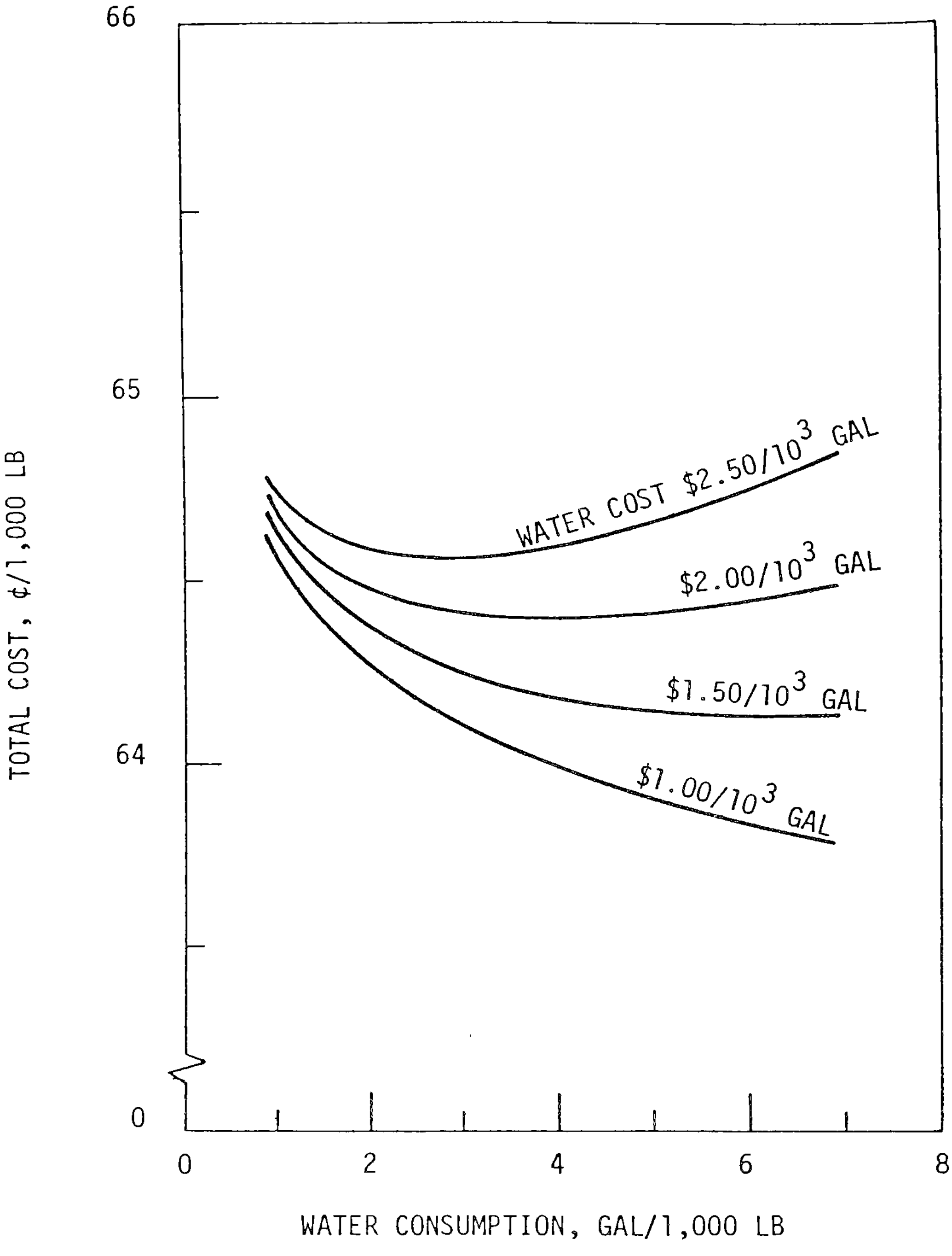


Figure A7-7. Cost of interstage cooling for compressing 1,000 lb air at Casper, Wyoming.

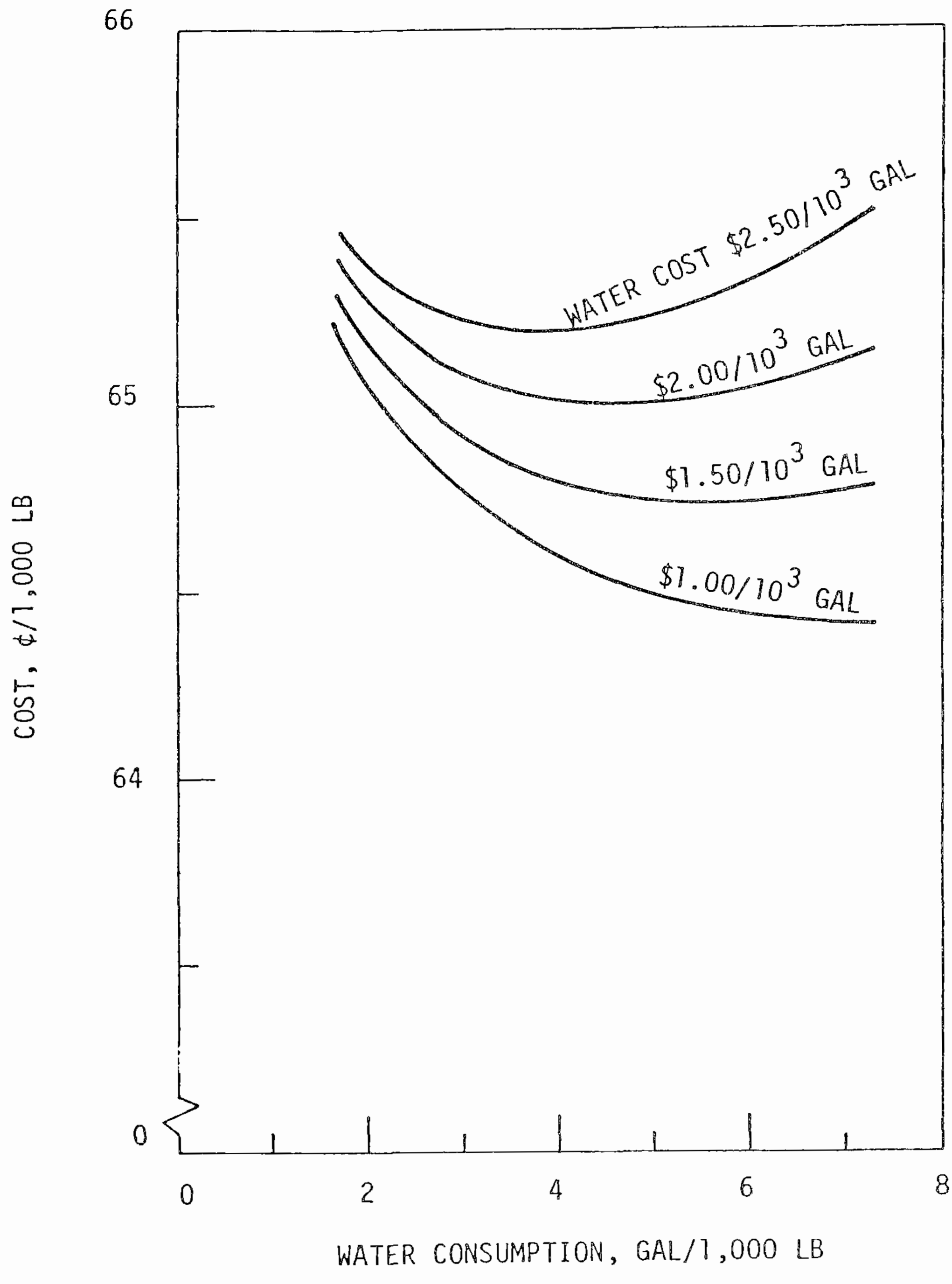


Figure A7-8. Cost of interstage cooling for compressing 1,000 lb air at Charleston, W. Virginia.

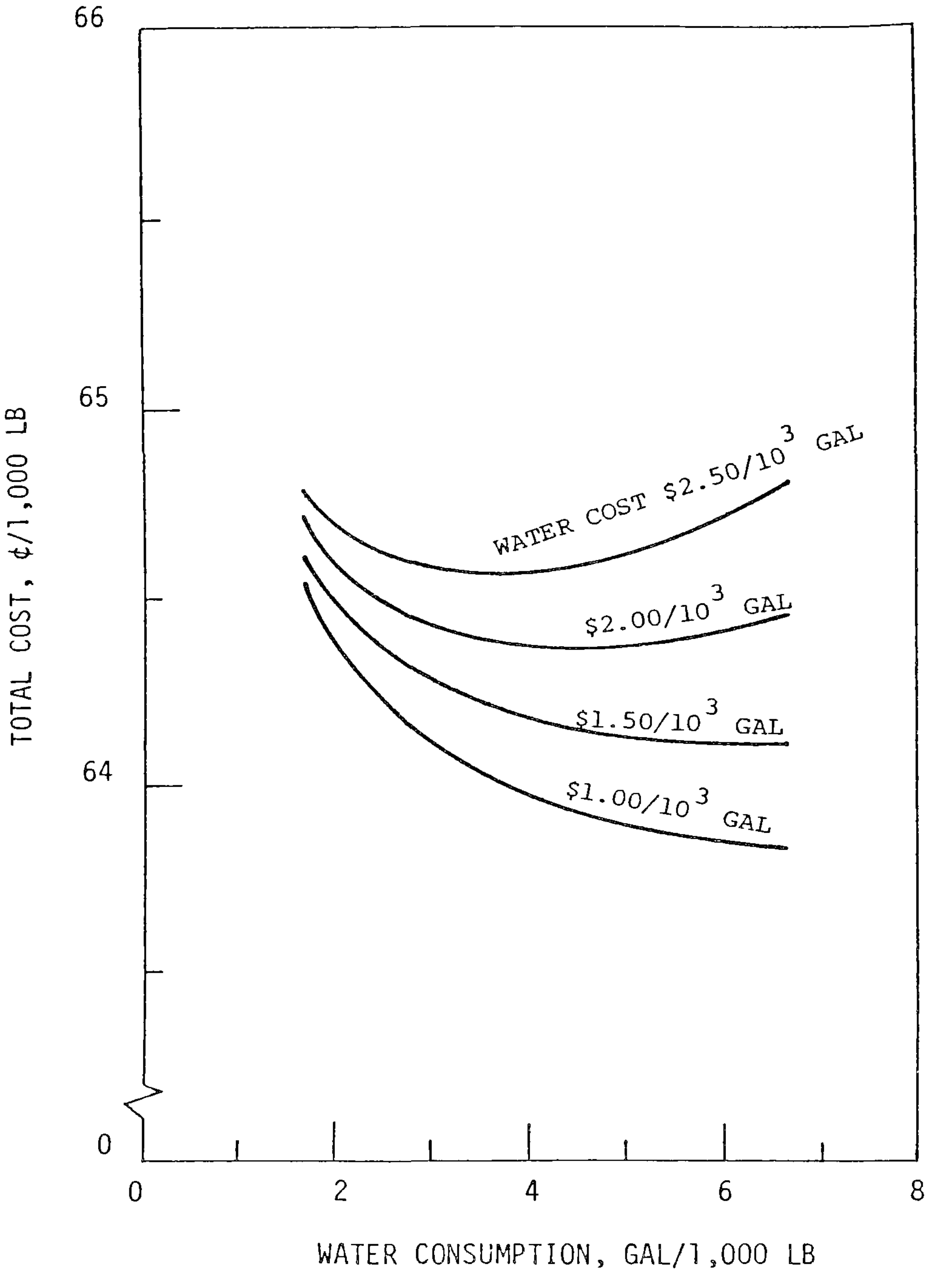


Figure A7-9. Cost of interstage cooling for compressing 1,000 lb air at Akron, Ohio.

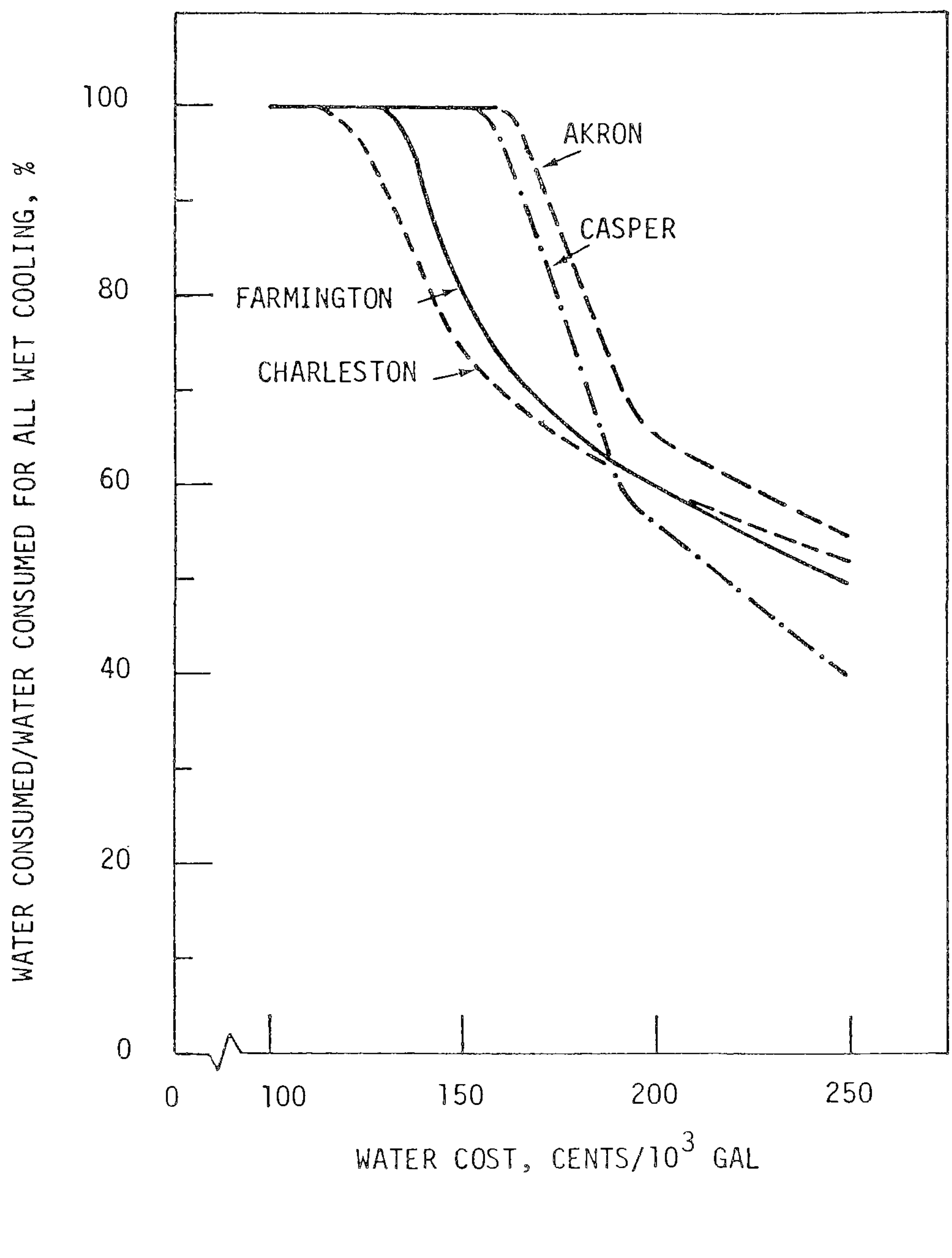


Figure A7-10. The effect of water cost on water consumed for interstage cooling when compressing 1,000 lb air.

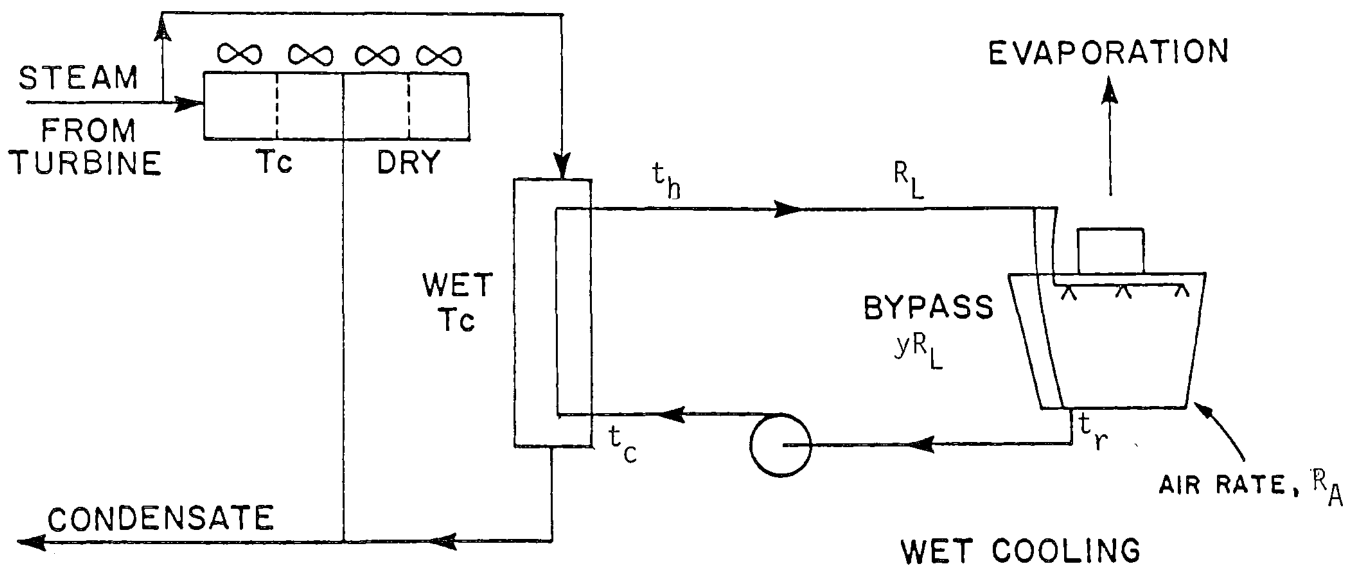


Figure A7-11. Turbine condenser cooling systems.

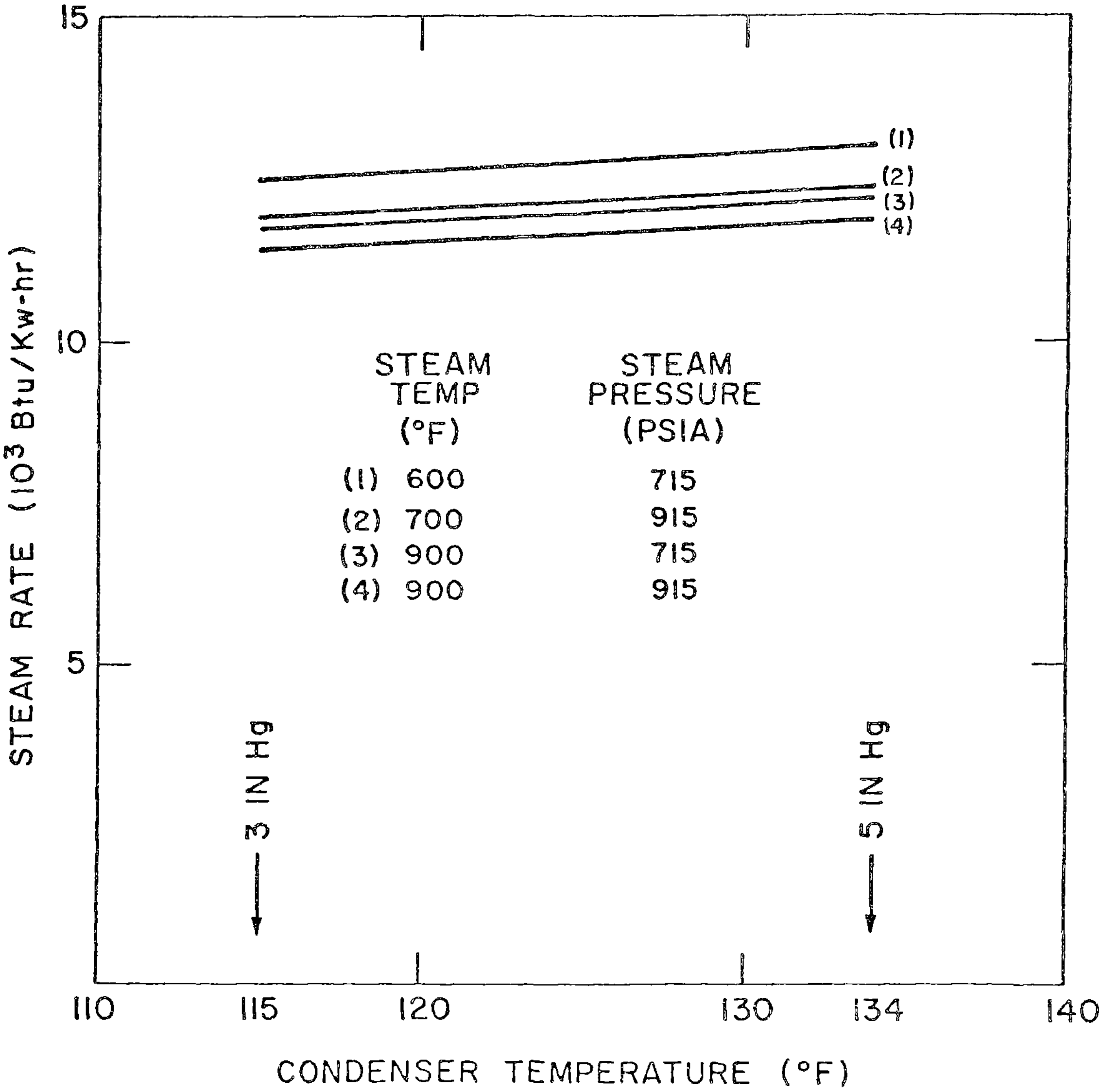


Figure A7-12. Turbine heat rates at full load.

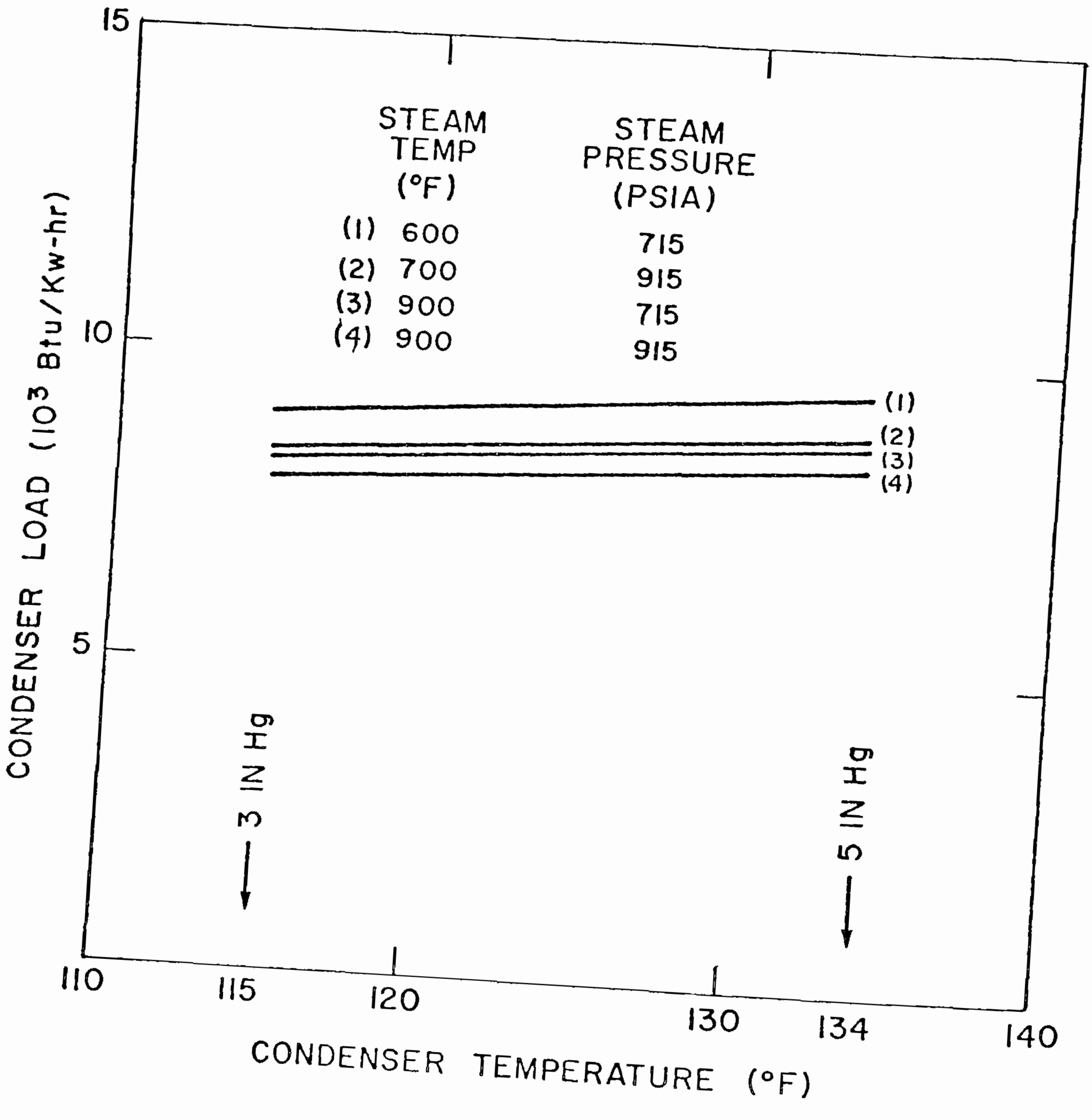


Figure A7-13. Turbine condenser cooling requirements at full load.

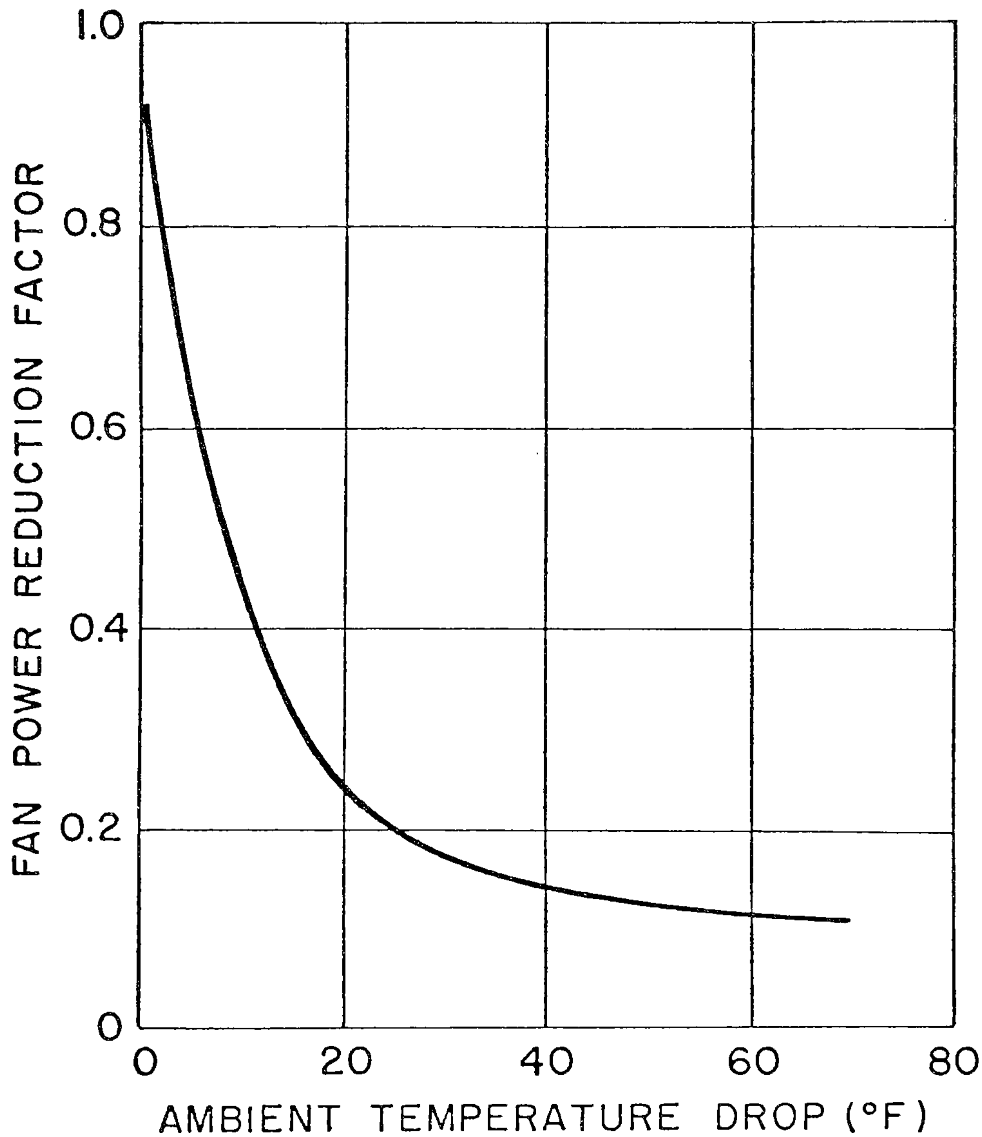


Figure A7-14. Fan power reduction factor for air coolers.

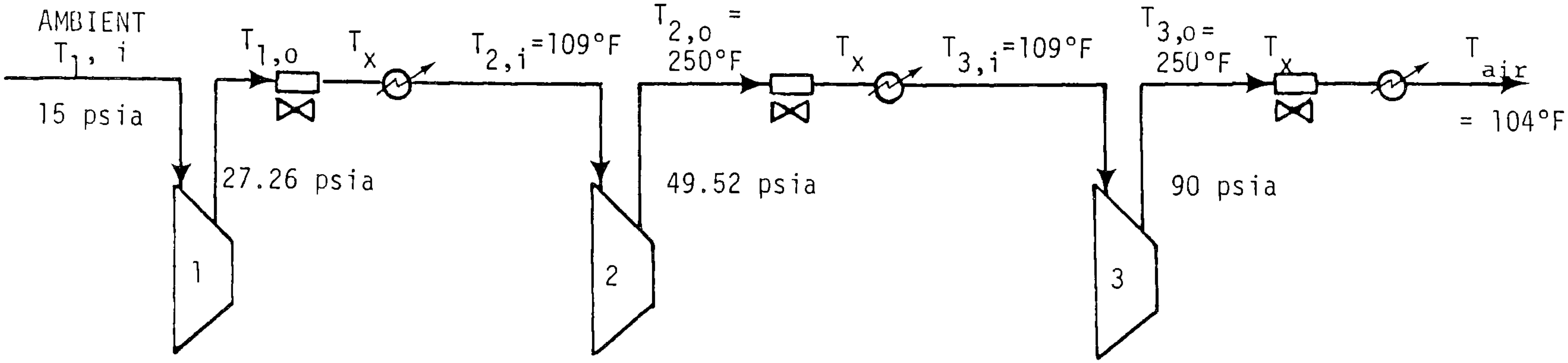


Figure A7-15. Air compressor design conditions.

TABLE A7-1. ASSIGNMENT OF COOLING LOADS

Assigned to dry cooling:	0% wet
Assigned to wet cooling:	100% wet
Gas purification regenerator condenser:	100% dry for Synthoil, Bigas and Synthane; 90% dry, 10% wet for SRC and Hygas
Steam turbine condensers:	site dependent
Gas compressor interstage coolers:	site dependent

TABLE A7-2. WATER AVAILABILITY AND EVAPORATION RATE

	Water Availability*	Btu/lb Evaporated
Alabama		
Jefferson	1	1310
Marengo	2	1310
Illinois		
Bureau	1	1390
Shelby	3	1390
St. Clair	1	1380
White	1	1370
Fulton	3	1390
Saline	3	1370
Indiana		
Gibson	1	1370
Vigo	1	1390
Sullivan	1	1380
Warrick	1	1370
Kentucky		
Floyd	3	1360
Harlan	3	1350
Henderson	1	1370
Muhlenberg	2	1370
Pike	2	1360
Ohio		
Gallia	1	1420
Tuscarawas	2	1410
Jefferson	1	1400
Pennsylvania		
Armstrong	1	1410
Somerset	2	1410
West Virginia		
Fayette	1	1360
Kanawha	1	1360
Marshall	1	1380
Monongalia	2	1380
Preston	2	1380
Mingo	2	1360

	Water Availability*	Btu/lb Evaporated
Wyoming		
Gillette (Wyodak)	3	1401
Lake de Smet-Banner-Healy	1	1401
Antelope Creek Mine (Verse)	3	1397
Spotted Horse Strip-Felix Bed	3	1401
Jim Bridger Mine	2	1397
Belle Ayr Mine	3	1401
Hanna Coal Field (Rosebud #4,5)	1	1397
Kemmerer	2	1397
Rainbow #8 Mine	1	1397
North Dakota		
Slope (Harmon)	3	1417
Knife River	2	1420
Dickinson	3	1420
Williston	1	1420
Center	3	1420
Bentley	3	1420
Underwood	1	1420
Scranton	3	1417
Montana		
Decker (Dietz)	1	1407
Otter Creek (Knobloch)	3	1407
East Moorhead Coal Field	3	1407
Foster Creek	2	1414
Pumpkin Creek	3	1414
Coalridge	3	1407
U.S. Steel, Chupp Mine	1	1417
Colstrip	2	1414
New Mexico		
El Paso	3	1375
Wesco	3	1375
Gallup	3	1375

*Classification: 1 = water available, 2 = water marginally available, 3 = water expensive to supply.

(continued)

TABLE A7-3. NOMENCLATURE

A	condenser area, ft^2
E_C	cooling tower circulation pump energy, kw
E_D	dry condenser fan energy, kw
E_W	cooling tower fan energy, kw
F	dry condenser fan factor
H	absolute humidity of air, lb water/lb dry air
i	enthalpy of air, Btu/lb dry air
LMTD	log mean temperature difference, °F
P	compression power, kw
Q	condenser cooling load, Btu/kw-hr
Q_D	condenser dry cooling load, Btu/kw-hr
Q_H	turbine heat rate, Btu/kw-hr
Q_W	condenser wet cooling load, Btu/kw-hr
r	compression ratio
R_A	air rate through the tower, lb/hr
R_G	cooling water circulation rate, gpm/kw
R_L	cooling water circulation rate, lb/kw-hr
T_C	steam condensing temperature, °F
t_c	cold circulating water temperature, °F
T_D	air dry bulb temperature, °F
T'_D	air temperature at which dry condenser will carry whole load, °F
t_h	hot circulating water temperature, °F
t_r	temperature at bottom of cooling tower, °F
T_W	air wet bulb temperature, °F
U	heat transfer coefficient, Btu/(hr)(ft^2)(°F)
x	fraction of cooling load carried dry
y	fraction of circulating water that bypasses the cooling tower

<u>Suffixes</u>

c	cold or entry temperature
C	condensing temperature
D	dry
d	design condition
e	exiting, or out
h	hot, or exit temperature
i	entering, or in
o	out, or discharge
W	wet
X	temperature between dry and wet series coolers between compression stages
1,2,3	compressor stages

TABLE A7-4. AVERAGE AMBIENT CONDITIONS

Month	Farmington, N.M.		Casper, Wyo.		Charleston, W.V.		Akron, Ohio	
	DBT*	WBT**	DBT	WBT	DBT	WBT	DBT	WBT
1, January	26	23	24	20	36	33	27	25
2, February	33	28	26	22	38	34	28	26
3, March	42	33	32	27	45	40	37	35
4, April	49	37	41	34	55	49	47	44
5, May	60	45	54	44	64	58	59	54
6, June	70	51	65	51	72	67	68	63
7, July	76	58	71	55	75	69	72	66
8, August	73	57	70	53	74	68	71	65
9, September	64	49	59	46	69	64	65	60
10, October	51	41	47	38	57	52	53	49
11, November	39	32	32	27	46	41	40	38
12, December	27	24	30	25	38	34	30	28
Design	98	65	96	60	87	79	83	76

*DBT = dry bulb temperature (°F).
**WBT = wet bulb temperature (°F).

TABLE A7-5. HEAT TRANSFER COEFFICIENTS, FAN AND PUMP ENERGIES

	$U[Btu/(hr)(ft^2)(°F)]$	
	Dry	Wet
Condensing steam from turbine drives:	120	170

	Dry		Wet	
	Air	Hydrogen	Air	Hydrogen
Cooling a compressed gas:				
10 psig	10	30	12	35
50 psig	20	45	20	75
100 psig	30	65	40	100
300 psig	40	85	60	135
$\geq$ 500 psig	50	95	70	150

Dry cooler fans: kw = 0.0112 x area ($U \leq 50$)

= 0.0130 x area ($50 \geq U > 100$)

= 0.0149 x area ($U \geq 100$)

Cooling tower fans: kw = 0.0089 x gpm circulated

Circulating water pumps: kw = 0.0246 x gpm circulated

TABLE A7-6. UNIT COSTS

	Cost	Pressure (p,psig)	Annual Charges for Amortization Plus Maintenance
Condensers and heat exchanger:			
Dry cooling	$22/ft^{2}$*	--	17%/yr
Wet cooling	$11.0/ft^{2}$	$p < 300$	20%/yr
	$12.1/ft^{2}$	$300 \leq p < 450$	
	$13.2/ft^{2}$	$450 \leq p < 600$	
	$19.2/ft^{2}$	$p \geq 600$	
Other:			
Cooling tower	$20/gpm circulated		15%/yr
Electrical energy	2¢/kw-hr		
Steam	$1.80/$10^{6}$ Btu		

*Based on bare tube area of finned tubes.

TABLE A7-7. CALCULATIONS ON STEAM TURBINE CONDENSERS AT FARMINGTON, NEW MEXICO

Design Conditions: Fraction designed dry 0.

Dry condenser area 0 ft^2/kw, wet condenser area 2.0069 ft^2/kw.

Cooling tower information: characteristic, KaY/L = 1.24, water/gas rates 2.12,
circulation rate 348 lb/kw-hr, 0.696 gpm/kw.

Month	1	2	3	4	5	6	7	8	9	10	11	12
Condenser temperature (°F)	115	115	117	119	124	126	131	129	125	120	116	115
Turbine heat rate (Btu/kw-hr)	11,700	11,700	11,753	11,806	11,938	11,990	12,122	12,069	11,964	11,832	11,727	11,700
Total condenser load (Btu/kw-hr)	8,200	8,200	8,253	8,306	8,437	8,490	8,622	8,569	8,464	8,332	8,227	8,200
Dry condenser load (Btu/kw-hr)	0	0	0	0	0	0	0	0	0	0	0	0
Wet condenser load (Btu/kw-hr)	8,200	8,200	8,253	8,306	8,437	8,490	8,622	8,569	8,464	8,332	8,227	8,200
Hot water temperature (°F)	101	101	103	105	109	111	116	114	110	106	102	101
Cold water temperature (°F)	77	77	79	81	85	87	91	90	86	82	78	77
Tower bottom temperature (°F)	60	65	79	81	85	87	91	90	86	82	78	61
Fraction circulating water that bypasses tower	0.41	0.33	0	0	0	0	0	0	0	0	0	0.40
Dry fan power (10^{-3} $\frac{kw\text{-}hr}{kw\text{-}hr}$)	0	0	0	0	0	0	0	0	0	0	0	0
Coolg tower fan pwr (10^{-3} $\frac{kw\text{-}hr}{kw\text{-}hr}$)	3.65	5.39	6.19	6.19	6.19	6.19	6.19	6.19	6.19	6.19	6.19	3.72
Circulating pump pwr (10^{-3} $\frac{kw\text{-}hr}{kw\text{-}hr}$)	17.1	17.1	17.1	17.1	17.1	17.1	17.1	17.1	17.1	17.1	17.1	17.1
Water evaporated (lb/kw-hr)	5.52	5.57	5.41	5.67	6.06	6.45	6.69	6.601	6.23	5.78	5.36	5.36

(continued)

TABLE A7-7 (continued)

Design Conditions: Fraction designed dry 0.25.

Dry condenser area 0.7689 ft^2/kw, wet condenser area 1.5051 ft^2/kw.

Cooling tower information: characteristic, KaY/L = 1.24, water/gas rates 2.12, circulation rate 261 lb/kw-hr, 0.522 gpm/kw.

Month	1	2	3	4	5	6	7	8	9	10	11	12
Condenser temperature (°F)	115	115	115	115	115	119	123	122	115	115	115	115
Turbine heat rate (Btu/kw-hr)	11,700	11,700	11,700	11,700	11,700	11,806	11,911	11,885	11,700	11,700	11,700	11,700
Total condenser load (Btu/kw-hr)	8,200	8,200	8,200	8,200	8,200	8,306	8,411	8,385	8,200	8,200	8,200	8,200
Dry condenser load (Btu/kw-hr)	5,377	4,954	4,410	3,987	3,322	2,960	2,839	2,960	3,081	3,867	4,592	5,316
Wet condenser load (Btu/kw-hr)	2,823	3,246	3,790	4,213	4,877	5,346	5,572	5,425	5,119	4,334	3,609	2,884
Hot water temperature (°F)	109	108	106	105	104	107	110	109	103	105	107	108
Cold water temperature (°F)	98	95	92	89	85	86	89	89	84	88	93	97
Tower bottom temperature (°F)	60	65	70	84	83	86	89	89	83	82	69	61
Fraction circulating water that bypasses tower	0.78	0.70	0.33	0.24	0.10	0	0	0	0.05	0.26	0.75	0.77
Dry fan power $(10^{-3} \frac{kw-hr}{kw-hr})$	11.5	11.5	11.5	11.5	11.5	11.5	11.5	11.5	11.5	11.5	11.5	11.5
Coolg tower fan pwr $(10^{-3} \frac{kw-hr}{kw-hr})$	1.02	1.39	3.11	3.53	4.18	4.64	4.64	4.64	4.41	3.44	1.16	1.06
Circulating pump pwr $(10^{-3} \frac{kw-hr}{kw-hr})$	12.8	12.8	12.8	12.8	12.8	12.8	12.8	12.8	12.8	12.8	12.8	12.8
Water evaporated (lb/kw-hr)	1.96	2.23	2.45	2.84	3.46	4.36	4.70	4.16	3.70	2.94	2.61	2.01

(continued)

TABLE A7-7 (continued)

Design Conditions: Fraction designed dry 0.50.

Dry condenser area 1.5378 ft^2/kw, wet condenser area 1.0035 ft^2/kw.

Cooling tower information: characteristic, KaY/L = 1.24, water/gas rates 2.12, circulation rate 174 lb/kw-hr, 0.348 gpm/kw.

Month	1	2	3	4	5	6	7	8	9	10	11	12
Condenser temperature (°F)	115	115	115	115	115	115	117	115	115	115	115	115
Turbine heat rate (Btu/kw-hr)	11,700	11,700	11,700	11,700	11,700	11,700	11,753	11,700	11,700	11,700	11,700	11,700
Total condenser load (Btu/kw-hr)	8,200	8,200	8,200	8,200	8,200	8,200	8,253	8,200	8,200	8,200	8,200	8,200
Dry condenser load (Btu/kw-hr)	8,200	8,200	8,200	7,975	6,646	5,438	4,954	5,075	6,163	7,734	8,200	8,200
Wet condenser load (Btu/kw-hr)	0	0	0	224	1,554	2,762	3,299	3,125	2,037	466	0	0
Hot water temperature (°F)	--	--	--	114	110	105	106	104	108	113	--	--
Cold water temperature (°F)	--	--	--	113	101	90	87	86	96	111	--	--
Tower bottom temperature (°F)	--	--	--	92	88	85	87	85	86	88	--	--
Fraction circulating water that bypasses tower	1.0	1.0	1.0	0.95	0.59	0.75	0	0.05	0.45	0.92	1.0	1.0
Dry fan power (10^{-3} $\frac{kw\text{-}hr}{kw\text{-}hr}$)	5.25	7.79	14.77	22.9	22.9	22.9	22.9	22.9	22.9	22.9	11.57	4.81
Coolg tower fan pwr (10^{-3} $\frac{kw\text{-}hr}{kw\text{-}hr}$)	0	0	0	0.15	1.27	0.77	3.10	2.94	1.70	0.25	0	0
Circulating pump pwr (10^{-3} $\frac{kw\text{-}hr}{kw\text{-}hr}$)	0	0	0	8.56	8.56	8.56	8.56	8.56	8.56	8.56	0	0
Water evaporated (lb/kw-hr)	0	0	0	0.16	1.06	2.18	2.56	2.45	1.49	0.24	0	0

(continued)

TABLE A7-7 (continued)

Design Conditions: Fraction designed dry 0.75.

Dry condenser area 2.3069 ft^2/kw, wet condenser area 0.5017 ft^2/kw.

Cooling tower information: characteristic, KaY/L = 1.24, water/gas rates 2.12, circulation rate 87 lb/kw-hr, 0.174 gpm/kw.

Month	1	2	3	4	5	6	7	8	9	10	11	12
Condenser temperature (°F)	115	115	115	115	115	115	115	115	115	115	115	115
Turbine heat rate (Btu/kw-hr)	11,700	11,700	11,700	11,700	11,700	11,700	11,700	11,700	11,700	11,700	11,700	11,700
Total condenser load (Btu/kw-hr)	8,200	8,200	8,200	8,200	8,200	8,200	8,200	8,200	8,200	8,200	8,200	8,200
Dry condenser load (Btu/kw-hr)	8,200	8,200	8,200	8,200	8,200	8,157	7,069	7,613	8,200	8,200	8,200	8,200
Wet condenser load (Btu/kw-hr)	0	0	0	0	0	43	1,131	587	0	0	0	0
Hot water temperature (°F)	--	--	--	--	--	115	107	111	--	--	--	--
Cold water temperature (°F)	--	--	--	--	--	114	94	104	--	--	--	--
Tower bottom temperature (°F)	--	--	--	--	--	88	92	89	--	--	--	--
Fraction circulating water that bypasses tower	1.0	1.0	1.0	1.0	1.0	0.96	0.13	0.68	1.0	1.0	1.0	1.0
Dry fan power (10^{-3} $\frac{kw\text{-}hr}{kw\text{-}hr}$)	4.50	4.98	6.19	7.97	15.5	34.4	34.4	34.4	21.21	8.83	4.85	4.54
Coolg tower fan pwr (10^{-3} $\frac{kw\text{-}hr}{kw\text{-}hr}$)	0	0	0	0	0	0.06	1.35	0.49	0	0	0	0
Circulating pump pwr (10^{-3} $\frac{kw\text{-}hr}{kw\text{-}hr}$)	0	0	0	0	0	4.28	4.28	4.28	0	0	0	0
Water evaporated (lb/kw-hr)	0	0	0	0	0	0.035	0.93	0.453	0	0	0	0

(continued)

TABLE 7-7 (continued)

Design Conditions: Fraction designed dry 0.95.

Dry condenser area 2.922 ft^2/kw, wet condenser area 0.1003 ft^2/kw.

Cooling tower information: characteristic, KaY/L = 1.24, water/gas rates 2.12, circulation rate 17.4 lb/kw-hr, 0.0348 gpm/kw.

Month	1	2	3	4	5	6	7	8	9	10	11	12
Condenser temperature (°F)	115	115	115	115	115	115	115	115	115	115	115	115
Turbine heat rate (Btu/kw-hr)	11,700	11,700	11,700	11,700	11,700	11,700	11,700	11,700	11,700	11,700	11,700	11,700
Total condenser load (Btu/kw-hr)	8,200	8,200	8,200	8,200	8,200	8,200	8,200	8,200	8,200	8,200	8,200	8,200
Dry condenser load (Btu/kw-hr)	8,200	8,200	8,200	8,200	8,200	8,200	8,200	8,200	8,200	8,200	8,200	8,200
Wet condenser load (Btu/kw-hr)	0	0	0	0	0	0	0	0	0	0	0	0
Hot water temperature (°F)	--	--	--	--	--	--	--	--	--	--	--	--
Cold water temperature (°F)	--	--	--	--	--	--	--	--	--	--	--	--
Tower bottom temperature (°F)	--	--	--	--	--	--	--	--	--	--	--	--
Fraction circulating water that bypasses tower	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Dry fan power (10^{-3} $\frac{\text{kw-hr}}{\text{kw-hr}}$)	5.22	5.70	6.26	7.27	10.8	20.2	33.18	25.69	13.63	7.71	6.05	5.27
Coolg tower fan pwr (10^{-3} $\frac{\text{kw-hr}}{\text{kw-hr}}$)	0	0	0	0	0	0	0	0	0	0	0	0
Circulating pump pwr (10^{-3} $\frac{\text{kw-hr}}{\text{kw-hr}}$)	0	0	0	0	0	0	0	0	0	0	0	0
Water evaporated (lb/kw-hr)	0	0	0	0	0	0	0	0	0	0	0	0

TABLE A7-8. CALCULATIONS ON STEAM TURBINE CONDENSERS AT CASPER, WYOMING

Design Conditions: Fraction designed dry 0.

Dry condenser area 0 ft^2/kw, wet condenser area 2.0069 ft^2/kw.

Cooling tower information: characteristic, KaY/L = 1.17, water/gas rates 2.24, circulation rate 348 lb/kw-hr, 0.696 gpm/kw.

Month	1	2	3	4	5	6	7	8	9	10	11	12
Condenser temperature (°F)	115	115	116	122	127	130	131	130	129	122	116	115
Turbine heat rate (Btu/kw-hr)	11,700	11,700	11,727	11,885	12,016	12,096	12,122	12,096	12,069	11,885	11,727	11,700
Total condenser load (Btu/kw-hr)	8,200	8,200	8,227	8,385	8,516	8,596	8,622	8,596	8,569	8,385	8,227	8,200
Dry condenser load (Btu/kw-hr)	0	0	0	0	0	0	0	0	0	0	0	0
Wet condenser load (Btu/kw-hr)	8,200	8,200	8,227	8,385	8,516	8,596	8,622	8,596	8,569	8,385	8,227	8,200
Hot water temperature (°F)	101	101	102	108	112	115	116	115	114	108	102	101
Cold water temperature (°F)	77	77	78	83	88	90	91	90	90	83	78	77
Tower bottom temperature (°F)	57	59	78	83	88	90	91	90	90	83	78	62
Fraction circulating water that bypasses tower	0.45	0.43	0	0	0	0	0	0	0	0	0	0.38
Dry fan power ($10^{-3}\ \frac{kw\text{-}hr}{kw\text{-}hr}$)	0	0	0	0	0	0	0	0	0	0	0	0
Coolg tower fan pwr ($10^{-3}\ \frac{kw\text{-}hr}{kw\text{-}hr}$)	3.40	3.53	6.19	6.19	6.19	6.19	6.19	6.19	6.19	6.19	6.19	3.84
Circulating pump pwr ($10^{-3}\ \frac{kw\text{-}hr}{kw\text{-}hr}$)	17.12	17.12	17.12	17.12	17.12	17.12	17.12	17.12	17.12	17.12	17.12	17.12
Water evaporated (lb/kw-hr)	5.54	5.57	5.28	5.47	6.00	6.39	6.56	6.52	6.22	5.78	5.28	5.49

(continued)

TABLE A7-8 (continued)

Design Conditions: Fraction designed dry 0.25.

Dry condenser area 0.728 ft^2/kw, wet condenser area 1.5051 ft^2/kw.

Cooling tower information: characteristic, KaY/L = 1.17, water/gas rates 2.24, circulation rate 261 lb/kw-hr, 0.522 gpm/kw.

Month	1	2	3	4	5	6	7	8	9	10	11	12
Condenser temperature (°F)	115	115	115	115	115	118	122	121	115	115	115	115
Turbine heat rate (Btu/kw-hr)	11,700	11,700	11,700	11,700	11,700	11,780	11,885	11,859	11,700	11,700	11,700	11,700
Total condenser load (Btu/kw-hr)	8,200	8,200	8,200	8,200	8,200	8,279	8,385	8,358	8,200	8,200	8,200	8,200
Dry condenser load (Btu/kw-hr)	5,206	5,091	4,747	4,233	3,203	3,032	2,917	2,917	3,203	3,890	4,748	4,862
Wet condenser load (Btu/kw-hr)	2,995	3,109	3,452	3,967	4,997	5,248	5,468	5,441	4,997	4,311	3,452	3,338
Hot water temperature (°F)	108	108	107	106	104	106	109	108	104	105	107	107
Cold water temperature (°F)	97	96	94	91	84	86	88	88	84	89	94	95
Tower bottom temperature (°F)	57	59	64	71	84	86	88	88	84	84	64	62
Fraction circulating water that bypasses tower	0.78	0.75	0.70	0.57	0	0	0	0	0	0.24	0.70	0.73
Dry fan power (10^{-3} $\frac{kw\text{-}hr}{kw\text{-}hr}$)	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8
Coolg tower fan pwr (10^{-3} $\frac{kw\text{-}hr}{kw\text{-}hr}$)	1.02	1.16	1.39	2.00	4.65	4.65	4.65	4.65	4.65	3.53	1.39	1.25
Circulating pump pwr (10^{-3} $\frac{kw\text{-}hr}{kw\text{-}hr}$)	12.8	12.8	12.8	12.8	12.8	12.8	12.8	12.8	12.8	12.8	12.8	12.8
Water evaporated (lb/kw-hr)	2.07	2.14	2.40	2.71	3.52	3.91	4.20	4.06	3.56	2.91	2.40	2.33

(continued)

TABLE A7-8 (continued)

Design Conditions: Fraction designed dry 0.50.

Dry condenser area 1.4568 ft^2/kw, wet condenser area 1.0035 ft^2/kw.

Cooling tower information: characteristic, KaY/L = 1.17, water/gas rates 2.24, circulation rate 174 lb/kw-hr, 0.348 gpm/kw.

Month	1	2	3	4	5	6	7	8	9	10	11	12
Condenser temperature (°F)	115	115	115	115	115	115	115	115	115	115	115	115
Turbine heat rate (Btu/kw-hr)	11,700	11,700	11,700	11,700	11,700	11,700	11,700	11,700	11,700	11,700	11,700	11,700
Total condenser load (Btu/kw-hr)	8,200	8,200	8,200	8,200	8,200	8,200	8,200	8,200	8,200	8,200	8,200	8,200
Dry condenser load (Btu/kw-hr)	8,200	8,200	8,200	8,200	6,982	5,723	5,036	5,151	6,410	7,784	8,200	8,200
Wet condenser load (Btu/kw-hr)	0	0	0	0	1,218	2,477	3,164	3,049	1,790	416	0	0
Hot water temperature (°F)	--	--	--	--	111	106	104	104	109	114	--	--
Cold water temperature (°F)	--	--	--	--	104	92	86	87	99	111	--	--
Tower bottom temperature (°F)	--	--	--	--	87	86	86	86	87	90	--	--
Fraction circulating water that bypasses tower	1.0	1.0	1.0	1.0	0.71	0.30	0	0.06	0.55	0.91	1.0	1.0
Dry fan power (10^{-3} $\frac{kw\text{-}hr}{kw\text{-}hr}$)	5.42	6.07	8.79	17.97	21.7	21.7	21.7	21.7	21.7	21.7	8.79	7.73
Coolg tower fan pwr (10^{-3} $\frac{kw\text{-}hr}{kw\text{-}hr}$)	0	0	0	0	0.90	2.17	3.10	2.91	1.39	0.29	0	0
Circulating pump pwr (10^{-3} $\frac{kw\text{-}hr}{kw\text{-}hr}$)	0	0	0	0	8.56	8.56	8.56	8.56	8.56	8.56	0	0
Water evaporated (lb/kw-hr)	0	0	0	0	0.87	1.86	2.40	2.36	1.29	0.009	0	0

(continued)

TABLE A7-8 (continued)

Design Conditions: Fraction designed dry 0.75.

Dry condenser area 2.185 ft^2/kw, wet condenser area 0.5017 ft^2/kw.

Cooling tower information: characteristic, KaY/L = 1.17, water/gas rates 2.24, circulation rate 87 lb/kw-hr, 0.174 gpm/kw.

Month	1	2	3	4	5	6	7	8	9	10	11	12
Condenser temperature (°F)	115	115	115	115	115	115	115	115	115	115	115	115
Turbine heat rate (Btu/kw-hr)	11,700	11,700	11,700	11,700	11,700	11,700	11,700	11,700	11,700	11,700	11,700	11,700
Total condenser load (Btu/kw-hr)	8,200	8,200	8,200	8,200	8,200	8,200	8,200	8,200	8,200	8,200	8,200	8,200
Dry condenser load (Btu/kw-hr)	8,200	8,200	8,200	8,200	8,200	8,200	7,554	7,726	8,200	8,200	8,200	8,200
Wet condenser load (Btu/kw-hr)	0	0	0	0	0	0	646	474	0	0	0	0
Hot water temperature (°F)	--	--	--	--	--	--	111	112	--	--	--	--
Cold water temperature (°F)	--	--	--	--	--	--	103	106	--	--	--	--
Tower bottom temperature (°F)	--	--	--	--	--	--	89	89	--	--	--	--
Fraction circulating water that bypasses tower	1.0	1.0	1.0	1.0	1.0	1.0	0.64	0.74	1.0	1.0	1.0	1.0
Dry fan power (10^{-3} $\frac{kw\text{-}hr}{kw\text{-}hr}$)	4.30	4.43	4.85	6.32	11.69	27.05	32.5	32.5	16.38	7.72	4.85	4.66
Coolg tower fan pwr (10^{-3} $\frac{kw\text{-}hr}{kw\text{-}hr}$)	0	0	0	0	0	0	0.56	0.40	0	0	0	0
Circulating pump pwr (10^{-3} $\frac{kw\text{-}hr}{kw\text{-}hr}$)	0	0	0	0	0	0	4.28	4.28	0	0	0	0
Water evaporated (lb/kw-hr)	0	0	0	0	0	0	0.48	0.36	0	0	0	0

(continued)

TABLE A7-8 (continued)

Design Conditions: Fraction designed dry 0.95.

Dry condenser area 2.7680 ft^2/kw, wet condenser area 0.1003 ft^2/kw.

Cooling tower information: characteristic, KaY/L = 1.17, water/gas rates 2.24, circulation rate 17.4 lb/kw-hr, 0.0348 gpm/kw.

Month	1	2	3	4	5	6	7	8	9	10	11	12
Condenser temperature (°F)	115	115	115	115	115	115	115	115	115	115	115	115
Turbine heat rate (Btu/kw-hr)	11,700	11,700	11,700	11,700	11,700	11,700	11,700	11,700	11,700	11,700	11,700	11,700
Total condenser load (Btu/kw-hr)	8,200	8,200	8,200	8,200	8,200	8,200	8,200	8,200	8,200	8,200	8,200	8,200
Dry condenser load (Btu/kw-hr)	8,200	8,200	8,200	8,200	8,200	8,200	8,200	8,200	8,200	8,200	8,200	8,200
Wet condenser load (Btu/kw-hr)	0	0	0	0	0	0	0	0	0	0	0	0
Hot water temperature (°F)	--	--	--	--	--	--	--	--	--	--	--	--
Cold water temperature (°F)	--	--	--	--	--	--	--	--	--	--	--	--
Tower bottom temperature (°F)	--	--	--	--	--	--	--	--	--	--	--	--
Fraction circulating water that bypasses tower	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Dry fan power (10^{-3} $\frac{\text{kw-hr}}{\text{kw-hr}}$)	4.95	4.99	5.32	6.06	8.66	15.71	24.29	22.11	10.81	6.89	5.32	4.65
Coolg tower fan pwr (10^{-3} $\frac{\text{kw-hr}}{\text{kw-hr}}$)	0	0	0	0	0	0	0	0	0	0	0	0
Circulating pump pwr (10^{-3} $\frac{\text{kw-hr}}{\text{kw-hr}}$)	0	0	0	0	0	0	0	0	0	0	0	0
Water evaporated (lb/kw-hr)	0	0	0	0	0	0	0	0	0	0	0	0

TABLE A7-9. CALCULATIONS ON STEAM TURBINE CONDENSERS AT CHARLESTON, WEST VIRGINIA

Design Conditions: Fraction designed dry 0.

Dry condenser area 0 ft^2/kw, wet condenser area 2.0069 ft^2/kw.

Cooling tower information: characteristic, KaY/L = 1.44, water/gas rates 1.45, circulation rate 348 lb/kw-hr, 0.696 gpm/kw.

Month	1	2	3	4	5	6	7	8	9	10	11	12
Condenser temperature (°F)	115	115	115	117	122	126	128	127	125	120	115	115
Turbine heat rate (Btu/kw-hr)	11,700	11,700	11,700	11,753	11,885	11,990	12,042	12,016	11,964	11,832	11,700	11,700
Total condenser load (Btu/kw-hr)	8,200	8,200	8,200	8,253	8,385	8,490	8,542	8,516	8,464	8,332	8,200	8,200
Dry condenser load (Btu/kw-hr)	0	0	0	0	0	0	0	0	0	0	0	0
Wet condenser load (Btu/kw-hr)	8,200	8,200	8,200	8,253	8,385	8,490	8,542	8,516	8,464	8,332	8,200	8,200
Hot water temperature (°F)	101	101	101	103	108	111	113	112	110	106	101	101
Cold water temperature (°F)	77	77	77	79	83	87	89	88	86	82	77	77
Tower bottom temperature (°F)	74	74	76	79	83	87	89	88	86	82	77	74
Fraction circulating water that bypasses tower	0.11	0.11	0.04	0	0	0	0	0	0	0	0	0.11
Dry fan power (10^{-3} $\frac{kw-hr}{kw-hr}$)	0	0	0	0	0	0	0	0	0	0	0	0
Coolg tower fan pwr (10^{-3} $\frac{kw-hr}{kw-hr}$)	5.51	5.51	5.95	6.19	6.19	6.19	6.19	6.19	6.19	6.19	6.19	5.51
Circulating pump pwr (10^{-3} $\frac{kw-hr}{kw-hr}$)	17.12	17.12	17.12	17.12	17.12	17.12	17.12	17.12	17.12	17.12	17.12	17.12
Water evaporated (lb/kw-hr)	5.13	5.17	5.32	5.66	5.98	6.24	6.36	6.02	5.98	5.71	5.33	5.17

(continued)

TABLE A7-9 (continued)

Design Conditions: Fraction designed dry 0.25.

Dry condenser area 0.5889 ft^2/kw, wet condenser area 1.5051 ft^2/kw.

Cooling tower information: characteristic, KaY/L = 1.44, water/gas rates 1.45, circulation rate 261 lb/kw-hr, 0.522 gpm/kw.

Month	1	2	3	4	5	6	7	8	9	10	11	12
Condenser temperature (°F)	115	115	115	115	118	124	126	125	122	115	115	115
Turbine heat rate (Btu/kw-hr)	11,700	11,700	11,700	11,700	11,780	11,938	11,990	11,964	11,885	11,700	11,700	11,700
Total condenser load (Btu/kw-hr)	8,200	8,200	8,200	8,200	8,279	8,437	8,490	8,464	8,385	8,200	8,200	8,200
Dry condenser load (Btu/kw-hr)	3,655	3,563	3,239	2,776	2,498	2,406	2,360	2,360	2,453	2,683	3,193	3,563
Wet condenser load (Btu/kw-hr)	4,545	4,637	4,961	5,424	5,781	6,031	6,130	6,104	5,932	5,517	5,007	4,637
Hot water temperature (°F)	105	104	103	103	105	110	112	111	108	102	103	104
Cold water temperature (°F)	87	87	85	82	83	87	88	88	86	81	84	87
Tower bottom temperature (°F)	77	76	77	79	83	87	88	88	86	79	78	76
Fraction circulating water that bypasses tower	0.36	0.39	0.46	0.13	0	0	0	0	0	0.09	0.24	0.39
Dry fan power $(10^{-3} \frac{kw\text{-}hr}{kw\text{-}hr})$	8.77	8.77	8.77	8.77	8.77	8.77	8.77	8.77	8.77	8.77	8.77	8.77
Coolg tower fan pwr $(10^{-3} \frac{kw\text{-}hr}{kw\text{-}hr})$	2.97	2.83	2.51	4.04	4.65	4.65	4.65	4.65	4.65	4.23	3.53	2.83
Circulating pump pwr $(10^{-3} \frac{kw\text{-}hr}{kw\text{-}hr})$	12.8	12.8	12.8	12.8	12.8	12.8	12.8	12.8	12.8	12.8	12.8	12.8
Water evaporated (lb/kw-hr)	2.87	2.98	3.31	3.77	4.12	4.45	4.50	4.47	4.30	3.75	3.28	2.98

(continued)

TABLE A7-9 (continued)

Design Conditions: Fraction designed dry 0.50.

Dry condenser area 1.177 ft^2/kw, wet condenser area 1.0035 ft^2/kw.

Cooling tower information: characteristic, KaY/L = 1.44, water/gas rates 1.45, circulation rate 174 lb/kw-hr, 0.348 gpm/kw.

Month	1	2	3	4	5	6	7	8	9	10	11	12
Condenser temperature (°F)	115	115	115	115	115	122	124	123	119	115	115	115
Turbine heat rate (Btu/kw-hr)	11,700	11,700	11,700	11,700	11,700	11,885	11,938	11,911	11,806	11,700	11,700	11,700
Total condenser load (Btu/kw-hr)	8,200	8,200	8,200	8,200	8,200	8,385	8,437	8,411	8,306	8,200	8,200	8,200
Dry condenser load (Btu/kw-hr)	7,306	7,121	6,474	5,549	4,716	4,624	4,532	4,532	4,624	5,364	6,381	7,121
Wet condenser load (Btu/kw-hr)	894	1,079	1,726	2,651	3,484	3,761	3,905	3,879	3,682	2,836	1,819	1,079
Hot water temperature (°F)	112	111	109	106	103	109	111	110	106	105	109	111
Cold water temperature (°F)	107	105	99	91	83	87	88	87	85	89	98	105
Tower bottom temperature (°F)	79	80	80	80	82	87	88	87	85	81	80	80
Fraction circulating water that bypasses tower	0.85	0.81	0.65	0.42	0.05	0	0	0	0	0.33	0.62	0.81
Dry fan power (10^{-3} $\frac{kw\text{-}hr}{kw\text{-}hr}$)	17.54	17.54	17.54	17.54	17.54	17.54	17.54	17.54	17.54	17.54	17.54	17.54
Coolg tower fan pwr (10^{-3} $\frac{kw\text{-}hr}{kw\text{-}hr}$)	0.46	0.59	1.08	1.80	2.94	3.10	3.10	3.10	3.10	2.08	1.18	0.59
Circulating pump pwr (10^{-3} $\frac{kw\text{-}hr}{kw\text{-}hr}$)	8.56	8.56	8.56	8.56	8.56	8.56	8.56	8.56	8.56	8.56	8.56	8.56
Water evaporated (lb/kw-hr)	0.57	0.70	1.22	1.84	2.52	2.76	2.76	2.76	2.69	1.97	1.20	0.70

(continued)

TABLE A7-9 (continued)

Design Conditions: Fraction designed dry 0.75.

Dry condenser area 1.7668 ft^2/kw, wet condenser area 0.5017 ft^2/kw.

Cooling tower information: characteristic, KaY/L = 1.44, water/gas rates 1.45, circulation rate 87 lb/kw-hr, 0.174 gpm/kw.

Month	1	2	3	4	5	6	7	8	9	10	11	12
Condenser temperature (°F)	115	115	115	115	115	118	122	121	116	115	115	115
Turbine heat rate (Btu/kw-hr)	11,700	11,700	11,700	11,700	11,700	11,780	11,885	11,859	11,727	11,700	11,700	11,700
Total condenser load (Btu/kw-hr)	8,200	8,200	8,200	8,200	8,200	8,306	8,385	8,358	8,227	8,200	8,200	8,200
Dry condenser load (Btu/kw-hr)	8,200	8,200	8,200	8,200	7,080	6,525	6,525	6,525	6,525	8,052	8,200	8,200
Wet condenser load (Btu/kw-hr)	0	0	0	0	1,120	1,781	1,860	1,833	1,702	148	0	0
Hot water temperature (°F)	--	--	--	--	107	107	109	108	104	114	--	--
Cold water temperature (°F)	--	--	--	--	94	86	88	87	85	112	--	--
Tower bottom temperature (°F)	--	--	--	--	83	86	88	87	85	84	--	--
Fraction circulating water that bypasses tower	1.0	1.0	1.0	1.0	0.46	0	0	0	0	0.93	1.0	1.0
Dry fan power $(10^{-3}\ \frac{\text{kw-hr}}{\text{kw-hr}})$	6.66	7.11	10.79	24.48	26.33	26.33	26.33	26.33	26.33	26.33	11.58	7.11
Coolg tower fan pwr $(10^{-3}\ \frac{\text{kw-hr}}{\text{kw-hr}})$	0	0	0	0	0.84	1.55	1.55	1.55	1.55	0.11	0	0
Circulating pump pwr $(10^{-3}\ \frac{\text{kw-hr}}{\text{kw-hr}})$	0	0	0	0	4.28	4.28	4.28	4.28	4.28	4.28	0	0
Water evaporated (lb/kw-hr)	0	0	0	0	0.77	1.30	1.38	1.36	1.24	0.13	0	0

(continued)

TABLE A7-9 (continued)

<u>Design Conditions</u>: Fraction designed dry 0.95.

Dry condenser area 2.238 ft^2/kw, wet condenser area 0.1003 ft^2/kw.

Cooling tower information: characteristic, KaY/L = 1.44, water/gas rates 1.45, circulation rate 17.4 lb/kw-hr, 0.0348 gpm/kw.

Month	1	2	3	4	5	6	7	8	9	10	11	12
Condenser temperature (°F)	115	115	115	115	115	117	121	120	115	115	115	115
Turbine heat rate (Btu/kw-hr)	11,700	11,700	11,700	11,700	11,700	11,753	11,859	11,832	11,700	11,700	11,700	11,700
Total condenser load (Btu/kw-hr)	8,200	8,200	8,200	8,200	8,200	8,253	8,358	8,332	8,200	8,200	8,200	8,200
Dry condenser load (Btu/kw-hr)	8,200	8,200	8,200	8,200	8,200	7,913	8,089	8,089	8,089	8,200	8,200	8,200
Wet condenser load (Btu/kw-hr)	0	0	0	0	0	340	269	243	111	0	0	0
Hot water temperature (°F)	--	--	--	--	--	105	112	112	111	--	--	--
Cold water temperature (°F)	--	--	--	--	--	86	96	98	105	--	--	--
Tower bottom temperature (°F)	--	--	--	--	--	86	96	98	87	--	--	--
Fraction circulating water that bypasses tower	1.0	1.0	1.0	1.0	1.0	0	0	0	0.75	1.0	1.0	1.0
Dry fan power (10^{-3} $\frac{\text{kw-hr}}{\text{kw-hr}}$)	5.33	5.67	7.00	12.17	24.01	33.3	33.3	33.3	33.3	13.67	7.34	5.67
Coolg tower fan pwr (10^{-3} $\frac{\text{kw-hr}}{\text{kw-hr}}$)	0	0	0	0	0	0.31	0.31	0.31	0.07	0	0	0
Circulating pump pwr (10^{-3} $\frac{\text{kw-hr}}{\text{kw-hr}}$)	0	0	0	0	0	0.86	0.86	0.86	0.86	0	0	0
Water evaporated (lb/kw-hr)	0	0	0	0	0	0.34	0.20	0.18	0.08	0	0	0

TABLE A7-10. CALCULATIONS ON STEAM TURBINE CONDENSERS AT AKRON, OHIO

Design Conditions: Fraction designed dry 0.

Dry condenser area 0 ft^2/kw, wet condenser area 2.0069 ft^2/kw.

Cooling tower information: characteristic, KaY/L = 1.45, water/gas rates 1.41, circulation rate 348 lb/kw-hr, 0.696 gpm/kw.

Month	1	2	3	4	5	6	7	8	9	10	11	12
Condenser temperature (°F)	115	115	115	115	119	124	126	125	122	117	115	115
Turbine heat rate (Btu/kw-hr)	11,700	11,700	11,700	11,700	11,806	11,938	11,990	11,964	11,885	11,753	11,700	11,700
Total condenser load (Btu/kw-hr)	8,200	8,200	8,200	8,200	8,306	8,437	8,490	8,464	8,385	8,253	8,200	8,200
Dry condenser load (Btu/kw-hr)	0	0	0	0	0	0	0	0	0	0	0	0
Wet condenser load (Btu/kw-hr)	8,200	8,200	8,200	8,200	8,306	8,437	8,490	8,464	8,385	8,253	8,200	8,200
Hot water temperature (°F)	101	101	101	101	105	109	111	110	108	103	101	101
Cold water temperature (°F)	77	77	77	77	81	85	87	86	83	79	77	77
Tower bottom temperature (°F)	62	63	75	77	81	85	87	86	83	79	74	65
Fraction circulating water that bypasses tower	0.38	0.37	0.08	0	0	0	0	0	0	0	0.11	0.33
Dry fan power (10^{-3} $\frac{kw\text{-}hr}{kw\text{-}hr}$)	0	0	0	0	0	0	0	0	0	0	0	0
Coolg tower fan pwr (10^{-3} $\frac{kw\text{-}hr}{kw\text{-}hr}$)	3.84	3.90	5.69	6.19	6.19	6.19	6.19	6.19	6.19	6.19	5.51	4.15
Circulating pump pwr (10^{-3} $\frac{kw\text{-}hr}{kw\text{-}hr}$)	17.12	17.12	17.12	17.12	17.12	17.12	17.12	17.12	17.12	17.12	17.12	17.12
Water evaporated (lb/kw-hr)	5.12	5.09	5.12	5.33	5.81	5.81	6.00	6.09	5.93	5.57	5.19	5.08

(continued)

TABLE A7-10 (continued)

Design Conditions: Fraction designed dry 0.25.

Dry condenser area 0.543 ft^2/kw, wet condenser area 1.5051 ft^2/kw.

Cooling tower information: characteristic, KaY/L = 1.45, water/gas rates 1.41, circulation rate 261 lb/kw-hr, 0.522 gpm/kw.

Month	1	2	3	4	5	6	7	8	9	10	11	12
Condenser temperature (°F)	115	115	115	115	115	122	125	124	120	115	115	115
Turbine heat rate (Btu/kw-hr)	11,700	11,700	11,700	11,700	11,700	11,885	11,964	11,938	11,832	11,700	11,700	11,700
Total condenser load (Btu/kw-hr)	8,200	8,200	8,200	8,200	8,200	8,385	8,464	8,437	8,332	8,200	8,200	8,200
Dry condenser load (Btu/kw-hr)	3,754	3,712	3,328	2,901	2,389	2,304	2,261	2,261	2,346	2,645	3,200	3,626
Wet condenser load (Btu/kw-hr)	4,446	4,488	4,873	5,299	5,811	6,080	6,203	6,176	5,985	5,555	5,001	4,574
Hot water temperature (°F)	105	105	104	103	102	108	111	110	106	102	103	104
Cold water temperature (°F)	88	87	85	83	79	85	87	86	83	81	84	87
Tower bottom temperature (°F)	62	63	76	77	79	85	87	86	83	78	75	65
Fraction circulating water that bypasses tower	0.60	0.57	0.39	0.23	0	0	0	0	0	0.13	0.32	0.56
Dry fan power (10^{-3} $\frac{\text{kw-hr}}{\text{kw-hr}}$)	8.09	8.09	8.09	8.09	8.09	8.09	8.09	8.09	8.09	8.09	8.09	8.09
Coolg tower fan pwr (10^{-3} $\frac{\text{kw-hr}}{\text{kw-hr}}$)	1.86	2.00	2.84	3.58	4.65	4.65	4.65	4.65	4.65	4.05	3.16	2.05
Circulating pump pwr (10^{-3} $\frac{\text{kw-hr}}{\text{kw-hr}}$)	12.8	12.8	12.8	12.8	12.8	12.8	12.8	12.8	12.8	12.8	12.8	12.8
Water evaporated (lb/kw-hr)	2.83	2.03	3.10	3.71	4.14	4.39	4.52	4.50	4.21	4.90	3.18	2.31

(continued)

TABLE A7-10 (continued)

Design Conditions: Fraction designed dry 0.50.

Dry condenser area 1.0855 ft^2/kw, wet condenser area 1.0035 ft^2/kw.

Cooling tower information: characteristic, KaY/L = 1.45, water/gas rates 1.41, circulation rate 174 lb/kw-hr, 0.348 gpm/kw.

Month	1	2	3	4	5	6	7	8	9	10	11	12
Condenser temperature (°F)	115	115	115	115	115	120	124	123	118	115	115	115
Turbine heat rate (Btu/kw-hr)	11,700	11,700	11,700	11,700	11,700	11,832	11,938	11,911	11,780	11,700	11,700	11,700
Total condenser load (Btu/kw-hr)	8,200	8,200	8,200	8,200	8,200	8,332	8,437	8,411	8,279	8,200	8,200	8,200
Dry condenser load (Btu/kw-hr)	7,506	7,420	6,653	5,800	4,776	4,435	4,435	4,435	4,520	5,288	6,397	7,250
Wet condenser load (Btu/kw-hr)	694	779	1,547	2,400	3,424	3,897	4,002	3,976	3,759	2,912	1,803	950
Hot water temperature (°F)	113	112	110	107	103	107	110	109	105	105	109	112
Cold water temperature (°F)	109	108	101	93	84	84	87	86	83	88	99	107
Tower bottom temperature (°F)	62	63	78	79	81	84	87	86	83	80	78	65
Fraction circulating water that bypasses tower	0.92	0.92	0.72	0.50	0.14	0	0	0	0	0.32	0.68	0.89
Dry fan power (10^{-3} $\frac{kw-hr}{kw-hr}$)	16.17	16.17	16.17	16.17	16.17	16.17	16.17	16.17	16.17	16.17	16.17	16.17
Coolg tower fan pwr (10^{-3} $\frac{kw-hr}{kw-hr}$)	0.25	0.25	0.87	1.55	2.67	3.10	3.10	3.10	3.10	2.11	0.99	0.34
Circulating pump pwr (10^{-3} $\frac{kw-hr}{kw-hr}$)	8.56	8.56	8.56	8.56	8.56	8.56	8.56	8.56	8.56	8.56	8.56	8.56
Water evaporated (lb/kw-hr)	0.45	0.46	0.98	1.55	2.39	2.81	2.92	2.88	2.68	2.00	1.16	0.63

(continued)

TABLE A7-10 (continued)

Design Conditions: Fraction designed dry 0.75.

Dry condenser area 1,628 ft^2/kw, wet condenser area 0.5017 ft^2/kw.

Cooling tower information: characteristic, KaY/L = 1.45, water/gas rates 1.41, circulation rate 87 lb/kw-hr, 0.174 gpm/kw.

Month	1	2	3	4	5	6	7	8	9	10	11	12
Condenser temperature (°F)	115	115	115	115	115	118	122	121	115	115	115	115
Turbine heat rate (Btu/kw-hr)	11,700	11,700	11,700	11,700	11,700	11,780	11,885	11,859	11,700	11,700	11,700	11,700
Total condenser load (Btu/kw-hr)	8,200	8,200	8,200	8,200	8,200	8,279	8,385	8,358	8,200	8,200	8,200	8,200
Dry condenser load (Btu/kw-hr)	8,200	8,200	8,200	8,200	7,163	6,396	6,396	6,396	6,396	7,931	8,200	8,200
Wet condenser load (Btu/kw-hr)	0	0	0	0	1,037	1,883	1,989	1,962	1,804	270	0	0
Hot water temperature (°F)	--	--	--	--	108	105	108	107	103	113	--	--
Cold water temperature (°F)	--	--	--	--	96	83	85	85	82	110	--	--
Tower bottom temperature (°F)	--	--	--	--	82	83	85	85	82	82	--	--
Fraction circulating water that bypasses tower	1.0	1.0	1.0	1.0	0.54	0	0	0	0	0.90	1.0	1.0
Dry fan power $(10^{-3} \frac{kw-hr}{kw-hr})$	4.90	5.12	8.25	17.39	24.3	24.3	24.3	24.3	24.3	24.3	9.95	5.60
Coolg tower fan pwr $(10^{-3} \frac{kw-hr}{kw-hr})$	0	0	0	0	0.71	1.55	1.55	1.55	1.55	0.16	0	0
Circulating pump pwr $(10^{-3} \frac{kw-hr}{kw-hr})$	0	0	0	0	4.28	4.28	4.28	4.28	4.28	4.28	0	0
Water evaporated (lb/kw-hr)	0	0	0	0	0.76	1.36	1.45	1.42	1.29	0.19	0	0

(continued)

TABLE A7-10 (continued)

Design Conditions: Fraction designed dry 0.95.

Dry condenser area 2.062 ft^2/kw, wet condenser area 0.1003 ft^2/kw.

Cooling tower information: characteristic, KaY/L = 1.45, water/gas rates 1.41, circulation rate 17.4 lb/kw-hr, 0.0348 gpm/kw.

Month	1	2	3	4	5	6	7	8	9	10	11	12
Condenser temperature (°F)	115	115	115	115	115	117	122	121	115	115	115	115
Turbine heat rate (Btu/kw-hr)	11,700	11,700	11,700	11,700	11,700	11,753	11,885	11,859	11,700	11,700	11,700	11,700
Total condenser load (Btu/kw-hr)	8,200	8,200	8,200	8,200	8,200	8,277	8,385	8,358	8,200	8,200	8,200	8,200
Dry condenser load (Btu/kw-hr)	8,200	8,200	8,200	8,200	8,200	7,939	8,101	8,101	8,101	8,200	8,200	8,200
Wet condenser load (Btu/kw-hr)	0	0	0	0	0	338	284	257	99	0	0	0
Hot water temperature (°F)	--	--	--	--	--	106	112	112	112	--	--	--
Cold water temperature (°F)	--	--	--	--	--	88	96	97	106	--	--	--
Tower bottom temperature (°F)	--	--	--	--	--	88	96	97	85	--	--	--
Fraction circulating water that bypasses tower	1.0	1.0	1.0	1.0	1.0	0	0	0	0.78	1.0	1.0	1.0
Dry fan power (10^{-3} $\frac{kw-hr}{kw-hr}$)	4.45	4.52	5.62	8.66	20.03	30.7	30.7	30.7	6.75	12.60	6.27	4.67
Coolg tower fan pwr (10^{-3} $\frac{kw-hr}{kw-hr}$)	0	0	0	0	0	0.31	0.31	0.31	0.07	0	0	0
Circulating pump pwr (10^{-3} $\frac{kw-hr}{kw-hr}$)	0	0	0	0	0	0.86	0.86	0.86	0.86	0	0	0
Water evaporated (lb/kw-hr)	0	0	0	0	0	0.23	0.21	0.19	0.07	0	0	0

TABLE A7-11. SUMMARY OF WET/DRY CONDENSER COOLING CALCULATIONS

Farmington, New Mexico

Fraction designed dry	0.95	0.75	0.50	0.25	0
Dry condenser area ft^2/kw	2.92	2.31	1.54	0.77	0
Wet condenser area ft^2/kw	0.100	0.50	1.00	1.51	2.01
Circulation rate gpm/kw	0.0348	0.174	0.348	0.52	0.696
Avg fuel penalty Btu/kw-hr	0	0	4.417	41.833	158.42
Avg fan & pump energy kw-hr/kw-hr	0.012	0.016	0.023	0.027	0.023
Avg water consumption gal/kw-hr	0*	0.014	0.101	0.374	0.707

Casper, Wyoming

Fraction designed dry	0.95	0.75	0.50	0.25	0
Dry condenser area ft^2/kw	2.77	2.19	1.46	0.728	0
Wet condenser area ft^2/kw	0.100	0.50	1.00	1.51	2.01
Circulation rate gpm/kw	0.0348	0.174	0.348	0.522	0.696
Avg fuel penalty Btu/kw-hr	0	0	0	35.33	193.58
Avg fan & pump energy kw-hr/kw-hr	0.010	0.014	0.021	0.027	0.023
Avg water consumption gal/kw-hr	0*	0.008	0.088	0.362	0.701

Charleston, West Virginia

Fraction designed dry	0.95	0.75	0.50	0.25	0
Dry condenser area ft^2/kw	2.24	1.77	1.18	0.59	0
Wet condenser area ft^2/kw	0.10	0.50	1.00	1.51	2.01
Circulation rate gpm/kw	0.0348	0.174	0.348	0.522	0.696
Avg fuel penalty Btu/kw-hr	28.58	37.58	61.67	88.08	131.83
Avg fan & pump energy kw-hr/kw-hr	0.018	0.022	0.028	0.025	0.023
Avg water consumption gal/kw-hr	0.008	0.062	0.215	0.448	0.681

Akron, Ohio

Fraction designed dry	0.95	0.75	0.50	0.25	0
Dry condenser area ft^2/kw	2.06	1.63	1.09	0.54	0
Wet condenser area ft^2/kw	0.10	0.50	1.00	1.51	2.01
Circulation rate gpm/kw	0.0348	0.174	0.348	0.522	0.696
Avg fuel penalty Btu/kw-hr	33.08	35.33	55.08	68.25	94.67
Avg fan & pump energy kw-hr/kw-hr	0.014	0.019	0.027	0.024	0.023
Avg water consumption gal/kw-hr	0.007	0.065	0.209	0.438	0.66

*Less than 0.001.

TABLE A7-12. ANNUAL AVERAGE COSTS FOR WET/DRY CONDENSER COOLING

Farmington, New Mexico

Fraction designed dry	0.95	0.75	0.50	0.25	0
Dry condenser cost ¢/kw-hr	0.156	0.123	0.082	0.041	0
Wet condenser cost ¢/kw-hr	0.0031	0.016	0.031	0.047	0.063
Electric energy ¢/kw-hr	0.024	0.032	0.046	0.054	0.046
Fuel penalty ¢/kw-hr	0	0	0.0008	0.0075	0.0285
Cooling tower ¢/kw-hr	0.0015	0.0075	0.015	0.022	0.030
Total ¢/kw-hr	0.185	0.179	0.175	0.172	0.167
Avg water consumption gal/kw-hr	0	0.014	0.101	0.374	0.707

Casper, Wyoming

Fraction designed dry	0.95	0.75	0.50	0.25	0
Dry condenser cost ¢/kw-hr	0.148	0.117	0.078	0.039	0
Wet condenser cost ¢/kw-hr	0.0031	0.016	0.031	0.047	0.063
Electric energy ¢/kw-hr	0.020	0.028	0.042	0.054	0.046
Fuel penalty ¢/kw-hr	0	0	0	0.0064	0.035
Cooling tower ¢/kw-hr	0.0015	0.0075	0.015	0.022	0.030
Total ¢/kw-h	0.173	0.168	0.166	0.169	0.174
Avg water consumption gal/kw-hr	0	0.008	0.088	0.362	0.701

Charleston, West Virginia

Fraction designed dry	0.95	0.75	0.50	0.25	0
Dry condenser cost ¢/kw-hr	0.120	0.0945	0.063	0.0315	0
Wet condenser cost ¢/kw-hr	0.0031	0.016	0.031	0.047	0.063
Electric energy ¢/kw-hr	0.036	0.044	0.056	0.050	0.046
Fuel penalty ¢/kw-hr	0.0051	0.0068	0.011	0.159	0.024
Cooling tower ¢/kw-hr	0.0015	0.0075	0.015	0.022	0.030
Total ¢/kw-hr	0.165	0.168	0.176	0.167	0.163
Avg water consumption gal/kw-hr	0.007	0.065	0.209	0.438	0.66

Akron, Ohio

Fraction designed dry	0.95	0.75	0.50	0.25	0
Dry condenser cost ¢/kw-hr	0.110	0.087	0.058	0.029	0
Wet condenser cost ¢/kw-hr	0.0031	0.016	0.031	0.047	0.063
Electric energy ¢/kw-hr	0.028	0.038	0.054	0.048	0.046
Fuel penalty ¢/kw-hr	0.0060	0.0064	0.0099	0.0123	0.017
Cooling tower ¢/kw-hr	0.0015	0.0075	0.015	0.022	0.030
Total ¢/kw-hr	0.149	0.155	0.168	0.159	0.156
Avg water consumption gal/kw-hr	0.008	0.062	0.215	0.448	0.681

TABLE A7-13. SUMMARY OF WET/DRY COMPRESSOR INTERSTAGE COOLING FOR AIR COMPRESSORS AT FARMINGTON, N.M., WITH WET COOLER OFF FOR MONTHS 1, 2, 3, 11, AND 12

Basis: 1000 lb air compressed/hr

Design intermediate temperature, °F	160
Dry cooler area, ft^2/1000 lb/hr	40.059
Wet cooler area, ft^2/1000 lb/hr	83.853
Circulation Rate, gpm/1000 lb/hr	3.046
Avg. fan & pump energy, kw-hr/1000 lb	0.509
Compression energy, kw-hr/1000 lb	28.140
Water consumed, gal/1000 lb	1.367

TABLE A7-14. ANNUAL AVERAGE COST FOR WET/DRY COMPRESSOR INTERSTAGE COOLING FOR AIR COMPRESSOR AT FARMINGTON, N.M. WITH WET COOLER OFF FOR MONTHS 1, 2, 3, 11, AND 12

<u>Basis:</u> 1000 lb air compressed/hr

Design intermediate temperature, °F	160
Dry cooler cost, ¢/1000 lb	2.140
Wet cooler cost, ¢/1000 lb	2.636
Tower cost, ¢/1000 lb	0.131
Fan and pump energy, ¢/1000 lb	1.018
Compression energy cost, ¢/1000 lb	59.263
Total, ¢/1000 lb compressed	65.188
Water consumed, gal/1000 lb	1.367

TABLE A7-15. CALCULATIONS ON INTERSTAGE COOLING OF AN AIR COMPRESSOR HANDLING 1000 LB AIR/HR AT FARMINGTON, N.M.

Design intermediate temperature T_x = 140°F

Design	ft^2/1000 lb	ft^2/1000 lb	lb/1000 lb	gpm/1000 lb		
	$A_{D,1}$ = 29.306	$A_{W,1}$ = 34.914	$R_{L,1}$ = 298.84	$R_{G,1}$ = 0.598	$Q_{W,1}$ = 7471	Cooling Tower Characteristic KaY/L = 1.24
	$A_{D,2}$ = 16.147	$A_{W,2}$ = 20.948	$R_{L,2}$ = 298.84	$R_{G,2}$ = 0.598	$Q_{W,2}$ = 7471	
	$A_{D,3}$ = 13.027	$A_{W,3}$ = 19.506	$R_{L,3}$ = 347.04	$R_{G,3}$ = 0.694	$Q_{W,3}$ = 8676	Water/Gas Rate in Tower R_L/R_A = 2.12
	Total: 58.480	75.368	944.72	1.890	23,618	

Month	1	2	3	4	5	6	7	8	9	10	11	12
$T_{1,o}$	146.5	155.3	166.4	175.2	189.0	201.4	208.9	205.2	194.0	178.0	162.8	147.8
$T_{X,1}$	62	70	80	87	99	110	116	113	103	90	77	64
$T_{2,i}$	55	62	69	74	83	90	95	93	86	76	67	57
$T_{2,o}$	183	191	200	206	218	226	233	230	221	209	198	185
$T_{X,2}$	69	77	86	92	104	113	119	116	107	95	83	71
$T_{3,i}$	60	66	73	77	86	92	97	95	88	79	71	61
$T_{3,o}$	189	196	205	210	221	229	235	233	224	213	203	190
$T_{X,3}$	71	78	87	94	105	114	120	117	108	96	84	72
T_{air}	71	78	87	94	84	89	94	92	86	77	84	72
t_c (avg)	54	59	65	68	76	81	85	84	78	70	63	55
t_h (avg)	60	68	75	80	90	97	103	100	93	83	72	62
Q_{W1}	1687	1928	2651	3133	3856	4820	5061	4820	4097	3374	2410	1687
Q_{W2}	2169	2651	3133	3615	4338	5061	5302	5061	4579	3856	2892	2410
Q_{W3}	0	0	0	0	5061	6025	6266	6025	5302	4338	0	0
Total Q_W	3856	4579	5784	6748	13255	15906	16629	15906	13978	11568	5302	4097
Total air fan energy (kw-hr/1000 lb)	0.655	0.655	0.655	0.655	0.655	0.655	0.655	0.655	0.655	0.655	0.655	0.655
Tower fan energy (kw-hr/1000 lb)	0.011	0.011	0.011	0.011	0.017	0.017	0.017	0.017	0.017	0.017	0.011	0.011
Circulation pump energy (kw-hr/1000 lb)	0.029	0.029	0.029	0.029	0.046	0.046	0.046	0.046	0.046	0.046	0.029	0.029
Compression energy (kw-hr/1000 lb)	26.482	26.830	27.231	27.509	28.240	28.414	28.693	28.571	28.171	27.614	27.109	26.552
Water consumed (gal/1000 lb)	0.267	0.337	0.449	0.588	1.177	1.460	1.578	1.493	1.257	0.936	0.396	0.278

(continued)

TABLE A7-15. (Farmington, N.M.) Continued

Design intermediate temperature T_x = 160°F; Fraction dry load = 0.638

Design	ft^2/1000 lb	ft^2/1000 lb	lb/1000 lb	gpm/1000 lb		
	$A_{D,1}$ = 19.688	$A_{W,1}$ = 39.61	$R_{L,1}$ = 491.64	$R_{G,1}$ = 0.983	$Q_{W,1}$ = 12,291	Cooling Tower Characteristic
	$A_{D,2}$ = 11.26	$A_{W,2}$ = 23.767	$R_{L,2}$ = 491.64	$R_{G,2}$ = 0.983	$Q_{W,2}$ = 12,291	KaY/L = 1.24
	$A_{D,3}$ = 9.111	$A_{W,3}$ = 20.476	$R_{L,3}$ = 539.84	$R_{G,3}$ = 1.080	$Q_{W,3}$ = 13,496	Water/Gas Rate in Tower
	Total: 40.059	83.853	1523.12	3.046	38,078	R_L/R_A = 2.12

Month	1	2	3	4	5	6	7	8	9	10	11	12
$T_{1,o}$	146.5	155.3	166.4	175.2	189.0	201.4	208.9	205.2	194.0	178.0	162.8	147.8
$T_{X,1}$	80	88	98	106	118	129	136	132	122	108	95	81
$T_{2,i}$	62	68	75	78	87	94	98	96	90	82	73	63
$T_{2,o}$	191	199	208	211	223	231	236	234	226	216	205	193
$T_{X,2}$	93	101	110	115	127	136	141	139	130	118	107	95
$T_{3,i}$	68	75	80	84	91	96	101	99	93	88	78	69
$T_{3,o}$	199	208	214	219	228	234	240	238	230	224	211	200
$T_{X,3}$	97	104	112	118	126	137	143	140	132	122	109	98
T_{air}	67	73	78	82	87	93	98	96	90	85	77	68
t_c (avg)	59	64	72	72	79	84	88	86	81	76	68	60
t_h (avg)	70	75	86	86	96	102	107	105	98	90	80	70
Q_{W1}	4338	4820	5543	6748	7471	8435	9158	8676	7712	6266	5302	4338
Q_{W2}	6025	6266	7230	7471	8676	9640	9833	9640	8917	7230	6989	6266
Q_{W3}	7230	7471	8194	8676	9399	10604	10848	10604	10122	8917	7712	7230
Total Q_W	17593	18557	20967	22895	25546	28679	29839	28920	26751	22413	20003	17834
Total air fan energy (kw-hr/1000 lb)	0.449	0.449	0.449	0.449	0.449	0.449	0.449	0.449	0.449	0.449	0.449	0.449
Tower fan energy (kw-hr/1000 lb)	0.027	0.027	0.027	0.027	0.027	0.027	0.027	0.027	0.027	0.027	0.027	0.027
Circulation pump energy (kw-hr/1000 lb)	0.075	0.075	0.075	0.075	0.075	0.075	0.075	0.075	0.075	0.075	0.075	0.075
Compression energy (kw-hr/1000 lb)	26.743	27.091	27.457	27.701	28.171	28.554	28.815	28.693	28.327	27.875	27.335	26.795
Water consumed (gal/1000 lb)	1.147	1.302	1.613	1.880	2.242	2.639	2.760	2.674	2.372	1.837	1.475	1.207

(continued)

TABLE A7-15. (Farmington, N.M.) Continued

Design intermediate temperature T_x = 180°F

Design	ft^2/1000 lb	ft^2/1000 lb	lb/1000 lb	gpm/1000 lb		
	$A_{D,1}$ = 12.743	$A_{W,1}$ = 43.485	$R_{L,1}$ = 684.44	$R_{G,1}$ = 1.369	$Q_{W,1}$ = 17,111	Cooling Tower Characteristic
	$A_{D,2}$ = 7.779	$A_{W,2}$ = 26.091	$R_{L,2}$ = 684.44	$R_{G,2}$ = 1.369	$Q_{W,2}$ = 17,111	KaY/L = 1.24
	$A_{D,3}$ = 6.297	$A_{W,3}$ = 21.647	$R_{L,3}$ = 732.64	$R_{G,3}$ = 1.465	$Q_{W,3}$ = 18,316	Water/Gas Rate in Tower
	Total: 26.819	91.123	2101.52	4.203	52,538	R_L/R_A = 2.12

Month	1	2	3	4	5	6	7	8	9	10	11	12
$T_{1,o}$	146.5	155.3	166.4	175.2	189.0	201.4	208.9	205.2	194.0	178.0	162.8	147.8
$T_{X,1}$	98	106	116	124	137	148	155	152	142	127	113	99
$T_{2,i}$	63	67	78	82	90	96	100	98	92	87	77	63
$T_{2,o}$	193	198	211	216	226	234	239	236	229	223	210	193
$T_{X,2}$	116	122	133	139	149	158	164	161	153	144	131	116
$T_{3,i}$	73	77	84	87	94	98	102	101	96	90	84	73
$T_{3,o}$	205	210	219	223	231	236	241	240	234	226	219	205
$T_{X,3}$	122	128	137	143	152	159	165	163	156	145	136	123
T_{air}	71	75	82	84	91	94	99	97	92	86	82	72
t_c (avg)	59	66	72	74	81	85	88	87	83	73	71	59
t_h (avg)	73	82	87	91	100	105	110	108	101	89	86	73
Q_{W1}	8435	9399	9158	10122	11327	12532	13255	13014	12050	9640	8676	8676
Q_{W2}	10363	10845	11809	12532	13255	14460	14942	14460	13737	13014	11327	10363
Q_{W3}	12291	12773	13255	14219	14701	15665	15906	15906	15424	14219	13014	12291
Total Q_W	31089	33017	34222	36873	39283	42657	44103	43380	41211	36873	33017	31330
Total air fan energy (kw-hr/1000 lb)	0.300	0.300	0.300	0.300	0.300	0.300	0.300	0.300	0.300	0.300	0.300	0.300
Tower fan energy (kw-hr/1000 lb)	0.037	0.037	0.037	0.037	0.037	0.037	0.037	0.037	0.037	0.037	0.037	0.037
Circulation pump energy (kw-hr/1000 lb)	0.103	0.103	0.103	0.103	0.103	0.103	0.103	0.103	0.103	0.103	0.103	0.103
Compression energy (kw-hr/1000 lb)	26.847	27.109	27.579	27.823	28.275	28.623	28.867	28.763	28.414	27.997	27.509	26.865
Water consumed (gal/1000 lb)	2.106	2.416	2.654	3.070	3.463	3.891	4.165	4.046	3.665	3.035	2.511	2.142

(continued)

TABLE A7-15. (Farmington, N.M.) Continued

Design intermediate temperature T_x = all wet

Design	$ft^2/1000$ lb	$ft^2/1000$ lb	lb/1000 lb		gpm/1000 lb	
	$A_{D,1}$ = 0	$A_{W,1}$ = 51.365	$R_{L,1}$ = 1224.28	$R_{G,1}$ = 2.449	$Q_{W,1}$ = 30,607	Cooling Tower Characteristic
	$A_{D,2}$ = 0	$A_{W,2}$ = 30.820	$R_{L,2}$ = 1224.28	$R_{G,2}$ = 2.449	$Q_{W,2}$ = 30,607	KaY/L = 1.24
	$A_{D,3}$ = 0	$A_{W,3}$ = 24.375	$R_{L,3}$ = 1272.48	$R_{G,3}$ = 2.545	$Q_{W,3}$ = 31,812	Water/Gas Rate in Tower
	Total: 0	106.560	3721.04	7.443	93,026	R_L/R_A = 2.12

Month	1	2	3	4	5	6	7	8	9	10	11	12
$T_{1,o}$	146.5	155.3	166.4	175.2	189.0	201.4	208.9	205.2	194.0	178.0	162.8	147.8
$T_{X,1}$	147	155	166	175	189	201	209	205	194	178	163	148
$T_{2,i}$	72	77	83	86	93	97	102	100	95	90	81	73
$T_{2,o}$	204	210	218	221	230	235	241	239	233	226	215	205
$T_{X,2}$	204	210	218	221	230	235	241	239	233	226	215	205
$T_{3,i}$	84	89	95	98	102	104	108	107	103	101	94	85
$T_{3,o}$	219	225	233	236	241	244	249	248	243	240	231	220
$T_{X,3}$	219	225	233	236	241	244	249	248	243	240	231	220
T_{air}	82	87	93	95	99	101	103	103	100	98	92	83
t_c (avg)	66	71	77	79	84	86	90	89	85	83	75	67
t_h (avg)	85	91	97	100	106	109	114	113	108	103	95	86
Q_{W1}	18075	18798	20003	21449	23136	25064	25787	25305	23859	21208	19762	18075
Q_{W2}	28920	29161	29643	29643	30848	31571	32053	31812	31330	30125	29161	28920
Q_{W3}	33017	33258	33740	33981	34222	34463	35186	34945	34463	34222	33499	33017
Total Q_W	80012	81217	83386	85073	88206	91098	93026	92062	89652	85555	82422	80012
Total air fan energy (kw-hr/1000 lb)	0	0	0	0	0	0	0	0	0	0	0	0
Tower fan energy (kw-hr/1000 lb)	0.066	0.066	0.066	0.066	0.066	0.066	0.066	0.066	0.066	0.066	0.066	0.066
Circulation pump energy (kw-hr/1000 lb)	0.183	0.183	0.183	0.183	0.183	0.183	0.183	0.183	0.183	0.183	0.183	0.183
Compression energy (kw-hr/1000 lb)	27.196	27.492	27.857	28.084	28.467	28.745	29.006	28.902	28.589	28.240	27.753	27.248
Water consumed (gal/1000 lb)	5.837	6.216	6.616	7.101	7.796	8.323	8.639	8.471	7.902	7.206	6.532	5.942

TABLE A7-16. CALCULATIONS ON INTERSTAGE COOLING OF AN AIR COMPRESSOR HANDLING 1000 LBS AIR/HR AT CASPER, WYOMING

Design intermediate temperature T_x = 140°F

Design	ft^2/1000 lb	ft^2/1000 lb	lb/1000 lb	gpm/1000 lb		
	$A_{D,1}$ = 28.156	$A_{W,1}$ = 34.914	$R_{L,1}$ = 298.84	$R_{G,1}$ = 0.598	$Q_{W,1}$ = 7471	Cooling Tower Characteristic KaY/L = 1.17
	$A_{D,2}$ = 14.334	$A_{W,2}$ = 20.948	$R_{L,2}$ = 298.84	$R_{G,2}$ = 0.598	$Q_{W,2}$ = 7471	
	$A_{D,3}$ = 11.572	$A_{W,3}$ = 19.506	$R_{L,3}$ = 347.04	$R_{G,3}$ = 0.694	$Q_{W,3}$ = 8676	Water/Gas Rate in Tower
	Total: 54.052	75.368	944.72	1.890	23,618	R_L/R_A = 2.24

Month	1	2	3	4	5	6	7	8	9	10	11	12
$T_{1,o}$	144.0	146.5	154.0	165.2	181.5	195.2	202.7	201.4	187.7	172.7	154.0	151.5
$T_{X,1}$	62	64	71	80	95	106	113	112	100	87	71	69
$T_{2,i}$	55	57	64	70	81	89	93	92	83	75	64	61
$T_{2,o}$	183	185	194	201	215	225	230	229	218	208	194	190
$T_{X,2}$	75	77	84	92	105	116	122	121	110	98	84	81
$T_{3,i}$	62	64	70	77	87	95	99	98	89	82	70	68
$T_{3,o}$	191	194	201	210	223	233	238	237	225	216	201	199
$T_{X,3}$	77	80	86	95	108	119	124	123	112	101	86	84
T_{air}	77	80	86	76	85	93	96	95	87	81	86	84
t_c (avg)	54	56	60	67	76	82	85	84	76	70	60	59
t_h (avg)	61	63	68	77	89	98	102	101	92	83	68	68
Q_{W1}	1687	1687	1687	2410	3374	4097	4820	4820	4097	2892	1687	1928
Q_{W2}	3133	3133	3374	3615	4338	5061	5543	5543	5061	3856	3374	3133
Q_{W3}	0	0	0	4579	5543	6266	6748	6748	6025	4820	0	0
Total Q_W	4820	4820	5061	10604	13255	15424	17111	17111	15183	11568	5061	5061
Total air fan energy (kw-hr/1000 lb)	0.605	0.605	0.605	0.605	0.605	0.605	0.605	0.605	0.605	0.605	0.605	0.605
Tower fan energy (kw-hr/1000 lb)	0.011	0.011	0.011	0.017	0.017	0.017	0.017	0.017	0.017	0.017	0.011	0.011
Circulation pump energy (kw-hr/1000 lb)	0.029	0.029	0.029	0.046	0.046	0.046	0.046	0.046	0.046	0.046	0.029	0.029
Compression energy (kw-hr/1000 lb)	26.482	26.586	26.917	27.300	27.892	28.362	28.606	28.554	28.049	27.579	26.917	26.795
Water consumed (gal/1000 lb)	0.304	0.314	0.354	0.810	1.134	1.392	1.580	1.570	1.327	0.927	0.354	0.349

(continued)

TABLE A7-16. (Casper, Wyoming) Continued

Design intermediate temperature T_x = 160°F

Design	ft^2/1000 lb	ft^2/1000 lb	lb/1000 lb	gpm/1000 lb		
	$A_{D,1}$ = 18.890	$A_{W,1}$ = 39.612	$R_{L,1}$ = 491.64	$R_{G,1}$ = 0.983	$Q_{W,1}$ = 12,291	Cooling Tower Characteristic
	$A_{D,2}$ = 11.037	$A_{W,2}$ = 23.767	$R_{L,2}$ = 491.64	$R_{G,2}$ = 0.983	$Q_{W,2}$ = 12,291	KaY/L = 1.17
	$A_{D,3}$ = 9.396	$A_{W,3}$ = 20.476	$R_{L,3}$ = 539.84	$R_{G,3}$ = 1.080	$Q_{W,3}$ = 13,496	Water/Gas Rate in Tower
	Total: 39.323	83.855	1523.12	3.046	38,078	R_L/R_A = 2.24

Month	1	2	3	4	5	6	7	8	9	10	11	12
$T_{1,o}$	144.0	146.5	154.0	165.2	181.5	195.2	202.7	201.4	187.7	172.7	154.0	151.5
$T_{X,1}$	80	82	89	99	113	125	132	131	119	105	89	86
$T_{2,i}$	61	63	69	76	85	93	96	95	86	80	69	66
$T_{2,o}$	190	193	200	209	220	230	234	233	221	214	200	196
$T_{X,2}$	93	95	102	111	123	134	139	138	126	116	102	99
$T_{3,i}$	67	69	75	82	89	96	100	99	89	85	75	72
$T_{3,o}$	198	200	208	216	225	234	239	238	225	220	208	204
$T_{X,3}$	93	95	102	110	122	130	138	137	125	116	102	99
T_{air}	64	66	72	79	86	91	96	95	86	82	72	69
t_c (avg)	57	59	65	71	77	84	86	86	77	74	65	62
t_h (avg)	68	70	76	84	93	101	105	104	93	88	76	74
Q_{W1}	4579	4579	4820	5543	6748	7712	8676	8676	7953	6025	4820	4820
Q_{W2}	6266	6266	6507	6989	8194	9158	9399	9399	8917	7471	6507	6507
Q_{W3}	6989	6989	7230	7471	8676	9399	10122	10122	9399	8194	7230	7230
Total Q_W	17834	17834	18557	20003	23618	26269	28197	28197	26269	21690	18557	18557
Total air fan energy (kw-hr/1000 lb)	0.440	0.440	0.440	0.440	0.440	0.440	0.440	0.440	0.440	0.440	0.440	0.440
Tower fan energy (kw-hr/1000 lb)	0.027	0.027	0.027	0.027	0.027	0.027	0.027	0.027	0.027	0.027	0.027	0.027
Circulation pump energy (kw-hr/1000 lb)	0.075	0.075	0.075	0.075	0.075	0.075	0.075	0.075	0.075	0.075	0.075	0.075
Compression energy (kw-hr/1000 lb)	26.67	26.78	27.09	27.49	28.00	28.45	28.68	28.62	28.10	27.72	27.09	26.95
Water consumed (gal/1000 lb)	1.151	1.216	1.314	1.535	2.000	2.343	2.571	2.563	2.367	1.755	1.314	1.224

(continued)

TABLE A7-16. (Casper, Wyoming) Continued

Design intermediate temperature $T_x = 180°F$

Design	$ft^2/1000$ lb	$ft^2/1000$ lb	lb/1000 lb	gpm/1000 lb		
	$A_{D,1} = 12.254$	$A_{W,1} = 43.485$	$R_{L,1} = 684.44$	$R_{G,1} = 1.369$	$Q_{W,1} = 17,111$	Cooling Tower Characteristic
	$A_{D,2} = 6.255$	$A_{W,2} = 26.091$	$R_{L,2} = 684.44$	$R_{G,2} = 1.369$	$Q_{W,2} = 17,111$	KaY/L = 1.17
	$A_{D,3} = 5.068$	$A_{W,3} = 21.647$	$R_{L,3} = 732.64$	$R_{G,3} = 1.465$	$Q_{W,3} = 18,316$	Water/Gas Rate in Tower
	Total: 23.577	91.123	2101.52	4.203	52,538	$R_L/R_A = 2.24$

Month	1	2	3	4	5	6	7	8	9	10	11	12
$T_{1,o}$	144.0	146.5	154.0	165.2	181.5	195.2	202.7	201.4	187.7	172.7	154.0	151.5
$T_{X,1}$	97	100	106	116	132	144	151	150	137	124	106	104
$T_{2,i}$	65	67	77	80	88	95	98	97	90	84	77	71
$T_{2,o}$	195	198	210	214	224	233	236	235	226	219	210	203
$T_{X,2}$	128	131	140	146	158	167	171	170	161	146	140	135
$T_{3,i}$	75	76	85	91	97	102	104	103	97	92	85	80
$T_{3,o}$	208	209	220	228	235	241	244	243	235	229	220	214
$T_{X,3}$	136	137	146	155	164	172	176	175	166	158	146	142
T_{air}	73	74	83	90	94	99	101	100	94	91	83	78
t_c (avg)	61	62	68	75	81	86	88	87	81	78	68	66
t_h (avg)	76	78	83	92	100	106	109	108	101	95	83	82
Q_{W1}	7712	7953	6989	8676	10604	11809	12773	12773	11327	9640	6989	7953
Q_{W2}	12773	13255	13255	13255	14701	15665	16147	16147	15424	13014	13255	13255
Q_{W3}	15183	15183	15183	15665	16870	17593	18075	18075	17352	16147	15183	15424
Total Q_W	35668	36391	35427	37596	42175	45067	46995	46995	44103	38801	35427	36632
Total air fan energy (kw-hr/1000 lb)	0.264	0.264	0.264	0.264	0.264	0.264	0.264	0.264	0.264	0.264	0.264	0.264
Tower fan energy (kw-hr/1000 lb)	0.037	0.037	0.037	0.037	0.037	0.037	0.037	0.037	0.037	0.037	0.037	0.037
Circulation pump energy (kw-hr/1000 lb)	0.103	0.103	0.103	0.103	0.103	0.103	0.103	0.103	0.103	0.103	0.103	0.103
Compression energy (kw-hr/1000 lb)	26.882	26.969	27.405	27.718	28.188	28.589	28.780	28.728	28.310	27.910	27.405	27.178
Water consumed (gal/1000 lb)	2.489	2.590	2.658	2.951	3.593	4.010	4.336	4.302	3.829	3.176	2.658	2.703

(continued)

TABLE A7-16. (Casper, Wyoming) Continued

Design intermediate temperature T_x = all wet

Design	ft^2/1000 lb	ft^2/1000 lb	lb/1000 lb	gpm/1000 lb	
	$A_{D,1}$ = 0	$A_{W,1}$ = 51.134	$R_{L,1}$ = 1205.0	$R_{G,1}$ = 2.410	$Q_{W,1}$ = 30,125
	$A_{D,2}$ = 0	$A_{W,2}$ = 30.681	$R_{L,2}$ = 1205.0	$R_{G,2}$ = 2.410	$Q_{W,2}$ = 30,125
	$A_{D,3}$ = 0	$A_{W,3}$ = 24.292	$R_{L,3}$ = 1253.2	$R_{G,3}$ = 2.506	$Q_{W,3}$ = 31,330
	Total: 0	106.107	3663.2	7.326	91,580

Cooling Tower Characteristic
KaY/L = 1.17

Water/Gas Rate in Tower
R_L/R_A = 2.24

Month	1	2	3	4	5	6	7	8	9	10	11	12
$T_{1,o}$	144.0	146.5	154.0	165.2	181.5	195.2	202.7	201.4	187.7	172.7	154.0	151.5
$T_{X,1}$	144	147	154	165	182	195	203	201	188	173	154	152
$T_{2,i}$	69	73	78	86	91	98	100	99	95	88	78	76
$T_{2,o}$	200	205	211	221	228	236	239	238	233	224	211	209
$T_{X,2}$	200	205	211	221	228	236	239	238	233	224	211	209
$T_{3,i}$	78	83	89	98	102	106	108	107	106	99	89	85
$T_{3,o}$	211	218	225	236	241	246	249	248	246	238	225	220
$T_{X,3}$	211	218	225	236	241	246	249	248	246	238	225	220
T_{air}	77	82	88	96	100	102	104	103	102	97	88	84
t_c (avg)	61	66	72	79	83	88	90	89	87	81	72	69
t_h (avg)	81	86	91	100	105	111	113	112	109	102	91	88
Q_{W1}	18075	17834	18316	19039	21931	23377	24823	24582	22413	20485	18316	18316
Q_{W2}	29402	29402	29402	29643	30366	31330	31571	31571	30607	30125	29402	29884
Q_{W3}	32294	32776	33017	33740	33981	34704	34945	34945	34704	33981	33017	32776
Total Q_W	79771	80012	80735	82422	86278	89411	91339	91098	87724	84591	80735	80976
Total air fan energy (kw-hr/1000 lb)	0	0	0	0	0	0	0	0	0	0	0	0
Tower fan energy (kw-hr/1000 lb)	0.065	0.065	0.065	0.065	0.065	0.065	0.065	0.065	0.065	0.065	0.065	0.065
Circulation pump energy (kw-hr/1000 lb)	0.180	0.180	0.180	0.180	0.180	0.180	0.180	0.180	0.180	0.180	0.180	0.180
Compression energy (kw-hr/1000 lb)	27.004	27.196	27.492	27.944	28.327	28.710	28.885	28.832	28.554	28.101	27.492	27.352
Water consumed (gal/1000 lb)	5.890	5.949	6.223	6.577	7.362	7.951	8.285	8.245	7.657	7.028	6.223	6.184

TABLE A7-17. CALCULATIONS ON INTERSTAGE COOLING OF AN AIR COMPRESSOR HANDLING 1000 LBS/HR AT CHARLESTON, W.VA.

Design intermediate temperature T_x = 140°F

Design	ft^2/1000 lb	ft^2/1000 lb	lb/1000 lb	gpm/1000 lb	
	$A_{D,1}$ = 23.206	$A_{W,1}$ = 34.914	$R_{L,1}$ = 298.84	$R_{G,1}$ = 0.598	$Q_{W,1}$ = 7471
	$A_{D,2}$ = 11.811	$A_{W,2}$ = 20.948	$R_{L,2}$ = 298.84	$R_{G,2}$ = 0.598	$Q_{W,2}$ = 7471
	$A_{D,3}$ = 9.579	$A_{W,3}$ = 19.506	$R_{L,3}$ = 347.04	$R_{G,3}$ = 0.694	$Q_{W,3}$ = 8676
	Total: 44.596	75.368	944.72	1.890	23,618

Cooling Tower Characteristic
KaY/L = 1.44

Water/Gas Rate in Tower
R_L/R_A = 1.45

Month	1	2	3	4	5	6	7	8	9	10	11	12
$T_{1,o}$	159.0	161.5	170.2	182.7	194.0	203.9	207.7	206.4	200.2	185.2	171.5	161.5
$T_{X,1}$	84	86	94	105	115	123	127	125	120	107	95	86
$T_{2,i}$	69	70	76	84	92	98	100	99	95	86	77	70
$T_{2,o}$	200	201	209	219	229	236	239	238	233	221	210	201
$T_{X,2}$	100	102	109	119	128	136	139	138	133	121	110	102
$T_{3,i}$	78	80	85	91	98	102	106	105	102	93	86	80
$T_{3,o}$	211	214	220	228	236	241	246	245	241	230	221	214
$T_{X,3}$	104	107	113	122	131	138	142	141	136	124	114	107
T_{air}	76	78	82	88	94	100	102	101	98	90	84	78
t_c (avg)	65	66	70	75	82	86	89	88	85	78	71	66
t_h (avg)	79	81	87	95	103	108	113	112	107	97	88	81
Q_{W1}	3615	3856	4338	5061	5543	6025	6507	6266	6025	5061	4338	3856
Q_{W2}	5302	5302	5784	6748	7230	8194	7953	7953	7471	6748	5784	5302
Q_{W3}	6748	6989	7471	8194	8917	9158	9640	9640	9158	8194	7230	6989
Total Q_W	15665	16147	17593	20003	21690	23377	24100	23859	22654	20003	17352	16147
Total air fan energy (kw-hr/1000 lb)	0.499	0.499	0.499	0.499	0.499	0.499	0.499	0.499	0.499	0.499	0.499	0.499
Tower fan energy (kw-hr/1000 lb)	0.017	0.017	0.017	0.017	0.017	0.017	0.017	0.017	0.017	0.017	0.017	0.017
Circulation pump energy (kw-hr/1000 lb)	0.046	0.046	0.046	0.046	0.046	0.046	0.046	0.046	0.046	0.046	0.046	0.046
Compression energy (kw-hr/1000 lb)	27.213	27.300	27.614	28.031	28.449	28.763	28.919	28.867	28.658	28.136	27.666	27.300
Water consumed (gal/1000 lb)	1.103	1.134	1.267	1.666	1.869	2.073	2.151	2.135	1.987	1.650	1.330	1.134

(continued)

TABLE A7-17. (Charleston, W. Va.) Continued

Design intermediate temperature T_x = 160°F

Design	ft^2/1000 lb	ft^2/1000 lb	lb/1000 lb		gpm/1000 lb	
	$A_{D,1}$ = 15.307	$A_{W,1}$ = 39.612	$R_{L,1}$ = 491.64	$R_{G,1}$ = 0.983	$Q_{W,1}$ = 12,291	Cooling Tower Characteristic
	$A_{D,2}$ = 7.818	$A_{W,2}$ = 23.767	$R_{L,2}$ = 491.64	$R_{G,2}$ = 0.983	$Q_{W,2}$ = 12,291	KaY/L = 1.44
	$A_{D,3}$ = 6.337	$A_{W,3}$ = 20.476	$R_{L,3}$ = 539.84	$R_{G,3}$ = 1.080	$Q_{W,3}$ = 13,496	Water/Gas Rate in Tower
	Total: 29.462	83.855	1523.12	3.046	38.078	R_L/R_A = 1.45

Month	1	2	3	4	5	6	7	8	9	10	11	12
$T_{1,o}$	159.0	161.5	170.2	182.7	194.0	203.9	207.7	206.4	200.2	185.2	171.5	161.5
$T_{X,1}$	102	105	112	124	134	143	146	145	139	126	114	105
$T_{2,i}$	72	74	78	86	94	99	101	100	96	88	79	74
$T_{2,o}$	204	206	211	220	231	238	240	239	234	224	213	206
$T_{X,2}$	126	128	134	144	154	161	164	163	158	147	136	128
$T_{3,i}$	82	84	88	93	101	105	107	106	104	96	90	84
$T_{3,o}$	216	219	224	230	290	245	248	246	244	234	226	219
$T_{X,3}$	133	135	141	149	158	165	168	166	163	152	143	135
T_{air}	81	82	86	90	96	101	102	102	100	93	88	82
t_c (avg)	66	68	71	77	84	87	89	88	85	79	72	68
t_h (avg)	84	86	91	98	107	112	114	113	109	101	92	86
Q_{W1}	7230	7471	8194	9158	9640	10604	10845	10845	10363	9158	8435	7471
Q_{W2}	10604	10604	11086	12291	12773	13496	13737	13737	13014	12291	11086	10604
Q_{W3}	12532	12773	13255	14219	14942	15424	19280	15424	15183	14219	13255	12773
Total Q_W	30366	30848	32535	35668	37355	39524	43862	40006	38560	35668	32776	30848
Total air fan energy (kw-hr/1000 lb)	0.330	0.330	0.330	0.330	0.330	0.330	0.330	0.330	0.330	0.330	0.330	0.330
Tower fan energy (kw-hr/1000 lb)	0.027	0.027	0.027	0.027	0.027	0.027	0.027	0.027	0.027	0.027	0.027	0.027
Circulation pump energy (kw-hr/1000 lb)	0.075	0.075	0.075	0.075	0.075	0.075	0.075	0.075	0.075	0.075	0.075	0.075
Compression energy (kw-hr/1000 lb)	27.335	27.439	27.701	28.101	28.536	28.832	28.954	28.902	28.710	28.223	27.770	27.439
Water consumed (gal/1000 lb)	2.180	2.232	2.522	2.938	3.203	3.493	3.909	3.569	3.064	2.963	2.522	2.232

(continued)

TABLE A7-17. (Charleston, W. Va.) Continued

Design intermediate temperature T_x = 180°F

Design	ft^2/1000 lb	ft^2/1000 lb	lb/1000 lb	gpm/1000 lb		
	$A_{D,1}$ = 9.381	$A_{W,1}$ = 43.485	$R_{L,1}$ = 684.44	$R_{G,1}$ = 1.369	$Q_{W,1}$ = 17,111	Cooling Tower Characteristic
	$A_{D,2}$ = 4.788	$A_{W,2}$ = 26.091	$R_{L,2}$ = 684.44	$R_{G,2}$ = 1.369	$Q_{W,2}$ = 17,111	KaY/L = 1.44
	$A_{D,3}$ = 3.880	$A_{W,3}$ = 21.647	$R_{L,3}$ = 732.64	$R_{G,3}$ = 1.465	$Q_{W,3}$ = 18,316	Water/Gas Rate in Tower
	Total: 18.049	91.123	2101.52	4.203	52,538	R_L/R_A = 1.45

Month	1	2	3	4	5	6	7	8	9	10	11	12
$T_{1,o}$	159.0	161.5	170.2	182.7	194.0	203.9	207.7	206.4	200.2	185.2	171.5	161.5
$T_{X,1}$	120	123	130	143	153	162	166	164	159	145	132	123
$T_{2,i}$	75	77	81	87	94	100	102	101	98	89	82	77
$T_{2,o}$	208	210	215	223	231	239	241	240	236	225	216	210
$T_{X,2}$	154	156	161	170	178	186	189	188	183	172	162	156
$T_{3,i}$	86	87	91	96	101	106	108	107	105	98	92	87
$T_{3,o}$	221	223	228	234	240	246	249	248	245	236	229	223
$T_{X,3}$	163	165	170	177	184	191	194	193	189	179	171	165
T_{air}	84	85	89	93	97	102	103	102	100	94	90	85
t_c (avg)	68	70	73	77	83	88	89	89	87	80	74	70
t_h (avg)	88	89	89	100	107	113	115	114	111	103	95	89
Q_{W1}	10845	11086	11809	13496	14219	14942	15424	15183	14701	13496	12050	11086
Q_{W2}	16388	16629	16870	17834	18557	19280	19521	19521	18798	17834	16870	16629
Q_{W3}	19039	19280	19521	20244	20967	21449	21931	21931	21449	20485	19521	19280
Total Q_W	46272	46995	48200	51574	53743	55671	56876	56635	54948	51815	48441	46995
Total air fan energy (kw-hr/1000 lb)	0.202	0.202	0.202	0.202	0.202	0.202	0.202	0.202	0.202	0.202	0.202	0.202
Tower fan energy (kw-hr/1000 lb)	0.037	0.037	0.037	0.037	0.037	0.037	0.037	0.037	0.037	0.037	0.037	0.037
Circulation pump energy (kw-hr/1000 lb)	0.103	0.103	0.103	0.103	0.103	0.103	0.103	0.103	0.103	0.103	0.103	0.103
Compression energy (kw-hr/1000 lb)	27.457	27.544	27.805	28.171	28.536	28.867	28.989	28.936	28.763	28.275	27.857	27.544
Water consumed (gal/1000 lb)	3.393	3.480	3.741	4.280	4.645	4.872	5.080	5.063	4.837	4.315	3.723	3.480

(continued)

TABLE A7-17. (Charleston, W. Va.) Continued

Design intermediate temperature T_x = all wet

Design	$ft^2/1000$ lb	$ft^2/1000$ lb	lb/1000 lb	gpm/1000 lb	
	$A_{D,1}$ = 0	$A_{W,1}$ = 49.812	$R_{L,1}$ = 1098.96	$R_{G,1}$ = 2.198	$Q_{W,1}$ = 27,474
	$A_{D,2}$ = 0	$A_{W,2}$ = 29.887	$R_{L,2}$ = 1098.96	$R_{G,2}$ = 2.198	$Q_{W,2}$ = 27,474
	$A_{D,3}$ = 0	$A_{W,3}$ = 28.579	$R_{L,3}$ = 1147.16	$R_{G,3}$ = 2.294	$Q_{W,3}$ = 28,679
	Total: 0	108.278	3345.08	6.690	83,627

Cooling Tower Characteristic
KaY/L = 1.44

Water/Gas Rate in Tower
R_L/R_A = 1.45

Month	1	2	3	4	5	6	7	8	9	10	11	12
$T_{1,o}$	159.0	161.5	170.2	182.7	194.0	203.9	207.7	206.4	200.2	185.2	171.5	161.5
$T_{X,1}$	159	162	170	183	194	204	208	206	200	185	172	162
$T_{2,i}$	77	78	84	89	95	100	102	101	98	92	85	78
$T_{2,o}$	210	211	219	225	233	239	241	240	236	229	220	211
$T_{X,2}$	210	211	219	225	233	239	241	240	236	229	220	211
$T_{3,i}$	88	89	94	97	103	107	108	107	105	100	95	89
$T_{3,o}$	224	225	231	235	243	248	249	248	245	239	233	225
$T_{X,3}$	224	225	231	235	243	248	249	248	245	239	233	225
T_{air}	82	83	87	90	94	99	100	99	97	92	88	83
t_c (avg)	69	70	75	78	84	88	89	88	86	81	76	70
t_h (avg)	91	93	98	102	109	114	115	114	112	105	100	93
Q_{W1}	19762	20244	20726	22654	23859	25064	25546	25305	24582	22413	20967	20244
Q_{W2}	29402	29402	30125	30848	31330	31812	32053	32053	31571	31089	30125	29402
Q_{W3}	34222	34222	34704	34945	35909	35909	35909	35909	35668	35427	34945	34222
Total Q_W	83386	83868	85555	88447	91098	92785	93508	93267	91821	88929	86037	83868
Total air fan energy (kw-hr/1000 lb)	0	0	0	0	0	0	0	0	0	0	0	0
Tower fan energy (kw-hr/1000 lb)	0.060	0.060	0.060	0.060	0.060	0.060	0.060	0.060	0.060	0.060	0.060	0.060
Circulation pump energy (kw-hr/1000 lb)	0.165	0.165	0.165	0.165	0.165	0.165	0.165	0.165	0.165	0.165	0.165	0.165
Compression energy (kw-hr/1000 lb)	27.527	27.596	27.910	28.223	28.589	28.885	28.989	28.937	28.763	28.362	27.962	27.596
Water consumed (gal/1000 lb)	6.204	6.287	6.730	7.339	7.782	8.170	8.364	8.336	8.087	7.339	6.785	6.287

TABLE A7-18. CALCULATIONS ON INTERSTAGE COOLING OF AN AIR COMPRESSOR HANDLING 1000 LBS AIR/HR AT AKRON, OHIO

Design intermediate temperature T_x = 140°F

Design	ft^2/1000 lb	ft^2/1000 lb	lb/1000 lb	gpm/1000 lb	
	$A_{D,1}$ = 21.231	$A_{W,1}$ = 34.914	$R_{L,1}$ = 298.84	$R_{G,1}$ = 0.598	$Q_{W,1}$ = 7471
	$A_{D,2}$ = 10.854	$A_{W,2}$ = 20.948	$R_{L,2}$ = 298.84	$R_{G,2}$ = 0.598	$Q_{W,2}$ = 7471
	$A_{D,3}$ = 8.763	$A_{W,3}$ = 19.506	$R_{L,3}$ = 347.04	$R_{G,3}$ = 0.694	$Q_{W,3}$ = 8676
	Total: 40.848	75.368	944.72	1.890	23,618

Cooling Tower Characteristic
KaY/L = 1.45

Water/Gas Rate in Tower
R_L/R_A = 1.41

Month	1	2	3	4	5	6	7	8	9	10	11	12
$T_{1,o}$	147.8	149.0	160.3	172.7	187.7	198.9	203.9	202.7	195.2	180.2	164.0	151.5
$T_{X,1}$	78	79	89	100	113	123	128	127	120	107	92	81
$T_{2,i}$	61	63	72	80	89	96	100	99	94	85	74	64
$T_{2,o}$	190	193	204	214	225	234	239	238	231	220	206	194
$T_{X,2}$	96	98	107	117	129	138	142	141	135	123	110	99
$T_{3,i}$	71	73	82	89	97	103	107	106	101	93	84	74
$T_{3,o}$	203	205	216	225	235	243	248	246	240	230	219	206
$T_{X,3}$	101	103	113	122	133	142	146	145	139	128	116	104
T_{air}	69	72	81	87	94	99	102	101	98	90	82	73
t_c (avg)	56	58	67	73	79	84	88	87	83	76	68	60
t_h (avg)	73	74	84	92	102	109	114	113	107	97	86	75
Q_{W1}	4097	3856	4097	4820	5784	6507	6748	6748	6266	5302	4338	4097
Q_{W2}	6025	6025	6025	6748	7712	8435	8435	8435	8194	7230	6266	6025
Q_{W3}	7712	7471	7712	8435	9399	10363	10604	10604	9881	9158	8194	7471
Total Q_W	17834	17352	17834	20003	22895	25305	25787	25787	24341	21690	18798	17593
Total air fan energy (kw-hr/1000 lb)	0.457	0.457	0.457	0.457	0.457	0.457	0.457	0.457	0.457	0.457	0.457	0.457
Tower fan energy (kw-hr/1000 lb)	0.017	0.017	0.017	0.017	0.017	0.017	0.017	0.017	0.017	0.017	0.017	0.017
Circulation pump energy (kw-hr/1000 lb)	0.046	0.046	0.046	0.046	0.046	0.046	0.046	0.046	0.046	0.046	0.046	0.046
Compression energy (kw-hr/1000 lb)	26.795	26.882	27.352	27.788	28.293	28.676	28.885	28.832	28.258	28.049	27.788	26.952
Water consumed (gal/1000 lb)	1.038	1.030	1.231	1.544	1.914	2.172	2.276	2.252	2.083	1.745	1.375	0.997

(continued)

TABLE A7-18. (Akron, Ohio) Continued

Design intermediate temperature $T_x = 160°F$

Design	$ft^2/1000$ lb	$ft^2/1000$ lb	lb/1000 lb	gpm/1000 lb		
	$A_{D,1} = 13.813$	$A_{W,1} = 39.612$	$R_{L,1} = 491.64$	$R_{G,1} = 0.983$	$Q_{W,1} = 12{,}291$	Cooling Tower Characteristic KaY/L = 1.45
	$A_{D,2} = 7.085$	$A_{W,2} = 23.767$	$R_{L,2} = 491.64$	$R_{G,2} = 0.983$	$Q_{W,2} = 12{,}291$	
	$A_{D,3} = 5.718$	$A_{W,3} = 20.476$	$R_{L,3} = 539.84$	$R_{G,3} = 1.080$	$Q_{W,3} = 13{,}496$	Water/Gas Rate in Tower
	Total: 26.616	83.855	1523.12	3.046	38,078	$R_L/R_A = 1.41$

Month	1	2	3	4	5	6	7	8	9	10	11	12
$T_{1,o}$	147.8	149.0	160.3	172.7	187.7	198.9	203.9	202.7	195.2	180.2	164.0	151.5
$T_{X,1}$	96	97	107	119	133	143	147	146	139	126	111	100
$T_{2,i}$	64	65	76	82	91	97	100	99	95	87	77	68
$T_{2,o}$	194	195	209	216	228	235	239	238	233	223	210	199
$T_{X,2}$	122	123	135	143	155	163	167	166	161	150	137	126
$T_{3,i}$	74	76	87	92	99	104	107	106	103	96	88	79
$T_{3,o}$	206	209	223	229	238	244	248	246	243	234	224	213
$T_{X,3}$	129	131	143	151	161	168	173	171	167	156	145	135
T_{air}	72	74	85	89	96	100	103	102	99	93	85	77
t_c (avg)	57	59	70	74	80	85	88	87	84	78	70	62
t_h (avg)	76	78	89	95	104	111	114	113	109	101	91	81
Q_{W1}	7712	7712	7471	8917	10122	11086	11327	11327	10604	9399	8194	7712
Q_{W2}	11568	11327	11568	12291	13496	14219	14460	14460	13978	13014	11809	11327
Q_{W3}	13737	13737	13978	14942	15665	16388	16870	16629	16388	15183	14460	13978
Total Q_W	33017	32776	33017	36150	39283	41693	42657	42416	40970	37596	34463	33017
Total air fan energy (kw-hr/1000 lb)	0.298	0.298	0.298	0.298	0.298	0.298	0.298	0.298	0.298	0.298	0.298	0.298
Tower fan energy (kw-hr/1000 lb)	0.027	0.027	0.027	0.027	0.027	0.027	0.027	0.027	0.027	0.027	0.027	0.027
Circulation pump energy (kw-hr/1000 lb)	0.075	0.075	0.075	0.075	0.075	0.075	0.075	0.075	0.075	0.075	0.075	0.075
Compression energy (kw-hr/1000 lb)	26.900	26.969	27.509	27.875	28.362	28.710	28.885	28.832	28.606	28.136	27.596	27.109
Water consumed (gal/1000 lb)	1.971	1.997	2.360	2.853	3.281	3.618	3.774	3.761	3.501	3.060	2.542	1.971

(continued)

TABLE A7-18. (Akron, Ohio) Continued

Design intermediate temperature $T_x = 180°F$

Design	ft^2/1000 lb	ft^2/1000 lb	lb/1000 lb	gpm/1000 lb		
	$A_{D,1} = 8.159$	$A_{W,1} = 43.485$	$R_{L,1} = 684.44$	$R_{G,1} = 1.369$	$Q_{W,1} = 17{,}111$	Cooling Tower Characteristic KaY/L = 1.45
	$A_{D,2} = 4.182$	$A_{W,2} = 26.091$	$R_{L,2} = 684.44$	$R_{G,2} = 1.369$	$Q_{W,2} = 17{,}111$	
	$A_{D,3} = 3.374$	$A_{W,3} = 21.647$	$R_{L,3} = 732.64$	$R_{G,3} = 1.465$	$Q_{W,3} = 18{,}316$	Water/Gas Rate in Tower
	Total: 15.715	91.123	2101.52	4.203	52,538	$R_L/R_A = 1.41$

Month	1	2	3	4	5	6	7	8	9	10	11	12
$T_{1,o}$	147.8	149.0	160.3	172.7	187.7	198.9	203.9	202.7	195.2	180.2	164.0	151.5
$T_{X,1}$	114	115	126	138	152	162	167	166	159	144	129	118
$T_{2,i}$	66	67	78	84	92	98	101	100	96	88	79	69
$T_{2,o}$	196	198	211	219	229	236	240	239	234	224	213	200
$T_{X,2}$	149	150	162	171	181	189	193	192	186	176	164	152
$T_{3,i}$	77	78	89	94	100	105	108	107	104	97	89	80
$T_{3,o}$	210	211	225	231	239	245	249	248	244	235	225	214
$T_{X,3}$	159	160	172	179	189	195	199	198	194	184	173	162
T_{air}	75	76	87	91	97	101	104	102	100	94	87	78
t_c (avg)	59	60	70	75	81	86	88	87	85	78	70	62
t_h (avg)	80	80	92	97	105	112	115	114	110	102	93	83
Q_{W1}	11568	11568	11568	13014	14460	15424	15906	15906	15183	13496	12050	11809
Q_{W2}	17352	17352	17593	18557	19521	20244	20485	20485	19762	19039	18075	17352
Q_{W3}	20244	20244	20485	21208	22172	22654	22895	23136	22654	21690	20726	20244
Total Q_W	49164	49164	49646	52779	56153	58322	59286	59527	57599	54225	50851	49405
Total air fan energy (kw-hr/1000 lb)	0.176	0.176	0.176	0.176	0.176	0.176	0.176	0.176	0.176	0.176	0.176	0.176
Tower fan energy (kw-hr/1000 lb)	0.037	0.037	0.037	0.037	0.037	0.037	0.037	0.037	0.037	0.037	0.037	0.037
Circulation pump energy (kw-hr/1000 lb)	0.103	0.103	0.103	0.103	0.103	0.103	0.103	0.103	0.103	0.103	0.103	0.103
Compression energy (kw-hr/1000 lb)	26.987	27.039	27.718	27.944	28.397	28.745	28.919	28.867	28.641	28.171	27.648	27.143
Water consumed (gal/1000 lb)	3.042	3.095	3.578	4.079	4.706	5.064	5.260	5.296	5.081	4.348	3.793	3.060

(continued)

TABLE A7-18. (Akron, Ohio) Continued

Design intermediate temperature T_x = all wet

Design	ft^2/1000 lb	ft^2/1000 lb	lb/1000 lb		gpm/1000 lb	
	$A_{D,1}$ = 0	$A_{W,1}$ = 49.178	$R_{L,1}$ = 1050.76	$R_{G,1}$ = 2.102	$Q_{W,1}$ = 26,269	Cooling Tower Characteristic
	$A_{D,2}$ = 0	$A_{W,2}$ = 29.507	$R_{L,2}$ = 1050.76	$R_{G,2}$ = 2.102	$Q_{W,2}$ = 26,269	KaY/L = 1.45
	$A_{D,3}$ = 0	$A_{W,3}$ = 28.308	$R_{L,3}$ = 1098.96	$R_{G,3}$ = 2.198	$Q_{W,3}$ = 27,474	Water/Gas Rate in Tower
	Total: 0	106.993	3200.48	6.402	80,012	R_L/R_A = 1.41

Month	1	2	3	4	5	6	7	8	9	10	11	12
$T_{1,o}$	147.8	149.0	160.3	172.7	187.7	198.9	203.9	202.7	195.2	180.2	164.0	151.5
$T_{X,1}$	148	149	160	173	188	199	204	203	195	180	164	152
$T_{2,i}$	68	69	79	85	93	98	101	100	97	89	80	71
$T_{2,o}$	199	200	213	220	230	236	240	239	235	225	214	203
$T_{X,2}$	199	200	213	220	230	236	240	239	235	225	214	203
$T_{3,i}$	79	81	91	96	101	105	108	107	104	99	91	83
$T_{3,o}$	213	215	228	234	240	245	249	248	244	238	228	218
$T_{X,3}$	213	215	228	234	240	245	249	248	244	238	228	218
T_{air}	72	75	85	88	93	96	98	97	95	90	85	77
t_c (avg)	59	61	71	75	81	85	88	87	85	78	71	63
t_h (avg)	82	84	94	100	107	112	115	114	110	103	95	86
Q_{W1}	19280	19280	19521	21208	22895	24341	24823	24823	23618	21931	20244	19521
Q_{W2}	28920	28679	29402	29884	31089	31571	31812	31812	31571	30607	29643	28920
Q_{W3}	33981	33740	34463	35186	35427	35909	36391	36391	35909	35668	34463	33981
Total Q_W	82181	81699	83386	86278	89411	91821	93026	93026	91098	88206	84350	82422
Total air fan energy (kw-hr/1000 lb)	0	0	0	0	0	0	0	0	0	0	0	0
Tower fan energy (kw-hr/1000 lb)	0.057	0.057	0.057	0.057	0.057	0.057	0.057	0.057	0.057	0.057	0.057	0.057
Circulation pump energy (kw-hr/1000 lb)	0.157	0.157	0.157	0.157	0.157	0.157	0.157	0.157	0.157	0.157	0.157	0.157
Compression energy (kw-hr/1000 lb)	27.056	27.126	27.631	27.997	28.432	28.745	28.919	28.867	28.658	28.223	27.701	27.231
Water consumed (gal/1000 lb)	5.232	5.395	6.186	6.840	7.493	7.957	8.801	8.311	7.820	7.221	6.376	5.177

TABLE A7-19. SUMMARY OF WET/DRY COMPRESSOR INTERSTAGE COOLING FOR AIR COMPRESSOR

Farmington, New Mexico

Basis: 1000 lb air compressed/hr

Design intermediate temperature, °F	140	160	180	all wet
Dry cooler area, ft^2/1000 lb/hr	58.480	40.059	26.819	0
Wet cooler area, ft^2/1000 lb/hr	75.368	83.853	91.123	106.560
Circulation rate, gpm/1000 lb/hr	1.890	3.046	4.203	7.443
Avg. fan & pump energy, kw-hr/1000 lb	0.704	0.551	0.440	0.249
Compression energy, kw-hr/1000 lb	27.618	27.796	27.889	28.132
Water consumed, gal/1000 lb	0.851	1.929	3.097	7.215

Charleston, West Virginia

Basis: 1000 lb air compressed/hr

Design intermediate temperature, °F	140	160	180	all wet
Dry cooler area, ft^2/1000 lb/hr	44.596	29.462	18.049	0
Wet cooler area, ft^2/1000 lb/hr	75.368	83.855	91.123	108.278
Circulation rate, gpm/1000 lb/hr	1.890	3.046	4.203	6.690
Avg. fan & pump energy, kw-hr/1000 lb	0.562	0.432	0.342	0.225
Compression energy, kw-hr/1000 lb	28.076	28.162	28.229	28.278
Water consumed, gal/1000 lb	1.625	2.902	4.242	7.309

Casper, Wyoming

Basis: 1000 lb/air compressed/hr

Design intermediate temperature, °F	140	160	180	all wet
Dry cooler area, ft^2/1000 lb	54.052	39.323	23.577	0
Wet cooler area, ft^2/1000 lb	75.368	83.855	91.123	106.107
Circulation rate, gpm/1000 lb/hr	1.890	3.046	4.203	7.326
Avg. fan & pump energy, kw-hr/1000 lb	0.658	0.542	0.404	0.245
Compression energy, kw-hr/1000 lb	27.503	27.640	27.839	27.991
Water consumed, gal/1000 lb	0.868	1.779	3.275	6.965

Akron, Ohio

Basis: 1000 lb air compressed/hr

Design intermediate temperature, °F	140	160	180	all wet
Dry cooler area, ft^2/1000 lb/hr	40.848	26.616	15.715	0
Wet cooler area, ft^2/1000 lb/hr	75.368	83.855	91.123	106.993
Circulation rate, gpm/1000 lb/hr	1.890	3.046	4.203	6.402
Avg. fan & pump energy, kw-hr/1000 lb	0.520	0.400	0.316	0.214
Compression energy, kw-hr/1000 lb	27.879	27.957	28.018	28.049
Water consumed, gal/1000 lb	1.638	2.891	4.200	6.651

TABLE A7-20. ANNUAL AVERAGE COST FOR WET/DRY COMPRESSOR INTERSTAGE COOLING FOR AIR COMPRSSOR

Farmington, New Mexico

Basis: 1000 lb air compressed/hr

Design intermediate temperature, °F	140	160	180	all wet
Dry cooler cost, ¢/1000 lb	3.123	2.139	1.432	0
Wet cooler cost, ¢/1000 lb	2.367	2.633	2.861	3.346
Tower cost, ¢/1000 lb	0.081	0.131	0.180	0.319
Fan and pump energy, ¢/1000 lb	1.408	1.102	0.88	0.498
Compression energy cost, ¢/1000 lb	58.164	58.538	58.734	59.246
Total, ¢/1000 lb compressed	65.142	64.543	64.088	63.409
Water consumed, gal/1000 lb	0.851	1.929	3.097	7.215

Casper, Wyoming

Basis: 1000 lb air compressed/hr

Design intermediate temperature, °F	140	160	180	all wet
Dry cooler cost, ¢/1000 lb	2.886	2.100	1.259	0
Wet cooler cost, ¢/1000 lb	2.367	2.633	2.861	3.332
Tower cost, ¢/1000 lb	0.081	0.131	0.180	0.314
Fan and pump energy, ¢/1000 lb	1.316	1.084	0.808	0.490
Compression energy cost, ¢/1000 lb	57.921	58.210	58.629	58.949
Total, ¢/1000 lb compressed	64.571	64.157	63.738	63.085
Water consumed, gal/1000 lb	0.868	1.779	3.275	6.965

Charleston, West Virginia

Basis: 1000 lb air compressed/hr

Design intermediate temperature, °F	140	160	180	all wet
Dry cooler cost, ¢/1000 lb	2.381	1.573	0.964	0
Wet cooler cost, ¢/1000 lb	2.367	2.633	2.861	3.400
Tower cost, ¢/1000 lb	0.081	0.131	0.180	0.287
Fan and pump energy, ¢/1000 lb	1.124	0.864	0.684	0.450
Compression energy cost, ¢/1000 lb	59.128	59.309	59.450	59.553
Total, ¢/1000 lb compressed	65.081	64.510	64.140	63.690
Water consumed, gal/1000 lb	1.625	2.902	4.242	7.309

Akron, Ohio

Basis: 1000 lb air compressed/hr

Design intermediate temperature, °F	140	160	180	all wet
Dry cooler cost, ¢/1000 lb	2.181	1.421	0.839	0
Wet cooler cost, ¢/1000 lb	2.367	2.633	2.861	3.349
Tower cost, ¢/1000 lb	0.081	0.131	0.180	0.275
Fan and pump energy, ¢/1000 lb	1.040	0.800	0.632	0.428
Compression energy cost, ¢/1000 lb	58.713	58.877	59.006	59.071
Total, ¢/1000 lb compressed	64.382	63.862	63.519	63.123
Water consumed, gal/1000 lb	1.638	2.891	4.200	6.651

APPENDIX 8

BOILERS, ASH DISPOSAL AND FLUE GAS DESULFURIZATION

In the four SNG processes, coal or char is burnt to raise steam in a boiler. The furnaces are assumed to be dry bottomed pulverized coal type with 80 percent of the ash as fly ash and 20 percent as bottom ash. As occurs in some 65 percent of the power generating stations today, fly ash is assumed to be handled dry; that is, water is added to wet the ash equal to 10 percent of the ash weight. Furnace bottom ash is assumed sluiced (as it usually must be) with recycled sluice water. The thickened ash slurry removed is 35 percent water. All ash from all gasifiers is assumed handled with the bottom ash. The water evaporated to quench gasifier ash is included in the wet cooling load of the various processes. The heat from quenching furnace bottom ash is normally lost by convection from the ash bins. The evaporation load is small and ignored, as is any evaporation caused by radiant heat transfer through the furnace ash throat to the bottom ash collection hopper.

Where a solid fuel (coal or char) boiler is used, flue gas desulfurization by a wet lime/limestone scrub is used. The water consumed in this scrubber is calculated from the equations[1]:

lb makeup water evaporated per lb coal or char fired

$$= 12.8\left(\frac{c}{12} + \frac{s}{32}\right) + 10.5\left(\frac{h}{4} - \frac{x}{32}\right) - w - 9h$$

lb water in sludge per lb coal or char fired = 13.8s

lb wet sludge per lb coal or char fired = 19.7s where c, s, h, x and w are the weight fractions of carbon, sulfur, hydrogen, oxygen and water in the fuel as fired. The wet sludge is 30 percent solids and 70 percent water.

The various sludge and ash numbers have been calculated for each site/process on the worksheets in Appendix 10.

REFERENCE, APPENDIX 8

1. Goldstein, D.J. and Yung, D., Water Purification Associates, "Water Conservation and Pollution Control in Coal Conversion Processes," U.S. Environmental Protection Agency, Report EPA-600/7-77, June 1977.

APPENDIX 9

ADDITIONAL WATER NEEDS

Needs for water not defined in the preceding appendices on process water, ash disposal and flue gas desulfurization, and on cooling are:

Dust control

Sanitary, potable and service water

Evaporation from storage ponds

Revegetation

DUST CONTROL

Water sprayed for dust control in the mine, on the road from the mine to the plant, and in the plant depends on the rate of handling of coal and on the length of the mine roads. Considèred first is dust control on the mine roads.

The length of unpaved haul roads and mine bench areas depends on the mine productivity as measured by the amount of coal recoverable per unit area of stripped land. In the present study the following mine yields are used:

Location	10^3 lb/acres
Beulah, North Dakota[3]	50,000
Gillette, Wyoming[1,2]	180,000
Navajo, New Mexico[4]	74,000
Colstrip, Montana[5]	80,000

For want of other information, these yields are taken to be representative of all mines in the state. In the assumed mine model, the mining of 100 acres per year would require 2 miles of 45 ft wide unpaved haul roads to serve as spurs to conveyor belts that would feed the coal to the plant. Such a belt line operation is described in Reference 1. The bench area acreage that would have to be wetted down is approximately equal to four times the daily acreage that is mined. The sum of the two unpaved areas determines the area where dust control must be practiced. This area is 5,320 ft^2/(acre mined/yr).

The simplest means of holding down fugitive dust is to wet down the mine area and haul roads. It is assumed that the roads and mine area can be kept in a wetted condition through an annual deposition of water equal to the net annual evaporation rate. Any rainfall is taken to be an additional safety factor. The annual pond evaporation rates for the areas examined are:

Location	inches/year
Beulah, North Dakota	45
Gillette, Wyoming	54
Navajo, New Mexico	61
Colstrip, Montana	49

The lay-down rate can be calculated from the relation:

$$\text{lay-down rate} = \text{disturbed area} \times \text{evaporation rate}$$

That is, for 10^3 lb coal mined:

$$\begin{aligned}\text{lay-down rate, lb} &= (10^3 \text{ lb coal}) \times (\text{acres mined}/10^3 \text{ lb coal}) \\ &\times (5230 \text{ ft}^2 \text{ wetted/(acre mined/yr)}) \times (1 \text{ ft}/12 \text{ inches}) \\ &\times (\text{wetting rate, inches/yr}) \times (62.4 \text{ lb water/ft}^3)\end{aligned}$$

This equation gives:

Location	Water for Road, Mine & Embankment Dust Control ($lb\ water/10^3\ lb\ coal$)
Beulah, North Dakota	24.5
Gillette, Wyoming	8.2
Navajo, New Mexico	22.4
Colstrip, Montana	16.7

For most of the processes the coal mining rate is equal to the coal utilization rate, as given in the various process description sections. However, because the Lurgi gasifiers cannot accept fines, the coal mining rate for Lurgi is equal to 1.2 times the utilization rate. The fines are assumed to be sold.

East of the Mississippi, dust control of this type is assumed not to be required. However, when the coal is mined underground a variable amount of water is consumed in the mine. An average value of 50 lb water/10^3 lb coal is used in this study. Water sprayed for dust control underground is taken to be of a better quality than water sprayed for dust control above ground because of the confined area and the possible harm to people.

In addition to the water sprayed on roads, water must be sprayed on the coal itself. In all coal preparation plants, dust is generated in the stages of loading and unloading, breaking, conveying, crushing, general screening and storage. The water required to hold down this dust will be considered next.

The ways of preventing dust from becoming airborne are through the application of water sprays or of nontoxic chemicals and the use of dry or wet dust collectors with partial or total enclosure. It is assumed that the principal dust generating sources will be enclosed and that, where feasible, air will be circulated and dry bag dust collection employed. Whenever coal pulverization is necessary, it will be done under conditions of total enclosure with no fugitive dust or hold-down water requirements. In inactive storage the use of water for holding down dust can be minimized by the use of nontoxic chemicals.

Despite the design precautions indicated, in large-scale plants with many transfer points, transfer belts, surge bins, storage silos and active storage sites, it is necessary to employ water sprays to wet down the coal. This is also generally necessary with breaking and primary crushing operations An examination of the Wesco Lurgi plant design[4] and the TOSCO oil shale plant design[6] indicates that a consumptive use of <u>1 lb of water for every 50 lbs of coal handled and crushed</u> is a reasonably conservative estimate. This applies to the mine area.

Within the boundaries of any of the plants, water will also be needed for dust control. Somewhat less water would be required in the plants than in the mines, since many of the operations tend to be enclosed. On this basis a good assumption is a consumptive use of one-half that applicable to the mine areas, specifically, <u>1 lb of water for every 100 lbs of coal handled and transferred</u>. This is a little less water than that deduced from the data of Reference 3.

The total water for dust control is shown on Table A9-1.

SANITARY, POTABLE AND SERVICE WATER

This requirement depends on the number of people employed in the mine and plant. The number of people employed differs from site to site and process to process, but the variations are, in fact, small so a single number will suffice for all process/site combinations. About 650 people are employed in the plants and about 270 more in the mines[3,4,6,7,8]. Each person uses about 32 gal/man-shift. The total consumption of sanitary and potable water is therefore:

$$920 \text{ people} \times 32 \text{ gal/man-shift} \times 5 \text{ shifts/week} \times 1 \text{ week/168 hrs} \times 8.33 \text{ lb/gal} = 7300 \text{ lb/hr}$$

This is all recovered as sewage.

The service water usage in the mine and plant such as for equipment washing, maintenance, pump seals, etc., along with the fire water usage through evaporation loss, is a difficult quantity to estimate. However, an analysis of a number of mine designs indicates that this usage is essentially nonrecoverable and can be related to the usage of sanitary and potable water.

The estimated ratio for service to sanitary usage for a proposed 10×10^6 ton/yr surface mine near Gillette, Wyoming is about 1.6[7]. This same figure for the proposed Kaiparowits underground mine[8] is about 1.3, based on estimated sanitary water usage. The two values are sufficiently close that the average service water usage for the mine has been taken to be 1.5 times the sanitary water usage. Moreover, all of the water is taken to be consumed, since recovery in the mine work areas would prove quite difficult In the plant the service water requirement is probably higher and is taken to be two times the sanitary and potable needs with about 65 percent recovered as sewage.

The total water requirements are shown on Table A9-1.

REVEGETATION

As part of any reclamation of mined land in arid and semi-arid regions, there exists a potential requirement for supplemental irrigation water associated with the establishment of soil stabilizing plant cover on mine spoils. It is concluded that coal mined areas with greater than 10 inches of mean annual precipitation can be reclaimed without supplemental irrigation[9]. Where there is less than 10 inches of annual rainfall, partially reshaped coal mine spoils can be successfully revegetated with supplemental irrigation of about 10 inches during the first growing season, with no further requirement during subsequent growing seasons[10]. Only at the Navajo, New Mexico site is irrigation for revegetation required. The water requirement can be calculated from the following formula:

$$\begin{aligned}\text{Revegetation water, lb/hr} = {} & \text{(lb coal/hr)} \times \text{(acres mined/74} \times 10^6 \text{ lb coal)} \\ & \times \text{(10 inches water)} \times \text{(43,560 ft}^2\text{/acre)} \\ & \times \text{(1 ft/12 inches)} \times \text{(62.4 lb/ft}^3\text{)}\end{aligned}$$

Revegetation water in New Mexico is:

$$30.6 \text{ lb water}/10^3 \text{ lb coal}$$

EVAPORATION

All plants require a reservoir from which evaporation will occur. Net evaporation rates (pond evaporation minus precipitation) are:

	Net Evaporation (inches/hr)
North Dakota	30
Wyoming	40
New Mexico	53
Montana	35

East of the Mississippi, precipitation usually exceeds evaporation.

The rate of loss of water by evaporation in lb/hr is:

$$\frac{(\text{reservoir capacity, in}^3)}{\text{reservoir depth, in}} \times \frac{(\text{evaporation rate, in/yr})}{(27.7\ \text{in}^3/\text{lb})(8550\ \text{hr/yr})}$$

Take the reservoir depth to be 30 ft = 360 inches and the reservoir capacity to be about 2 weeks, or 4 percent of the annual water consumption. If Q is the water consumption in lb/hr, the reservoir capacity is:

$$(0.04 \times Q \times 8550)\ \text{lb} \times 27.7\ \text{in}^3/\text{lb} = 9473\ Q\ \text{in}^3$$

The evaporation rate is:

$$0.000111\ Q\ (\text{evaporation rate, in/yr})\ \text{lb/hr}$$

Evaporation rates are also entered on Table A9-1.

REFERENCES, APPENDIX 9

1. Wyoming Coal Gas Co. and Rochelle Coal Co., "Applicant's Environmental Assessment for a Proposed Gasification Project in Campbell and Converse Counties, Wyoming," prepared by SERNCO, October 1974.

2. Geological Survey, "Proposed Plan of Mining and Reclamation--Cordero Mine, Sun Oil Co., Coal Lease W-8385, Campbell County, Wyoming," Final Environmental Statement No. 76-22, U.S. Dept. of the Interior, April 30, 1976.

3. North Dakota Gasification Project for ANG Coal Gasification Co., "Environmental Impact Report in Connection with Joint Application of Michigan Wisconsin Pipe Line Co. and ANG Coal Gasification Co. for a Certificate of Public Convenience and Necessity, Woodward-Clyde Consultants," Fed. Power Commission Docket No. CP75-278, Vol. III, March 1975.

4. Batelle Columbus Laboratories, "Detailed Environmental Analysis Concerning a Proposed Gasification Plant for Transwestern Coal Gasification Co. Pacific Coal Gasification Co., Western Gasification and the Expansion of a Strip Mine Operation near Burnham, New Mexico, Owned and Operated by Utah International Inc.," Fed. Power Commission, February 1, 1973.

5. Gold, H., et al, "Water Requirements for Steam-Electric Power Generation and Synthetic Fuel Plants in the Western United States," EPA Report 600/7-77-037, February 1977.

6. Colony Development Operation, "An Environmental Impact Analysis for a Shale Oil Complex at Parachute Creek, Colorado, Part 1--Plant Complex and Service Corridor," Atlantic Richfield Co., Denver, Colo., 1974.

7. Atlantic Richfield Co., "Preliminary Environmental Impact Assessment for the Proposed Black Thunder Coal Mine, Campbell County, Wyoming" and "Revised Mining and Reclamation Plan for the Proposed Black Thunder Coal Mine," 1974; also, "Black Thunder Mine, 10 Million Ton Per Year Water Supply" (personal communication, Hugh W. Evans), Denver, Colo., March 6, 1975.

8. Bureau of Land Management, "Final Environmental Impact Statement Proposed Kaiparowits Project," Chapter I, FES-76-12, U.S. Dept. of the Interior, March 3, 1976.

9. National Academy of Sciences, _Rehabilitation Potential of Western Coal Lands_, pp. 32-33, Ballinger Publishing, Cambridge, Mass., 1974.

10. Aldon, F.E., "Techniques for Establishing Native Plants on Coal Mine Spoils in New Mexico," in _Proc. Third Symposium on Surface Mining and Reclamation_, Vol. I, pp. 28-28, National Coal Assoc., Washington, D.C., 1975.

TABLE A9-1. OTHER WATER NEEDS

Dust Control:

Sites	Water Required lb/lb Coal Handled*
North Dakota	0.055
Wyoming	0.038
New Mexico	0.052
Montana	0.047
East & Central:	
Surface Mining	0.03
Underground Mining	0.08

Service, Sanitary and Potable Water:

Sites	Water Required 10^3 lb/hr	Sewage Recovered 10^3 lb/hr
All sites, all plants	21	14

Revegetation Water:

Sites	Water Required lb/lb Coal Handled*
New Mexico only	0.0306

Evaporation:

Sites	Evaporation Losses as % of Water Consumed
North Dakota	0.33
Wyoming	0.44
New Mexico	0.59
Montana	0.39
Eastern & Central States	0.0

*For Lurgi plants, coal handled equals 1.2 times coal consumed.

APPENDIX 10

WORK SHEETS FOR NET WATER CONSUMED AND WET SOLID RESIDUALS GENERATED

A three-page work sheet is presented for each plant/site combination. On the first page is listed the coal quantities from the process appendix and flue gas desulfurization information (where needed) as well as water for ash handling from Appendix 8. On the second page the water and water streams are listed; process water streams from the process appendix, other streams from Appendix 9, and the grand total raw water input and treatment sludges from Appendix 11. On the third page the conversion efficiency, heat loss and the water evaported for cooling are given, calculated from the information in the process appendices and Appendix 7. The work sheets are enclosed in the following order:

Solvent Refined Coal
Synthoil
Hygas
Bigas
Synthane
Lurgi

For each process a cover sheet is given showing where each of the quantities found in the work sheet comes from.

WORK SHEET: WATER QUANTITY CALCULATIONS FOR SRC PROCESS

SITE:

PRODUCT SIZE: 10,000 ton/day

ENERGY: Table A1-7, Stream 3

Coal Analysis (wt % as-received)

Moisture	____	
C	____	Tables 3-18, 3-19
H	____	
O	____	
N	____	
S	____	
Ash	____	
	100	
HHV Calculated (10^3 Btu/lb)	____	

COAL FEED

to dissolver: Table A1-3; Table A1-7, Stream 5

to gasifier: Table A1-4, Stream 17; Table A1-8, Stream 17

ASH HANDLING

		10^3 lb/hr
Bottom ash:	dry	____
	water	____
	sludge	Appendix 8
Fly ash:	dry	____
	water	____
	sludge	____

(continued)

______________________________(continued)

PROCESS WATER

	10^3 lb/hr
a. Steam and boiler feed water required	Table A1-4, Stream 11 & 14 + 10,000 lb/hr
b. Dirty condensate from dissolving section	Table A1-3, Stream 5 + 10,000 lb/hr
c. Medium quality condensate from gasifier	Table A1-4, Stream 13
d. Medium quality condensate after shift	Table A1-4, Stream 15

OTHER WATER NEEDS

	10^3 lb/hr
a. Dust control	________
b. Service, sanitary & potable water:	
Required	________
Sewage recovered	Appendix 9
c. Revegetation water	________
d. Evaporation from storage ponds	________
GRAND TOTAL RAW WATER INPUT TO PLANT:	Appendix 11

TREATMENT SLUDGES

	10^3 lb/hr solids	10^3 lb/hr water & sludge
a. Lime softening	________	________
b. Ion exchange	Appendix 11	________
c. Biotreatment	________	________

______________________________(continued)

ENERGY

Energy Totals

	10^9 Btu/hr
Feed	Table A1-10
Product and byproduct	Table A1-10 (Total output energy)
Unrecovered heat	Table A1-10
Conversion efficiency	Table A1-10

Disposition of Unrecovered Heat

	10^9 Btu/hr	% wet	Btu/lb evap	10^3 lb water evap/hr
Direct loss	Table A1-11	________	________	________
Designed dry	Table A1-11	________	________	________
Designed wet	Table A1-11	________	________	________
Acid gas removal regenerator condenser	Table A1-11	Table A7-1	Table A7-2	CALCULATED
Total turbine condensers	Table A1-11			
Total gas compressor interstage cooling	Table A1-11	________	________	________
TOTAL:	Table A1-11			________

WORK SHEET: WATER QUANTITY CALCULATIONS FOR SRC PROCESS

SITE: Marengo, Alabama — Ground water & Surface water

PRODUCT SIZE: 10,000 ton/day

ENERGY: 12.92 x 10^9 Btu/hr

Coal Analysis (wt % as-received)

Moisture	48.7
C	32.1
H	2.2
O	9.8
N	0.6
S	1.8
Ash	4.8
	100
HHV Calculated (10^3 Btu/lb)	5.34

COAL FEED

to dissolver:	3231	10^3 lb/hr	to gasifier: 500	10^3 lb/hr
	17.3	10^9 Btu/hr	2.67	10^9 Btu/hr

FGD WATER

Vaporized	-0.11	lb/lb coal	0	10^3 lb/hr
With sludge	0.25	lb/lb coal	0	10^3 lb/hr
TOTAL:			0	10^3 lb/hr
FGD sludge produced, wet			0	10^3 lb/hr

ASH HANDLING

		10^3 lb/hr
Bottom ash:	dry	179
	water	96.4
	sludge	276
Fly ash:	dry	0
	water	0
	sludge	0

Marengo, Alabama SRC (continued)

PROCESS WATER

	10^3 lb/hr
a. Steam and boiler feed water required	428
b. Dirty condensate from dissolving section	247
c. Medium quality condensate from gasifier	223
d. Medium quality condensate after shift	153

OTHER WATER NEEDS

	10^3 lb/hr
a. Dust control	112
b. Service, sanitary & potable water:	
Required	21
Sewage recovered	14
c. Revegetation water	0
d. Evaporation from storage ponds	0
GRAND TOTAL RAW WATER INPUT TO PLANT:	1,354

TREATMENT SLUDGES (Note: Ground water and Surface water are the same)

	10^3 lb/hr solids	10^3 lb/hr water & sludge
a. Lime softening	0.3	1.7
b. Ion exchange	--	27
c. Biotreatment	0.4	2.0

(continued)

Marengo, Alabama SRC (continued)

ENERGY

Energy Totals

	10^9 Btu/hr
Feed	19.9
Product and byproduct	8.1
Unrecovered heat	11.8
Conversion efficiency	59.4 %

Disposition of Unrecovered Heat

	10^9 Btu/hr	% wet	Btu/lb evap	10^3 lb water evap/hr
Direct loss	3.92	0	1,310	0
Designed dry	0.78	0	1,310	0
Designed wet	1.03	100	1,310	786
Acid gas removal regenerator condenser	0.52	10	1,310	40
Total turbine condensers	1.35	10	1,310	103
Total gas compressor interstage cooling	0.49	100	1,310	374
TOTAL:	8.09			1,303

WORK SHEET: WATER QUANTITY CALCULATIONS FOR SRC PROCESS

SITE: Bureau, Illinois

PRODUCT SIZE: 10,000 ton/day

ENERGY: 13.16×10^9 Btu/hr

Coal Analysis (wt % as-received)

Moisture	16.1
C	60.1
H	4.1
O	8.3
N	1.1
S	2.9
Ash	7.4
	100
HHV Calculated (10^3 Btu/lb)	10.76

COAL FEED

to dissolver: 1,725 10^3 lb/hr; 18.6 10^9 Btu/hr

to gasifier: 77.0 10^3 lb/hr; 0.83 10^9 Btu/hr

FGD WATER

Vaporized	0.56 lb/lb coal	0 10^3 lb/hr
With sludge	0.40 lb/lb coal	0 10^3 lb/hr
TOTAL:		0 10^3 lb/hr
FGD sludge produced, wet		0 10^3 lb/hr

ASH HANDLING

		10^3 lb/hr
Bottom ash:	dry	129
	water	69.4
	sludge	198
Fly ash:	dry	0
	water	0
	sludge	0

(continued)

Bureau, Illinois SRC (continued)

PROCESS WATER

	10^3 lb/hr
a. Steam and boiler feed water required	290
b. Dirty condensate from dissolving section	81
c. Medium quality condensate from gasifier	21
d. Medium quality condensate after shift	85

OTHER WATER NEEDS

	10^3 lb/hr
a. Dust control	139
b. Service, sanitary & potable water:	
Required	21
Sewage recovered	14
c. Revegetation water	0
d. Evaporation from storage ponds	0
GRAND TOTAL RAW WATER INPUT TO PLANT:	1,747

TREATMENT SLUDGES

	10^3 lb/hr solids	10^3 lb/hr water & sludge
a. Lime softening	1.5	7.0
b. Ion exchange	--	17
c. Biotreatment	0.16	0.8

Bureau, Illinois SRC (continued)

ENERGY

Energy Totals

	10^9 Btu/hr
Feed	19.4
Product and byproduct	15.0
Unrecovered heat	4.4
Conversion efficiency	77.6 %

Disposition of Unrecovered Heat

	10^9 Btu/hr	% wet	Btu/lb evap	10^3 lb water evap/hr
Direct loss	1.86	0	1,390	0
Designed dry	0.27	0	1,390	0
Designed wet	0.80	100	1,390	576
Acid gas removal regenerator condenser	0.30	10	1,390	22
Total turbine condensers	0.85	100	1,390	612
Total gas compressor interstage cooling	0.27	100	1,390	194
TOTAL:	4.35			1,404

WORK SHEET: WATER QUANTITY CALCULATIONS FOR SRC PROCESS

SITE: White, Illinois

PRODUCT SIZE: 10,000 ton/day

ENERGY: 13.16×10^9 Btu/hr

Coal Analysis (wt % as-received)

Moisture	8.5
C	66.6
H	4.6
O	7.1
N	1.4
S	2.8
Ash	9.0
	100
HHV Calculated (10^3 Btu/lb)	12.10

COAL FEED

to dissolver:	1,557 10^3 lb/hr	to gasifier: 16.0 10^3 lb/hr
	18.8 10^9 Btu/hr	0.19 10^9 Btu/hr

FGD WATER

Vaporized	0.73 lb/lb coal	0 10^3 lb/hr
With sludge	0.39 lb/lb coal	0 10^3 lb/hr
TOTAL:		0 10^3 lb/hr
FGD sludge produced, wet		0 10^3 lb/hr

ASH HANDLING

		10^3 lb/hr
Bottom ash:	dry	142
	water	76.2
	sludge	218
Fly ash:	dry	0
	water	0
	sludge	0

White, Illinois SRC (continued)

PROCESS WATER

	10^3 lb/hr
a. Steam and boiler feed water required	228
b. Dirty condensate from dissolving section	48
c. Medium quality condensate from gasifier	9
d. Medium quality condensate after shift	64

OTHER WATER NEEDS

	10^3 lb/hr
a. Dust control	126
b. Service, sanitary & potable water:	
Required	21
Sewage recovered	14
c. Revegetation water	0
d. Evaporation from storage ponds	0
GRAND TOTAL RAW WATER INPUT TO PLANT:	1,617

TREATMENT SLUDGES

	10^3 lb/hr	
	solids	water & sludge
a. Lime softening	0.7	4
b. Ion exchange	--	14
c. Biotreatment	0.08	0.4

(continued)

White, Illinois SRC (continued)

ENERGY

Energy Totals

	10^9 Btu/hr
Feed	19.0
Product and byproduct	15.6
Unrecovered heat	3.4
Conversion efficiency	81.9 %

Disposition of Unrecovered Heat

	10^9 Btu/hr	% wet	Btu/lb evap	10^3 lb water evap/hr
Direct loss	1.49	0	1,370	0
Designed dry	0.19	0	1,370	0
Designed wet	0.62	100	1,370	453
Acid gas removal regenerator condenser	0.24	10	1,370	175
Total turbine condensers	0.69	100	1,370	504
Total gas compressor interstage cooling	0.21	100	1,370	153
TOTAL:	3.44			1,285

WORK SHEET: WATER QUANTITY CALCULATIONS FOR SRC PROCESS

SITE: Fulton, Illinois

PRODUCT SIZE: 10,000 ton/day

ENERGY: 13.16 x 10^9 Btu/hr

Coal Analysis (wt % as-received)

Moisture	15.6
C	58.8
H	4.1
O	7.3
N	1.1
S	3.1
Ash	10.0
	100
HHV Calculated (10^3 Btu/lb)	10.65

COAL FEED

to dissolver: 1,764 10^3 lb/hr; 18.8 10^9 Btu/hr

to gasifier: 60.0 10^3 lb/hr; 0.64 10^9 Btu/hr

FGD WATER

Vaporized	0.56 lb/lb coal	0 10^3 lb/hr
With sludge	0.49 lb/lb coal	0 10^3 lb/hr
TOTAL:		0 10^3 lb/hr
FGD sludge produced, wet		0 10^3 lb/hr

ASH HANDLING

		10^3 lb/hr
Bottom ash:	dry	182
	water	98.2
	sludge	281
Fly ash:	dry	0
	water	0
	sludge	0

(continued)

Fulton, Illinois SRC (continued)

PROCESS WATER

	10^3 lb/hr
a. Steam and boiler feed water required	271
b. Dirty condensate from dissolving section	66
c. Medium quality condensate from gasifier	18
d. Medium quality condensate after shift	78

OTHER WATER NEEDS

	10^3 lb/hr
a. Dust control	55
b. Service, sanitary & potable water:	
Required	21
Sewage recovered	14
c. Revegetation water	0
d. Evaporation from storage ponds	0
GRAND TOTAL RAW WATER INPUT TO PLANT:	1,297

TREATMENT SLUDGES

	10^3 lb/hr	
	solids	water & sludg
a. Lime softening	---	---
b. Ion exchange	---	11
c. Biotreatment	0.09	0.5
d. Electrodialysis	---	237

Fulton, Illinois SRC (continued)

ENERGY

Energy Totals

	10^9 Btu/hr
Feed	19.4
Product and byproduct	15.1
Unrecovered heat	4.3
Conversion efficiency	77.8 %

Disposition of Unrecovered Heat

	10^9 Btu/hr	% wet	Btu/lb evap	10^3 lb water evap/hr
Direct loss	1.89	0	1,390	0
Designed dry	0.25	0	1,390	0
Designed wet	0.85	100	1,390	612
Acid gas removal regenerator condenser	0.28	10	1,390	20
Total turbine condensers	0.80	10	1,390	58
Total gas compressor interstage cooling	0.25	50	1,390	90
TOTAL:	4.32			780

WORK SHEET: WATER QUANTITY CALCULATIONS FOR SRC PROCESS

SITE: Saline, Illinois

PRODUCT SIZE: 10,000 ton/day

ENERGY: 13.16×10^9 Btu/hr

Coal Analysis (wt % as-received)

Moisture	6.8
C	67.9
H	4.5
O	6.8
N	1.4
S	3.1
Ash	9.5
	100
HHV Calculated (10^3 Btu/lb)	12.26

COAL FEED

to dissolver:	1,527 10^3 lb/hr	to gasifier: 50.5 10^3 lb/hr
	18.7 10^9 Btu/hr	0.62 10^9 Btu/hr

FGD WATER

Vaporized	0.76 lb/lb coal	0 10^3 lb/hr
With sludge	0.43 lb/lb coal	0 10^3 lb/hr
TOTAL:		0 10^3 lb/hr
FGD sludge produced, wet		0 10^3 lb/hr

ASH HANDLING

		10^3 lb/hr
Bottom ash:	dry	150
	water	80.7
	sludge	231
Fly ash:	dry	0
	water	0
	sludge	0

PROCESS WATER

	10^3 lb/hr
a. Steam and boiler feed water required	272
b. Dirty condensate from dissolving section	42
c. Medium quality condensate from gasifier	12
d. Medium quality condensate after shift	78

OTHER WATER NEEDS

	10^3 lb/hr
a. Dust control	47
b. Service, sanitary & potable water:	
Required	21
Sewage recovered	14
c. Revegetation water	0
d. Evaporation from storage ponds	0
GRAND TOTAL RAW WATER INPUT TO PLANT:	1,020

TREATMENT SLUDGES

	10^3 lb/hr solids	water & sludge
a. Lime softening	0.4	2
b. Ion exchange	--	16
c. Biotreatment	0.06	0.3

(continued)

Saline, Illinois SRC (continued)

ENERGY

Energy Totals

	10^9 Btu/hr
Feed	19.3
Product and byproduct	15.4
Unrecovered heat	3.9
Conversion efficiency	79.8 %

Disposition of Unrecovered Heat

	10^9 Btu/hr	% wet	Btu/lb evap	10^3 lb water evap/hr
Direct loss	1.63	0	1,370	0
Designed dry	0.21	0	1,370	0
Designed wet	0.77	100	1,370	562
Acid gas removal regenerator condenser	0.28	10	1,370	20
Total turbine condensers	0.78	10	1,370	57
Total gas compressor interstage cooling	0.24	50	1,370	88
TOTAL:	3.91			727

WORK SHEET: WATER QUANTITY CALCULATIONS FOR SRC PROCESS

SITE: Rainbow #8, Wyoming

PRODUCT SIZE: 10,000 ton/day

ENERGY: 13.16 x 10^9 Btu/hr

Coal Analysis (wt % as-received)

Moisture	10.4
C	66.1
H	4.6
O	11.0
N	1.6
S	0.9
Ash	5.4
	100
HHV Calculated (10^3 Btu/lb)	11.65

COAL FEED

to dissolver: 1,569 10^3 lb/hr; 18.2 10^9 Btu/hr

to gasifier: 88.0 10^3 lb/hr; 1.03 10^9 Btu/hr

FGD WATER

Vaporized	0.68 lb/lb coal	0 10^3 lb/hr
With sludge	0.12 lb/lb coal	0 10^3 lb/hr
TOTAL:		0 10^3 lb/hr
FGD sludge produced, wet		0 10^3 lb/hr

ASH HANDLING

		10^3 lb/hr
Bottom ash:	dry	89.5
	water	48.2
	sludge	138
Fly ash:	dry	0
	water	0
	sludge	0

(continued)

Rainbow #8, Wyoming SRC (continued)

PROCESS WATER

	10^3 lb/hr
a. Steam and boiler feed water required	312
b. Dirty condensate from dissolving section	111
c. Medium quality condensate from gasifier	23
d. Medium quality condensate after shift	92

OTHER WATER NEEDS

	10^3 lb/hr
a. Dust control	63
b. Service, sanitary & potable water:	
Required	21
Sewage recovered	14
c. Revegetation water	0
d. Evaporation from storage ponds	0
GRAND TOTAL RAW WATER INPUT TO PLANT:	1,499

TREATMENT SLUDGES

	10^3 lb/hr solids	10^3 lb/hr water & sludge
a. Lime softening	1.1	6.0
b. Ion exchange	--	19
c. Biotreatment	0.18	0.90

Rainbow #8, Wyoming SRC (continued)

ENERGY

Energy Totals

	10^9 Btu/hr
Feed	19.3
Product and byproduct	15.1
Unrecovered heat	4.1
Conversion efficiency	78.8 %

Disposition of Unrecovered Heat

	10^9 Btu/hr	% wet	Btu/lb evap	10^3 lb water evap/hr
Direct loss	1.72	0	1,397	0
Designed dry	0.32	0	1,397	0
Designed wet	0.56	100	1,397	401
Acid gas removal regenerator condenser	0.32	10	1,397	23
Total turbine condensers	0.87	100	1,397	623
Total gas compressor interstage cooling	0.29	100	1,397	208
TOTAL:	4.08			1,255

WORK SHEET: WATER QUANTITY CALCULATIONS FOR SRC PROCESS

SITE: Gillette, Wyoming

PRODUCT SIZE: 10.000 ton/day

ENERGY: 12.92×10^9 Btu/hr

Coal Analysis (wt % as-received)

Moisture	30.4
C	45.8
H	3.4
O	11.3
N	0.6
S	0.7
Ash	7.8
	100
HHV Calculated (10^3 Btu/lb)	7.92

COAL FEED

to dissolver: 2,264 10^3 lb/hr; 17.9 10^9 Btu/hr

to gasifier: 145 10^3 lb/hr; 1.15 10^9 Btu/hr

FGD WATER

Vaporized	0.24 lb/lb coal	0 10^3 lb/hr
With sludge	0.10 lb/lb coal	0 10^3 lb/hr
TOTAL:		0 10^3 lb/hr
FGD sludge produced, wet		0 10^3 lb/hr

ASH HANDLING

		10^3 lb/hr
Bottom ash:	dry	188
	water	101
	sludge	289
Fly ash:	dry	0
	water	0
	sludge	0

Gillette, Wyoming SRC (continued)

PROCESS WATER

	10^3 lb/hr
a. Steam and boiler feed water required	308
b. Dirty condensate from dissolving section	186
c. Medium quality condensate from gasifier	57
d. Medium quality condensate after shift	97

OTHER WATER NEEDS

	10^3 lb/hr
a. Dust control	92
b. Service, sanitary & potable water:	
Required	21
Sewage recovered	14
c. Revegetation water	0
d. Evaporation from storage ponds	5
GRAND TOTAL RAW WATER INPUT TO PLANT:	802

TREATMENT SLUDGES

	10^3 lb/hr solids	water & sludge
a. Lime softening	1.0	5.0
b. Ion exchange	--	18
c. Biotreatment	0.30	1.5

(continued)

Gillette, Wyoming (continued)

ENERGY

Energy Totals

	10^9 Btu/hr
Feed	19.1
Product and byproduct	13.9
Unrecovered heat	5.2
Conversion efficiency	72.8 %

Disposition of Unrecovered Heat

	10^9 Btu/hr	% wet	Btu/lb evap	10^3 lb water evap/hr
Direct loss	2.60	0	1,401	0
Designed dry	0.46	0	1,401	0
Designed wet	0.56	100	1,401	400
Acid gas removal regenerator condenser	0.34	10	1,401	24
Total turbine condensers	0.93	10	1,401	66
Total gas compressor interstage cooling	0.31	50	1,401	111
TOTAL:	5.20			601

WORK SHEET: WATER QUANTITY CALCULATIONS FOR SRC PROCESS

SITE: Antelope Creek, Wyoming

PRODUCT SIZE: 10,000 ton/day

ENERGY: 12.92×10^9 Btu/hr

Coal Analysis (wt % as-received)

Moisture	26.2
C	52.6
H	3.6
O	12.0
N	0.6
S	0.5
Ash	4.5
	100
HHV Calculated (10^3 Btu/lb)	9.00

COAL FEED

to dissolver:	1,971 10^3 lb/hr	17.7 10^9 Btu/hr
to gasifier:	140 10^3 lb/hr	1.26 10^9 Btu/hr

FGD WATER

Vaporized	0.35 lb/lb coal	0 10^3 lb/hr
With sludge	0.07 lb/lb coal	0 10^3 lb/hr
TOTAL:		0 10^3 lb/hr
FGD sludge produced, wet		0 10^3 lb/hr

ASH HANDLING

		10^3 lb/hr
Bottom ash:	dry	95.0
	water	51.2
	sludge	146
Fly ash:	dry	0
	water	0
	sludge	0

(continued)

PROCESS WATER

	10^3 lb/hr
a. Steam and boiler feed water required	323
b. Dirty condensate from dissolving section	166
c. Medium quality condensate from gasifier	49
d. Medium quality condensate after shift	102

OTHER WATER NEEDS

	10^3 lb/hr
a. Dust control	81
b. Service, sanitary & potable water:	
Required	21
Sewage recovered	14
c. Revegetation water	0
d. Evaporation from storage ponds	5
GRAND TOTAL RAW WATER INPUT TO PLANT:	846

TREATMENT SLUDGES

	10^3 lb/hr solids	10^3 lb/hr water & sludge
a. Lime softening	--	--
b. Ion exchange	--	19
c. Biotreatment	0.26	1.3
d. Electrodialysis	--	120

227

ENERGY

Energy Totals

	10^9 Btu/hr
Feed	19.0
Product and byproduct	14.2
Unrecovered heat	4.8
Conversion efficiency	74.7 %

Disposition of Unrecovered Heat

	10^9 Btu/hr	% wet	Btu/lb evap	10^3 lb water evap/hr
Direct loss	2.21	0	1,397	0
Designed dry	0.43	0	1,397	0
Designed wet	0.48	100	1,397	344
Acid gas removal regenerator condenser	0.36	10	1,397	26
Total turbine condensers	0.95	10	1,397	68
Total gas compressor interstage cooling	0.32	50	1,397	115
TOTAL:	4.75			553

WORK SHEET: WATER QUANTITY CALCULATIONS FOR SRC PROCESS

SITE: Dickinson, North Dakota

PRODUCT SIZE: 10,000 ton/day

ENERGY: 12.92 x 10^9 Btu/hr

Coal Analysis (wt % as-received)

Moisture	41.2
C	37.6
H	2.7
O	11.0
N	0.5
S	0.5
Ash	6.5
	100
HHV Calculated (10^3 Btu/lb)	6.31

COAL FEED

to dissolver:	2,758 10^3 lb/hr	to gasifier:	308 10^3 lb/hr
	17.4 10^9 Btu/hr		1.94 10^9 Btu/hr

FGD WATER

Vaporized	0.23 lb/lb coal	0 10^3 lb/hr
With sludge	0.07 lb/lb coal	0 10^3 lb/hr
TOTAL:		0 10^3 lb/hr
FGD sludge produced, wet		0 10^3 lb/hr

ASH HANDLING

		10^3 lb/hr
Bottom ash:	dry	199
	water	107
	sludge	307
Fly ash:	dry	0
	water	0
	sludge	0

228

Dickinson, North Dakota SRC (continued)

PROCESS WATER

	10^3 lb/hr
a. Steam and boiler feed water required	374
b. Dirty condensate from dissolving section	234
c. Medium quality condensate from gasifier	127
d. Medium quality condensate after shift	127

OTHER WATER NEEDS

	10^3 lb/hr
a. Dust control	167
b. Service, sanitary & potable water:	
Required	21
Sewage recovered	14
c. Revegetation water	0
d. Evaporation from storage ponds	4
GRAND TOTAL RAW WATER INPUT TO PLANT:	907

TREATMENT SLUDGES

	10^3 lb/hr	
	solids	water & sludge
a. Lime softening	--	--
b. Ion exchange	--	22
c. Biotreatment	0.37	1.9

(continued)

ENERGY

Energy Totals

	10^9 Btu/hr
Feed	19.3
Product and byproduct	12.8
Unrecovered heat	6.5
Conversion efficiency	66.1 %

Disposition of Unrecovered Heat

	10^9 Btu/hr	% wet	Btu/lb evap	10^3 lb water evap/hr
Direct loss	3.25	0	1,420	0
Designed dry	0.63	0	1,420	0
Designed wet	0.64	100	1,420	451
Acid gas removal regenerator condenser	0.49	10	1,420	35
Total turbine condensers	1.14	10	1,420	80
Total gas compressor interstage cooling	0.40	50	1,420	141
TOTAL:	6.55			707

WORK SHEET: WATER QUANTITY CALCULATIONS FOR SRC PROCESS

SITE: Bentley, North Dakota

PRODUCT SIZE: 10,000 ton/day

ENERGY: 12.92×10^9 Btu/hr

Coal Analysis (wt % as-received)

Moisture	36.4
C	41.6
H	3.1
O	11.3
N	0.6
S	1.2
Ash	5.8
	100
HHV Calculated (10^3 Btu/lb)	7.14

COAL FEED

to dissolver: 2,493 10^3 lb/hr; 17.8 10^9 Btu/hr

to gasifier: 225 10^3 lb/hr; 1.61 10^9 Btu/hr

FGD WATER

Vaporized	0.13 lb/lb coal	0 10^3 lb/hr
With sludge	0.17 lb/lb coal	0 10^3 lb/hr
TOTAL:		0 10^3 lb/hr
FGD sludge produced, wet		0 10^3 lb/hr

ASH HANDLING

		10^3 lb/hr
Bottom ash:	dry	158
	water	84.9
	sludge	243
Fly ash:	dry	0
	water	0
	sludge	0

(continued)

PROCESS WATER

	10^3 lb/hr
a. Steam and boiler feed water required	346
b. Dirty condensate from dissolving section	213
c. Medium quality condensate from gasifier	91
d. Medium quality condensate after shift	113

OTHER WATER NEEDS

	10^3 lb/hr
a. Dust control	148
b. Service, sanitary & potable water:	
Required	21
Sewage recovered	14
c. Revegetation water	0
d. Evaporation from storage ponds	4
GRAND TOTAL RAW WATER INPUT TO PLANT:	947

TREATMENT SLUDGES

	10^3 lb/hr solids	water & sludge
a. Lime softening	0.8	4.0
b. Ion exchange	--	21
c. Biotreatment	0.34	1.7

Bentley, North Dakota SRC (continued)

ENERGY

Energy Totals

	10^9 Btu/hr
Feed	19.4
Product and byproduct	13.5
Unrecovered heat	5.9
Conversion efficiency	69.4 %

Disposition of Unrecovered Heat

	10^9 Btu/hr	% wet	Btu/lb evap	10^3 lb water evap/hr
Direct loss	2.86	0	1,420	0
Designed dry	0.55	0	1,420	0
Designed wet	0.73	100	1,420	514
Acid gas removal regenerator condenser	0.39	10	1,420	27
Total turbine condensers	1.05	10	1,420	74
Total gas compressor interstage cooling	0.36	50	1,420	127
TOTAL:	5.94			742

WORK SHEET: WATER QUANTITY CALCULATIONS FOR SRC PROCESS

SITE: Underwood, North Dakota

PRODUCT SIZE: 10,000 ton/day

ENERGY: 12.92 x 10^9 Btu/hr

Coal Analysis (wt % as-received)

Moisture	35.4
C	42.7
H	3.0
O	12.2
N	0.6
S	0.5
Ash	5.6
	100
HHV Calculated (10^3 Btu/lb)	7.14

COAL FEED

to dissolver:	2,429 10^3 lb/hr	to gasifier: 272 10^3 lb/hr
	17.3 10^9 Btu/hr	1.94 10^9 Btu/hr

FGD WATER

Vaporized	0.14 lb/lb coal	0 10^3 lb/hr
With sludge	0.07 lb/lb coal	0 10^3 lb/hr
TOTAL:		0 10^3 lb/hr
FGD sludge produced, wet		0 10^3 lb/hr

ASH HANDLING

		10^3 lb/hr
Bottom ash:	dry	151
	water	81.4
	sludge	233
Fly ash:	dry	0
	water	0
	sludge	0

Underwood, North Dakota SRC (continued)

PROCESS WATER

	10^3 lb/hr
a. Steam and boiler feed water required	383
b. Dirty condensate from dissolving section	226
c. Medium quality condensate from gasifier	104
d. Medium quality condensate after shift	127

OTHER WATER NEEDS

	10^3 lb/hr
a. Dust control	147
b. Service, sanitary & potable water:	
Required	21
Sewage recovered	14
c. Revegetation water	0
d. Evaporation from storage ponds	10
GRAND TOTAL RAW WATER INPUT TO PLANT:	1,724

TREATMENT SLUDGES

	10^3 lb/hr	
	solids	water & sludge
a. Lime softening	1.2	6
b. Ion exchange	--	23
c. Biotreatment	0.36	1.8

(continued)

Underwood, North Dakota (continued)

ENERGY

Energy Totals

	10^9 Btu/hr
Feed	19.3
Product and byproduct	13.3
Unrecovered heat	6.0
Conversion efficiency	69.1 %

Disposition of Unrecovered Heat

	10^9 Btu/hr	% wet	Btu/lb evap	10^3 lb water evap/hr
Direct loss	2.83	0	1,420	0
Designed dry	0.58	0	1,420	0
Designed wet	0.58	100	1,420	408
Acid gas removal regenerator condenser	0.44	10	1,420	31
Total turbine condensers	1.13	100	1,420	796
Total gas compressor interstage cooling	0.40	100	1,420	282
TOTAL:	5.96			1,517

WORK SHEET: WATER QUANTITY CALCULATIONS FOR SRC PROCESS

SITE: Otter Creek, Montana

PRODUCT SIZE: 10,000 ton/day

ENERGY: 12.92 x 10^9 Btu/hr

Coal Analysis (wt % as-received)

Moisture	29.4
C	50.3
H	2.9
O	11.2
N	0.6
S	0.6
Ash	5.0
	100
HHV Calculated (10^3 Btu/lb)	8.27

COAL FEED

to dissolver: 2,062 10^3 lb/hr; 17.1 10^9 Btu/hr

to gasifier: 286 10^3 lb/hr; 2.37 10^9 Btu/hr

FGD WATER

Vaporized	0.29 lb/lb coal	0 10^3 lb/hr
With sludge	0.08 lb/lb coal	0 10^3 lb/hr
TOTAL:		0 10^3 lb/hr
FGD sludge produced, wet		0 10^3 lb/hr

ASH HANDLING

		10^3 lb/hr
Bottom ash:	dry	117
	water	63.2
	sludge	181
Fly ash:	dry	0
	water	0
	sludge	0

(continued)

Otter Creek, Montana SRC (continued)

PROCESS WATER

	10^3 lb/hr
a. Steam and boiler feed water required	445
b. Dirty condensate from dissolving section	161
c. Medium quality condensate from gasifier	84
d. Medium quality condensate after shift	143

OTHER WATER NEEDS

	10^3 lb/hr
a. Dust control	110
b. Service, sanitary & potable water:	
Required	21
Sewage recovered	14
c. Revegetation water	0
d. Evaporation from storage ponds	6
GRAND TOTAL RAW WATER INPUT TO PLANT:	1,192

TREATMENT SLUDGES

	10^3 lb/hr solids	10^3 lb/hr water & sludge
a. Lime softening	0.2	1.0
b. Ion exchange	---	28
c. Biotreatment	0.26	1.3
d Electrodialysis	---	183

Otter Creek, Montana (continued)

ENERGY

Energy Totals

	10^9 Btu/hr
Feed	19.4
Product and byproduct	13.6
Unrecovered heat	5.8
Conversion efficiency	70.1 %

Disposition of Unrecovered Heat

	10^9 Btu/hr	% wet	Btu/lb evap	10^3 lb water evap/hr
Direct loss	2.51	0	1,407	0
Designed dry	0.51	0	1,407	0
Designed wet	0.65	100	1,407	462
Acid gas removal regenerator condenser	0.49	10	1,407	35
Total turbine condensers	1.23	10	1,407	87
Total gas compressor interstage cooling	0.42	50	1,407	149
TOTAL:	5.81			733

WORK SHEET: WATER QUANTITY CALCULATIONS FOR SRC PROCESS

SITE: Pumpkin Creek, Montana

PRODUCT SIZE: 10,000 ton/day

ENERGY: 12.92×10^9 Btu/hr

Coal Analysis (wt % as-received)

Moisture	30.7
C	44.6
H	3.1
O	12.5
N	0.7
S	0.5
Ash	7.9
	100
HHV Calculated (10^3 Btu/lb)	7.46

COAL FEED

to dissolver: 2,325 10^3 lb/hr; 17.3 10^9 Btu/hr

to gasifier: 270 10^3 lb/hr; 2.01 10^9 Btu/hr

FGD WATER

Vaporized	0.21 lb/lb coal	0 10^3 lb/hr
With sludge	0.07 lb/lb coal	0 10^3 lb/hr
TOTAL:		0 10^3 lb/hr
FGD sludge produced, wet		0 10^3 lb/hr

ASH HANDLING

		10^3 lb/hr
Bottom ash:	dry	205
	water	110
	sludge	315
Fly ash:	dry	0
	water	0
	sludge	0

Pumpkin Creek, Montana (continued)

PROCESS WATER

	10^3 lb/hr
a. Steam and boiler feed water required	396
b. Dirty condensate from dissolving section	222
c. Medium quality condensate from gasifier	94
d. Medium quality condensate after shift	129

OTHER WATER NEEDS

	10^3 lb/hr
a. Dust control	121
b. Service, sanitary & potable water:	
Required	21
Sewage recovered	14
c. Revegetation water	0
d. Evaporation from storage ponds	5
GRAND TOTAL RAW WATER INPUT TO PLANT:	952

TREATMENT SLUDGES

	10^3 lb/hr solids	10^3 lb/hr water & sludge
a. Lime softening	0.2	1.0
b. Ion exchange	--	24
c. Biotreatment	0.36	1.8

(continued)

Pumpkin Creek, Montana (continued)

ENERGY

Energy Totals

	10^9 Btu/hr
Feed	19.4
Product and byproduct	13.2
Unrecovered heat	6.2
Conversion efficiency	67.8 %

Disposition of Unrecovered Heat

	10^9 Btu/hr	% wet	Btu/lb evap	10^3 lb water evap/hr
Direct loss	2.70	0	1,414	0
Designed dry	0.58	0	1,414	0
Designed wet	0.67	100	1,414	474
Acid gas removal regenerator condenser	0.45	10	1,414	32
Total turbine condensers	1.14	10	1,414	81
Total gas compressor interstage cooling	0.40	50	1,414	141
TOTAL:	6.24			728

WORK SHEET: WATER QUANTITY CALCULATIONS FOR SRC PROCESS

SITE: Coalridge, Montana

PRODUCT SIZE: 10,000 ton/day

ENERGY: 12.92×10^9 Btu/hr

Coal Analysis (wt % as-received)

Moisture	40.4
C	35.2
H	2.4
O	13.5
N	0.6
S	0.4
Ash	7.5
	100
HHV Calculated (10^3 Btu/lb)	5.60

COAL FEED

to dissolver: 2.946 10^3 lb/hr; 16.5 10^9 Btu/hr

to gasifier: 620 10^3 lb/hr; 3.47 10^9 Btu/hr

FGD WATER

Vaporized	- 0.01 lb/lb coal	0 10^3 lb/hr
With sludge	0.06 lb/lb coal	0 10^3 lb/hr
TOTAL:		0 10^3 lb/hr
FGD sludge produced, wet		0 10^3 lb/hr

ASH HANDLING

		10^3 lb/hr
Bottom ash:	dry	267
	water	144
	sludge	411
Fly ash:	dry	0
	water	0
	sludge	0

(continued)

Coalridge, Montana SRC (continued)

PROCESS WATER

	10^3 lb/hr
a. Steam and boiler feed water required	521
b. Dirty condensate from dissolving section	330
c. Medium quality condensate from gasifier	251
d. Medium quality condensate after shift	189

OTHER WATER NEEDS

	10^3 lb/hr
a. Dust control	167
b. Service, sanitary & potable water:	
Required	21
Sewage recovered	14
c. Revegetation water	0
d. Evaporation from storage ponds	4
GRAND TOTAL RAW WATER INPUT TO PLANT:	1,081

TREATMENT SLUDGES

	10^3 lb/hr solids	10^3 lb/hr water & sludge
a. Lime softening	1.0	5.0
b. Ion exchange	--	31
c. Biotreatment	0.53	2.7

Coalridge, Montana (continued)

ENERGY

Energy Totals

	10^9 Btu/hr
Feed	20.0
Product and byproduct	11.8
Unrecovered heat	8.2
Conversion efficiency	59.1 %

Disposition of Unrecovered Heat

	10^9 Btu/hr	% wet	Btu/lb evap	10^3 lb water evap/hr
Direct loss	3.60	0	1,407	0
Designed dry	0.95	0	1,407	0
Designed wet	0.85	100	1,407	604
Acid gas removal regenerator condenser	0.65	10	1,407	45
Total turbine condensers	1.55	10	1,407	110
Total gas compressor interstage cooling	0.58	50	1,407	206
TOTAL:	8.17			965

WORK SHEET: WATER QUANTITY CALCULATIONS FOR SRC PROCESS

SITE: Colstrip, Montana

PRODUCT SIZE: 10,000 ton/day

ENERGY: 12.92×10^9 Btu/hr

Coal Analysis (wt % as-received)

Moisture	24.4
C	52.4
H	3.5
O	11.6
N	0.8
S	0.4
Ash	6.9
	100
HHV Calculated (10^3 Btu/lb)	8.91

COAL FEED

to dissolver:	1,979 10^3 lb/hr	to gasifier:	180 10^3 lb/hr
	17.6 10^9 Btu/hr		1.60 10^9 Btu/hr

FGD WATER

Vaporized	0.37 lb/lb coal	0 10^3 lb/hr
With sludge	0.06 lb/lb coal	0 10^3 lb/hr
TOTAL:		0 10^3 lb/hr
FGD sludge produced, wet		0 10^3 lb/hr

ASH HANDLING

		10^3 lb/hr
Bottom ash:	dry	149
	water	80
	sludge	229
Fly ash:	dry	0
	water	0
	sludge	0

PROCESS WATER

	10^3 lb/hr
a. Steam and boiler feed water required	364
b. Dirty condensate from dissolving section	160
c. Medium quality condensate from gasifier	55
d. Medium quality condensate after shift	114

OTHER WATER NEEDS

	10^3 lb/hr
a. Dust control	101
b. Service, sanitary & potable water:	
Required	21
Sewage recovered	14
c. Revegetation water	0
d. Evaporation from storage ponds	6
GRAND TOTAL RAW WATER INPUT TO PLANT:	1,051

TREATMENT SLUDGES

	10^3 lb/hr solids	10^3 lb/hr water & sludge
a. Lime softening	0.1	0.6
b. Ion exchange	--	22
c. Biotreatment	0.25	1.3

(continued)

Colstrip, Montana (continued)

ENERGY

Energy Totals

	10^9 Btu/hr
Feed	19.2
Product and byproduct	14.1
Unrecovered heat	5.1
Conversion efficiency	73.3 %

Disposition of Unrecovered Heat

	10^9 Btu/hr	% wet	Btu/lb evap	10^3 lb water evap/hr
Direct loss	2.27	0	1,414	0
Designed dry	0.45	0	1,414	0
Designed wet	0.62	100	1,414	438
Acid gas removal regenerator condenser	0.40	10	1,414	28
Total turbine condensers	1.03	10	1,414	73
Total gas compressor interstage cooling	0.36	100	1,414	255
TOTAL:	5.13			794

WORK SHEET: WATER QUANTITY CALCULATIONS FOR SYNTHOIL PROCESS

SITE:

PRODUCT SIZE: 50,000 bbl/day

ENERGY: 12.7 x 10^9 Btu/hr

Coal Analysis (wt % as-received)

Moisture	______	
C	______	Tables 3-18, 3-19
H	______	
O	______	
N	______	
S	______	
Ash	______	
	100	
HHV Calculated (10^3 Btu/lb)	______	

COAL FEED

to reactor: Table A2-1, Stream 2; Table A2-6

to gasifier: Table A2-2, Stream 3; Table A2-6

ASH HANDLING

		10^3 lb/hr
Bottom ash:	dry	______
	water	Appendix B
	sludge	______

(continued)

____________________(continued)

PROCESS WATER

		10^3 lb/hr
a.	Steam and boiler feed water required	Table A2-2, Streams 21 & 16
b.	Quench water required	Table A2-2, Stream 14
c.	Dirty condensate	Table A2-2, Stream 13
d.	Medium quality condensate from hydrogen production	Table A2-2, Stream 15
e.	Clean condensate from hydrogen production	Table A2-2, Stream 17

OTHER WATER NEEDS

		10^3 lb/hr
a.	Dust control	
b.	Service, sanitary & potable water:	
	Required	Appendix 9
	Sewage recovered	
c.	Revegetation water	
d.	Evaporation from storage ponds	
	GRAND TOTAL RAW WATER INPUT TO PLANT:	Appendix 11

TREATMENT SLUDGES

		10^3 lb/hr solids	10^3 lb/hr water & sludge
a.	Lime softening		
b.	Ion exchange	Appendix 11	
c.	Biotreatment		

____________________(continued)

ENERGY

Energy Totals

	10^9 Btu/hr
Feed	Table A2-6
Product and byproduct	Table A2-6
Unrecovered heat	Table A2-6
Conversion efficiency	Table A2-6

Disposition of Unrecovered Heat

	10^9 Btu/hr	% wet	Btu/lb evap	10^3 lb water evap/hr
Direct loss	Table A2-7			
Designed dry	Table A2-7			
Designed wet	Table A2-7	Table A7-1	Table A7-2	CALCULATED
Acid gas removal regenerator condenser	Table A2-7			
Total turbine condensers	Table A2-7			
Total gas compressor interstage cooling	Table A2-7			
TOTAL:	Table A2-7			

WORK SHEET: WATER QUANTITY CALCULATIONS FOR SYNTHOIL PROCESS

SITE: Jefferson, Alabama

PRODUCT SIZE: 50,000 bbl/day

ENERGY: 12.7 x 10^9 Btu/hr

Coal Analysis (wt % as-received)

Moisture	2.3
C	71.0
H	4.4
O	3.8
N	1.5
S	0.9
Ash	16.1
	100
HHV Calculated (10^3 Btu/lb)	12.79

COAL FEED

to reactor: 1,173 10^3 lb/hr; 15 10^9 Btu/hr

to gasifier: 218 10^3 lb/hr; 2.79 10^9 Btu/hr

ASH HANDLING

		10^3 lb/hr
Bottom ash:	dry	224
	water	121
	sludge	345

Jefferson, Alabama (continued)

PROCESS WATER

	10^3 lb/hr
a. Steam and boiler feed water required	232
b. Quench water required	266
c. Dirty condensate	23
d. Medium quality condensate from hydrogen production	59
e. Clean condensate from hydrogen production	67

OTHER WATER NEEDS

	10^3 lb/hr
a. Dust control	111
b. Service, sanitary & potable water:	
Required	21
Sewage recovered	14
c. Revegetation water	0
d. Evaporation from storage ponds	0
GRAND TOTAL RAW WATER INPUT TO PLANT:	2,237

TREATMENT SLUDGES

	10^3 lb/hr	
	solids	water & sludge
a. Lime softening	---	---
b. Ion exchange	---	15
c. Biotreatment	0.04	0.18

(continued)

ENERGY

Energy Totals

	10^9 Btu/hr
Feed	17.8
Product and byproduct	13.9
Unrecovered heat	3.9
Conversion efficiency	77.9 %

Disposition of Unrecovered Heat

	10^9 Btu/hr	% wet	Btu/lb evap	10^3 lb water evap/hr
Direct loss	1.192	0	1,310	0
Designed dry	0.12	0	1,310	0
Designed wet	1.00	100	1,310	763
Acid gas removal regenerator condenser	0.49	0	1,310	0
Total turbine condensers	0.87	100	1,310	664
Total gas compressor interstage cooling	0.27	100	1,310	206
TOTAL:	3.94			1,633

WORK SHEET: WATER QUANTITY CALCULATIONS FOR SYNTHOIL PROCESS

SITE: Gibson, Indiana

PRODUCT SIZE: 50,000 bbl/day

ENERGY: 12.7 x 10^9 Btu/hr

Coal Analysis (wt % as-received)

Moisture	10.0
C	68.2
H	4.6
O	7.6
N	1.1
S	2.1
Ash	6.4
	100
HHV Calculated (10^3 Btu/lb)	12.20

COAL FEED

to reactor:	1,221 10^3 lb/hr	14.9 10^9 Btu/hr
to gasifier:	234 10^3 lb/hr	2.85 10^9 Btu/hr

ASH HANDLING

		10^3 lb/hr
Bottom ash:	dry	93.1
	water	50.2
	sludge	143

(continued)

PROCESS WATER

	10^3 lb/hr
a. Steam and boiler feed water required	215
b. Quench water required	286
c. Dirty condensate	71
d. Medium quality condensate from hydrogen production	95
e. Clean condensate from hydrogen production	59

OTHER WATER NEEDS

	10^3 lb/hr
a. Dust control	116
b. Service, sanitary & potable water:	
Required	21
Sewage recovered	14
c. Revegetation water	0
d. Evaporation from storage ponds	0
GRAND TOTAL RAW WATER INPUT TO PLANT:	2,028

TREATMENT SLUDGES

	10^3 lb/hr solids	10^3 lb/hr water & sludge
a. Lime softening	0.6	3.0
b. Ion exchange	---	14
c. Biotreatment	0.11	0.57

Gibson, Indiana (continued)

ENERGY

Energy Totals

	10^9 Btu/hr
Feed	17.7
Product and byproduct	13.6
Unrecovered heat	4.1
Conversion efficiency	76.8%

Disposition of Unrecovered Heat

	10^9 Btu/hr	% wet	Btu/lb evap	10^3 lb water evap/hr
Direct loss	1.335	0	1,370	0
Designed dry	0.15	0	1,370	0
Designed wet	0.96	100	1,370	701
Acid gas removal regenerator condenser	0.50	0	1,370	0
Total turbine condensers	0.90	100	1,370	657
Total gas compressor interstage cooling	0.28	100	1,370	204
TOTAL:	4.12			1,562

WORK SHEET: WATER QUANTITY CALCULATIONS FOR SYNTHOIL PROCESS

SITE: Warrick, Indiana

PRODUCT SIZE: 50,000 bbl/day

ENERGY: 12.7 x 10^9 Btu/hr

Coal Analysis (wt % as-received)

Moisture	9.3
C	64.8
H	4.6
O	9.4
N	1.2
S	2.4
Ash	8.3
	100
HHV Calculated (10^3 Btu/lb)	11.65

COAL FEED

to reactor:	1,286 10^3 lb/hr	to gasifier:	246 10^3 lb/hr
	15.0 10^9 Btu/hr		2.87 10^9 Btu/hr

ASH HANDLING

		10^3 lb/hr
Bottom ash:	dry	127.1
	water	68.4
	sludge	195.6

Warrick, Indiana (continued)

PROCESS WATER

	10^3 lb/hr
a. Steam and boiler feed water required	211
b. Quench water required	289
c. Dirty condensate	99
d. Medium quality condensate from hydrogen production	103
e. Clean condensate from hydrogen production	57

OTHER WATER NEEDS

	10^3 lb/hr
a. Dust control	46
b. Service, sanitary & potable water:	
Required	21
Sewage recovered	14
c. Revegetation water	0
d. Evaporation from storage ponds	0
GRAND TOTAL RAW WATER INPUT TO PLANT:	2,126

TREATMENT SLUDGES

	10^3 lb/hr	
	solids	water & sludge
a. Lime softening	---	---
b. Ion exchange	---	13
c. Biotreatment	0.02	0.08

(continued)

Warr ck, Indiana (continued)

ENERGY

Energy Totals

	10^9 Btu/hr
Feed	17.8
Product and byproduct	13.6
Unrecovered heat	4.2
Conversion efficiency	76.3 %

Disposition of Unrecovered Heat

	10^9 Btu/hr	% wet	Btu/lb evap	10^3 lb water evap/hr
Direct loss	1.348	0	1,370	0
Designed dry	0.15	0	1,370	0
Designed wet	1.04	100	1,370	759
Acid gas removal regenerator condenser	0.50	0	1,370	0
Total turbine condensers	0.90	100	1,370	657
Total gas compressor interstage cooling	0.28	100	1,370	204
TOTAL:	4.22			1,620

WORK SHEET: WATER QUANTITY CALCULATIONS FOR SYNTHOIL PROCESS

SITE: Harlan, Kentucky

PRODUCT SIZE: 50,000 bbl/day

ENERGY: 12.7 x 10^9 Btu/hr

Coal Analysis (wt % as-received)

Moisture	3.6
C	77.8
H	5.1
O	7.6
N	1.5
S	0.6
Ash	3.8
	100
HHV Calculated (10^3 Btu/lb)	13.90

COAL FEED

to reactor: 1,071 10^3 lb/hr; 14.9 10^9 Btu/hr

to gasifier: 203 10^3 lb/hr; 2.82 10^9 Btu/hr

ASH HANDLING

		10^3 lb/hr
Bottom ash:	dry	48.4
	water	26.1
	sludge	74.5

(continued)

PROCESS WATER

	10^3 lb/hr
a. Steam and boiler feed water required	228
b. Quench water required	274
c. Dirty condensate	59
d. Medium quality condensate from hydrogen production	73
e. Clean condensate from hydrogen production	64

OTHER WATER NEEDS

	10^3 lb/hr
a. Dust control	102
b. Service, sanitary & potable water:	
Required	21
Sewage recovered	14
c. Revegetation water	0
d. Evaporation from storage ponds	0
GRAND TOTAL RAW WATER INPUT TO PLANT:	1,406

TREATMENT SLUDGES

	10^3 lb/hr solids	10^3 lb/hr water & sludge
a. Lime softening	---	---
b. Ion exchange	---	15
c. Biotreatment	0.01	0.05

Harlan, Kentucky (continued)

ENERGY

Energy Totals

	10^9 Btu/hr
Feed	17.7
Product and byproduct	13.8
Unrecovered heat	4.1
Conversion efficiency	78.1 %

Disposition of Unrecovered Heat

	10^9 Btu/hr	% wet	Btu/lb evap	10^3 lb water evap/hr
Direct loss	1.179	0	1,350	0
Designed dry	0.13	0	1,350	0
Designed wet	0.93	100	1,350	689
Acid gas removal regenerator condenser	0.50	0	1,350	0
Total turbine condensers	0.87	10	1,350	64
Total gas compressor interstage cooling	0.27	50	1,350	100
TOTAL:	3.88			853

WORK SHEET: WATER QUANTITY CALCULATIONS FOR SYNTHOIL PROCESS

SITE: Pike, Kentucky

PRODUCT SIZE: 50,000 bbl/day

ENERGY: 12.7×10^9 Btu/hr

Coal Analysis (wt % as-received)

Moisture	3.0
C	79.6
H	5.1
O	5.3
N	1.5
S	0.7
Ash	4.8
	100
HHV Calculated (10^3 Btu/lb)	14.30

COAL FEED

to reactor: 1,047 10^3 lb/hr; 14.9 10^9 Btu/hr

to gasifier: 196 10^3 lb/hr; 2.82 10^9 Btu/hr

ASH HANDLING

		10^3 lb/hr
Bottom ash:	dry	59.6
	water	32.1
	sludge	91.8

Pike, Kentucky (continued)

PROCESS WATER

	10^3 lb/hr
a. Steam and boiler feed water required	229
b. Quench water required	268
c. Dirty condensate	66
d. Medium quality condensate from hydrogen production	33
e. Clean condensate from hydrogen production	63

OTHER WATER NEEDS

	10^3 lb/hr
a. Dust control	37
b. Service, sanitary & potable water:	
Required	21
Sewage recovered	14
c. Revegetation water	0
d. Evaporation from storage ponds	0
GRAND TOTAL RAW WATER INPUT TO PLANT:	1,359

TREATMENT SLUDGES

	10^3 lb/hr solids	10^3 lb/hr water & sludge
a. Lime softening	---	---
b. Ion exchange	---	15
c. Biotreatment	0.01	0.05

(continued)

Pike, Kentucky (continued)

ENERGY

Energy Totals

	10^9 Btu/hr
Feed	17.8
Product and byproduct	13.9
Unrecovered heat	3.8
Conversion efficiency	78.4 %

Disposition of Unrecovered Heat

	10^9 Btu/hr	% wet	Btu/lb evap	10^3 lb water evap/hr
Direct loss	1.156	0	1,360	0
Designed dry	0.13	0	1,360	0
Designed wet	0.91	100	1,360	669
Acid gas removal regenerator condenser	0.50	0	1,360	0
Total turbine condensers	0.86	10	1,360	63
Total gas compressor interstage cooling	0.27	100	1,360	199
TOTAL:	3.83			931

WORK SHEET: WATER QUANTITY CALCULATIONS FOR SYNTHOIL PROCESS

SITE: Tuscarawas, Ohio (Ground water and surface water)

PRODUCT SIZE: 50,000 bbl/day

ENERGY: 12.7 x 10^9 Btu/hr

Coal Analysis (wt % as-received)

Moisture	6.3
C	71.2
H	4.9
O	8.1
N	1.4
S	2.5
Ash	5.6
	100
HHV Calculated (10^3 Btu/lb)	12.90

COAL FEED

to reactor: 1,170 10^3 lb/hr; 15.1 10^9 Btu/hr

to gasifier: 220 10^3 lb/hr; 2.84 10^9 Btu/hr

ASH HANDLING

		10^3 lb/hr
Bottom ash:	dry	77.8
	water	41.9
	sludge	120

(continued)

Tuscarawas, Ohio (continued)

PROCESS WATER

	10^3 lb/hr
a. Steam and boiler feed water required	219
b. Quench water required	278
c. Dirty condensate	73
d. Medium quality condensate from hydrogen production	83
e. Clean condensate from hydrogen production	61

OTHER WATER NEEDS

	10^3 lb/hr
a. Dust control	111
b. Service, sanitary & potable water:	
Required	21
Sewage recovered	14
c. Revegetation water	0
d. Evaporation from storage ponds	0
GRAND TOTAL RAW WATER INPUT TO PLANT:	1,493

TREATMENT SLUDGES

	Ground water 10^3 lb/hr		Surface Water 10^3 lb/hr	
	solids	water & sludge	solids	water & sludge
a. Lime softening	0.7	3.5	0.8	4.3
b. Ion exchange	---	14	---	14
c. Biotreatment	0.01	0.06	0.01	0.06

Tuscarawas, Ohio (continued)

ENERGY

Energy Totals

	10^9 Btu/hr
Feed	17.9
Product and byproduct	13.8
Unrecovered heat	4.1
Conversion efficiency	77.0 %

Disposition of Unrecovered Heat

	10^9 Btu/hr	% wet	Btu/lb evap	10^3 lb water evap/hr
Direct loss	1.242	0	1,410	0
Designed dry	0.14	0	1.410	0
Designed wet	1.10	100	1,410	780
Acid gas removal regenerator condenser	0.50	0	1,410	0
Total turbine condensers	0.88	10	1,410	62
Total gas compressor interstage cooling	0.27	100	1,410	191
TOTAL:	4.13			1,033

WORK SHEET: WATER QUANTITY CALCULATIONS FOR SYNTHOIL PROCESS

SITE: Jefferson, Ohio

PRODUCT SIZE: 50,000 bbl/day

ENERGY: 12.7 x 10^9 Btu/hr

Coal Analysis (wt % as-received)

Moisture	2.4
C	71.1
H	4.9
O	5.3
N	1.2
S	5.0
Ash	10.1
	100
HHV Calculated (10^3 Btu/lb)	13.10

COAL FEED

to reactor:	1,172 10^3 lb/hr	15.4 10^9 Btu/hr
to gasifier:	214 10^3 lb/hr	2.80 10^9 Btu/hr

ASH HANDLING

		10^3 lb/hr
Bottom ash:	dry	139.9
	water	75.4
	sludge	215.3

Jefferson, Ohio (continued)

PROCESS WATER

	10^3 lb/hr
a. Steam and boiler feed water required	225
b. Quench water required	265
c. Dirty condensate	40
d. Medium quality condensate from hydrogen production	59
e. Clean condensate from hydrogen production	66

OTHER WATER NEEDS

	10^3 lb/hr
a. Dust control	42
b. Service, sanitary & potable water:	
Required	21
Sewage recovered	14
c. Revegetation water	0
d. Evaporation from storage ponds	0
GRAND TOTAL RAW WATER INPUT TO PLANT:	2,069

TREATMENT SLUDGES

	10^3 lb/hr	
	solids	water & sludge
a. Lime softening	---	---
b. Ion exchange	---	14
c. Biotreatment	0.01	0.03

(continued)

Jefferson, Ohio (continued)

ENERGY

Energy Totals

	10^9 Btu/hr
Feed	18.2
Product and byproduct	11.1
Unrecovered heat	4.1
Conversion efficiency	77.6 %

Disposition of Unrecovered Heat

	10^9 Btu/hr	% wet	Btu/lb evap	10^3 lb water evap/hr
Direct loss	1.232	0	1,400	0
Designed dry	0.12	0	1,400	0
Designed wet	1.10	100	1,400	786
Acid gas removal regenerator condenser	0.48	0	1,400	0
Total turbine condensers	0.86	100	1,400	614
Total gas compressor interstage cooling	0.28	100	1,400	200
TOTAL:	4.07			1,600

WORK SHEET: WATER QUANTITY CALCULATIONS FOR SYNTHOIL PROCESS

SITE: Somerset, Pennsylvania

PRODUCT SIZE: 50,000 bbl/day

ENERGY: 12.7 x 10^9 Btu/hr

Coal Analysis (wt % as-received)

Moisture	1.8
C	74.0
H	4.0
O	3.1
N	1.4
S	2.1
Ash	13.6
	100
HHV Calculated (10^3 Btu/lb)	13.08

COAL FEED

to reactor: 1,126 10^3 lb/hr; 14.7 10^9 Btu/hr

to gasifier: 213 10^3 lb/hr; 2.79 10^9 Btu/hr

ASH HANDLING

		10^3 lb/hr
Bottom ash:	dry	182.1
	water	98.0
	sludge	280.0

(continued)

Somerset, Pennsylvania (continued)

PROCESS WATER

	10^3 lb/hr
a. Steam and boiler feed water required	245
b. Quench water required	266
c. Dirty condensate	13
d. Medium quality condensate from hydrogen production	59
e. Clean condensate from hydrogen production	68

OTHER WATER NEEDS

	10^3 lb/hr
a. Dust control	107
b. Service, sanitary & potable water:	
Required	21
Sewage recovered	14
c. Revegetation water	0
d. Evaporation from storage ponds	0
GRAND TOTAL RAW WATER INPUT TO PLANT:	1,581

TREATMENT SLUDGES

	10^3 lb/hr solids	10^3 lb/hr water & sludge
a. Lime softening	---	---
b. Ion exchange	---	16
c. Biotreatment	0.002	0.01

Somerset, Pennsylvania (continued)

ENERGY

Energy Totals

	10^9 Btu/hr
Feed	17.5
Product and byproduct	13.6
Unrecovered heat	3.9
Conversion efficiency	77.4 %

Disposition of Unrecovered Heat

	10^9 Btu/hr	% wet	Btu/lb evap	10^3 lb water evap/hr
Direct loss	1.159	0	1,410	0
Designed dry	0.13	0	1,410	0
Designed wet	1.03	100	1,410	730
Acid gas removal regenerator condenser	0.50	0	1,410	0
Total turbine condensers	0.86	10	1,410	61
Total gas compressor interstage cooling	0.27	100	1,410	191
TOTAL:	3.95			982

WORK SHEET: WATER QUANTITY CALCULATIONS FOR SYNTHOIL PROCESS

SITE: Mingo, West Virginia

PRODUCT SIZE: 50,000 bbl/day

ENERGY: 12.7×10^9 Btu/hr

Coal Analysis (wt % as-received)

Moisture	2.2
C	79.5
H	5.2
O	5.9
N	1.4
S	0.9
Ash	4.9
	100
HHV Calculated (10^3 Btu/lb)	14.30

COAL FEED

to reactor: 1,048 10^3 lb/hr; 15.0 10^9 Btu/hr

to gasifier: 196 10^3 lb/hr; 2.80 10^9 Btu/hr

ASH HANDLING

		10^3 lb/hr
Bottom ash:	dry	61.0
	water	32.8
	sludge	93.8

Mingo, West Virginia (continued)

PROCESS WATER

		10^3 lb/hr
a.	Steam and boiler feed water required	228
b.	Quench water required	267
c.	Dirty condensate	40
d.	Medium quality condensate from hydrogen production	62
e.	Clean condensate from hydrogen production	66

OTHER WATER NEEDS

		10^3 lb/hr
a.	Dust control	37
b.	Service, sanitary & potable water:	
	Required	21
	Sewage recovered	14
c.	Revegetation water	0
d.	Evaporation from storage ponds	0
	GRAND TOTAL RAW WATER INPUT TO PLANT:	1,352

TREATMENT SLUDGES

		10^3 lb/hr solids	10^3 lb/hr water & sludge
a.	Lime softening	---	---
b.	Ion exchange	---	15
c.	Biotreatment	0.01	0.03

(continued)

ENERGY

Energy Totals

	10^9 Btu/hr
Feed	17.8
Product and byproduct	14.0
Unrecovered heat	3.8
Conversion efficiency	78.6 %

Disposition of Unrecovered Heat

	10^9 Btu/hr	% wet	Btu/lb evap	10^3 lb water evap/hr
Direct loss	1.152	0	1,360	0
Designed dry	0.13	0	1,360	0
Designed wet	0.91	100	1,360	669
Acid gas removal regenerator condenser	0.49	0	1,360	0
Total turbine condensers	0.86	10	1,360	63
Total gas compressor interstage cooling	0.27	100	1,360	199
TOTAL:	3.81			931

WORK SHEET: WATER QUANTITY CALCULATIONS FOR SYNTHOIL PROCESS

SITE: Lake de Smet, Wyoming

PRODUCT SIZE: 50,000 bbl/day

ENERGY: 12.7 x 10^9 Btu/hr

Coal Analysis (wt % as-received)

Moisture	23.6
C	48.3
H	3.5
O	13.2
N	0.7
S	1.0
Ash	9.7
	100
HHV Calculated (10^3 Btu/lb)	8.20

COAL FEED

to reactor: 1,725 10^3 lb/hr; 14.1 10^9 Btu/hr

to gasifier: 413 10^3 lb/hr; 3.39 10^9 Btu/hr

ASH HANDLING

		10^3 lb/hr
Bottom ash:	dry	207
	water	112
	sludge	319

(continued)

PROCESS WATER

	10^3 lb/hr
a. Steam and boiler feed water required	197
b. Quench water required	352
c. Dirty condensate	206
d. Medium quality condensate from hydrogen production	243
e. Clean condensate from hydrogen production	45

OTHER WATER NEEDS

	10^3 lb/hr
a. Dust control	82
b. Service, sanitary & potable water:	
Required	21
Sewage recovered	14
c. Revegetation water	0
d. Evaporation from storage ponds	8
GRAND TOTAL RAW WATER INPUT TO PLANT:	1,805

TREATMENT SLUDGES

	10^3 lb/hr solids	10^3 lb/hr water & sludge
a. Lime softening	---	---
b. Ion exchange	---	13
c. Biotreatment	0.33	1.7

Lake de Smet, Wyoming (continued)

ENERGY

Energy Totals

	10^9 Btu/hr
Feed	17.5
Product and byproduct	12.7
Unrecovered heat	4.8
Conversion efficiency	72.4 %

Disposition of Unrecovered Heat

	10^9 Btu/hr	% wet	Btu/lb evap	10^3 lb water evap/hr
Direct loss	1.876	0	1,401	0
Designed dry	0.26	0	1,401	0
Designed wet	0.81	100	1,401	578
Acid gas removal regenerator condenser	0.56	0	1,401	0
Total turbine condensers	1.01	100	1,401	721
Total gas compressor interstage cooling	0.31	100	1,401	221
TOTAL:	4.83			1,520

WORK SHEET: WATER QUANTITY CALCULATIONS FOR SYNTHOIL PROCESS

SITE: Jim Bridger, Wyoming

PRODUCT SIZE: 50,000 bbl/day

ENERGY: 12.7×10^9 Btu/hr

Coal Analysis (wt % as-received)

Moisture	21.2
C	51.9
H	3.2
O	13.9
N	1.1
S	0.5
Ash	8.2
	100
HHV Calculated (10^3 Btu/lb)	8.50

COAL FEED

to reactor:	1,605 10^3 lb/hr	to gasifier:	449 10^3 lb/hr
	13.6 10^9 Btu/hr		3.81 10^9 Btu/hr

ASH HANDLING

		10^3 lb/hr
Bottom ash:	dry	168.4
	water	90.7
	sludge	259

Jim Bridger, Wyoming (continued)

PROCESS WATER

	10^3 lb/hr
a. Steam and boiler feed water required	213
b. Quench water required	351
c. Dirty condensate	201
d. Medium quality condensate from hydrogen production	234
e. Clean condensate from hydrogen production	43

OTHER WATER NEEDS

	10^3 lb/hr
a. Dust control	78
b. Service, sanitary & potable water:	
Required	21
Sewage recovered	14
c. Revegetation water	0
d. Evaporation from storage ponds	5
GRAND TOTAL RAW WATER INPUT TO PLANT:	1,205

TREATMENT SLUDGES

	10^3 lb/hr	
	solids	water & sludge
a. Lime softening	---	---
b. Ion exchange	---	14
c. Biotreatment	0.32	1.6

(continued)

Jim Bridger, Wyoming (continued)

ENERGY

Energy Totals

	10^9 Btu/hr
Feed	17.5
Product and byproduct	12.7
Unrecovered heat	4.8
Conversion efficiency	72.8 %

Disposition of Unrecovered Heat

	10^9 Btu/hr	% wet	Btu/lb evap	10^3 lb water evap/hr
Direct loss	1.76	0	1,397	0
Designed dry	0.25	0	1,397	0
Designed wet	0.87	100	1,397	623
Acid gas removal regenerator condenser	0.57	0	1,397	0
Total turbine condensers	0.99	10	1,397	71
Total gas compressor interstage cooling	0.31	100	1,397	222
TOTAL:	4.75			916

WORK SHEET: WATER QUANTITY CALCULATIONS FOR SYNTHOIL PROCESS

SITE: Gallup, New Mexico

PRODUCT SIZE: 50,000 bbl/day

ENERGY: 12.7 x 10^9 Btu/hr

Coal Analysis (wt % as-received)

Moisture	15.1
C	63.2
H	4.7
O	10.4
N	1.1
S	0.4
Ash	5.1
	100
HHV Calculated (10^3 Btu/lb)	11.30

COAL FEED

to reactor: 1,318 10^3 lb/hr; 14.9 10^9 Btu/hr

to gasifier: 258 10^3 lb/hr; 2.92 10^9 Btu/hr

ASH HANDLING

		10^3 lb/hr
Bottom ash:	dry	80.4
	water	43.3
	sludge	124

(continued)

PROCESS WATER

		10^3 lb/hr
a.	Steam and boiler feed water required	197
b.	Quench water required	302
c.	Dirty condensate	115
d.	Medium quality condensate from hydrogen production	130
e.	Clean condensate from hydrogen production	53

OTHER WATER NEEDS

		10^3 lb/hr
a.	Dust control	83
b.	Service, sanitary & potable water:	
	Required	21
	Sewage recovered	14
c.	Revegetation water	48
d.	Evaporation from storage ponds	8
	GRAND TOTAL RAW WATER INPUT TO PLANT:	1,313

TREATMENT SLUDGES

		10^3 lb/hr solids	10^3 lb/hr water & sludge
a.	Lime softening	---	---
b.	Ion exchange	---	13
c.	Biotreatment	0.19	0.95
d.	Electrodialysis	---	130

Gallup, New Mexico (continued)

ENERGY

Energy Totals

	10^9 Btu/hr
Feed	17.8
Product and byproduct	13.5
Unrecovered heat	4.3
Conversion efficiency	75.9 %

Disposition of Unrecovered Heat

	10^9 Btu/hr	% wet	Btu/lb evap	10^3 lb water evap/hr
Direct loss	1.458	0	1,375	0
Designed dry	0.17	0	1,375	0
Designed wet	0.95	100	1,375	691
Acid gas removal regenerator condenser	0.51	0	1,375	0
Total turbine condensers	0.92	10	1,375	67
Total gas compressor interstage cooling	0.29	50	1,375	105
TOTAL:	4.3			863

HYGAS

WORK SHEET: WATER QUANTITY CALCULATIONS FOR HYGAS PROCESS

SITE:

PRODUCT SIZE: 250 x 10^6 SCF/day

ENERGY: Table A3-11 (Product gas)

Coal Analysis (wt % as-received)

Moisture	______	
C	______	Tables 3-18, 3-19
H	______	
O	______	
N	______	
S	______	
Ash	______	
	100	
HHV Calculated (10^3 Btu/lb)	______	

COAL FEED

to reactor: Table A3-10 / Table A3-11

to boiler: Table A3-10 / Table A3-11

FGD WATER

Vaporized	Appendix 8	______	
With sludge	Appendix 8	______	10^3 lb/hr
TOTAL:		Calcd.	10^3 lb/hr
FGD sludge produced, wet		______	10^3 lb/hr

ASH HANDLING

		10^3 lb/hr
Bottom ash:	dry	______
	water	______
	sludge	Appendix 8
Fly ash:	dry	______
	water	______
	sludge	______

(continued)

______________________________(continued)

PROCESS WATER

	10^3 lb/hr
a. Steam and boiler feed water required	Table A3-10
b. Dirty condensate	Table A3-10
c. Methanation water	Table A3-10

OTHER WATER NEEDS

	10^3 lb/hr
a. Dust control	______
b. Service, sanitary & potable water:	
Required	Appendix 9
Sewage recovered	______
c. Revegetation water	______
d. Evaporation from storage ponds	______
GRAND TOTAL RAW WATER INPUT TO PLANT:	Appendix 11

TREATMENT SLUDGES

	10^3 lb/hr solids	10^3 lb/hr water & sludge
a. Lime softening	______	______
b. Ion exchange	Appendix 11	
c. Biotreatment	______	______

______________________________(continued)

ENERGY

Energy Totals

	10^9 Btu/hr
Feed	Table A3-11 (coal to pretreatment & boiler)
Product and byproduct	Table A3-11 (Product gas & fines, tar and oil)
Unrecovered heat	Table A3-11
Conversion efficiency	Table A3-11

Disposition of Unrecovered Heat

	10^9 Btu/hr	% wet	Btu/lb evap	10^3 lb water evap/hr
Direct loss	Calcd. from efficiency	______	______	______
Designed dry	______	Table A7-1	Table A7-2	CALCULATED
Designed wet	______			
Acid gas removal regenerator condenser	Table A3-9			
Total turbine condensers	______	______	______	______
Total gas compressor interstage cooling	______	______	______	______
TOTAL:	Table A3-11			______

WORK SHEET: WATER QUANTITY CALCULATIONS FOR HYGAS PROCESS

SITE: Jefferson, Alabama

PRODUCT SIZE: 250 x 10^6 SCF/day

ENERGY: 10.34 x 10^9 Btu/hr

Coal Analysis (wt % as-received)

Moisture	2.3
C	71.0
H	4.4
O	3.8
N	1.5
S	0.9
Ash	16.1
	100
HHV Calculated (10^3 Btu/lb)	12.79

COAL FEED

to reactor:	1,149 10^3 lb/hr	to boiler:	115 10^3 lb/hr
	14.7 10^9 Btu/hr		1.47 10^9 Btu/hr

FGD WATER

Vaporized	0.84 lb/lb coal	96.5 10^3 lb/hr
With sludge	0.12 lb/lb coal	13.8 10^3 lb/hr
TOTAL:		110 10^3 lb/hr
FGD sludge produced, wet		19.7 10^3 lb/hr

ASH HANDLING

		10^3 lb/hr
Bottom ash:	dry	189
	water	102
	sludge	290
Fly ash:	dry	14.8
	water	1.48
	sludge	16.3

Jefferson, Alabama (continued)

PROCESS WATER

	10^3 lb/hr
a. Steam and boiler feed water required	1,434
b. Dirty condensate	537
c. Methanation water	180

OTHER WATER NEEDS

	10^3 lb/hr
a. Dust control	101
b. Service, sanitary & potable water:	
Required	21
Sewage recovered	14
c. Revegetation water	0
d. Evaporation from storage ponds	0
GRAND TOTAL RAW WATER INPUT TO PLANT:	2,130

TREATMENT SLUDGES

	10^3 lb/hr solids	10^3 lb/hr water & sludge
a. Lime softening	0.01	0.05
b. Ion exchange	---	80
c. Biotreatment	0.1	0.5

(continued)

Jefferson, Alabama (continued)

ENERGY

Energy Totals

	10^9 Btu/hr
Feed	16.2
Product and byproduct	10.7
Unrecovered heat	5.5
Conversion efficiency	65.9 %

Disposition of Unrecovered Heat

	10^9 Btu/hr	% wet	Btu/lb evap	10^3 lb water evap/hr
Direct loss	2.92	0	1,310	0
Designed dry	0.55	0	1,310	0
Designed wet	0.40	100	1,310	305
Acid gas removal regenerator condenser	0.80	10	1,310	61
Total turbine condensers	0.67	100	1,310	511
Total gas compressor interstage cooling	0.17	100	1,310	130
TOTAL:	5.51			1,007

WORK SHEET: WATER QUANTITY CALCULATIONS FOR HYGAS PROCESS

SITE: Marengo, Alabama (Ground water and surface water)

PRODUCT SIZE: 250 x 10^6 SCF/day

ENERGY: 10.34 x 10^9 Btu/hr

Coal Analysis (wt % as-received)

Moisture	48.7
C	32.1
H	2.2
O	9.8
N	0.6
S	1.8
Ash	4.8
	100
HHV Calculated (10^3 Btu/lb)	5.34

COAL FEED

to reactor: 2,281 10^3 lb/hr; 12.2 10^9 Btu/hr

to boiler: 148 10^3 lb/hr; 1.67 10^9 Btu/hr

FGD WATER

Vaporized	-0.11 lb/lb coal	(treat as zero)	0 10^3 lb/hr
With sludge	0.25 lb/lb coal		37.0 10^3 lb/hr
TOTAL:			37.0 10^3 lb/hr
FGD sludge produced, wet			52.8 10^3 lb/hr

ASH HANDLING

		10^3 lb/hr
Bottom ash:	dry	111
	water	59.7
	sludge	170
Fly ash:	dry	5.68
	water	0.57
	sludge	6.25

(continued)

PROCESS WATER

	10^3 lb/hr
a. Steam and boiler feed water required	1,015
b. Dirty condensate	296
c. Methanation water	200

OTHER WATER NEEDS

	10^3 lb/hr
a. Dust control	73
b. Service, sanitary & potable water:	
Required	21
Sewage recovered	14
c. Revegetation water	0
d. Evaporation from storage ponds	0
GRAND TOTAL RAW WATER INPUT TO PLANT:	1,298

TREATMENT SLUDGES

	10^3 lb/hr	
	solids	water & sludge
a. Lime softening	0.001	0.005
b. Ion exchange	---	52
c. Biotreatment	0.2	1.0

Marengo, Alabama (continued)

ENERGY

Energy Totals

	10^9 Btu/hr
Feed	13.9
Product and byproduct	10.1
Unrecovered heat	3.8
Conversion efficiency	73.00%

Disposition of Unrecovered Heat

	10^9 Btu/hr	% wet	Btu/lb evap	10^3 lb water evap/hr
Direct loss	1.15	0	1,310	0
Designed dry	0.55	0	1,310	0
Designed wet	0.40	100	1,310	305
Acid gas removal regenerator condenser	0.80	10	1,310	61
Total turbine condensers	0.67	10	1,310	51
Total gas compressor interstage cooling	0.17	100	1,310	130
TOTAL:	3.74			547

WORK SHEET: WATER QUANTITY CALCULATIONS FOR HYGAS PROCESS

SITE: Gibson, Indiana

PRODUCT SIZE: 250 x 10^6 SCF/day

ENERGY: 10.34 x 10^9 Btu/hr

Coal Analysis (wt % as-received)

Moisture	10.0
C	68.2
H	4.6
O	7.6
N	1.1
S	2.1
Ash	6.4
	100
HHV Calculated (10^3 Btu/lb)	12.20

COAL FEED

to reactor:	1,205 10^3 lb/hr	to boiler:	130 10^3 lb/hr
	14.7 10^9 Btu/hr		1.59 10^9 Btu/hr

FGD WATER

Vaporized	0.73 lb/lb coal	95.1 10^3 lb/hr
With sludge	0.29 lb/lb coal	37.8 10^3 lb/hr
TOTAL:		133 10^3 lb/hr
FGD sludge produced, wet		54.0 10^3 lb/hr

ASH HANDLING

		10^3 lb/hr
Bottom ash:	dry	78.8
	water	42.4
	sludge	121
Fly ash:	dry	6.67
	water	0.67
	sludge	7.34

Gibson, Indiana (continued)

PROCESS WATER

	10^3 lb/hr
a. Steam and boiler feed water required	1,434
b. Dirty condensate	537
c. Methanation water	180

OTHER WATER NEEDS

	10^3 lb/hr
a. Dust control	107
b. Service, sanitary & potable water:	
Required	21
Sewage recovered	14
c. Revegetation water	0
d. Evaporation from storage ponds	0
GRAND TOTAL RAW WATER INPUT TO PLANT:	2,048

TREATMENT SLUDGES

	10^3 lb/hr solids	10^3 lb/hr water & sludge
a. Lime softening	0.80	4.0
b. Ion exchange	---	80
c. Biotreatment	0.1	0.5

(continued)

Gibson, Indiana (continued)

ENERGY

Energy Totals

	10^9 Btu/hr
Feed	16.3
Product and byproduct	10.7
Unrecovered heat	5.6
Conversion efficiency	65.4 %

Disposition of Unrecovered Heat

	10^9 Btu/hr	% wet	Btu/lb evap	10^3 lb water evap/hr
Direct loss	3.04	0	1,370	0
Designed dry	0.55	0	1,370	0
Designed wet	0.40	100	1,370	292
Acid gas removal regenerator condenser	0.80	10	1,370	58
Total turbine condensers	0.67	100	1,370	489
Total gas compressor interstage cooling	0.17	100	1,370	124
TOTAL:	5.63			963

WORK SHEET: WATER QUANTITY CALCULATIONS FOR HYGAS PROCESS

SITE: Warrick, Indiana

PRODUCT SIZE: 250 x 10^6 SCF/day

ENERGY: 10.34 x 10^9 Btu/hr

Coal Analysis (wt % as-received)

Moisture	9.3
C	64.8
H	4.6
O	9.4
N	1.2
S	2.4
Ash	8.3
	100
HHV Calculated (10^3 Btu/lb)	11.65

COAL FEED

to reactor:	1,262 10^3 lb/hr	to boiler: 136 10^3 lb/hr
	14.7 10^9 Btu/hr	1.58 10^9 Btu/hr

FGD WATER

Vaporized	0.69 lb/lb coal	93.6 10^3 lb/hr
With sludge	0.33 lb/lb coal	44.8 10^3 lb/hr
TOTAL:		138 10^3 lb/hr
FGD sludge produced, wet		63.9 10^3 lb/hr

ASH HANDLING

		10^3 lb/hr
Bottom ash:	dry	107
	water	57.6
	sludge	165
Fly ash:	dry	9.01
	water	0.90
	sludge	9.91

(continued)

PROCESS WATER

	10^3 lb/hr
a. Steam and boiler feed water required	1,434
b. Dirty condensate	537
c. Methanation water	180

OTHER WATER NEEDS

	10^3 lb/hr
a. Dust control	42
b. Service, sanitary & potable water:	
Required	21
Sewage recovered	14
c. Revegetation water	0
d. Evaporation from storage ponds	0
GRAND TOTAL RAW WATER INPUT TO PLANT:	2,016

TREATMENT SLUDGES

	10^3 lb/hr solids	10^3 lb/hr water & sludge
a. Lime softening	0.05	0.27
b. Ion exchange	---	80
c. Biotreatment	0.1	0.5

Warrick, Indiana (continued)

ENERGY

Energy Totals

	10^9 Btu/hr
Feed	16.3
Product and byproduct	10.7
Unrecovered heat	5.6
Conversion efficiency	65.5 %

Disposition of Unrecovered Heat

	10^9 Btu/hr	% wet	Btu/lb evap	10^3 lb water evap/hr
Direct loss	3.03	0	1,370	0
Designed dry	0.55	0	1,370	0
Designed wet	0.40	100	1,370	292
Acid gas removal regenerator condenser	0.80	10	1,370	58
Total turbine condensers	0.67	100	1,370	489
Total gas compressor interstage cooling	0.17	100	1,370	124
TOTAL:	5.62			963

WORK SHEET: WATER QUANTITY CALCULATIONS FOR HYGAS PROCESS

SITE: Tuscarawas, Ohio (Ground water and Surface water)

PRODUCT SIZE: 250 x 10^6 SCF/day

ENERGY: 10.34 x 10^9 Btu/hr

Coal Analysis (wt % as-received)

Moisture	6.3
C	71.2
H	4.9
O	8.1
N	1.4
S	2.5
Ash	5.6
	100
HHV Calculated (10^3 Btu/lb)	12.90

COAL FEED

to reactor: 1,140 10^3 lb/hr; 14.7 10^9 Btu/hr

to boiler: 118 10^3 lb/hr; 1.52 10^9 Btu/hr

FGD WATER

Vaporized	0.80 lb/lb coal	94.3 10^3 lb/hr
With sludge	0.34 lb/lb coal	40.1 10^3 lb/hr
TOTAL:		134 10^3 lb/hr
FGD sludge produced, wet		57.2 10^3 lb/hr

ASH HANDLING

		10^3 lb/hr
Bottom ash:	dry	65.1
	water	35.1
	sludge	100
Fly ash:	dry	5.28
	water	0.53
	sludge	5.81

PROCESS WATER

	10^3 lb/hr
a. Steam and boiler feed water required	1,434
b. Dirty condensate	537
c. Methanation water	180

OTHER WATER NEEDS

	10^3 lb/hr
a. Dust control	101
b. Service, sanitary & potable water:	
Required	21
Sewage recovered	14
c. Revegetation water	0
d. Evaporation from storage ponds	0
GRAND TOTAL RAW WATER INPUT TO PLANT:	1,600

TREATMENT SLUDGES	Ground water 10^3 lb/hr		Surface water 10^3 lb/hr	
	Solids	water & sludge	solids	water & sludge
a. Lime softening	0.86	4.3	0.95	4.8
b. Ion exchange	---	80	---	80
c. Biotreatment	0.1	0.5	0.1	0.5

(continued)

Tuscarawas, Ohio (continued)

ENERGY

Energy Totals

	10^9 Btu/hr
Feed	16.2
Product and byproduct	10.7
Unrecovered heat	5.5
Conversion efficiency	65.7 %

Disposition of Unrecovered Heat

	10^9 Btu/hr	% wet	Btu/lb evap	10^3 lb water evap/hr
Direct loss	2.97	0	1,410	0
Designed dry	0.55	0	1,410	0
Designed wet	0.40	100	1,410	284
Acid gas removal regenerator condenser	0.80	10	1,410	57
Total turbine condensers	0.67	10	1,410	48
Total gas compressor interstage cooling	0.17	100	1,410	121
TOTAL:	5.56			510

WORK SHEET: WATER QUANTITY CALCULATIONS FOR HYGAS PROCESS

SITE: Jefferson, Ohio

PRODUCT SIZE: 250 x 10^6 SCF/day

ENERGY: 10.34 x 10^9 Btu/hr

Coal Analysis (wt % as-received)

Moisture	2.4
C	71.1
H	4.9
O	5.3
N	1.2
S	5.0
Ash	10.1
	100
HHV Calculated (10^3 Btu/lb)	13.10

COAL FEED

to reactor: 1,122 10^3 lb/hr; 14.7 10^9 Btu/hr

to boiler: 112 10^3 lb/hr; 1.47 10^9 Btu/hr

FGD WATER

Vaporized	0.86 lb/lb coal	96.5 10^3 lb/hr
With sludge	0.69 lb/lb coal	77.4 10^3 lb/hr
TOTAL:		174 10^3 lb/hr
FGD sludge produced, wet		110 10^3 lb/hr

ASH HANDLING

		10^3 lb/hr
Bottom ash:	dry	116
	water	62.2
	sludge	179
Fly ash:	dry	9.07
	water	0.91
	sludge	9.98

(continued)

Jefferson, Ohio (continued)

PROCESS WATER

	10^3 lb/hr
a. Steam and boiler feed water required	1,434
b. Dirty condensate	537
c. Methanation water	180

OTHER WATER NEEDS

	10^3 lb/hr
a. Dust control	37
b. Service, sanitary & potable water:	
Required	21
Sewage recovered	14
c. Revegetation water	0
d. Evaporation from storage ponds	0
GRAND TOTAL RAW WATER INPUT TO PLANT:	2,031

TREATMENT SLUDGES

	10^3 lb/hr solids	10^3 lb/hr water & sludge
a. Lime softening	0.06	0.3
b. Ion exchange	---	80
c. Biotreatment	0.1	0.5

Jefferson, Ohio (continued)

ENERGY

Energy Totals

	10^9 Btu/hr
Feed	16.2
Product and byproduct	10.7
Unrecovered heat	5.51
Conversion efficiency	65.9 %

Disposition of Unrecovered Heat

	10^9 Btu/hr	% wet	Btu/lb evap	10^3 lb water evap/hr
Direct loss	2.92	0	1,400	0
Designed dry	0.55	0	1,400	0
Designed wet	0.40	100	1,400	286
Acid gas removal regenerator condenser	0.80	10	1,400	57
Total turbine condensers	0.67	100	1,400	479
Total gas compressor interstage cooling	0.17	100	1,400	121
TOTAL:	5.51			943

WORK SHEET: WATER QUANTITY CALCULATIONS FOR HYGAS PROCESS

SITE: Armstrong, Pennsylvania

PRODUCT SIZE: 250 x 10^6 SCF/day

ENERGY: 10.34 x 10^9 Btu/hr

Coal Analysis (wt % as-received)

Moisture	2.3
C	73.6
H	4.9
O	5.3
N	1.4
S	2.8
Ash	9.7
	100
HHV Calculated (10^3 Btu/lb)	13.40

COAL FEED

to reactor:	1,097	10^3 lb/hr	to boiler:	110 10^3 lb/hr
	14.7	10^9 Btu/hr		1.47 10^9 Btu/hr

FGD WATER

Vaporized	0.88	lb/lb coal	96.5 10^3 lb/hr
With sludge	0.39	lb/lb coal	42.8 10^3 lb/hr
TOTAL:			139 10^3 lb/hr
FGD sludge produced, wet			61.1 10^3 lb/hr

ASH HANDLING

		10^3 lb/hr
Bottom ash:	dry	109
	water	58.4
	sludge	167
Fly ash:	dry	8.51
	water	0.85
	sludge	9.36

Armstrong, Pennsylvania (continued)

PROCESS WATER

	10^3 lb/hr
a. Steam and boiler feed water required	1,434
b. Dirty condensate	537
c. Methanation water	180

OTHER WATER NEEDS

	10^3 lb/hr
a. Dust control	97
b. Service, sanitary & potable water:	
Required	21
Sewage recovered	14
c. Revegetation water	0
d. Evaporation from storage ponds	0
GRAND TOTAL RAW WATER INPUT TO PLANT:	2,096

TREATMENT SLUDGES

	10^3 lb/hr	
	solids	water & sludge
a. Lime softening	0.1	0.5
b. Ion exchange	---	80
c. Biotreatment	0.1	0.5

(continued)

ENERGY

Energy Totals

	10^9 Btu/hr
Feed	16.2
Product and byproduct	10.7
Unrecovered heat	5.5
Conversion efficiency	65.9 %

Disposition of Unrecovered Heat

	10^9 Btu/hr	% wet	Btu/lb evap	10^3 lb water evap/hr
Direct loss	2.92	0	1,410	0
Designed dry	0.55	0	1,410	0
Designed wet	0.40	100	1,410	284
Acid gas removal regenerator condenser	0.80	10	1,410	57
Total turbine condensers	0.67	100	1,410	475
Total gas compressor interstage cooling	0.17	100	1,410	121
TOTAL:	5.51			937

WORK SHEET: WATER QUANTITY CALCULATIONS FOR HYGAS PROCESS

SITE: Fayette, West Virginia

PRODUCT SIZE: 250 x 10^6 SCF/day

ENERGY: 10.34 x 10^9 Btu/hr

Coal Analysis (wt % as-received)

Moisture	3.0
C	78.5
H	4.6
O	3.7
N	1.4
S	0.8
Ash	8.0
	100
HHV Calculated (10^3 Btu/lb)	14.00

COAL FEED

to reactor:	1,050 10^3 lb/hr	14.7 10^9 Btu/hr
to boiler:	106 10^3 lb/hr	1.48 10^9 Btu/hr

FGD WATER

Vaporized	0.91 lb/lb coal	96.2 10^3 lb/hr
With sludge	0.11 lb/lb coal	11.6 10^3 lb/hr
TOTAL:		108 10^3 lb/hr
FGD sludge produced, wet		16.6 10^3 lb/hr

ASH HANDLING

		10^3 lb/hr
Bottom ash:	dry	85.7
	water	46.1
	sludge	132
Fly ash:	dry	6.77
	water	0.68
	sludge	7.45

(continued)

Fayette, West Virginia (continued)

PROCESS WATER

	10^3 lb/hr
a. Steam and boiler feed water required	1,434
b. Dirty condensate	537
c. Methanation water	180

OTHER WATER NEEDS

	10^3 lb/hr
a. Dust control	92
b. Service, sanitary & potable water:	
Required	21
Sewage recovered	14
c. Revegetation water	0
d. Evaporation from storage ponds	0
GRAND TOTAL RAW WATER INPUT TO PLANT:	2,032

TREATMENT SLUDGES

	10^3 lb/hr solids	10^3 lb/hr water & sludge
a. Lime softening	0.1	0.3
b. Ion exchange	---	80
c. Biotreatment	0.1	0.5

Fayette, West Virginia (continued)

ENERGY

Energy Totals

	10^9 Btu/hr
Feed	16.2
Product and byproduct	10.7
Unrecovered heat	5.5
Conversion efficiency	65.9 %

Disposition of Unrecovered Heat

	10^9 Btu/hr	% wet	Btu/lb evap	10^3 lb water evap/hr
Direct loss	2.93	0	1,360	0
Designed dry	0.55	0	1,360	0
Designed wet	0.40	100	1,360	294
Acid gas removal regenerator condenser	0.80	10	1,360	59
Total turbine condensers	0.67	100	1,360	493
Total gas compressor interstage cooling	0.17	100	1,360	125
TOTAL:	5.52			971

WORK SHEET: WATER QUANTITY CALCULATIONS FOR HYGAS PROCESS

SITE: Monongalia, West Virginia

PRODUCT SIZE: 250×10^6 SCF/day

ENERGY: 10.34×10^9 Btu/hr

Coal Analysis (wt % as-received)

Moisture	3.1
C	78.8
H	4.9
O	4.2
N	1.5
S	1.1
Ash	6.4
	100
HHV Calculated (10^3 Btu/lb)	14.20

COAL FEED

to reactor:	1,035	10^3 lb/hr	to boiler: 104	10^3 lb/hr
	14.7	10^9 Btu/hr	1.48	10^9 Btu/hr

FGD WATER

Vaporized	0.92 lb/lb coal	95.9	10^3 lb/hr
With sludge	0.15 lb/lb coal	15.6	10^3 lb/hr
TOTAL:		112	10^3 lb/hr
FGD sludge produced, wet		22.3	10^3 lb/hr

ASH HANDLING

		10^3 lb/hr
Bottom ash:	dry	67.6
	water	36.4
	sludge	104
Fly ash:	dry	5.34
	water	0.53
	sludge	5.87

Monongalia, West Virginia (continued)

PROCESS WATER

	10^3 lb/hr
a. Steam and boiler feed water required	1,434
b. Dirty condensate	537
c. Methanation water	' 180

OTHER WATER NEEDS

	10^3 lb/hr
a. Dust control	94
b. Service, sanitary & potable water:	
Required	21
Sewage recovered	14
c. Revegetation water	0
d. Evaporation from storage ponds	0
GRAND TOTAL RAW WATER INPUT TO PLANT:	1,577

TREATMENT SLUDGES

	10^3 lb/hr	
	solids	water & sludge
a. Lime softening	0.02	0.11
b. Ion exchange	---	80
c. Biotreatment	0.1	0.5

(continued)

Monongalia, West Virginia (continued)

ENERGY

Energy Totals

	10^9 Btu/hr
Feed	16.2
Product and byproduct	10.7
Unrecovered heat	5.5
Conversion efficiency	65.9 %

Disposition of Unrecovered Heat

	10^9 Btu/hr	% wet	Btu/lb evap	10^3 lb water evap/hr
Direct loss	2.93	0	1,380	0
Designed dry	0.55	0	1,380	0
Designed wet	0.40	100	1,380	290
Acid gas removal regenerator condenser	0.80	10	1,380	58
Total turbine condensers	0.67	10	1,380	49
Total gas compressor interstage cooling	0.17	100	1,380	123
TOTAL:	5.52			520

WORK SHEET: WATER QUANTITY CALCULATIONS FOR HYGAS PROCESS

SITE: Mingo, West Virginia

PRODUCT SIZE: 250 x 10^6 SCF/day

ENERGY: 10.34 x 10^9 Btu/hr

Coal Analysis (wt % as-received)

Moisture	2.2
C	79.5
H	5.2
O	5.9
N	1.4
S	0.9
Ash	4.9
	100
HHV Calculated (10^3 Btu/lb)	14.30

COAL FEED

to reactor: 1,028 10^3 lb/hr; 14.7 10^9 Btu/hr

to boiler: 103 10^3 lb/hr; 1.47 10^9 Btu/hr

FGD WATER

Vaporized	0.94 lb/lb coal	96.6 10^3 lb/hr
With sludge	0.12 lb/lb coal	12.3 10^3 lb/hr
TOTAL:		109 10^3 lb/hr
FGD sludge produced, wet		17.6 10^3 lb/hr

ASH HANDLING

		10^3 lb/hr
Bottom ash:	dry	51.4
	water	27.7
	sludge	79.1
Fly ash:	dry	4.03
	water	0.40
	sludge	4.43

(continued)

PROCESS WATER

	10^3 lb/hr
a. Steam and boiler feed water required	1,434
b. Dirty condensate	537
c. Methanation water	180

OTHER WATER NEEDS

	10^3 lb/hr
a. Dust control	34
b. Service, sanitary & potable water:	
Required	21
Sewage recovered	14
c. Revegetation water	0
d. Evaporation from storage ponds	0
GRAND TOTAL RAW WATER INPUT TO PLANT:	1,507

TREATMENT SLUDGES

	10^3 lb/hr	
	solids	water & sludge
a. Lime softening	0.03	0.17
b. Ion exchange	---	80
c. Biotreatment	0.1	0.5

ENERGY

Energy Totals

	10^9 Btu/hr
Feed	16.2
Product and byproduct	10.7
Unrecovered heat	5.5
Conversion efficiency	65.9 %

Disposition of Unrecovered Heat

	10^9 Btu/hr	% wet	Btu/lb evap	10^3 lb water evap/hr
Direct loss	2.92	0	1,360	0
Designed dry	0.55	0	1,360	0
Designed wet	0.40	100	1,360	294
Acid gas removal regenerator condenser	0.80	10	1,360	59
Total turbine condensers	0.67	10	1,360	49
Total gas compressor interstage cooling	0.17	100	1,360	125
TOTAL:	5.51			527

WORK SHEET: WATER QUANTITY CALCULATIONS FOR HYGAS PROCESS

SITE: Gillette, Wyoming

PRODUCT SIZE: 250×10^6 SCF/day

ENERGY: 10.34×10^9 Btu/hr

Coal Analysis (wt % as-received)

Moisture	30.4
C	45.8
H	3.4
O	11.3
N	0.6
S	0.7
Ash	7.8
	100
HHV Calculated (10^3 Btu/lb)	7.92

COAL FEED

to reactor:	1,538 10^3 lb/hr	to boiler:	249 10^3 lb/hr
	12.2 10^9 Btu/hr		1.97 10^9 Btu/hr

FGD WATER

Vaporized	0.24 lb/lb coal	59.7 10^3 lb/hr
With sludge	0.10 lb/lb coal	24.9 10^3 lb/hr
TOTAL:		84.6 10^3 lb/hr
FGD sludge produced, wet		35.5 10^3 lb/hr

ASH HANDLING

		10^3 lb/hr
Bottom ash:	dry	124
	water	66.7
	sludge	191
Fly ash:	dry	15.5
	water	1.55
	sludge	17.1

Gillette, Wyoming (continued)

PROCESS WATER

	10^3 lb/hr
a. Steam and boiler feed water required	1,015
b. Dirty condensate	296
c. Methanation water	200

OTHER WATER NEEDS

	10^3 lb/hr
a. Dust control	68
b. Service, sanitary & potable water:	
Required	21
Sewage recovered	14
c. Revegetation water	0
d. Evaporation from storage ponds	6
GRAND TOTAL RAW WATER INPUT TO PLANT:	1,267

TREATMENT SLUDGES

	10^3 lb/hr solids	10^3 lb/hr water & sludge
a. Lime softening	1.2	6.0
b. Ion exchange	---	52
c. Biotreatment	0.2	1.0

(continued)

ENERGY

Energy Totals

	10^9 Btu/hr
Feed	14.2
Product and byproduct	10.1
Unrecovered heat	4.1
Conversion efficiency	71.5 %

Disposition of Unrecovered Heat

	10^9 Btu/hr	% wet	Btu/lb evap	10^3 lb water evap/hr
Direct loss	1.45	0	1,401	0
Designed dry	0.55	0	1,401	0
Designed wet	0.40	100	1,401	286
Acid gas removal regenerator condenser	0.80	10	1,401	57
Total turbine condensers	0.67	10	1,401	48
Total gas compressor interstage cooling	0.17	50	1,401	61
TOTAL:	4.04			452

WORK SHEET: WATER QUANTITY CALCULATIONS FOR HYGAS PROCESS

SITE: Antelope Creek, Wyoming

PRODUCT SIZE: 250 x 10^6 SCF/day

ENERGY: 10.34 x 10^9 Btu/hr

Coal Analysis (wt % as-received)

Moisture	26.2
C	52.6
H	3.6
O	12.0
N	0.6
S	0.5
Ash	4.5
	100
HHV Calculated (10^3 Btu/lb)	9.00

COAL FEED

to reactor: 1,353 10^3 lb/hr; 12.2 10^9 Btu/hr

to boiler: 202 10^3 lb/hr; 1.82 10^9 Btu/hr

FGD WATER

Vaporized	0.35 lb/lb coal	70.8 10^3 lb/hr
With sludge	0.07 lb/lb coal	14.2 10^3 lb/hr
TOTAL:		84.9 10^3 lb/hr
FGD sludge produced, wet		20.2 10^3 lb/hr

ASH HANDLING

		10^3 lb/hr
Bottom ash:	dry	62.7
	water	33.8
	sludge	96.5
Fly ash:	dry	7.28
	water	0.73
	sludge	8.01

(continued)

Antelope Creek, Wyoming (continued)

PROCESS WATER

	10^3 lb/hr
a. Steam and boiler feed water required	1,015
b. Dirty condensate	296
c. Methanation water	200

OTHER WATER NEEDS

	10^3 lb/hr
a. Dust control	59
b. Service, sanitary & potable water:	
Required	21
Sewage recovered	14
c. Revegetation water	0
d. Evaporation from storage ponds	6
GRAND TOTAL RAW WATER INPUT TO PLANT:	1,359

TREATMENT SLUDGES

	10^3 lb/hr	
	solids	water & sludge
a. Lime softening	0.02	0.08
b. Ion exchange	---	52
c. Biotreatment	0.2	1.0
d. Electrodialysis	---	135

Antelope Creek, Wyoming (continued)

ENERGY

Energy Totals

	10^9 Btu/hr
Feed	14.0
Product and byproduct	10.1
Unrecovered heat	3.9
Conversion efficiency	72.2 %

Disposition of Unrecovered Heat

	10^9 Btu/hr	% wet	Btu/lb evap	10^3 lb water evap/hr
Direct loss	1.30	0	1,397	0
Designed dry	0.55	0	1,397	0
Designed wet	0.40	100	1,397	286
Acid gas removal regenerator condenser	0.80	10	1,397	57
Total turbine condensers	0.67	10	1,397	48
Total gas compressor interstage cooling	0.17	50	1,397	61
TOTAL:	3.89			452

WORK SHEET: WATER QUANTITY CALCULATIONS FOR HYGAS PROCESS

SITE: Belle Ayr, Wyoming

PRODUCT SIZE: 250 x 10^6 SCF/day

ENERGY: 10.34 x 10^9 Btu/hr

Coal Analysis (wt % as-received)

Moisture	21.7
C	54.3
H	3.9
O	13.2
N	0.9
S	0.5
Ash	5.5
	100
HHV Calculated (10^3 Btu/lb)	9.31

COAL FEED

to reactor:	1,308 10^3 lb/hr	to boiler:	186 10^3 lb/hr
	12.2 10^9 Btu/hr		1.73 10^9 Btu/hr

FGD WATER

Vaporized	0.42 lb/lb coal	78.0 10^3 lb/hr
With sludge	0.069 lb/lb coal	12.8 10^3 lb/hr
TOTAL:		91 10^3 lb/hr
FGD sludge produced, wet		183 10^3 lb/hr

ASH HANDLING

		10^3 lb/hr
Bottom ash:	dry	74.0
	water	39.9
	sludge	114
Fly ash:	dry	8.18
	water	0.82
	sludge	9.00

PROCESS WATER

	10^3 lb/hr
a. Steam and boiler feed water required	1,015
b. Dirty condensate	296
c. Methanation water	200

OTHER WATER NEEDS

	10^3 lb/hr
a. Dust control	57
b. Service, sanitary & potable water:	
Required	21
Sewage recovered	14
c. Revegetation water	0
d. Evaporation from storage ponds	6
GRAND TOTAL RAW WATER INPUT TO PLANT:	1,380

TREATMENT SLUDGES

	10^3 lb/hr	
	solids	water & sludge
a. Lime softening	1.3	6.5
b. Ion exchange	---	52
c. Biotreatment	0.2	1.0

(continued)

ENERGY

Energy Totals

	10^9 Btu/hr
Feed	13.9
Product and byproduct	10.1
Unrecovered heat	3.8
Conversion efficiency	72.7 %

Disposition of Unrecovered Heat

	10^9 Btu/hr	% wet	Btu/lb evap	10^3 lb water evap/hr
Direct loss	1.21	0	1,401	0
Designed dry	0.55	0	1,401	0
Designed wet	0.40	100	1,401	286
Acid gas removal regenerator condenser	0.80	10	1,401	57
Total turbine condensers	0.67	10	1,401	48
Total gas compressor interstage cooling	0.17	50	1,401	61
TOTAL:	3.80			452

WORK SHEET: WATER QUANTITY CALCULATIONS FOR HYGAS PROCESS

SITE: Hanna Coal Fld., Wyoming

PRODUCT SIZE: 250×10^6 SCF/day

ENERGY: 10.34×10^9 Btu/hr

Coal Analysis (wt % as-received)

Moisture	11.8
C	60.5
H	4.5
O	12.5
N	1.5
S	1.1
Ash	8.1
	100
HHV Calculated (10^3 Btu/lb)	10.66

COAL FEED

to reactor: 1,143 10^3 lb/hr; 12.2 10^9 Btu/hr

to boiler: 144 10^3 lb/hr; 1.53 10^9 Btu/hr

FGD WATER

Vaporized	0.60 lb/lb coal	86.1 10^3 lb/hr
With sludge	0.15 lb/lb coal	21.5 10^3 lb/hr
TOTAL:		108 10^3 lb/hr
FGD sludge produced, wet		30.8 10^3 lb/hr

ASH HANDLING

		10^3 lb/hr
Bottom ash:	dry	94.9
	water	51.1
	sludge	146
Fly ash:	dry	9.30
	water	0.93
	sludge	10.2

(continued)

Hanna Coal Fld., Wyoming (continued)

PROCESS WATER

	10^3 lb/hr
a. Steam and boiler feed water required	1,015
b. Dirty condensate	296
c. Methanation water	200

OTHER WATER NEEDS

	10^3 lb/hr
a. Dust control	49
b. Service, sanitary & potable water:	
Required	21
Sewage recovered	14
c. Revegetation water	0
d. Evaporation from storage ponds	8
GRAND TOTAL RAW WATER INPUT TO PLANT:	1,750

TREATMENT SLUDGES

	10^3 lb/hr	
	solids	water & sludge
a. Lime softening	1.33	6.65
b. Ion exchange	---	52
c. Biotreatment	0.2	1.0

Hanna Coal Fld., Wyoming (continued)

ENERGY

Energy Totals

	10^9 Btu/hr
Feed	13.7
Product and byproduct	10.1
Unrecovered heat	3.6
Conversion efficiency	73.7 %

Disposition of Unrecovered Heat

	10^9 Btu/hr	% wet	Btu/lb evap	10^3 lb water evap/hr
Direct loss	1.01	0	1,397	0
Designed dry	0.55	0	1,397	0
Designed wet	0.40	100	1,397	286
Acid gas removal regenerator condenser	0.80	10	1,397	57
Total turbine condensers	0.67	100	1,397	480
Total gas compressor interstage cooling	0.17	100	1,397	122
TOTAL:	3.60			945

WORK SHEET: WATER QUANTITY CALCULATIONS FOR HYGAS PROCESS

SITE: Decker, Montana

PRODUCT SIZE: 250 x 10^6 SCF/day

ENERGY: 10.34 x 10^9 Btu/hr

Coal Analysis (wt % as-received)

Moisture	23.9
C	57.2
H	3.2
O	10.9
N	0.6
S	0.5
Ash	3.7
	100
HHV Calculated (10^3 Btu/lb)	9.48

COAL FEED

to reactor: 1,285 10^3 lb/hr; 12.2 10^9 Btu/hr

to boiler: 186 10^3 lb/hr; 1.76 10^9 Btu/hr

FGD WATER

Vaporized	0.42 lb/lb coal	78.0 10^3 lb/hr
With sludge	0.07 lb/lb coal	13.0 10^3 lb/hr
TOTAL:		91.0 10^3 lb/hr
FGD sludge produced, wet		18.6 10^3 lb/hr

ASH HANDLING

		10^3 lb/hr
Bottom ash:	dry	48.9
	water	26.3
	sludge	75.3
Fly ash:	dry	5.50
	water	0.55
	sludge	6.05

282

Decker, Montana (continued)

PROCESS WATER

	10^3 lb/hr
a. Steam and boiler feed water required	1,015
b. Dirty condensate	296
c. Methanation water	200

OTHER WATER NEEDS

	10^3 lb/hr
a. Dust control	67
b. Service, sanitary & potable water:	
Required	21
Sewage recovered	14
c. Revegetation water	0
d. Evaporation from storage ponds	7
GRAND TOTAL RAW WATER INPUT TO PLANT:	1,900

TREATMENT SLUDGES

	10^3 lb/hr solids	10^3 lb/hr water & sludge
a. Lime softening	0.05	0.3
b. Ion exchange	---	52
c. Biotreatment	0.2	1.0
d. Electrodialysis	---	189

(continued)

Decker, Montana (continued)

ENERGY

Energy Totals

	10^9 Btu/hr
Feed	13.9
Product and byproduct	10.1
Unrecovered heat	3.8
Conversion efficiency	72.5 %

Disposition of Unrecovered Heat

	10^9 Btu/hr	% wet	Btu/lb evap	10^3 lb water evap/hr
Direct loss	1.24	0	1,407	0
Designed dry	0.55	0	1,407	0
Designed wet	0.40	100	1,407	284
Acid gas removal regenerator condenser	0.80	10	1,407	57
Total turbine condensers	0.67	100	1,407	476
Total gas compressor interstage cooling	0.17	100	1,407	121
TOTAL:	3.83			938

WORK SHEET: WATER QUANTITY CALCULATIONS FOR HYGAS PROCESS

SITE: East Moorhead, Montana

PRODUCT SIZE: 250×10^6 SCF/day

ENERGY: 10.34×10^9 Btu/hr

Coal Analysis (wt % as-received)

Moisture	36.1
C	42.4
H	2.8
O	11.4
N	0.7
S	0.6
Ash	6.2
	100
HHV Calculated (10^3 Btu/lb)	7.04

COAL FEED

to reactor:	1,730 10^3 lb/hr	to boiler: 308 10^3 lb/hr
	12.2 10^9 Btu/hr	2.17 10^9 Btu/hr

FGD WATER

Vaporized	0.13 lb/lb coal	40.1 10^3 lb/hr
With sludge	0.08 lb/lb coal	24.7 10^3 lb/hr
TOTAL:		64.7 10^3 lb/hr
FGD sludge produced, wet		35.2 10^3 lb/hr

ASH HANDLING

		10^3 lb/hr
Bottom ash:	dry	111
	water	59.8
	sludge	171
Fly ash:	dry	15.3
	water	1.53
	sludge	16.8

(continued)

East Moorhead, Montana (continued)

PROCESS WATER

	10^3 lb/hr
a. Steam and boiler feed water required	1,015
b. Dirty condensate	296
c. Methanation water	200

OTHER WATER NEEDS

	10^3 lb/hr
a. Dust control	95
b. Service, sanitary & potable water:	
Required	21
Sewage recovered	14
c. Revegetation water	0
d. Evaporation from storage ponds	5
GRAND TOTAL RAW WATER INPUT TO PLANT:	1,263

TREATMENT SLUDGES

	10^3 lb/hr	
	solids	water & sludge
a. Lime softening	1.2	6.0
b. Ion exchange	---	52
c. Biotreatment	0.2	1.0

East Moorhead, Montana (continued)

ENERGY

Energy Totals

	10^9 Btu/hr
Feed	14.4
Product and byproduct	10.1
Unrecovered heat	4.24
Conversion efficiency	70.5 %

Disposition of Unrecovered Heat

	10^9 Btu/hr	% wet	Btu/lb evap	10^3 lb water evap/hr
Direct loss	1.65	0	1,407	0
Designed dry	0.55	0	1,407	0
Designed wet	0.40	100	1,407	284
Acid gas removal regenerator condenser	0.80	10	1,407	57
Total turbine condensers	0.67	10	1,407	48
Total gas compressor interstage cooling	0.17	50	1,407	60
TOTAL:	4.24			449

WORK SHEET: WATER QUANTITY CALCULATIONS FOR HYGAS PROCESS

SITE: Colstrip, Montana

PRODUCT SIZE: 250×10^6 SCF/day

ENERGY: 10.34×10^9 Btu/hr

Coal Analysis (wt % as-received)

Moisture	24.4
C	52.4
H	3.5
O	11.6
N	0.8
S	0.4
Ash	6.9
	100
HHV Calculated (10^3 Btu/lb)	8.91

COAL FEED

to reactor:	1,367 10^3 lb/hr	to boiler: 202 10^3 lb/hr
	12.2 10^9 Btu/hr	1.80 10^9 Btu/hr

FGD WATER

Vaporized	0.37 lb/lb coal	74.8 10^3 lb/hr
With sludge	0.06 lb/lb coal	12.1 10^3 lb/hr
TOTAL:		86.9 10^3 lb/hr
FGD sludge produced, wet		17.3 10^3 lb/hr

ASH HANDLING

		10^3 lb/hr
Bottom ash:	dry	97.1
	water	52.3
	sludge	149
Fly ash:	dry	11.2
	water	1.12
	sludge	12.3

Colstrip, Montana (continued)

PROCESS WATER

	10^3 lb/hr
a. Steam and boiler feed water required	1,015
b. Dirty condensate	296
c. Methanation water	200

OTHER WATER NEEDS

	10^3 lb/hr
a. Dust control	73
b. Service, sanitary & potable water:	
Required	21
Sewage recovered	14
c. Revegetation water	0
d. Evaporation from storage ponds	5
GRAND TOTAL RAW WATER INPUT TO PLANT:	1,306

TREATMENT SLUDGES

	10^3 lb/hr solids	10^3 lb/hr water & sludge
a. Lime softening	0.02	0.003
b. Ion exchange	---	52
c. Biotreatment	0.2	1.0

(continued)

Costrip, Montana (continued)

ENERGY

Energy Totals

	10^5 Btu/hr
Feed	14.0
Product and byproduct	10.1
Unrecovered heat	3.9
Conversion efficiency	72.3 %

Disposition of Unrecovered Heat

	10^9 Btu/hr	% wet	Btu/lb evap	10^3 lb water evap/hr
Direct loss	1.28	0	1,414	0
Designed dry	0.55	0	1,414	0
Designed wet	0.40	100	1,414	283
Acid gas removal regenerator condenser	0.80	10	1,414	57
Total turbine condensers	0.67	10	1,414	47
Total gas compressor interstage cooling	0.17	100	1,414	120
TOTAL:	3.87			507

WORK SHEET: WATER QUANTITY CALCULATIONS FOR HYGAS PROCESS

SITE: El Paso, New Mexico

PRODUCT SIZE: 250 x 10^6 SCF/day

ENERGY: 10.34 x 10^9 Btu/hr

Coal Analysis (wt % as-received)

Moisture	16.3
C	49.2
H	3.6
O	10.2
N	0.8
S	0.7
Ash	19.2
	100
HHV Calculated (10^3 Btu/lb)	8.62

COAL FEED

to reactor: 1,413 10^3 lb/hr; 12.2 10^9 Btu/hr

to boiler: 193 10^3 lb/hr; 1.66 10^9 Btu/hr

FGD WATER

Vaporized	0.42 lb/lb coal	80.9 10^3 lb/hr
With sludge	0.10 lb/lb coal	19.3 10^3 lb/hr
TOTAL:		100 10^3 lb/hr
FGD sludge produced, wet		27.5 10^3 lb/hr

ASH HANDLING

		10^3 lb/hr
Bottom ash:	dry	279
	water	150
	sludge	429
Fly ash:	dry	29.6
	water	2.96
	sludge	32.5

(continued)

El Paso, New Mexico (continued)

PROCESS WATER

	10^3 lb/hr
a. Steam and boiler feed water required	1,015
b. Dirty condensate	296
c. Methanation water	200

OTHER WATER NEEDS

	10^3 lb/hr
a. Dust control	84
b. Service, sanitary & potable water:	
Required	21
Sewage recovered	14
c. Revegetation water	49
d. Evaporation from storage ponds	8
GRAND TOTAL RAW WATER INPUT TO PLANT:	1,436

TREATMENT SLUDGES

	10^3 lb/hr	
	solids	water & sludge
a. Lime softening	--	--
b. Ion exchange	--	52
c. Biotreatment	0.2	1.0

El Paso, New Mexico (continued)

ENERGY

Energy Totals

	10^9 Btu/hr
Feed	13.8
Product and byproduct	10.1
Unrecovered heat	3.7
Conversion efficiency	73.1 %

Disposition of Unrecovered Heat

	10^9 Btu/hr	% wet	Btu/lb evap	10^3 lb water evap/hr
Direct loss	1.14	0	1,375	0
Designed dry	0.55	0	1,375	0
Designed wet	0.40	100	1,375	291
Acid gas removal regenerator condenser	0.80	10	1,375	58
Total turbine condensers	0.67	10	1,375	49
Total gas compressor interstage cooling	0.17	50	1,375	62
TOTAL:	1.73			460

WORK SHEET: WATER QUANTITY CALCULATIONS FOR HYGAS PROCESS

SITE: Gallup, New Mexico

PRODUCT SIZE: 250×10^6 SCF/day

ENERGY: 10.34×10^9 Btu/hr

Coal Analysis (wt % as-received)

Moisture	15.1
C	63.2
H	4.7
O	10.4
N	1.1
S	0.4
Ash	5.1
	100
HHV Calculated (10^3 Btu/lb)	11.30

COAL FEED

to reactor:	1,078 10^3 lb/hr	to boiler:	140 10^3 lb/hr
	12.2 10^9 Btu/hr		1.58 10^9 Btu/hr

FGD WATER

Vaporized	0.61 lb/lb coal	85.3 10^3 lb/hr
With sludge	0.06 lb/lb coal	8.39 10^3 lb/hr
TOTAL:		93.7 10^3 lb/hr
FGD sludge produced, wet		12.0 10^3 lb/hr

ASH HANDLING

		10^3 lb/hr
Bottom ash:	dry	56.4
	water	30.4
	sludge	86.8
Fly ash:	dry	5.70
	water	0.57
	sludge	6.27

Gallup, New Mexico (continued)

PROCESS WATER

	10^3 lb/hr
a. Steam and boiler feed water required	1,015
b. Dirty condensate	296
c. Methanation water	200

OTHER WATER NEEDS

	10^3 lb/hr
a. Dust control	64
b. Service, sanitary & potable water:	
Required	21
Sewage recovered	14
c. Revegetation water	37
d. Evaporation from storage ponds	8
GRAND TOTAL RAW WATER INPUT TO PLANT:	1,412

TREATMENT SLUDGES

	10^3 lb/hr solids	10^3 lb/hr water & sludge
a. Lime softening	0.02	0.11
b. Ion exchange	---	52
c. Biotreatment	0.2	1.0
d. Electrodialysis	---	137

(continued)

Gallup, New Mexico (continued)

ENERGY

Energy Totals

	10^9 Btu/hr
Feed	13.8
Product and byproduct	10.1
Unrecovered heat	3.7
Conversion efficiency	73.5 %

Disposition of Unrecovered Heat

	10^9 Btu/hr	% wet	Btu/lb evap	10^3 lb water evap/hr
Direct loss	1.06	0	1,375	0
Designed dry	0.55	0	1,375	0
Designed wet	0.40	100	1,375	291
Acid gas removal regenerator condenser	0.80	10	1,375	58
Total turbine condensers	0.67	10	1,375	49
Total gas compressor interstage cooling	0.17	50	1,375	62
TOTAL:	3.65			460

WORK SHEET: WATER QUANTITY CALCULATIONS FOR BIGAS PROCESS

SITE:

PRODUCT SIZE: 250×10^6 SCF/day

ENERGY: 9.9×10^9 Btu/hr

Coal Analysis (wt % as-received)

Moisture	______	
C	______	Tables 3-18, 3-19
H	______	Tables 3-18, 3-19
O	______	Tables 3-18, 3-19
N	______	Tables 3-18, 3-19
S	______	Tables 3-18, 3-19
Ash	______	Tables 3-18, 3-19
	100	
HHV Calculated (10^3 Btu/lb)	______	

COAL FEED

to reactor:	Table A4-3	to boiler:	Table A4-5
bituminous	12.5		
lignite	12.1		Table A4-5

FGD WATER

Vaporized	Appendix 8	______ 10^3 lb/hr
With sludge	Appendix 8	______ 10^3 lb/hr
TOTAL:		Calcd. 10^3 lb/hr
FGD sludge produced, wet		______ 10^3 lb/hr

ASH HANDLING

		10^3 lb/hr
Bottom ash:	dry	______
	water	______
	sludge	______
Fly ash:	dry	Appendix 8
	water	______
	sludge	______

(continued)

_______________ (continued)

PROCESS WATER

	10^3 lb/hr
a. Steam and boiler feed water required	Table A4-4 (steam to gasifier)
b. Dirty water input	Table A4-4 (water to quench & water to slurry coal)
c. Dirty condensate	Table A4-4
d. Methanation water	Table A4-4

OTHER WATER NEEDS

	10^3 lb/hr
a. Dust control	______
b. Service, sanitary & potable water:	
Required	______
Sewage recovered	Appendix 9
c. Revegetation water	______
d. Evaporation from storage ponds	______
GRAND TOTAL RAW WATER INPUT TO PLANT:	Appendix 11

TREATMENT SLUDGES

	10^3 lb/hr solids	10^3 lb/hr water & sludge
a. Lime softening	______	______
b. Ion exchange	Appendix 11	______

_______________ (continued)

ENERGY

Energy Totals

	10^9 Btu/hr
Feed	Calculated
Product and byproduct	9.9
Unrecovered heat	Table A4-5
Conversion efficiency	Table A4-5

Disposition of Unrecovered Heat

	10^9 Btu/hr	% wet	Btu/lb evap	10^3 lb water evap/hr
Direct loss	Table A4-6	______	______	______
Designed dry	Table A4-6	______	______	______
Designed wet	Table A4-6*	Table A7-1	Table A7-2	CALCULATED
Acid gas removal regenerator condenser	1.02			
Total turbine condensers	1.14			
Total gas compressor interstage cooling	0.33	______	______	______
TOTAL:	______			______

*Slag quench and wet cooling in the process

WORK SHEET: WATER QUANTITY CALCULATIONS FOR
BIGAS PROCESS

SITE: Bureau, Illinois
(Illinois river water and well water)

PRODUCT SIZE: 250 x 10^6 SCF/day

ENERGY: 9.9 x 10^9 Btu/hr

Coal Analysis (wt % as-received)

Moisture	16.1
C	60.1
H	4.1
O	8.3
N	1.1
S	2.9
Ash	7.4
	100
HHV Calculated (10^3 Btu/lb)	10.76

COAL FEED

to reactor:	1,170 10^3 lb/hr	to boiler:	151 10^3 lb/hr
	12.6 10^9 Btu/hr		1.62 10^9 Btu/hr

FGD WATER

Vaporized	0.57 lb/lb coal	86.1 10^3 lb/hr
With sludge	0.40 lb/lb coal	60.4 10^3 lb/hr
TOTAL:		146 10^3 lb/hr
FGD sludge produced, wet		86.3 10^3 lb/hr

ASH HANDLING

		10^3 lb/hr
Bottom ash:	dry	88.8
	water	47.8
	sludge	137
Fly ash:	dry	8.94
	water	0.89
	sludge	9.83

Bureau, Illinois (continued)

PROCESS WATER

	10^3 lb/hr
a. Steam and boiler feed water required	410
b. Dirty water input	1,198
c. Dirty condensate	890
d. Methanation water	234

OTHER WATER NEEDS

	10^3 lb/hr
a. Dust control	106
b. Service, sanitary & potable water:	
Required	21
Sewage recovered	14
c. Revegetation water	0
d. Evaporation from storage ponds	0
GRAND TOTAL RAW WATER INPUT TO PLANT:	2,151

TREATMENT SLUDGES

	Well water 10^3 lb/hr		Illinois river water 10^3 lb/hr	
	solids	water & sludge	solids	water & sludge
a. Lime softening	0.96	4.8	0.06	0.3
b. Ion exchange	---	11	---	11

(continued)

Bureau, Illinois (continued)

ENERGY

Energy Totals

	10^9 Btu/hr
Feed	14.2
Product and byproduct	9.9
Unrecovered heat	4.2
Conversion efficiency	70.1 %

Disposition of Unrecovered Heat

	10^9 Btu/hr	% wet	Btu/lb evap	10^3 lb water evap/hr
Direct loss	1.00	0	1,390	0
Designed dry	0.35	0	1,390	0
Designed wet	0.39	100	1,390	281
Acid gas removal regenerator condenser	1.02	0	1,390	0
Total turbine condensers	1.14	100	1,390	820
Total gas compressor interstage cooling	0.33	100	1,390	237
TOTAL.	4.23			1,338

WORK SHEET: WATER QUANTITY CALCULATIONS FOR BIGAS PROCESS

SITE: Shelby, Illinois

PRODUCT SIZE: 250 x 10^6 SCF/day

ENERGY: 9.9 x 10^9 Btu/hr

Coal Analysis (wt % as-received)

Moisture	13.9
C	56.0
H	4.0
O	7.2
N	1.3
S	3.1
Ash	14.5
	100
HHV Calculated (10^3 Btu/lb)	10.19

COAL FEED

to reactor:	1,228	10^3 lb/hr	to boiler:	158 10^3 lb/hr
	12.5	10^9 Btu/hr		1.61 10^9 Btu/hr

FGD WATER

Vaporized	0.55	lb/lb coal	86.9 10^3 lb/hr
With sludge	0.43	lb/lb coal	67.9 10^3 lb/hr
TOTAL:			155 10^3 lb/hr
FGD sludge produced, wet			97.1 10^3 lb/hr

ASH HANDLING

		10^3 lb/hr
Bottom ash:	dry	183
	water	98.3
	sludge	281
Fly ash:	dry	18.3
	water	1.83
	sludge	20.2

(continued)

Shelby, Illinois (continued)

PROCESS WATER

	10^3 lb/hr
a. Steam and boiler feed water required	410
b. Dirty water input	1,273
c. Dirty condensate	980
d. Methanation water	234

OTHER WATER NEEDS

	10^3 lb/hr
a. Dust control	111
b. Service, sanitary & potable water:	
Required	21
Sewage recovered	14
c. Revegetation water	0
d. Evaporation from storage ponds	0
GRAND TOTAL RAW WATER INPUT TO PLANT:	1,355

TREATMENT SLUDGES

	10^3 lb/hr	
	solids	water & sludge
a. Lime softening	---	---
b. Ion exchange	---	11

Shelby, Illinois (continued)

ENERGY

Energy Totals

	10^9 Btu/hr
Feed	14.1
Product and byproduct	9.9
Unrecovered heat	4.2
Conversion efficiency	70.2%

Disposition of Unrecovered Heat

	10^9 Btu/hr	% wet	Btu/lb evap	10^3 lb water evap/hr
Direct loss	0.98	0	1,390	0
Designed dry	0.32	0	1,390	0
Designed wet	0.42	100	1,390	302
Acid gas removal regenerator condenser	1.02	0	1,390	0
Total turbine condensers	1.14	10	1,390	82
Total gas compressor interstage cooling	0.33	50	1,390	119
TOTAL:	4.21			503

WORK SHEET: WATER QUANTITY CALCULATIONS FOR BIGAS PROCESS

SITE: Vigo, Indiana

PRODUCT SIZE: 250 x 10^6 SCF/day

ENERGY: 9.9 x 10^9 Btu/hr

Coal Analysis (wt % as-received)

Moisture	16.2
C	62.8
H	4.4
O	8.1
N	1.4
S	0.6
Ash	6.5
	100
HHV Calculated (10^3 Btu/lb)	11.26

COAL FEED

to reactor:	1,111 10^3 lb/hr	to boiler:	143 10^3 lb/hr
	12.5 10^9 Btu/hr		1.61 10^9 Btu/hr

FGD WATER

Vaporized	0.59 lb/lb coal	84.4 10^3 lb/hr
With sludge	0.09 lb/lb coal	12.9 10^3 lb/hr
TOTAL:		97.2 10^3 lb/hr
FGD sludge produced, wet		18.4 10^3 lb/hr

ASH HANDLING

		10^3 lb/hr
Bottom ash:	dry	87.8
	water	47.3
	sludge	135
Fly ash:	dry	8.81
	water	0.88
	sludge	9.69

Vigo, Indiana (continued)

PROCESS WATER

		10^3 lb/hr
a.	Steam and boiler feed water required	410
b.	Dirty water input	1,147
c.	Dirty condensate	841
d.	Methanation water	234

OTHER WATER NEEDS

		10^3 lb/hr
a.	Dust control	100
b.	Service, sanitary & potable water:	
	Required	21
	Sewage recovered	14
c.	Revegetation water	0
d.	Evaporation from storage ponds	0
	GRAND TOTAL RAW WATER INPUT TO PLANT:	2,092

TREATMENT SLUDGES

		10^3 lb/hr solids	water & sludge
a.	Lime softening	0.76	4 0
b.	Ion exchange	--	11

(continued)

Vigo, Indiana (continued)

ENERGY

Energy Totals

	10^9 Btu/hr
Feed	14.1
Product and byproduct	9.9
Unrecovered heat	4.2
Conversion efficiency	70.2 %

Disposition of Unrecovered Heat

	10^9 Btu/hr	% wet	Btu/lb evap	10^3 lb water evap/hr
Direct loss	0.98	0	1,390	0
Designed dry	0.36	0	1,390	0
Designed wet	0.39	100	1,390	281
Acid gas removal regenerator condenser	1.02	0	1,390	0
Total turbine condensers	1.14	100	1,390	820
Total gas compressor interstage cooling	0.33	100	1,390	237
TOTAL:	4.22			1,338

WORK SHEET: WATER QUANTITY CALCULATIONS FOR BIGAS PROCESS

SITE: Kemmerer, Wyoming

PRODUCT SIZE: 250 x 10^6 SCF/day

ENERGY: 9.9 x 10^9 Btu/hr

Coal Analysis (wt % as-received)

Moisture	2.8
C	71.8
H	5.0
O	9.0
N	1.2
S	1.0
Ash	9.2
	100
HHV Calculated (10^3 Btu/lb)	12.88

COAL FEED

to reactor:	981 10^3 lb/hr		to boiler:	113 10^3 lb/hr
	12.6 10^9 Btu/hr			1.46 10^9 Btu/hr

FGD WATER

Vaporized	0.84 lb/lb coal	94.9 10^3 lb/hr
With sludge	0.14 lb/lb coal	15.8 10^3 lb/hr
TOTAL:		111 10^3 lb/hr
FGD sludge produced, wet		22.6 10^3 lb/hr

ASH HANDLING

		10^3 lb/hr
Bottom ash:	dry	92.3
	water	49.7
	sludge	142
Fly ash:	dry	8.32
	water	0.83
	sludge	9.15

(continued)

Kemmerer, Wyoming (continued)

PROCESS WATER

	10^3 lb/hr
a. Steam and boiler feed water required	410
b. Dirty water input	1,168
c. Dirty condensate	863
d. Methanation water	234

OTHER WATER NEEDS

	10^3 lb/hr
a. Dust control	42
b. Service, sanitary & potable water:	
Required	21
Sewage recovered	14
c. Revegetation water	0
d. Evaporation from storage ponds	4
GRAND TOTAL RAW WATER INPUT TO PLANT:	1,308

TREATMENT SLUDGES

	10^3 lb/hr solids	10^3 lb/hr water & sludge
a. Lime softening	---	---
b. Ion exchange	---	11

Kemmerer, Wyoming (continued)

ENERGY

Energy Totals

	10^9 Btu/hr
Feed	14.1
Product and byproduct	9.9
Unrecovered heat	4.05
Conversion efficiency	71.0 %

Disposition of Unrecovered Heat

	10^9 Btu/hr	% wet	Btu/lb evap	10^3 lb water evap/hr
Direct loss	0.81	0	1,397	0
Designed dry	0.36	0	1,397	0
Designed wet	0.39	100	1,397	279
Acid gas removal regenerator condenser	1.02	0	1,397	0
Total turbine condensers	1.14	10	1,397	82
Total gas compressor interstage cooling	0.33	100	1,397	236
TOTAL:	4.05			597

WORK SHEET: WATER QUANTITY CALCULATIONS FOR BIGAS PROCESS

SITE: Slope, North Dakota

PRODUCT SIZE: 250 x 10^6 SCF/day

ENERGY: 9.9 x 10^9 Btu/hr

Coal Analysis (wt % as-received)

Moisture	44.4
C	32.9
H	2.6
O	11.0
N	0.6
S	1.8
Ash	6.7
	100
HHV Calculated (10^3 Btu/lb)	5.62

COAL FEED

to reactor:	2,164 10^3 lb/hr	to boiler:	514 10^3 lb/hr
	12.2 10^9 Btu/hr		2.89 10^9 Btu/hr

FGD WATER

Vaporized	(-0.06*) lb/lb coal	0 10^3 lb/hr
With sludge	0.25 lb/lb coal	129 10^3 lb/hr
TOTAL:		129 10^3 lb/hr
FGD sludge produced, wet		184 10^3 lb/hr

ASH HANDLING

		10^3 lb/hr
Bottom ash:	dry	152
	water	81.8
	sludge	234
Fly ash:	dry	27.6
	water	2.75
	sludge	30.3

* Due to large moisture content of coal; treat as zero.

Slope, North Dakota (continued)

PROCESS WATER

	10^3 lb/hr
a. Steam and boiler feed water required	691
b. Dirty water input	1,424
c. Dirty condensate	1,478
d. Methanation water	234

OTHER WATER NEEDS

	10^3 lb/hr
a. Dust control	146
b. Service, sanitary & potable water:	
Required	21
Sewage recovered	14
c. Revegetation water	0
d. Evaporation from storage ponds	3
GRAND TOTAL RAW WATER INPUT TO PLANT:	1,410

TREATMENT SLUDGES

	10^3 lb/hr	
	solids	water & sludge
a. Lime softening	---	---
b. Ion exchange	---	29

(continued)

Slope, North Dakota (continued)

ENERGY

Energy Totals

	10^9 Btu/hr
Feed	15.1
Product and byproduct	9.9
Unrecovered heat	5.2
Conversion efficiency	66.0 %

Disposition of Unrecovered Heat

	10^9 Btu/hr	% wet	Btu/lb evap	10^3 lb water evap/hr
Direct loss	1.55	0	1,417	0
Designed dry	0.49	0	1,417	0
Designed wet	0.56	100	1,417	395
Acid gas removal regenerator condenser	1.02	0	1,417	0
Total turbine condensers	1.14	10	1,417	80
Total gas compressor interstage cooling	0.33	50	1,417	116
TOTAL:	5.09			591

WORK SHEET: WATER QUANTITY CALCULATIONS FOR BIGAS PROCESS

SITE: Center, North Dakota

PRODUCT SIZE: 250×10^6 SCF/day

ENERGY: 9.9×10^9 Btu/hr

Coal Analysis (wt % as-received)

Moisture	36.2
C	39.9
H	2.8
O	11.0
N	0.6
S	0.9
Ash	8.6
	100
HHV Calculated (10^3 Btu/lb)	6.72

COAL FEED

to reactor:	1,814 10^3 lb/hr	to boiler:	378 10^3 lb/hr
	12.2 10^9 Btu/hr		2.54 10^9 Btu/hr

FGD WATER

Vaporized	0.10 lb/lb coal	37.8 10^3 lb/hr
With sludge	0.12 lb/lb coal	45.4 10^3 lb/hr
TOTAL:		83.2 10^3 lb/hr
FGD sludge produced, wet		64.8 10^3 lb/hr

ASH HANDLING

		10^3 lb/hr
Bottom ash:	dry	163
	water	87.5
	sludge	250
Fly ash:	dry	260
	water	2.60
	sludge	28.6

(continued)

Center, North Dakota (continued)

PROCESS WATER

	10^3 lb/hr
a. Steam and boiler feed water required	691
b. Dirty water input	1,377
c. Dirty condensate	1,368
d. Methanation water	234

OTHER WATER NEEDS

	10^3 lb/hr
a. Dust control	119
b. Service, sanitary & potable water:	
Required	21
Sewage recovered	14
c. Revegetation water	0
d. Evaporation from storage ponds	5
GRAND TOTAL RAW WATER INPUT TO PLANT:	1,401

TREATMENT SLUDGES

	10^3 lb/hr	
	solids	water & sludge
a. Lime softening	0	0
b. Ion exchange	---	29

Center, North Dakota (continued)

ENERGY

Energy Totals

	10^9 Btu/hr
Feed	14.7
Product and byproduct	9.9
Unrecovered heat	4.8
Conversion efficiency	67.6 %

Disposition of Unrecovered Heat

	10^9 Btu/hr	% wet	Btu/lb evap	10^3 lb water evap/hr
Direct loss	1.20	0	1,420	0
Designed dry	0.49	0	1,420	0
Designed wet	0.56	100	1,420	394
Acid gas removal regenerator condenser	1.02	0	1,420	0
Total turbine condensers	1.14	10	1,420	80
Total gas compressor interstage cooling	0.33	50	1,420	116
TOTAL:	4.74			590

WORK SHEET: WATER QUANTITY CALCULATIONS FOR BIGAS PROCESS

SITE: Scranton, North Dakota

PRODUCT SIZE: 250×10^6 SCF/day

ENERGY: 9.9×10^9 Btu/hr

Coal Analysis (wt % as-received)

Moisture	40.2
C	38.2
H	2.6
O	9.8
N	0.6
S	1.3
Ash	7.5
	100
HHV Calculated (10^3 Btu/lb)	6.43

COAL FEED

to reactor:	1,898 10^3 lb/hr	to boiler:	415 10^3 lb/hr
	12.2 10^9 Btu/hr		2.67 10^9 Btu/hr

FGD WATER

Vaporized	0.04 lb/lb coal	16.6 10^3 lb/hr
With sludge	0.18 lb/lb coal	74.7 10^3 lb/hr
TOTAL:		91.3 10^3 lb/hr
FGD sludge produced, wet		106.7 10^3 lb/hr

ASH HANDLING

		10^3 lb/hr
Bottom ash:	dry	149
	water	80.0
	sludge	229
Fly ash:	dry	24.9
	water	2.49
	sludge	27.4

Scranton, North Dakota (continued)

PROCESS WATER

	10^3 lb/hr
a. Steam and boiler feed water required	691
b. Dirty water input	1,355
c. Dirty condensate	1,338
d. Methanation water	234

OTHER WATER NEEDS

	10^3 lb/hr
a. Dust control	126
b. Service, sanitary & potable water:	
Required	21
Sewage recovered	14
c. Revegetation water	0
d. Evaporation from storage ponds	3
GRAND TOTAL RAW WATER INPUT TO PLANT:	1,419

TREATMENT SLUDGES

	10^3 lb/hr solids	water & sludge
a. Lime softening	0.27	1.4
b. Ion exchange	---	29

(continued)

Scranton, North Dakota (continued)

ENERGY

Energy Totals

	10^9 Btu/hr
Feed	14.9
Product and byproduct	9.9
Unrecovered heat	5.0
Conversion efficiency	67.0 %

Disposition of Unrecovered Heat

	10^9 Btu/hr	% wet	Btu/lb evap	10^3 lb water evap/hr
Direct loss	1.33	0	1,417	0
Designed dry	0.49	0	1,417	0
Designed wet	0.56	100	1,417	395
Acid gas removal regenerator condenser	1.02	0	1,417	0
Total turbine condensers	1.14	10	1,417	80
Total gas compressor interstage cooling	0.33	50	1,417	116
TOTAL:	4 87			591

WORK SHEET: WATER QUANTITY CALCULATIONS FOR
BIGAS PROCESS

SITE: Chupp Mine, Montana

PRODUCT SIZE: 250 x 10^6 SCF/day

ENERGY: 9.9 x 10^9 Btu/hr

Coal Analysis (wt % as-received)

Moisture	38.3
C	40.4
H	2.5
O	10.6
N	0.6
S	0.3
Ash	7.3
	100
HHV Calculated (10^3 Btu/lb)	6.60

COAL FEED

to reactor:	1,840 10^3 lb/hr	to boiler:	394 10^3 lb/hr
	12.1 10^9 Btu/hr		2.60 10^9 Btu/hr

FGD WATER

Vaporized	0.08 lb/lb coal	31.5 10^3 lb/hr
With sludge	0.04 lb/lb coal	15.8 10^3 lb/hr
TOTAL:		47.3 10^3 lb/hr
FGD sludge produced, wet		22.5 10^3 lb/hr

ASH HANDLING

		10^3 lb/hr
Bottom ash:	dry	140
	water	75.4
	sludge	215
Fly ash:	dry	23.0
	water	2.30
	sludge	25.3

(continued)

Chupp Mine, Montana (continued)

PROCESS WATER

	10^3 lb/hr
a. Steam and boiler feed water required	691
b. Dirty water input	1,355
c. Dirty condensate	1,307
d. Methanation water	234

OTHER WATER NEEDS

	10^3 lb/hr
a. Dust control	104
b. Service, sanitary & potable water:	
Required	21
Sewage recovered	14
c. Revegetation water	0
d. Evaporation from storage ponds	7
GRAND TOTAL RAW WATER INPUT TO PLANT:	2,224

TREATMENT SLUDGES

	10^3 lb/hr solids	10^3 lb/hr water & sludge
a. Lime softening	---	---
b. Ion exchange	---	29

ENERGY

Energy Totals

	10^9 Btu/hr
Feed	14.7
Product and byproduct	9.9
Unrecovered heat	4.8
Conversion efficiency	67.3 %

Disposition of Unrecovered Heat

	10^9 Btu/hr	% wet	Btu/lb evap	10^3 lb water evap/hr
Direct loss	1.27	0	1,417	0
Designed dry	0.48	0	1,417	0
Designed wet	0.56	100	1,417	395
Acid gas removal regenerator condenser	1.02	0	1,417	0
Total turbine condensers	1.14	100	1,417	805
Total gas compressor interstage cooling	0.33	100	1,417	233
TOTAL:	4.80			1,433

WORK SHEET: WATER QUANTITY CALCULATIONS FOR SYNTHANE PROCESS

SITE:

PRODUCT SIZE: 250×10^6 SCF/day

ENERGY: 9.79×10^9 Btu/hr

Coal Analysis (wt % as-received)			Char Analysis (wt %)	
Moisture	______		______	
C	______	Tables 3-18, 3-19	______	Table A5-11
H	______		______	
O	______		______	
N	______		______	
S	______		______	
Ash	______		______	
	100		100	
HHV Calculated (10^3 Btu/lb)	______		______	

COAL FEED TO REACTOR:

Table A5-4

Calculated 10^9 Btu/hr

CHAR FEED TO BOILER:

Calculated 10^9 Btu/hr

Table A5-10

FGD WATER

Vaporized	Last 2 paragraphs in Appendix 5	______ 10^3 lb/hr
With sludge	Also Appendix 8	______ 10^3 lb/hr
TOTAL:		Calcd. 10^3 lb/hr
FGD sludge produced, wet		______ 10^3 lb/hr

ASH HANDLING

		10^3 lb/hr
Bottom ash:	dry	______
	water	______
	sludge	______
Fly ash:	dry	Appendix 8
	water	______
	sludge	______

(continued)

_______________ (continued)

PROCESS WATER

	10^3 lb/hr
a. Steam to gasifier & shift converter	Table A5-4
b. Dirty condensate (after scrub)	Table A5-4
c. Medium quality condensate*	Table A5-4
d. Methanation water	Table A5-4

OTHER WATER NEEDS

	10^3 lb/hr
a. Dust control	______
b. Service, sanitary & potable water:	
Required	______
Sewage recovered	Appendix 9
c. Revegetation water	______
d. Evaporation from storage ponds	______
GRAND TOTAL RAW WATER INPUT TO PLANT:	Appendix 11

TREATMENT SLUDGES

	10^3 lb/hr solids	10^3 lb/hr water & sludge
a. Lime softening	______	______
b. Ion exchange	Appendix 11	______
c. Biotreatment	______	______

*After shift reactor & after acid gas removal.

_______________ (continued)

ENERGY

Energy Totals

	10^9 Btu/hr
Feed	Calculated
Product and byproduct	Table A5-10 (Char not fired to boiler)
Unrecovered heat	Table A5-10
Conversion efficiency	Table A5-10

Disposition of Unrecovered Heat

	10^9 Btu/hr	% wet	Btu/lb evap	10^3 lb water evap/hr
Direct loss	Table A5-10	______	______	______
Designed dry	Table A5-10	______	______	______
Designed wet	Table A5-10*	______	______	______
Acid gas removal regenerator condenser	Table A5-10	TABLE A7-1	TABLE A7-2	CALCULATED
Total turbine condensers	Table A5-10			
Total gas compressor interstage cooling	Table A5-10	______	______	______
TOTAL:	______			______

*Wet cooling & bottom ash quench.

WORK SHEET: WATER QUANTITY CALCULATIONS FOR SYNTHANE PROCESS

SITE: Jefferson, Alabama

PRODUCT SIZE: 250 x 10^6 SCF/day

ENERGY: 9.79 x 10^9 Btu/hr

	Coal Analysis (wt % as-received)	Char Analysis (wt %)
Moisture	2.3	
C	71.0	71.4
H	4.4	0.9
O	3.8	0.5
N	1.5	1.8
S	0.9	1.5
Ash	16.1	23.9
	100	100
HHV Calculated (10^3 Btu/lb)	12.79	10.90

COAL FEED TO REACTOR:

1,243 10^3 lb/hr

15.9 10^9 Btu/hr

CHAR FEED TO BOILER:

231 10^3 lb/hr

2.52 10^9 Btu/hr

FGD WATER

Vaporized	0.79 lb/lb coal	182 10^3 lb/hr
With sludge	0.21 lb/lb coal	47.8 10^3 lb/hr
TOTAL:		230 10^3 lb/hr
FGD sludge produced, wet		68.23 10^3 lb/hr

ASH HANDLING

		10^3 lb/hr
Bottom ash:	dry	27.5
	water	14.8
	sludge	42.3
Fly ash:	dry	110
	water	11.0
	sludge	121

Jefferson, Alabama (continued)

PROCESS WATER

	10^3 lb/hr
a. Steam required	1,215
b. Dirty condensate	578
c. Medium quality condensate	115
d. Methanation water	130

OTHER WATER NEEDS

	10^3 lb/hr
a. Dust control	118
b. Service, sanitary & potable water:	
Required	21
Sewage recovered	14
c. Revegetation water	0
d. Evaporation from storage ponds	0
GRAND TOTAL RAW WATER INPUT TO PLANT:	1,981

TREATMENT SLUDGES

	10^3 lb/hr solids	10^3 lb/hr water & sludge
a. Lime softening	0.06	0.3
b. Ion exchange	---	69
c. Biotreatment	0.68	3.4

(continued)

Jefferson, Alabama (continued)

ENERGY

Energy Totals

	10^9 Btu/hr
Feed	15.9
Product and byproduct	11.5
Unrecovered heat	4.4
Conversion efficiency	72.5%

Disposition of Unrecovered Heat

	10^9 Btu/hr	% wet	Btu/lb evap	10^3 lb water evap/hr
Direct loss	0.82	0	1,310	0
Designed dry	1.38	0	1,310	0
Designed wet	0.49	100	1,310	374
Acid gas removal regenerator condenser	0.69	0	1,310	0
Total turbine condensers	0.77	100	1,310	588
Total gas compressor interstage cooling	0.22	100	1,310	168
TOTAL:	4.37			1,130

WORK SHEET: WATER QUANTITY CALCULATIONS FOR SYNTHANE PROCESS

SITE: Gibson, Indiana

PRODUCT SIZE: 250 x 10^6 SCF/day

ENERGY: 9.79 x 10^9 Btu/hr

	Coal Analysis (wt % as-received)	Char Analysis (wt %)
Moisture	10.0	
C	68.2	71.4
H	4.6	0.9
O	7.6	0.5
N	1.1	1.8
S	2.1	1.5
Ash	6.4	23.9
	100	100
HHV Calculated (10^3 Btu/lb)	12.20	10.90

COAL FEED TO REACTOR:

1,224 10^3 lb/hr

14.9 10^9 Btu/hr

CHAR FEED TO BOILER:

238 10^3 lb/hr

2.59 10^9 Btu/hr

FGD WATER

Vaporized	0.79 lb/lb coal	188 10^3 lb/hr
With sludge	0.21 lb/lb coal	49.1 10^3 lb/hr
TOTAL:		237 10^3 lb/hr
FGD sludge produced, wet		70.1 10^3 lb/hr

ASH HANDLING

		10^3 lb/hr
Bottom ash:	dry	7.32
	water	3.94
	sludge	11.3
Fly ash:	dry	36.6
	water	3.66
	sludge	40.3

(continued)

Gibson, Indiana (continued)

PROCESS WATER

	10^3 lb/hr
a. Steam required	1,237
b. Dirty condensate	599
c. Medium quality condensate	115
d. Methanation water	130

OTHER WATER NEEDS

	10^3 lb/hr
a. Dust control	117
b. Service, sanitary & potable water:	
Required	21
Sewage recovered	14
c. Revegetation water	0
d. Evaporation from storage ponds	0
GRAND TOTAL RAW WATER INPUT TO PLANT:	1,926

TREATMENT SLUDGES

	10^3 lb/hr solids	10^3 lb/hr water & sludge
a. Lime softening	0.77	3.85
b. Ion exchange	---	71
c. Biotreatment	0.7	3.5

Gibson, Indiana (continued)

ENERGY

Energy Totals

	10^9 Btu/hr
Feed	15.9
Product and byproduct	11.5
Unrecovered heat	4.4
Conversion efficiency	72.1%

Disposition of Unrecovered Heat

	10^9 Btu/hr	% wet	Btu/lb evap	10^3 lb water evap/hr
Direct loss	0.89	0	1,370	0
Designed dry	1.38	0	1,370	0
Designed wet	0.49	100	1,370	358
Acid gas removal regenerator condenser	0.69	0	1,370	0
Total turbine condensers	0.77	100	1,370	562
Total gas compressor interstage cooling	0.22	100	1,370	161
TOTAL:	4.44			1,081

WORK SHEET: WATER QUANTITY CALCULATIONS FOR SYNTHANE PROCESS

SITE: Sullivan, Indiana

PRODUCT SIZE: 250 x 10^6 SCF/day

ENERGY: 9.79 x 10^9 Btu/hr

	Coal Analysis (wt % as-received)	Char Analysis (wt %)
Moisture	13.5	
C	63.9	71.4
H	4.5	0.9
O	7.1	0.5
N	1.4	1.8
S	2.2	1.5
Ash	7.4	23.9
	100	100
HHV Calculated (10^3 Btu/lb)	11.60	10.90

COAL FEED TO REACTOR:

1,243 10^3 lb/hr

14.4 10^9 Btu/hr

CHAR FEED TO BOILER:

242 10^3 lb/hr

2.64 10^9 Btu/hr

FGD WATER

Vaporized	0.79 lb/lb coal	191 10^3 lb/hr
With sludge	0.21 lb/lb coal	50.0 10^3 lb/hr
TOTAL:		241 10^3 lb/hr
FGD sludge produced, wet		71.5 10^3 lb/hr

ASH HANDLING

		10^3 lb/hr
Bottom ash:	dry	13.2
	water	7.12
	sludge	20.4
Fly ash:	dry	52.9
	water	5.29
	sludge	58.2

Sullivan, Indiana (continued)

PROCESS WATER

	10^3 lb/hr
a. Steam required	1,234
b. Dirty condensate	595
c. Medium quality condensate	115
d. Methanation water	130

OTHER WATER NEEDS

	10^3 lb/hr
a. Dust control	45
b. Service, sanitary & potable water:	
Required	21
Sewage recovered	14
c. Revegetation water	0
d. Evaporation from storage ponds	0
GRAND TOTAL RAW WATER INPUT TO PLANT:	1,847

TREATMENT SLUDGES

	10^3 lb/hr solids	10^3 lb/hr water & sludge
a. Lime softening	0.46	2.30
b. Ion exchange	---	70
c. Biotreatment	0.23	1.1

(continued)

Sullivan, Indiana (continued)

ENERGY

Energy Totals

	10^9 Btu/hr
Feed	15.9
Product and byproduct	11.4
Unrecovered heat	4.4
Conversion efficiency	71.8%

Disposition of Unrecovered Heat

	10^9 Btu/hr	% wet	Btu/lb evap	10^3 lb water evap/hr
Direct loss	0.94	0	1,380	0
Designed dry	1.38	0	1,380	0
Designed wet	0.49	100	1,380	355
Acid gas removal regenerator condenser	0.69	0	1,380	0
Total turbine condensers	0.77	100	1,380	560
Total gas compressor interstage cooling	0.22	100	1,380	159
TOTAL:	4.49			1,074

WORK SHEET: WATER QUANTITY CALCULATIONS FOR SYNTHANE PROCESS

SITE: Floyd, Kentucky

PRODUCT SIZE: 250 x 10^6 SCF/day

ENERGY: 9.79 x 10^9 Btu/hr

	Coal Analysis (wt % as-received)	Char Analysis (wt %)
Moisture	3.4	
C	79.8	71.4
H	5.2	0.9
O	6.5	0.5
N	1.6	1.8
S	0.6	1.5
Ash	2.9	23.9
	100	100
HHV Calculated (10^3 Btu/lb)	14.30	10.90

	Coal	Char / Boiler
COAL FEED TO REACTOR: / CHAR FEED TO BOILER:	1,113 10^3 lb/hr	231.2 10^3 lb/hr
	15.9 10^9 Btu/hr	2.52 10^9 Btu/hr
FGD WATER		
Vaporized	0.79 lb/lb coal	182 10^3 lb/hr
With sludge	0.21 lb/lb coal	47.8 10^3 lb/hr
TOTAL:		231 10^3 lb/hr
FGD sludge produced, wet		68.2 10^3 lb/hr

ASH HANDLING

		10^3 lb/hr
Bottom ash:	dry	4.43
	water	2.39
	sludge	6.82
Fly ash:	dry	17.7
	water	1.77
	sludge	19.5

(continued)

Floyd, Kentucky (continued)

PROCESS WATER

	10^3 lb/hr
a. Steam required	1,247
b. Dirty condensate	609
c. Medium quality condensate	115
d. Methanation water	130

OTHER WATER NEEDS

	10^3 lb/hr
a. Dust control	108
b. Service, sanitary & potable water:	
Required	21
Sewage recovered	14
c. Revegetation water	0
d. Evaporation from storage ponds	0
GRAND TOTAL RAW WATER INPUT TO PLANT:	1,320

TREATMENT SLUDGES

	10^3 lb/hr solids	10^3 lb/hr water & sludge
a. Lime softening	0.03	0.15
b. Ion exchange	---	71
c. Biotreatment	0.72	3.6

Floyd, Kentucky (continued)

ENERGY

Energy Totals

	10^9 Btu/hr
Feed	15.9
Product and byproduct	11.5
Unrecovered heat	4.37
Conversion efficiency	72.5%

Disposition of Unrecovered Heat

	10^9 Btu/hr	% wet	Btu/lb evap	10^3 lb water evap/hr
Direct loss	0.82	0	1,360	0
Designed dry	1,38	0	1,360	0
Designed wet	0.49	100	1,360	360
Acid gas removal regenerator condenser	0.69	0	1,360	0
Total turbine condensers	0.77	10	1,360	57
Total gas compressor interstage cooling	0.22	50	1,360	81
TOTAL:	4.37			498

WORK SHEET: WATER QUANTITY CALCULATIONS FOR SYNTHANE PROCESS

SITE: Gallia, Ohio

PRODUCT SIZE: 250 x 10^6 SCF/day

ENERGY: 9.79 x 10^9 Btu/hr

	Coal Analysis (wt % as-received)	Char Analysis (wt %)
Moisture	7.4	
C	64.8	71.4
H	4.6	0.9
O	9.1	0.5
N	1.1	1.8
S	3.2	1.5
Ash	9.8	23.9
	100	100
HHV Calculated (10^3 Btu/lb)	11.70	10.90

COAL FEED TO REACTOR:

1,315 10^3 lb/hr

15.4 10^9 Btu/hr

CHAR FEED TO BOILER:

235 10^3 lb/hr

2.56 10^9 Btu/hr

FGD WATER

Vaporized	0.79 lb/lb coal	185 10^3 lb/hr
With sludge	0.21 lb/lb coal	48.52 10^3 lb/hr
TOTAL:		233 10^3 lb/hr
FGD sludge produced, wet		69.3 10^3 lb/hr

ASH HANDLING

		10^3 lb/hr
Bottom ash:	dry	18.0
	water	9.68
	sludge	27.7
Fly ash:	dry	71.9
	water	7.19
	sludge	79.1

Gallia, Ohio (continued)

PROCESS WATER

	10^3 lb/hr
a. Steam required	1,228
b. Dirty condensate	590
c. Medium quality condensate	115
d. Methanation water	130

OTHER WATER NEEDS

	10^3 lb/hr
a. Dust control	124
b. Service, sanitary & potable water:	
Required	21
Sewage recovered	14
c. Revegetation water	0
d. Evaporation from storage ponds	0
GRAND TOTAL RAW WATER INPUT TO PLANT:	1,896

TREATMENT SLUDGES

	10^3 lb/hr solids	10^3 lb/hr water & sludge
a. Lime softening	0.06	0.3
b. Ion exchange	---	70
c. Biotreatment	0.22	1.1

(continued)

Gallia, Ohio (continued)

ENERGY

Energy Totals

	10^9 Btu/hr
Feed	15.9
Product and byproduct	11.5
Unrecovered heat	4.4
Conversion efficiency	72.3%

Disposition of Unrecovered Heat

	10^9 Btu/hr	% wet	Btu/lb evap	10^3 lb water evap/hr
Direct loss	0.86	0	1,420	0
Designed dry	1.38	0	1,420	0
Designed wet	0.49	100	1,420	345
Acid gas removal regenerator condenser	0.69	0	1,420	0
Total turbine condensers	0.77	100	1,420	542
Total gas compressor interstage cooling	0.22	100	1,420	155
TOTAL:	4.41			1,042

WORK SHEET: WATER QUANTITY CALCULATIONS FOR SYNTHANE PROCESS

SITE: Jefferson, Ohio

PRODUCT SIZE: 250 x 10^6 SCF/day

ENERGY: 9.79 x 10^9 Btu/hr

	Coal Analysis (wt % as-received)	Char Analysis (wt %)
Moisture	2.4	
C	71.1	71.4
H	4.9	0.9
O	5.3	0.5
N	1.2	1.8
S	5.0	1.5
Ash	10.1	23.9
	100	100
HHV Calculated (10^3 Btu/lb)	13.10	10.90

COAL FEED TO REACTOR:		CHAR FEED TO BOILER:
	1,215 10^3 lb/hr	231 10^3 lb/hr
	15.9 10^9 Btu/hr	2.52 10^9 Btu/hr
FGD WATER		
Vaporized	0.79 lb/lb coal	182 10^3 lb/hr
With sludge	0.21 lb/lb coal	47.8 10^3 lb/hr
TOTAL:		230 10^3 lb/hr
FGD sludge produced, wet		68.2 10^3 lb/hr

ASH HANDLING

		10^3 lb/hr
Bottom ash:	dry	16.9
	water	9.07
	sludge	25.9
Fly ash:	dry	67.4
	water	6.74
	sludge	74.2

(continued)

PROCESS WATER

	10^3 lb/hr
a. Steam required	1,229
b. Dirty condensate	591
c. Medium quality condensate	115
d. Methanation water	130

OTHER WATER NEEDS

	10^3 lb/hr
a. Dust control	43
b. Service, sanitary & potable water:	
Required	21
Sewage recovered	14
c. Revegetation water	0
d. Evaporation from storage ponds	0
GRAND TOTAL RAW WATER INPUT TO PLANT:	1,810

TREATMENT SLUDGES

	10^3 lb/hr	
	solids	water & sludge
a. Lime softening	0.06	0.3
b. Ion exchange	---	70
c. Biotreatment	0.22	1.1

ENERGY

Energy Totals

	10^9 Btu/hr
Feed	15.9
Product and byproduct	11.5
Unrecovered heat	4.4
Conversion efficiency	72.5%

Disposition of Unrecovered Heat

	10^9 Btu/hr	% wet	Btu/lb evap	10^3 lb water evap/hr
Direct loss	0.82	0	1,400	0
Designed dry	1.38	0	1,400	0
Designed wet	0.49	100	1,400	345
Acid gas removal regenerator condenser	0.69	0	1,400	0
Total turbine condensers	0.77	100	1,400	542
Total gas compressor interstage cooling	0.22	100	1,400	155
TOTAL:	4.37			1,042

WORK SHEET: WATER QUANTITY CALCULATIONS FOR SYNTHANE PROCESS

SITE: Armstrong, Pennsylvania

PRODUCT SIZE: 250×10^6 SCF/day

ENERGY: 9.79×10^9 Btu/hr

Coal Analysis (wt % as-received)		Char Analysis (wt %)
Moisture	2.3	
C	73.6	71.4
H	4.9	0.9
O	5.3	0.5
N	1.4	1.8
S	2.8	1.5
Ash	9.7	23.9
	100	100
HHV Calculated (10^3 Btu/lb)	13.40	10.90

COAL FEED TO REACTOR:

1,187 10^3 lb/hr

15.9 10^9 Btu/hr

CHAR FEED TO BOILER:

231 10^3 lb/hr

2.52 10^9 Btu/hr

FGD WATER

Vaporized	0.79 lb/lb coal	182.3 10^3 lb/hr
With sludge	0.21 lb/lb coal	47.8 10^3 lb/hr
TOTAL:		230 10^3 lb/hr
FGD sludge produced, wet		68.2 10^3 lb/hr

ASH HANDLING

		10^3 lb/hr
Bottom ash:	dry	15.8
	water	8.51
	sludge	24.3
Fly ash:	dry	63.3
	water	6.33
	sludge	69.6

Armstrong, Pennsylvania (continued)

PROCESS WATER

	10^3 lb/hr
a. Steam required	1,231
b. Dirty condensate	593
c. Medium quality condensate	115
d. Methanation water	130

OTHER WATER NEEDS

	10^3 lb/hr
a. Dust control	113
b. Service, sanitary & potable water:	
Required	21
Sewage recovered	14
c. Revegetation water	0
d. Evaporation from storage ponds	0
GRAND TOTAL RAW WATER INPUT TO PLANT:	1,872

TREATMENT SLUDGES

	10^3 lb/hr solids	10^3 lb/hr water & sludge
a. Lime softening	0.06	0.31
b. Ion exchange	---	70
c. Biotreatment	0.23	1.2

(continued)

Armstrong, Pennsylvania (continued)

ENERGY

Energy Totals

	10^9 Btu/hr
Feed	15.9
Product and byproduct	11.5
Unrecovered heat	4.4
Conversion efficiency	72.5%

Disposition of Unrecovered Heat

	10^9 Btu/hr	% wet	Btu/lb evap	10^3 lb water evap/hr
Direct loss	0.82	0	1,410	0
Designed dry	1.38	0	1,410	0
Designed wet	0.49	100	1,410	348
Acid gas removal regenerator condenser	0.69	0	1,410	0
Total turbine condensers	0.77	100	1,410	546
Total gas compressor interstage cooling	0.22	100	1,410	156
TOTAL:	4.37			1,050

WORK SHEET: WATER QUANTITY CALCULATIONS FOR SYNTHANE PROCESS

SITE: Kanawha, West Virginia

PRODUCT SIZE: 250 x 10^6 SCF/day

ENERGY: 9.79 x 10^9 Btu/hr

	Coal Analysis (wt % as-received)	Char Analysis (wt %)
Moisture	1.9	
C	75.1	71.4
H	4.9	0.9
O	6.7	0.5
N	1.4	1.8
S	0.7	1.5
Ash	9.3	23.9
	100	100
HHV Calculated (10^3 Btu/lb)	13.40	10.90

COAL FEED TO REACTOR:

1,187 10^3 lb/hr

15.9 10^9 Btu/hr

CHAR FEED TO BOILER:

231 10^3 lb/hr

2.52 10^9 Btu/hr

FGD WATER

Vaporized	0.79 lb/lb coal	182 10^3 lb/hr
With sludge	0.21 lb/lb coal	47.8 10^3 lb/hr
TOTAL:		230 10^3 lb/hr
FGD sludge produced, wet		68.2 10^3 lb/hr

ASH HANDLING

		10^3 lb/hr
Bottom ash:	dry	15.2
	water	8.16
	sludge	23.3
Fly ash:	dry	60.6
	water	6.06
	sludge	66.7

(continued)

Kanawha, West Virginia (continued)

PROCESS WATER

	10^3 lb/hr
a. Steam required	1,232
b. Dirty condensate	594
c. Medium quality condensate	115
d. Methanation water	130

OTHER WATER NEEDS

	10^3 lb/hr
a. Dust control	113
b. Service, sanitary & potable water:	
Required	21
Sewage recovered	14
c. Revegetation water	0
d. Evaporation from storage ponds	0
GRAND TOTAL RAW WATER INPUT TO PLANT:	1,865

TREATMENT SLUDGES

	10^3 lb/hr	
	solids	water & sludge
a. Lime softening	0.06	0.3
b. Ion exchange	---	70
c. Biotreatment	0.23	1.1

Kanawha, West Virginia (continued)

ENERGY

Energy Totals

	10^9 Btu/hr
Feed	15.9
Product and byproduct	11.5
Unrecovered heat	4.4
Conversion efficiency	72.5%

Disposition of Unrecovered Heat

	10^9 Btu/hr	% wet	Btu/lb evap	10^3 lb water evap/hr
Direct loss	0.82	0	1,360	0
Designed dry	1.38	0	1,360	0
Designed wet	0.49	100	1,360	360
Acid gas removal regenerator condenser	0.69	0	1,360	0
Total turbine condensers	0.77	100	1,360	566
Total gas compressor interstage cooling	0.22	100	1,360	162
TOTAL:	4.37			1,088

WORK SHEET: WATER QUANTITY CALCULATIONS FOR SYNTHANE PROCESS

SITE: Preston, West Virginia

PRODUCT SIZE: 250 x 10^6 SCF/day

ENERGY: 9.79 x 10^9 Btu/hr

	Coal Analysis (wt % as-received)	Char Analysis (wt %)
Moisture	2.5	
C	74.6	71.4
H	4.7	0.9
O	3.3	0.5
N	1.5	1.8
S	2.7	1.5
Ash	10.7	23.9
	100	100
HHV Calculated (10^3 Btu/lb)	13.60	10.90

COAL FEED TO REACTOR:

1,170 10^3 lb/hr

15.9 10^9 Btu/hr

CHAR FEED TO BOILER:

231 10^3 lb/hr

2.52 10^9 Btu/hr

FGD WATER

Vaporized	0.79 lb/lb coal	183 10^3 lb/hr
With sludge	0.21 lb/lb coal	47.8 10^3 lb/hr
TOTAL:		230 10^3 lb/hr
FGD sludge produced, wet		68.2 10^3 lb/hr

ASH HANDLING

		10^3 lb/hr
Bottom ash:	dry	17.2
	water	9.26
	sludge	26.5
Fly ash:	dry	68.8
	water	6.88
	sludge	75.7

Preston, West Virginia (continued)

PROCESS WATER

	10^3 lb/hr
a. Steam required	1,229
b. Dirty condensate	591
c. Medium quality condensate	115
d. Methanation water	130

OTHER WATER NEEDS

	10^3 lb/hr
a. Dust control	112
b. Service, sanitary & potable water:	
Required	21
Sewage recovered	14
c. Revegetation water	0
d. Evaporation from storage ponds	0
GRAND TOTAL RAW WATER INPUT TO PLANT:	1,392

TREATMENT SLUDGES

	10^3 lb/hr	
	solids	water & sludge
a. Lime softening	0.03	0.15
b. Ion exchange	---	70
c. Biotreatment	0.23	1.2

(continued)

Preston, West Virginia (continued)

ENERGY

Energy Totals

	10^9 Btu/hr
Feed	15.9
Product and byproduct	11.5
Unrecovered heat	4.4
Conversion efficiency	72.5%

Disposition of Unrecovered Heat

	10^9 Btu/hr	% wet	Btu/lb evap	10^3 lb water evap/hr
Direct loss	0.82	0	1,380	0
Designed dry	1.38	0	1,380	0
Designed wet	0.49	100	1,380	355
Acid gas removal regenerator condenser	0.69	0	1,380	0
Total turbine condensers	0.77	10	1,380	56
Total gas compressor interstage cooling	0.22	100	1,380	159
TOTAL:	4.37			570

WORK SHEET: WATER QUANTITY CALCULATIONS FOR SYNTHANE PROCESS

SITE: Antelope Creek, Wyoming

PRODUCT SIZE: 250 x 10^6 SCF/day

ENERGY: 9.79 x 10^9 Btu/hr

	Coal Analysis (wt % as-received)	Char Analysis (wt %)
Moisture	26.2	
C	52.6	63.6
H	3.6	1.0
O	12.0	1.4
N	0.6	0.4
S	0.5	0.3
Ash	4.5	33.3
	100	100
HHV Calculated (10^3 Btu/lb)	9.00	9.73

COAL FEED TO REACTOR:

1,472 10^3 lb/hr

13.3 10^9 Btu/hr

CHAR FEED TO BOILER:

370 10^3 lb/hr

3.61 10^9 Btu/hr

FGD WATER

Vaporized	0.70 lb/lb coal	259 10^3 lb/hr
With sludge	0.041 lb/lb coal	15.2 10^3 lb/hr
TOTAL:		274 10^3 lb/hr
FGD sludge produced, wet		2.20 10^3 lb/hr

ASH HANDLING

		10^3 lb/hr
Bottom ash:	dry	11.5
	water	6.19
	sludge	17.7
Fly ash:	dry	46.0
	water	4.60
	sludge	50.6

(continued)

Antelope Creek, Wyoming (continued)

PROCESS WATER

	10^3 lb/hr
a. Steam required	1,177
b. Dirty condensate	526
c. Medium quality condensate	169
d. Methanation water	141

OTHER WATER NEEDS

	10^3 lb/hr
a. Dust control	58
b. Service, sanitary & potable water:	
Required	21
Sewage recovered	14
c. Revegetation water	0
d. Evaporation from storage ponds	6
GRAND TOTAL RAW WATER INPUT TO PLANT:	1,432

TREATMENT SLUDGES

	10^3 lb/hr solids	water & sludge
a. Lime softening	0.03	0.14
b. Ion exchange	---	66
c. Biotreatment	0.33	1.65
d. Electrodialysis	---	143

Antelope Creek, Wyoming (continued)

ENERGY

Energy Totals

	10^9 Btu/hr
Feed	17.1
Product and byproduct	11.1
Unrecovered heat	6.0
Conversion efficiency	65.2%

Disposition of Unrecovered Heat

	10^9 Btu/hr	% wet	Btu/lb evap	10^3 lb water evap/hr
Direct loss	1.77	0	1,397	0
Designed dry	1.33	0	1,397	0
Designed wet	0.45	100	1,397	322
Acid gas removal regenerator condenser	1.01	0	1,397	0
Total turbine condensers	1.04	10	1,397	74
Total gas compressor interstage cooling	0.34	50	1,397	122
TOTAL:	5.94			518

WORK SHEET: WATER QUANTITY CALCULATIONS FOR SYNTHANE PROCESS

SITE: Spotted Horse, Wyoming

PRODUCT SIZE: 250×10^6 SCF/day

ENERGY: 9.79×10^9 Btu/hr

	Coal Analysis (wt % as-received)	Char Analysis (wt %)
Moisture	28.0	
C	46.8	63.6
H	3.5	1.0
O	12.3	1.4
N	0.7	0.4
S	0.9	0.3
Ash	7.8	33.3
	100	100
HHV Calculated (10^3 Btu/lb)	8.06	9.73

COAL FEED TO REACTOR:

1,596 10^3 lb/hr

12.9 10^9 Btu/hr

CHAR FEED TO BOILER:

381 10^3 lb/hr

3.71 10^9 Btu/hr

FGD WATER

Vaporized	0.70 lb/lb coal	267 10^3 lb/hr
With sludge	0.04 lb/lb coal	15.6 10^3 lb/hr
TOTAL:		282 10^3 lb/hr
FGD sludge produced, wet		2.26 10^3 lb/hr

ASH HANDLING

		10^3 lb/hr
Bottom ash:	dry	22.2
	water	12.0
	sludge	34.2
Fly ash:	dry	88.8
	water	8.88
	sludge	97.7

Spotted Horse, Wyoming (continued)

PROCESS WATER

	10^3 lb/hr
a. Steam required	1,162
b. Dirty condensate	511
c. Medium quality condensate	169
d. Methanation water	141

OTHER WATER NEEDS

	10^3 lb/hr
a. Dust control	62
b. Service, sanitary & potable water:	
Required	21
Sewage recovered	14
c. Revegetation water	0
d. Evaporation from storage ponds	6
GRAND TOTAL RAW WATER INPUT TO PLANT:	1,315

TREATMENT SLUDGES

	solids (10^3 lb/hr)	water & sludge (10^3 lb/hr)
a. Lime softening	1.32	6.41
b. Ion exchange	---	65
c. Biotreatment	0.30	1.5

(continued)

Spotted Horse, Wyoming (continued)

ENERGY

Energy Totals

	10^9 Btu/hr
Feed	17.1
Product and byproduct	11.0
Unrecovered heat	6.1
Conversion efficiency	64.6%

Disposition of Unrecovered Heat

	10^9 Btu/hr	% wet	Btu/lb evap	10^3 lb water evap/hr
Direct loss	1.87	0	1,401	0
Designed dry	1.33	0	1 401	0
Designed wet	0.45	100	1,401	321
Acid gas removal regenerator condenser	1.01	0	1 401	0
Total turbine condensers	1.04	10	1,401	74
Total gas compressor interstage cooling	0.34	50	1,401	121
TOTAL:	6.04			516

WORK SHEET: WATER QUANTITY CALCULATIONS FOR SYNTHANE PROCESS

SITE: Colstrip, Montana

PRODUCT SIZE: 250 x 10^6 SCF/day

ENERGY: 9.79 x 10^9 Btu/hr

	Coal Analysis (wt % as-received)	Char Analysis (wt %)
Moisture	24.4	
C	52.4	63.6
H	3.5	1.0
O	11.6	1.4
N	0.8	0.4
S	0.4	0.3
Ash	6.9	33.3
	100	100
HHV Calculated (10^3 Btu/lb)	8.91	9.73

COAL FEED TO REACTOR:

1,525 10^3 lb/hr

13.6 10^9 Btu/hr

CHAR FEED TO BOILER:

367 10^3 lb/hr

3.57 10^9 Btu/hr

FGD WATER

Vaporized	0.70 lb/lb coal	257 10^3 lb/hr
With sludge	0.04 lb/lb coal	14.7 10^3 lb/hr
TOTAL:		272 10^3 lb/hr
FGD sludge produced, wet		2.17 10^3 lb/hr

ASH HANDLING

		10^3 lb/hr
Bottom ash:	dry	18.1
	water	9.72
	sludge	27.8
Fly ash:	dry	72.2
	water	7.22
	sludge	79.5

(continued)

PROCESS WATER

	10^3 lb/hr
a. Steam required	1,168
b. Dirty condensate	518
c. Medium quality condensate	169
d. Methanation water	141

OTHER WATER NEEDS

	10^3 lb/hr
a. Dust control	73
b. Service, sanitary & potable water:	
Required	21
Sewage recovered	14
c. Revegetation water	0
d. Evaporation from storage ponds	6
GRAND TOTAL RAW WATER INPUT TO PLANT:	1,420

TREATMENT SLUDGES

	10^3 lb/hr solids	10^3 lb/hr water & sludge
a. Lime softening	0.03	0.16
b. Ion exchange	---	79
c. Biotreatment	0.30	1.5

Colstrip, Montana (continued)

ENERGY

Energy Totals

	10^9 Btu/hr
Feed	17.1
Product and byproduct	11.2
Unrecovered heat	5.9
Conversion efficiency	65.5%

Disposition of Unrecovered Heat

	10^9 Btu/hr	% wet	Btu/lb evap	10^3 lb water evap/hr
Direct loss	1.73	0	1,414	0
Designed dry	1.33	0	1,414	0
Designed wet	0.45	100	1,414	318
Acid gas removal regenerator condenser	1.01	0	1,414	0
Total turbine condensers	1.04	10	1,414	74
Total gas compressor interstage cooling	0.34	100	1,414	240
TOTAL:	5.90			632

WORK SHEET: WATER QUANTITY CALCULATIONS FOR
LURGI PROCESS

SITE:

PRODUCT SIZE: 250 x 10^6 SCF/day

ENERGY: 9.9 x 10^9 Btu/hr

<u>Coal Analysis (wt % as-received)</u>

Moisture	____	
C	____	Tables 3-18, 3-19
H	____	Tables 3-18, 3-19
O	____	Tables 3-18, 3-19
N	____	Tables 3-18, 3-19
S	____	Tables 3-18, 3-19
Ash	____	
	100	
HHV Calculated (10^3 Btu/lb)	____	

<u>COAL FEED</u>

to reactor: <u>Table A6-3</u> to boiler: <u>Table A6-3</u>

<u>Table A6-3</u> <u>Table A6-3</u>

<u>FGD WATER</u>

Vaporized	<u>Appendix 8</u>	____ 10^3 lb/hr
With sludge	<u>Appendix 8</u>	____ 10^3 lb/hr
TOTAL:		<u>Calcd.</u> 10^3 lb/hr
FGD sludge produced, wet		____ 10^3 lb/hr

<u>ASH HANDLING</u>

		<u>10^3 lb/hr</u>
Bottom ash:	dry	____
	water	____
	sludge	____
Fly ash:	dry	<u>Appendix 8</u>
	water	____
	sludge	____

(continued)

______________________ (continued)

PROCESS WATER

	10^3 lb/hr
a. Steam and boiler feed water required	Table A6-3
b. Dirty condensate	Table A6-3
c. Methanation water	Table A6-3

OTHER WATER NEEDS

	10^3 lb/hr
a. Dust control	______
b. Service, sanitary & potable water:	
Required	______
Sewage recovered	Appendix 9
c. Revegetation water	______
d. Evaporation from storage ponds	______
GRAND TOTAL RAW WATER INPUT TO PLANT:	Appendix 11

TREATMENT SLUDGES

	10^3 lb/hr solids	10^3 lb/hr water & sludge
a. Lime softening	______	______
b. Ion exchange	Appendix 11 ______	______
c. Biotreatment	______	______

______________________ (continued)

ENERGY

Energy Totals

	10^9 Btu/hr
Feed	Table A6-3
Product and byproduct	Table A6-3 (Product gas & byproduct)
Unrecovered heat	Table A6-3
Conversion efficiency	Table A6-3

Total unrecovered heat	Table A6-3
% of unrecovered heat wet cooled	From other gas plants in the same area*
Wet cooling load	Calculated
Btu/lb evap	Table A7-2
10^3 lb water evap/hr	Calculated

*Synthane

WORK SHEET: WATER QUANTITY CALCULATIONS FOR LURGI PROCESS

SITE: Marengo, Alabama (Ground water and surface water)

PRODUCT SIZE: 250 x 10^6 SCF/day

ENERGY: 9.9 x 10^9 Btu/hr

Coal Analysis (wt % as-received)

Moisture	48.7
C	32.1
H	2.2
O	9.8
N	0.6
S	1.8
Ash	4.8
	100
HHV Calculated (10^3 Btu/lb)	5.34

COAL FEED

to reactor: 2,765 10^3 lb/hr; 14.8 10^9 Btu/hr

to boiler: 845 10^3 lb/hr; 4.51 10^9 Btu/hr

FGD WATER

Vaporized	0.11 lb/lb coal	0 10^3 lb/hr
With sludge	0.25 lb/lb coal	211 10^3 lb/hr
TOTAL:		211 10^3 lb/hr
FGD sludge produced, wet		302 10^3 lb/hr

ASH HANDLING

		10^3 lb/hr
Bottom ash:	dry	141
	water	75.8
	sludge	217
Fly ash:	dry	32.6
	water	3.25
	sludge	35.7

Marengo, Alabama (continued)

PROCESS WATER

	10^3 lb/hr
a. Steam and boiler feed water required	1,767
b. Dirty condensate	2,325
c. Methanation water	260

OTHER WATER NEEDS

	10^3 lb/hr
a. Dust control	130
b. Service, sanitary & potable water:	
Required	21
Sewage recovered	14
c. Revegetation water	0
d. Evaporation from storage ponds	0
GRAND TOTAL RAW WATER INPUT TO PLANT:	810

TREATMENT SLUDGES

	10^3 lb/hr solids	10^3 lb/hr water & sludge
a. Lime softening	---	---
b. Ion exchange & reverse osmosis	---	186
c. Biotreatment	1.47	7.4

(continued)

Marengo, Alabama (continued)

ENERGY

Energy Totals

	10^9 Btu/hr
Feed	19.3
Product and byproduct	12.6
Unrecovered heat	6.76
Conversion efficiency	65 %

Disposition of Unrecovered Heat

Total unrecovered heat	6.76	10^9 Btu/hr
% of unrecovered heat wet cooled	19	%
Wet cooling load	1.28	10^9 Btu/hr
Btu/lb evap	1,310	
10^3 lb water evap/hr	980	

WORK SHEET: WATER QUANTITY CALCULATIONS FOR
LURGI PROCESS

SITE: Bureau, Illinois

PRODUCT SIZE: 250 x 10^6 SCF/day
ENERGY: 9.9 x 10^9 Btu/hr

Coal Analysis (wt % as-received)

Moisture	16.1
C	60.1
H	4.1
O	8.3
N	1.1
S	2.9
Ash	7.4
	100
HHV Calculated (10^3 Btu/lb)	10.76

COAL FEED

to reactor:	1,364	10^3 lb/hr	to boiler:	204	10^3 lb/hr
	14.7	10^9 Btu/hr		2.2	10^9 Btu/hr

FGD WATER

Vaporized	0.57	lb/lb coal	116	10^3 lb/hr
With sludge	0.40	lb/lb coal	81.6	10^3 lb/hr
TOTAL:			198	10^3 lb/hr
FGD sludge produced, wet			117	10^3 lb/hr

ASH HANDLING

		10^3 lb/hr
Bottom ash:	dry	104
	water	56.0
	sludge	160
Fly ash:	dry	12.1
	water	1.21
	sludge	13.3

(continued)

Bureau, Illinois (continued)

PROCESS WATER

	10^3 lb/hr
a. Steam and boiler feed water required	2.693
b. Dirty condensate	2,149
c. Methanation water	279

OTHER WATER NEEDS

	10^3 lb/hr
a. Dust control	150
b. Service, sanitary & potable water:	
Required	21
Sewage recovered	14
c. Revegetation water	0
d. Evaporation from storage ponds	0
GRAND TOTAL RAW WATER INPUT TO PLANT:	2,668

TREATMENT SLUDGES

	10^3 lb/hr	
	solids	water & sludge
a. Lime softening	1.4	6.7
b. Ion exchange	---	150
c. Biotreatment	0.68	3.4

Bureau, Illinois (continued)

ENERGY

Energy Totals

	10^9 Btu/hr
Feed	16.9
Product and byproduct	11.4
Unrecovered heat	5.55
Conversion efficiency	67 %

Disposition of Unrecovered Heat

Total unrecovered heat	5.55 10^9 Btu/hr
% of unrecovered heat wet cooled	44 %
Wet cooling load	2.44 10^9 Btu/hr
Btu/lb evap	1,390
10^3 lb water evap/hr	1,757

WORK SHEET: WATER QUANTITY CALCULATIONS FOR LURGI PROCESS

SITE: St. Clair, Illinois (Underground and Surface Coal Mining)

PRODUCT SIZE: 250 x 10^6 SCF/day

ENERGY: 9.9 x 10^9 Btu/hr

Coal Analysis (wt % as-received)

Moisture	11.3
C	61.1
H	4.2
O	7.4
N	1.2
S	3.7
Ash	11.1
	100
HHV Calculated (10^3 Btu/lb)	11.07

COAL FEED

to reactor:	1,351 10^3 lb/hr	14.9 10^9 Btu/hr
to boiler:	199 10^3 lb/hr	2.2 10^9 Btu/hr

FGD WATER

Vaporized	0.63 lb/lb coal	125 10^3 lb/hr
With sludge	0.51 lb/lb coal	101 10^3 lb/hr
TOTAL:		226 10^3 lb/hr
FGD sludge produced, wet		145 10^3 lb/hr

ASH HANDLING

		10^3 lb/hr
Bottom ash:	dry	154
	water	83.1
	sludge	238
Fly ash:	dry	17.7
	water	1.77
	sludge	19.4

St. Clair, Illinois (continued)

PROCESS WATER

	10^3 lb/hr
a. Steam and boiler feed water required	2,705
b. Dirty condensate	2,089
c. Methanation water	277

OTHER WATER NEEDS

	10^3 lb/hr
a. Dust control { Surface coal mining	56
a. Dust control { Underground coal mining	149
b. Service, sanitary & potable water:	
Required	21
Sewage recovered	14
c. Revegetation water	0
d. Evaporation from storage ponds	0
GRAND TOTAL RAW WATER INPUT TO PLANT:	
{ Surface coal mine	2,653
{ Underground coal mine	2,736

TREATMENT SLUDGES (Note: Surface coal mining & underground coal mining are the same)

	10^3 lb/hr solids	10^3 lb/hr water & sludge
a. Lime softening	0.07	0.33
b. Ion exchange	---	160
c. Biotreatment	0.66	3.3

(continued)

St. Clair, Illinois (continued)

ENERGY

Energy Totals

	10^9 Btu/hr
Feed	17.1
Product and byproduct	11.5
Unrecovered heat	5.6
Conversion efficiency	67 %

Disposition of Unrecovered Heat

Total unrecovered heat	5.64 10^9 Btu/hr
% of unrecovered heat wet cooled	44 %
Wet cooling load	2.48 10^9 Btu/hr
Btu/lb evap	1,370
10^3 lb water evap/hr	1,752

WORK SHEET: WATER QUANTITY CALCULATIONS FOR LURGI PROCESS

SITE: Fulton, Illinois

PRODUCT SIZE: 250 x 10^6 SCF/day

ENERGY: 9.9 x 10^9 Btu/hr

Coal Analysis (wt % as-received)

Moisture	15.6
C	58.8
H	4.1
O	7.3
N	1.1
S	3.1
Ash	10.0
	100
HHV Calculated (10^3 Btu/lb)	10.65

COAL FEED

to reactor:	1,410 10^3 lb/hr	to boiler: 207 10^3 lb/hr
	15.0 10^9 Btu/hr	2.2 10^9 Btu/hr

FGD WATER

Vaporized	0.56 lb/lb coal	116 10^3 lb/hr
With sludge	0.43 lb/lb coal	89.0 10^3 lb/hr
TOTAL:		205 10^3 lb/hr
FGD sludge produced, wet		127 10^3 lb/hr

ASH HANDLING

		10^3 lb/hr
Bottom ash:	dry	145
	water	78.1
	sludge	223
Fly ash:	dry	16.6
	water	1.66
	sludge	18.2

(continued)

Fulton, Illinois (continued)

PROCESS WATER

	10^3 lb/hr
a. Steam and boiler feed water required	2,707
b. Dirty condensate	2,158
c. Methanation water	277

OTHER WATER NEEDS

	10^3 lb/hr
a. Dust control	58
b. Service, sanitary & potable water:	
Required	21
Sewage recovered	14
c. Revegetation water	0
d. Evaporation from storage ponds	0
GRAND TOTAL RAW WATER INPUT TO PLANT:	2,058

TREATMENT SLUDGES

	10^3 lb/hr solids	10^3 lb/hr water & sludge
a. Lime softening	---	---
b. Ion exchange & reverse osmosis	---	163
c. Biotreatment	0.68	3.42
d. Electrodialysis	---	206

Fulton, Illinois (continued)

ENERGY

Energy Totals

	10^9 Btu/hr
Feed	17.2
Product and byproduct	11.4
Unrecovered heat	5.8
Conversion efficiency	67 %

Disposition of Unrecovered Heat

Total unrecovered heat	5.76 10^9 Btu/hr
% of unrecovered heat wet cooled	25 %
Wet cooling load	1.44 10^9 Btu/hr
Btu/lb evap	1,390
10^3 lb water evap/hr	1,034

WORK SHEET: WATER QUANTITY CALCULATIONS FOR LURGI PROCESS

SITE: Muhlenberg, Kentucky

PRODUCT SIZE: 250 x 10^6 SCF/day

ENERGY: 9.9 x 10^9 Btu/hr

Coal Analysis (wt % as-received)

Moisture	11.0
C	64.8
H	4.7
O	8.3
N	1.4
S	2.6
Ash	7.2
	100
HHV Calculated (10^3 Btu/lb)	11.80

COAL FEED

to reactor: 1,183 10^3 lb/hr; 13.9 10^9 Btu/hr

to boiler: 269 10^3 lb/hr; 3.17 10^9 Btu/hr

FGD WATER

Vaporized	0.68 lb/lb coal	182.9 10^3 lb/hr
With sludge	0.36 lb/lb coal	96.8 10^3 lb/hr
TOTAL:		280 10^3 lb/hr
FGD sludge produced, wet		138.3 10^3 lb/hr

ASH HANDLING

		10^3 lb/hr
Bottom ash:	dry	89.1
	water	48.0
	sludge	137.0
Fly ash:	dry	15.5
	water	1.55
	sludge	17.0

Muhlenberg, Kentucky (continued)

PROCESS WATER

	10^3 lb/hr
a. Steam and boiler feed water required	2,496
b. Dirty condensate	1,918
c. Methanation water	291

OTHER WATER NEEDS

	10^3 lb/hr
a. Dust control	52
b. Service, sanitary & potable water:	
Required	21
Sewage recovered	14
c. Revegetation water	0
d. Evaporation from storage ponds	0
GRAND TOTAL RAW WATER INPUT TO PLANT:	1,478

TREATMENT SLUDGES

	10^3 lb/hr solids	10^3 lb/hr water & sludge
a. Lime softening	---	---
b. Ion exchange & reverse osmosis	---	239
c. Biotreatment	0.61	3.1

(continued)

Muhlenburg, Kentucky (continued)

ENERGY

Energy Totals

	10^9 Btu/hr
Feed	17.1
Product and byproduct	11.4
Unrecovered heat	5.7
Conversion efficiency	67 %

Disposition of Unrecovered Heat

Total unrecovered heat	5.63 10^9 Btu/hr
% of unrecovered heat wet cooled	13 %
Wet cooling load	0.73 10^9 Btu/hr
Btu/lb evap	1,370
10^3 lb water evap/hr	533

333

WORK SHEET: WATER QUANTITY CALCULATIONS FOR LURGI PROCESS

SITE: Jim Bridger, Wyoming

PRODUCT SIZE: 250 x 10^6 SCF/day

ENERGY: 9.9 x 10^9 Btu/hr

Coal Analysis (wt % as-received)

Moisture	21.2
C	51.9
H	3.2
O	13.9
N	1.1
S	0.5
Ash	8.2
	100
HHV Calculated (10^3 Btu/lb)	8.50

COAL FEED

to reactor:	1,661 10^3 lb/hr	to boiler:	519 10^3 lb/hr
	14.1 10^9 Btu/hr		4.41 10^9 Btu/hr

FGD WATER

Vaporized	0.38 lb/lb coal	197 10^3 lb/hr
With sludge	0.07 lb/lb coal	36.3 10^3 lb/hr
TOTAL:		234 10^3 lb/hr
FGD sludge produced, wet		51.9 10^3 lb/hr

ASH HANDLING

		10^3 lb/hr
Bottom ash:	dry	145
	water	77.9
	sludge	223
Fly ash:	dry	34.1
	water	3.41
	sludge	37.5

(continued)

PROCESS WATER

	10^3 lb/hr
a. Steam and boiler feed water required	1,596
b. Dirty condensate	1,121
c. Methanation water	265

OTHER WATER NEEDS

	10^3 lb/hr
a. Dust control	100
b. Service, sanitary & potable water:	
Required	21
Sewage recovered	14
c. Revegetation water	0
d. Evaporation from storage ponds	7
GRAND TOTAL RAW WATER INPUT TO PLANT:	1,548

TREATMENT SLUDGES

	10^3 lb/hr	
	solids	water & sludge
a. Lime softening	---	---
b. Ion exchange	---	85
c. Biotreatment	0.71	3.6

Jim Bridger, Wyoming (continued)

ENERGY

Energy Totals

	10^9 Btu/hr
Feed	18.5
Product and byproduct	12.4
Unrecovered heat	6.1
Conversion efficiency	67 %

Disposition of Unrecovered Heat

Total unrecovered heat	6.11 10^9 Btu/hr
% of unrecovered heat wet cooled	18.5 %
Wet cooling load	1.13 10^9 Btu/hr
Btu/lb evap	1,401
10^3 lb water evap/hr	807

WORK SHEET: WATER QUANTITY CALCULATIONS FOR LURGI PROCESS

SITE: Kemmerer, Wyoming

PRODUCT SIZE: 250×10^6 SCF/day

ENERGY: 9.9×10^9 Btu/hr

Coal Analysis (wt % as-received)

Moisture	2.8
C	71.8
H	5.0
O	9.0
N	1.2
S	1.0
Ash	9.2
	100
HHV Calculated (10^3 Btu/lb)	12.88

COAL FEED

to reactor:	1,170	10^3 lb/hr	to boiler:	220 10^3 lb/hr
	14.9	10^9 Btu/hr		2.83 10^9 Btu/hr

FGD WATER

Vaporized	0.84	lb/lb coal	185 10^3 lb/hr
With sludge	0.14	lb/lb coal	30.8 10^3 lb/hr
TOTAL:			216 10^3 lb/hr
FGD sludge produced, wet			44.0 10^3 lb/hr

ASH HANDLING

		10^3 lb/hr
Bottom ash:	dry	112
	water	60.1
	sludge	172
Fly ash:	dry	16.2
	water	1.62
	sludge	17.8

Kemmerer, Wyoming (continued)

PROCESS WATER

	10^3 lb/hr
a. Steam and boiler feed water required	2,656
b. Dirty condensate	1,934
c. Methanation water	272

OTHER WATER NEEDS

	10^3 lb/hr
a. Dust control	64
b. Service, sanitary & potable water:	
Required	21
Sewage recovered	14
c. Revegetation water	0
d. Evaporation from storage ponds	8
GRAND TOTAL RAW WATER INPUT TO PLANT:	1,925

TREATMENT SLUDGES

	10^3 lb/hr solids	10^3 lb/hr water & sludge
a. Lime softening	---	---
b. Ion exchange & reverse osmosis	---	213
c. Biotreatment	1.91	9.5

(continued)

Kemmerer, Wyoming (continued)

ENERGY

Energy Totals

	10^9 Btu/hr
Feed	17.7
Product and byproduct	11.9
Unrecovered heat	5.8
Conversion efficiency	67

Disposition of Unrecovered Heat

Total unrecovered heat	5.85	10^9 Btu/hr
% of unrecovered heat wet cooled	20.6	%
Wet cooling load	1.21	10^9 Btu/hr
Btu/lb evap	1,397	
10^3 lb water evap/hr	866	

WORK SHEET: WATER QUANTITY CALCULATIONS FOR LURGI PROCESS

SITE: Knife River, North Dakota

PRODUCT SIZE: 250 x 10^6 SCF/day

ENERGY: 9.9 x 10^9 Btu/hr

Coal Analysis (wt % as-received)

Moisture	35.0
C	42.5
H	2.8
O	12.3
N	0.6
S	0.7
Ash	6.1
	100
HHV Calculated (10^3 Btu/lb)	7.00

COAL FEED

to reactor:	2,037	10^3 lb/hr	to boiler: 589	10^3 lb/hr
	14.3	10^9 Btu/hr	4.12	10^9 Btu/hr

FGD WATER

Vaporized	0.14	lb/lb coal	82.5	10^3 lb/hr
With sludge	0.10	lb/lb coal	58.9	10^3 lb/hr
TOTAL:			141	10^3 lb/hr
FGD sludge produced, wet			84.1	10^3 lb/hr

ASH HANDLING

		10^3 lb/hr
Bottom ash:	dry	131
	water	70.8
	sludge	202
Fly ash:	dry	28.7
	water	2.87
	sludge	31.6

(continued)

Knife River, North Dakota (continued)

PROCESS WATER

	10^3 lb/hr
a. Steam and boiler feed water required	1,754
b. Dirty condensate	1,694
c. Methanation water	264

OTHER WATER NEEDS

	10^3 lb/hr
a. Dust control	172
b. Service, sanitary & potable water:	
Required	21
Sewage recovered	14
c. Revegetation water	0
d. Evaporation from storage ponds	4
GRAND TOTAL RAW WATER INPUT TO PLANT:	1,199

TREATMENT SLUDGES

	10^3 lb/hr solids	10^3 lb/hr water & sludge
a. Lime softening	---	---
b. Ion exchange & reverse osmosis	---	141
c. Biotreatment	1.1	4.3

Knife River, North Dakota (continued)

ENERGY

Energy Totals

	10^9 Btu/hr
Feed	18.4
Product and byproduct	12.0
Unrecovered heat	6.4
Conversion efficiency	65 %

Disposition of Unrecovered Heat

Total unrecovered heat	6.45 10^9 Btu/hr
% of unrecovered heat wet cooled	18.5 %
Wet cooling load	1.19 10^9 Btu/hr
Btu/lb evap	1,420
10^3 lb water evap/hr	838

WORK SHEET: WATER QUANTITY CALCULATIONS FOR LURGI PROCESS

SITE: Williston, North Dakota

PRODUCT SIZE: 250 x 10^6 SCF/day

ENERGY: 9.9 x 10^9 Btu/hr

Coal Analysis (wt % as-received)

Moisture	40.0
C	39.1
H	2.8
O	11.2
N	0.7
S	0.6
Ash	5.6
	100
HHV Calculated (10^3 Btu/lb)	6.58

COAL FEED

to reactor:	2,245 10^3 lb/hr	to boiler: 678 10^3 lb/hr
	14.8 10^9 Btu/hr	4.46 10^9 Btu/hr

FGD WATER

Vaporized	0.53 lb/lb coal	359 10^3 lb/hr
With sludge	0.08 lb/lb coal	54.2 10^3 lb/hr
TOTAL:		413 10^3 lb/hr
FGD sludge produced, wet		77.5 10^3 lb/hr

ASH HANDLING

		10^3 lb/hr
Bottom ash:	dry	133
	water	71.8
	sludge	205
Fly ash:	dry	30.4
	water	3.04
	sludge	33.4

Williston, North Dakota (continued)

PROCESS WATER

	10^3 lb/hr
a. Steam and boiler feed water required	1,780
b. Dirty condensate	1,897
c. Methanation water	268

OTHER WATER NEEDS

	10^3 lb/hr
a. Dust control	191
b. Service, sanitary & potable water:	
Required	21
Sewage recovered	14
c. Revegetation water	0
d. Evaporation from storage ponds	8
GRAND TOTAL RAW WATER INPUT TO PLANT:	2,464

TREATMENT SLUDGES

	10^3 lb/hr solids	10^3 lb/hr water & sludge
a. Lime softening	0.09	0.45
b. Ion exchange	---	97
c. Biotreatment	1.20	4.8

(continued)

Williston, North Dakota (continued)

ENERGY

Energy Totals

	10^9 Btu/hr
Feed	19.3
Product and byproduct	12.5
Unrecovered heat	6.8
Conversion efficiency	65 %

Disposition of Unrecovered Heat

Total unrecovered heat	6.74	10^9 Btu/hr
% of unrecovered heat wet cooled	43	%
Wet cooling load	2.88	10^9 Btu/hr
Btu/lb evap	1,420	
10^3 lb water evap/hr	2,028	

WORK SHEET: WATER QUANTITY CALCULATIONS FOR LURGI PROCESS

SITE: Decker, Montana

PRODUCT SIZE: 250 x 10^6 SCF/day

ENERGY: 9.9 x 10^9 Btu/hr

Coal Analysis (wt % as-received)

Moisture	23.9
C	57.2
H	3.2
O	10.9
N	0.6
S	0.5
Ash	3.7
	100
HHV Calculated (10^3 Btu/lb)	9.48

COAL FEED

to reactor:	1,505 10^3 lb/hr		to boiler:	448 10^3 lb/hr
	14.3 10^9 Btu/hr			4.25 10^9 Btu/hr

FGD WATER

Vaporized	0.42	lb/lb coal	188 10^3 lb/hr
With sludge	0.07	lb/lb coal	31.4 10^3 lb/hr
TOTAL:			220 10^3 lb/hr
FGD sludge produced, wet			44.8 10^3 lb/hr

ASH HANDLING

		10^3 lb/hr
Bottom ash:	dry	59.0
	water	31.8
	sludge	90.8
Fly ash:	dry	13.3
	water	1.33
	sludge	14.6

(continued)

PROCESS WATER

	10^3 lb/hr
a. Steam and boiler feed water required	1,698
b. Dirty condensate	1,186
c. Methanation water	265

OTHER WATER NEEDS

	10^3 lb/hr
a. Dust control	109
b. Service, sanitary & potable water:	
Required	21
Sewage recovered	14
c. Revegetation water	0
d. Evaporation from storage ponds	9
GRAND TOTAL RAW WATER INPUT TO PLANT:	2,472

TREATMENT SLUDGES

	10^3 lb/hr	
	solids	water & sludge
a. Lime softening	0.08	0.40
b. Ion exchange	---	91
c. Biotreatment	0.75	3.8
d. Electrodialysis	---	247

Decker, Montana (continued)

ENERGY

Energy Totals

	10^9 Btu/hr
Feed	18.6
Product and byproduct	12.4
Unrecovered heat	6.2
Conversion efficiency	67 %

Disposition of Unrecovered Heat

Total unrecovered heat	6.12 10^9 Btu/hr
% of unrecovered heat wet cooled	35 %
Wet cooling load	2.11 10^9 Btu/hr
Btu/lb evap	1,407
10^3 lb water evap/hr	1,500

WORK SHEET: WATER QUANTITY CALCULATIONS FOR LURGI PROCESS

SITE: Foster Creek, Montana

PRODUCT SIZE: 250×10^6 SCF/day

ENERGY: 9.9×10^9 Btu/hr

Coal Analysis (wt % as-received)

Moisture	30.7
C	45.7
H	2.9
O	11.8
N	0.7
S	0.5
Ash	7.7
	100
HHV Calculated (10^3 Btu/lb)	7.55

COAL FEED

to reactor:	1,897 10^3 lb/hr	to boiler:	574 10^3 lb/hr
	14.3 10^9 Btu/hr		4.33 10^9 Btu/hr

FGD WATER

Vaporized	0.22 lb/lb coal	126 10^3 lb/hr
With sludge	0.07 lb/lb coal	40.2 10^3 lb/hr
TOTAL:		167 10^3 lb/hr
FGD sludge produced, wet		57.4 10^3 lb/hr

ASH HANDLING

		10^3 lb/hr
Bottom ash:	dry	155
	water	83.4
	sludge	238
Fly ash:	dry	35.4
	water	3.54
	sludge	38.9

Foster Creek, Montana (continued)

PROCESS WATER

	10^3 lb/hr
a. Steam and boiler feed water required	1,618
b. Dirty condensate	1,362
c. Methanation water	265

OTHER WATER NEEDS

	10^3 lb/hr
a. Dust control	138
b. Service, sanitary & potable water:	
Required	21
Sewage recovered	14
c. Revegetation water	0
d. Evaporation from storage ponds	5
GRAND TOTAL RAW WATER INPUT TO PLANT:	1,312

TREATMENT SLUDGES

	10^3 lb/hr solids	10^3 lb/hr water & sludge
a. Lime softening	---	---
b. Ion exchange & reverse osmosis	---	103
c. Biotreatment	0.87	4.4

(continued)

Foster Creek, Montana (continued)

ENERGY

Energy Totals

	10^9 Btu/hr
Feed	18.6
Product and byproduct	12.5
Unrecovered heat	6.16
Conversion efficiency	67 %

Disposition of Unrecovered Heat

Total unrecovered heat	6.16 10^9 Btu/hr
% of unrecovered heat wet cooled	19 %
Wet cooling load	1.14 10^9 Btu/hr
Btu/lb evap	1,414
10^3 lb water evap/hr	806

WORK SHEET: WATER QUANTITY CALCULATIONS FOR LURGI PROCESS

SITE: El Paso, New Mexico

PRODUCT SIZE: 250 x 10^6 SCF/day

ENERGY: 9.9 x 10^9 Btu/hr

Coal Analysis (wt % as-received)

Moisture	16.3
C	49.2
H	3.6
O	10.2
N	0.8
S	0.7
Ash	19.2
	100
HHV Calculated (10^3 Btu/lb)	8.62

COAL FEED

to reactor:	1,672 10^3 lb/hr	to boiler: 463 10^3 lb/hr
	14.4 10^9 Btu/hr	3.99 10^9 Btu/hr

FGD WATER

Vaporized	0.42 lb/lb coal	194 10^3 lb/hr
With sludge	0.10 lb/lb coal	46.3 10^3 lb/hr
TOTAL:		241 10^3 lb/hr
FGD sludge produced, wet		66.1 10^3 lb/hr

ASH HANDLING

		10^3 lb/hr
Bottom ash:	dry	339
	water	182
	sludge	521
Fly ash:	dry	71.1
	water	7.11
	sludge	78.2

(continued)

El Paso, New Mexico (continued)

PROCESS WATER

	10^3 lb/hr
a. Steam and boiler feed water required	1,640
b. Dirty condensate	1,080
c. Methanation water	270

OTHER WATER NEEDS

	10^3 lb/hr
a. Dust control	134
b. Service, sanitary & potable water:	
Required	21
Sewage recovered	14
c. Revegetation water	78
d. Evaporation from storage ponds	10
GRAND TOTAL RAW WATER INPUT TO PLANT:	1,725

TREATMENT SLUDGES

	10^3 lb/hr	
	solids	water & sludge
a. Lime softening	---	---
b. Ion exchange	---	88
c. Biotreatment	0.69	3.5

El Paso, New Mexico (continued)

ENERGY

Energy Totals

	10^9 Btu/hr
Feed	18.4
Product and byproduct	12.3
Unrecovered heat	6.07
Conversion efficiency	67 %

Disposition of Unrecovered Heat

Total unrecovered heat	6.07 10^9 Btu/hr
% of unrecovered heat wet cooled	18 %
Wet cooling load	1.09 10^9 Btu/hr
Btu/lb evap	1,375
10^3 lb water evap/hr	793

WORK SHEET: WATER QUANTITY CALCULATIONS FOR LURGI PROCESS

SITE: Wesco, New Mexico

PRODUCT SIZE: 250 x 10^6 SCF/day

ENERGY: 9.9 x 10^9 Btu/hr

Coal Analysis (wt % as-received)

Moisture	12.4
C	47.5
H	3.6
O	9.3
N	0.9
S	0.7
Ash	25.6
	100
HHV Calculated (10^3 Btu/lb)	8.44

COAL FEED

to reactor:	1,689	10^3 lb/hr	to boiler:	475	10^3 lb/hr
	14.3	10^9 Btu/hr		4.01	10^9 Btu/hr

FGD WATER

Vaporized	0.45	lb/lb coal	214	10^3 lb/hr
With sludge	0.10	lb/lb coal	47.5	10^3 lb/hr
TOTAL:			262	10^3 lb/hr
FGD sludge produced, wet			67.9	10^3 lb/hr

ASH HANDLING

		10^3 lb/hr
Bottom ash:	dry	457
	water	246
	sludge	703
Fly ash:	dry	97.3
	water	9.73
	sludge	107

Wesco, New Mexico (continued)

PROCESS WATER

		10^3 lb/hr
a.	Steam and boiler feed water required	1,990
b.	Dirty condensate	1,490
c.	Methanation water	310

OTHER WATER NEEDS

		10^3 lb/hr
a.	Dust control	136
b.	Service, sanitary & potable water:	
	Required	21
	Sewage recovered	14
c.	Revegetation water	79
d.	Evaporation from storage ponds	11
	GRAND TOTAL RAW WATER INPUT TO PLANT:	1,865

TREATMENT SLUDGES

		10^3 lb/hr	
		solids	water & sludge
a.	Lime softening	---	---
b.	Ion exchange & reverse osmosis	---	111
c.	Biotreatment	0.95	4.8

(continued)

Wesco, New Mexico (continued)

ENERGY

Energy Totals

	10^9 Btu/hr
Feed	18.3
Product and byproduct	12.3
Unrecovered heat	6.04
Conversion efficiency	67 %

Disposition of Unrecovered Heat

Total unrecovered heat	6.04 10^9 Btu/hr
% of unrecovered heat wet cooled	18 %
Wet cooling load	1.09 10^9 Btu/hr
Btu/lb evap	1,375
10^3 lb water evap/hr	793

WORK SHEET: WATER QUANTITY CALCULATIONS FOR LURGI PROCESS

SITE: Gallup, New Mexico

PRODUCT SIZE: 250 x 10^6 SCF/day

ENERGY: 9.9 x 10^9 Btu/hr

Coal Analysis (wt % as-received)

Moisture	15.1
C	63.2
H	4.7
O	10.4
N	1.1
S	0.4
Ash	5.1
	100
HHV Calculated (10^3 Btu/lb)	11.30

COAL FEED

to reactor:	1,263 10^3 lb/hr	to boiler: 355 10^3 lb/hr
	14.3 10^9 Btu/hr	4.01 10^9 Btu/hr

FGD WATER

Vaporized	0.61 lb/lb coal	217 10^3 lb/hr
With sludge	0.06 lb/lb coal	21.3 10^3 lb/hr
TOTAL:		238 10^3 lb/hr
FGD sludge produced, wet		30.4 10^3 lb/hr

ASH HANDLING

		10^3 lb/hr
Bottom ash:	dry	68.0
	water	36.6
	sludge	105
Fly ash:	dry	14.5
	water	1.45
	sludge	15.9

(continued)

PROCESS WATER

	10^3 lb/hr
a. Steam and boiler feed water required	1,603
b. Dirty condensate	1,007
c. Methanation water	278

OTHER WATER NEEDS

	10^3 lb/hr
a. Dust control	102
b. Service, sanitary & potable water:	
Required	21
Sewage recovered	14
c. Revegetation water	59
d. Evaporation from storage ponds	6
GRAND TOTAL RAW WATER INPUT TO PLANT:	1,778

TREATMENT SLUDGES

	10^3 lb/hr solids	10^3 lb/hr water & sludge
a. Lime softening	0.03	0.15
b. Ion exchange	---	85
c. Biotreatment	0.64	3.2
d. Electrodialysis	---	114

ENERGY

Energy Totals

	10^9 Btu/hr
Feed	18.3
Product and byproduct	12.3
Unrecovered heat	6.0
Conversion efficiency	67 %

Disposition of Unrecovered Heat

Total unrecovered heat	6.04 10^9 Btu/hr
% of unrecovered heat wet cooled	18 %
Wet cooling load	1.09 10^9 Btu/hr
Btu/lb evap	1,375
10^3 lb water evap/hr	793

APPENDIX 11

WATER TREATMENT PLANTS

In this appendix we estimate the dollar and energy cost of the water treatment sections of each process/site combination. The quantity of waste sludge and waste soluble salts is also estimated. (The costs and energy requirements for disposing of the wet-solid residual streams are not included in this study.) The background information for this appendix will be found in Reference 1.

In making these estimates the following sequence of decision and calculation is used:

1) Individual water treatment blocks are chosen and a water flow diagram is made. The blocks used are described briefly in the following paragraph; details are given in Reference 1. For convenience in presentation and to avoid printing many similar diagrams, standardized flow diagrams, each applicable to one or more processes at many sites, are given on Figure All-1 (A through E) and in Figure All-2 (Scheme 1 through Scheme 3).

2) For each process/site combination the flows of all streams are entered on the summary Table All-4 (which has a page for each process/site). The streams are entered by number, corresponding to the flow diagram. Since water losses in waste sludge are accounted for, this step proceeds simultaneously with the next step. On each page of Table All-4 will be found reference to the applicable flow diagrams.

3) For each treatment block at each process/site, the dollars cost, the energy cost and the water produced are calculated and entered on the summary table. Each result is the product of a unit cost and a parameter measuring quality. The unit costs are given on Table All-1 and the quality parameters on Tables All-2 and All-3.

Brief mention is now made of the treatment blocks used.

Lime soda softening. This is used on cooling water makeup and blowdown, and occasionally on total plant raw water or boiler feed. Theoretical lime, soda ash and magnesia additions are assumed for cost estimation. The treatment conditions are 1) Ca^{++} reduced to 20 mg/l, 2) Mg^{++} reduced to 7 mg/l, 3) 1 mg SiO_2 removed per 2 mg Mg^{++}. Two or three probable locations are shown on Figure 11-1; not all locations will be used at the same time.

Electrodialysis. This is required for all plants when the raw intake water is brackish. The cost depends on the fraction of total dissolved solids removed, and the fraction is taken to be one of four stages: 50% demineralization, 75%, 87.5% 93.8%. The water recovery is 90%. Two locations are shown, one on Figure A11-1 and one on Figure A11-2. In fact, they will be separate streams in the same piece of equipment.

Ion exchange. This is required for all boiler feed water procedures. The cost of the ion exchange depends on the quality of the intake water, which is usually site dependent, and on the pressure of the steam raised in the boiler. All the plants use a lot of high pressure steam for driving machinery, but this condensate is returned with less than 2 percent loss. The big need for boiler water makeup is for steam which enters into reaction. Thus to some extent the Lurgi, SRC and Synthoil plants make lower pressure steam at less cost, and Hygas, Bigas and Synthane make higher pressure steam at more cost for boiler feed water treatment. Based on Reference 1, three ion exchange systems have been chosen and costed; they are shown on Figure A11-2. Scheme 1 is the general purpose scheme for reasonable river water. Scheme 2 is for presoftened high alkalinity water. Scheme 3 is for brackish water intake.

Condensate polishing, while necessary, is minor and its cost is treated as zero in the calculations.

Phenol extraction. This is a solvent extraction of phenolic compounds. The phenols are recovered, which helps to defray the cost. This process is used only when the foul condensate has a high concentration of phenol. The process is not used for Lurgi or Synthane when the coal fed is bituminous. It is not used for Hygas and Bigas processes. Ninety-five percent removal is assumed. Since 1 mg phenol is equivalent to 2.38 mg BOD, the BOD is reduced during phenol extraction by 2.26p, where p is the influent phenol concentration.

Ammonia separation. This is required at all process/sites. It is a distillative, extractive process. Ammonia is assumed recovered as 30 wt % solution and sold to help defray costs. Ammonia is usually reduced to 450 mg/l, at which concentration it is a suitable nutrient for subsequent biotreatment.

Biotreatment. Because of lack of clear information on how much organic contamination is acceptable in cooling water, this procedure is used on dirty condensate from all plants except Bigas. Two multistage, high purity oxygen activated sludge tanks are used in series and the removal percentage is high; costs, energy and sludge are therefore calculated on the assumption of 100 percent removal.

Filter. Water effluent from dissolved air floation in biotreatment contains about 100 mg/l suspended solids. This is usually undesirable for cooling tower feed. A sand filter is assumed to remove 80 percent of the solids and to give a waste backwash stream which is 5 percent solids. The filter backwash is returned to the biotreatment clarifiers and so is not shown on the flow diagram.

Acid treatment of cooling water. This is used on all high alkalinity cooling water makeup streams. Since more than 90 percent of the alkalinity must be replaced to do any good, a 100 percent replacement is assumed.

Chemicals added to cooling water. Biocides, anticorrosion chemicals and suspending agents are added to the cooling water. Their cost is shown on Table A11-1.

Potable water treatment. This is just chlorination; the quantity is low and the cost is treated as zero.

Reverse osmosis. This is used to return treatment condensate to the boiler in those Lurgi plants where all of the condensate is not required in the cooling tower. It is followed by activated carbon adsorption.

Activated carbon adsorption. This is used when treated condensate is returned to a boiler.

The following additional notes apply to specific conversion processes.

Synthane. Since so much of the ash is removed from Synthane plants as dry fly ash, not enough cooling tower blowdown can be disposed of with the ash to control the tower. To maintain the concentration in the circulating cooling water at 10 cycles blowdown is removed, softened and used as makeup to the flue gas desulfurization scrubber. All Synthane plants are shown on Figure A11-1A.

Lurgi. Many Lurgi plants yield more treated condensate than is required in the cooling tower. These plants use flow diagram Figure A11-1B. When all the condensate is consumed in the cooling tower, the same flow diagram as Synthane is used (see Figure A11-1A). In selected plants, and as required, cooling tower blowdown in addition to that used for ash handling is taken to maintain 10 cycles of concentration.

Bigas. Figure A11-1C applies to all Bigas plants and to no others. In some plants, fresh water or softened tower blowdown is used for dust control and FGD makeup because there is not enough condensate. Where necessary the tower is blown down to maintain 10 cycles.

Synthoil. Synthoil plants take in large amounts of quench water into the hydrogen production train and put out large amounts of condensate. Figure 11-1D applies to all Synthoil plants, and on this figure Stream 33 is the net of input minus output water to the hydrogen plant. Furthermore, all cooling towers are blown down at 10 cycles to Stream 33. In doing this we have assumed that the inorganic salts dissolved in the quench water are removed with fly ash somewhere beyond the point of quench and do not accumulate in the system. If the plant were not designed this way, or if this were not possible, then the quench water would have to be of boiler feed quality with hydrogen plant condensates returned through a polishing demineralizer.

SRC. Figure A11-1E is used for all plants. Condensate from the hydrogen plant is usually softened before use as makeup to the cooling tower. The treated organically contaminated Stream 14 is small and with little organic matter in the cooling tower the blowdown is used for dust control as well as ash disposal. Tower cycles of concentration sometimes reach as high as 14, and when high cycles are used the makeup is softened to ensure satisfactory operation.

Hygas. Hygas plants use the same flow scheme as Synthane, in Figure A11-1A.

REFERENCE - APPENDIX 11

1. Goldstein, D.J. and Yung, D., "Water Conservation and Pollution Control in Coal Conversion Processes," Report EPA-600/7-77, U.S. Environmental Protection Agency, Research Triangle Park, N.C., June 1977.

Streams are numbered for identification
Flow rates are given in Appendix 11

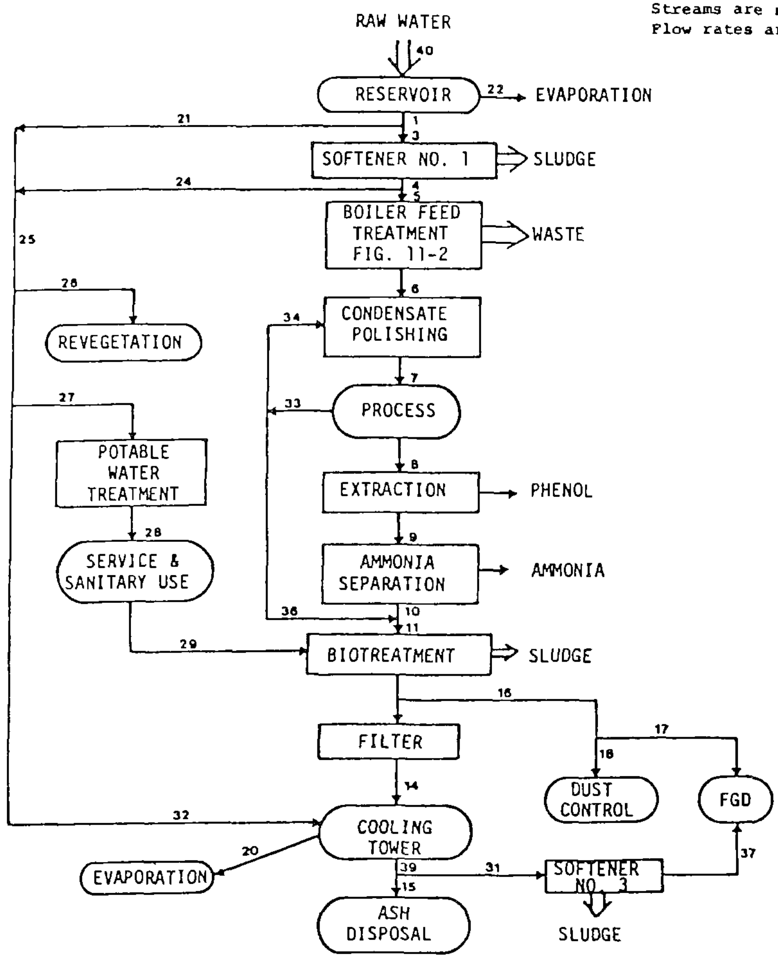


Figure A11-1A. Water treatment plant block diagram for all Synthane, some Lurgi and all Hygas.

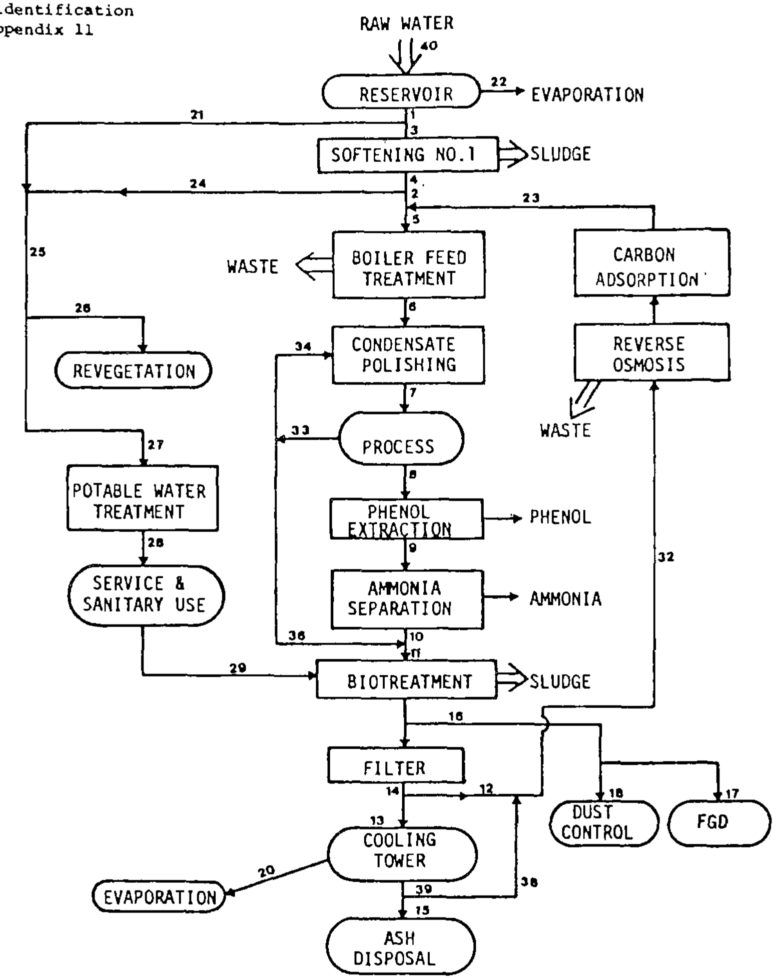


Figure A11-1B. Water treatment plant Block diagram for some Lurgi.

Figure A11-1 Water treatment block diagrams.

Streams are numbered for identification
Flow rates are given in Appendix 11

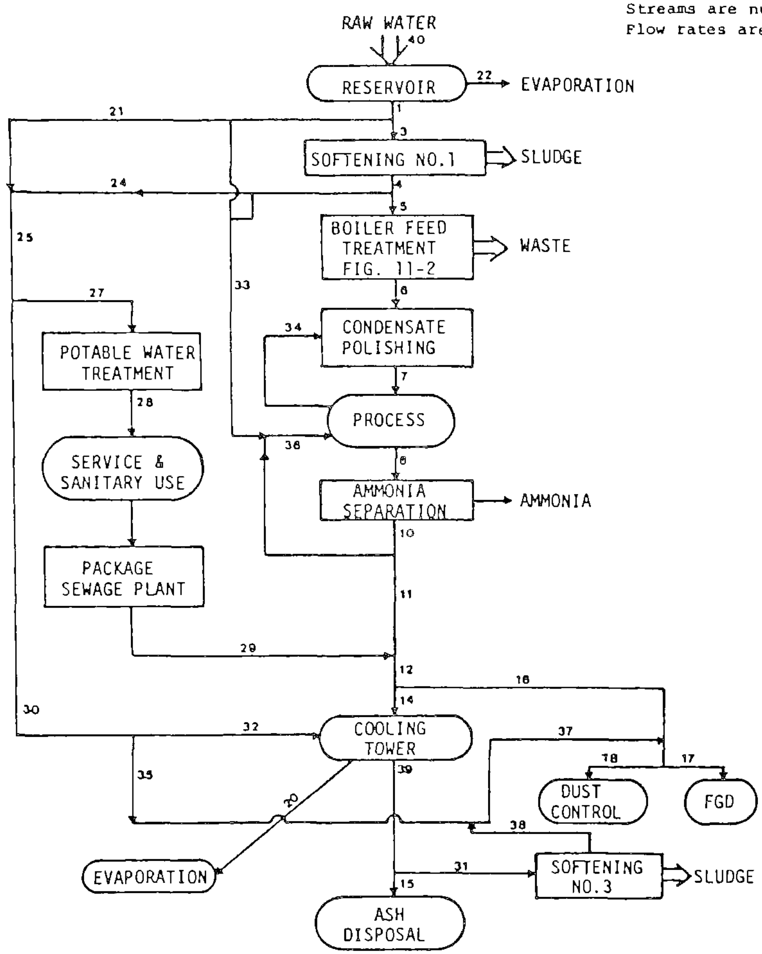


Figure A11-1C. Water treatment plant block diagram for Bigas process.

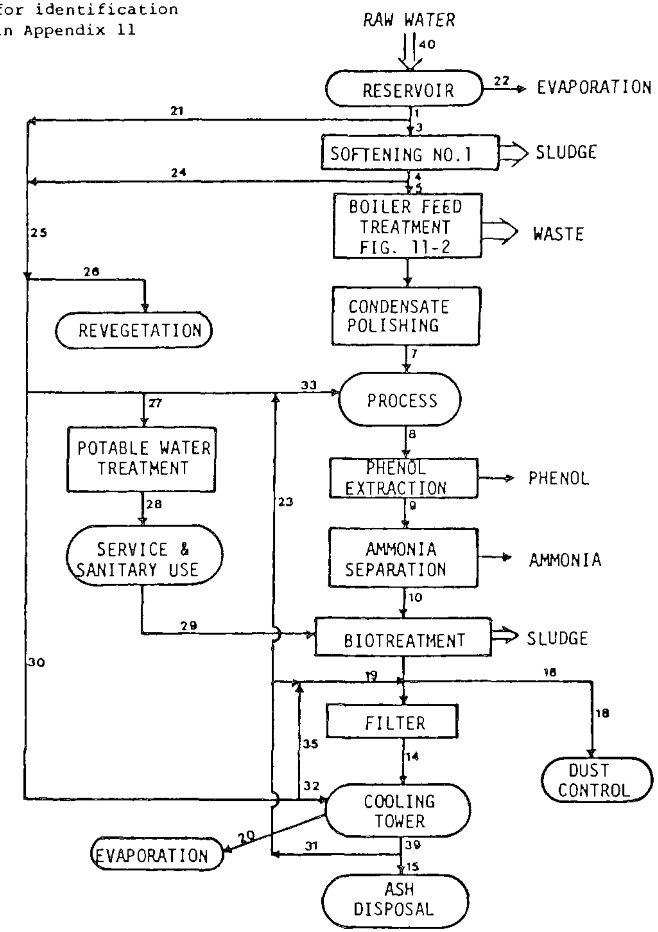


Figure A11-1D. Water treatment block diagram for Synthoil process.

Figure A11-1 (continued)

Streams are numbered for identification
Flow rates are given in Appendix 11

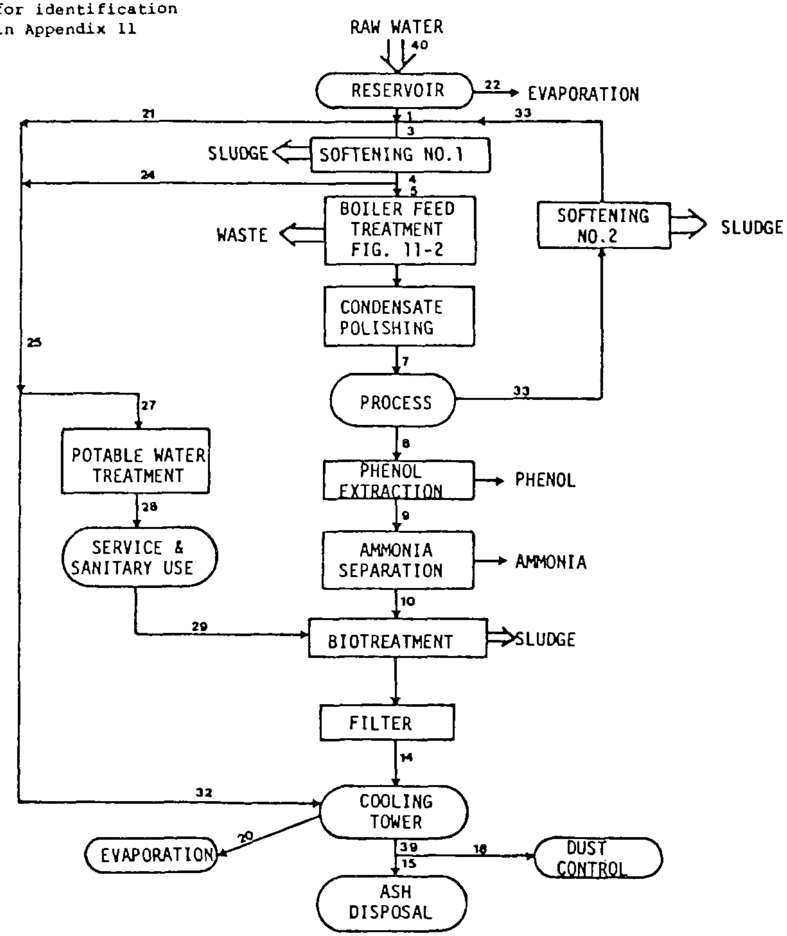


Figure A11-1E. Water treatment block diagram for SRC process.

Figure A11-1 (concluded).

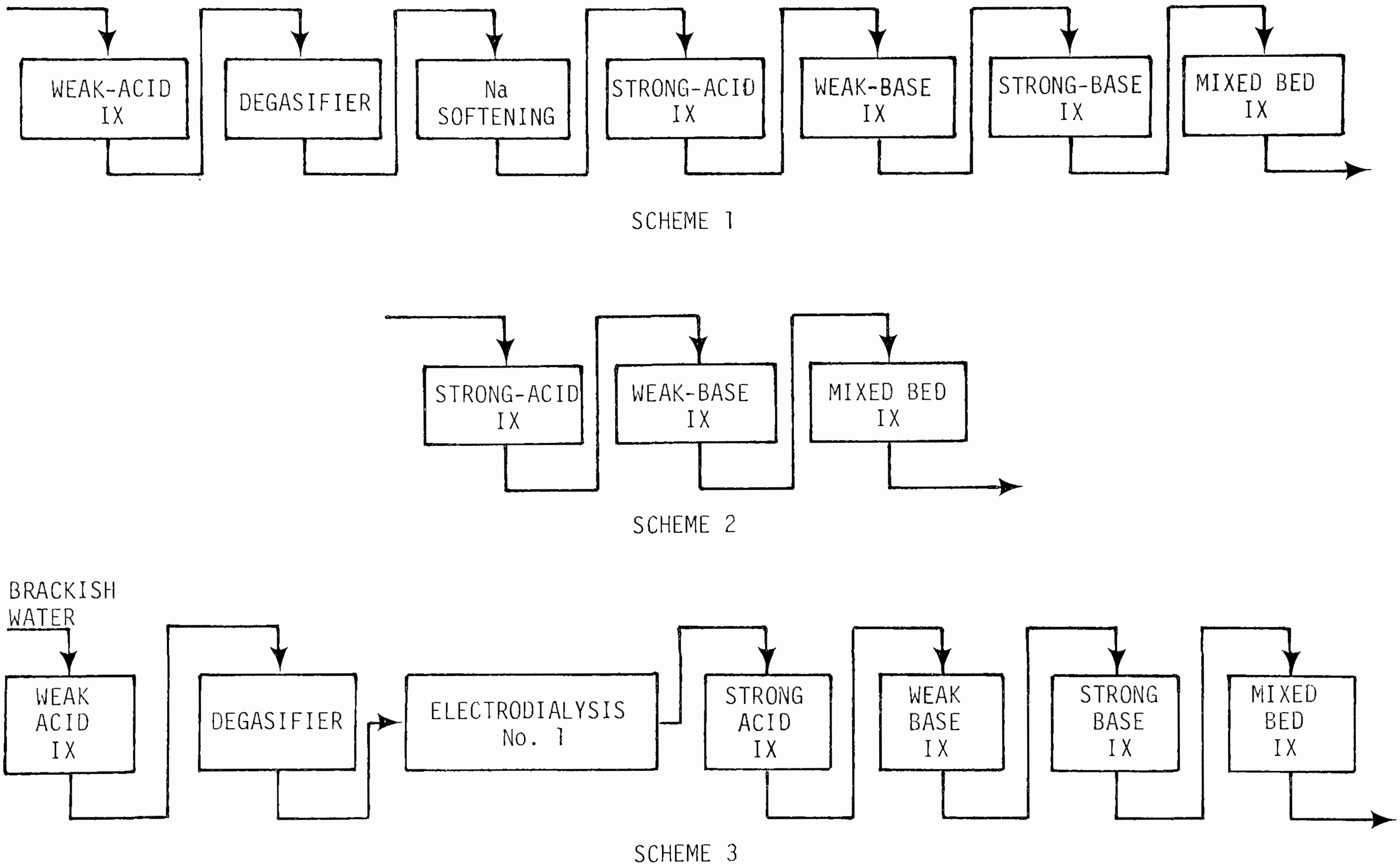


Figure A11-2. Boiler feed water treatment schemes.

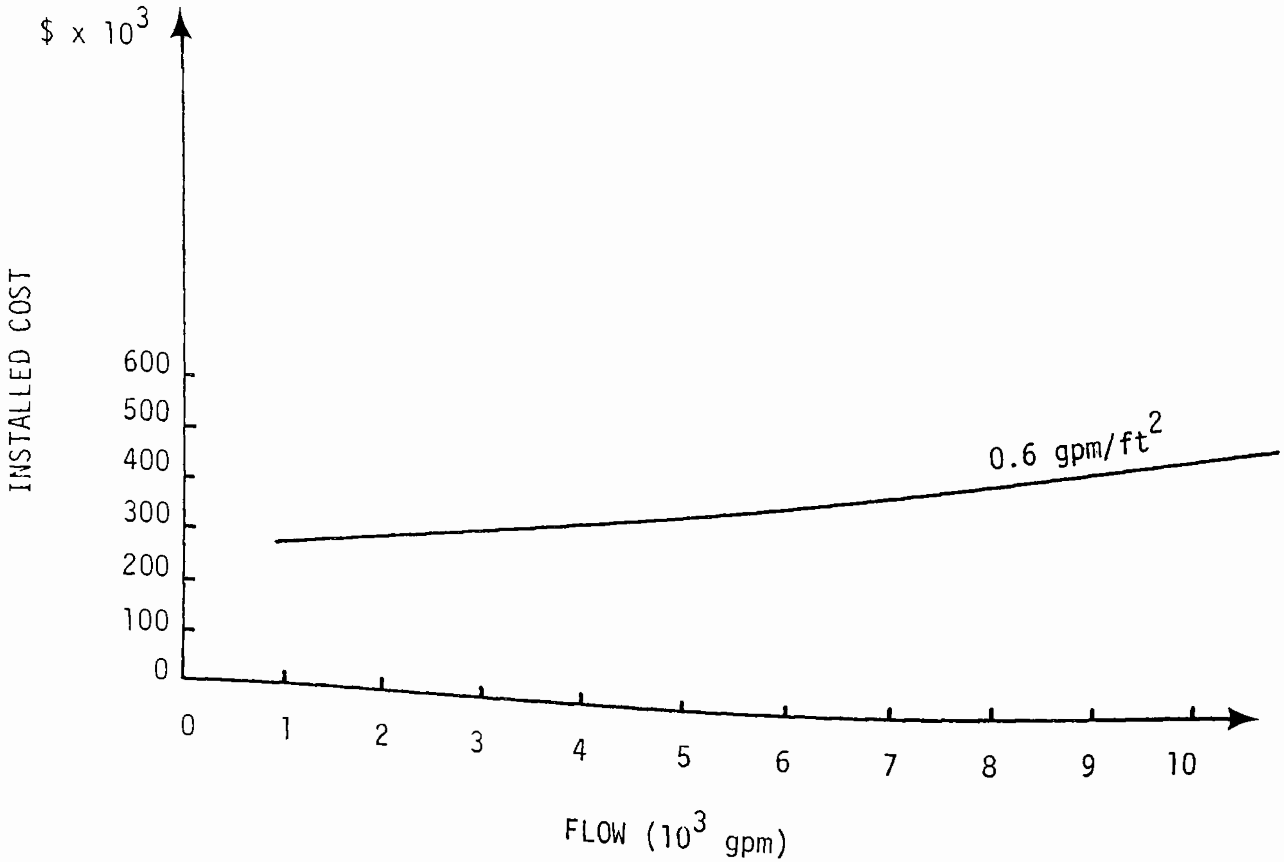


Figure A11-3. Clarifier costs.

1 = One Stage, approximately 50% demineralization

2 = Two Stages, approximately 75% demineralization

3 = Three Stages, approximately 87.5% demineralization

4 = Four Stages, approximately 93.8% demineralization

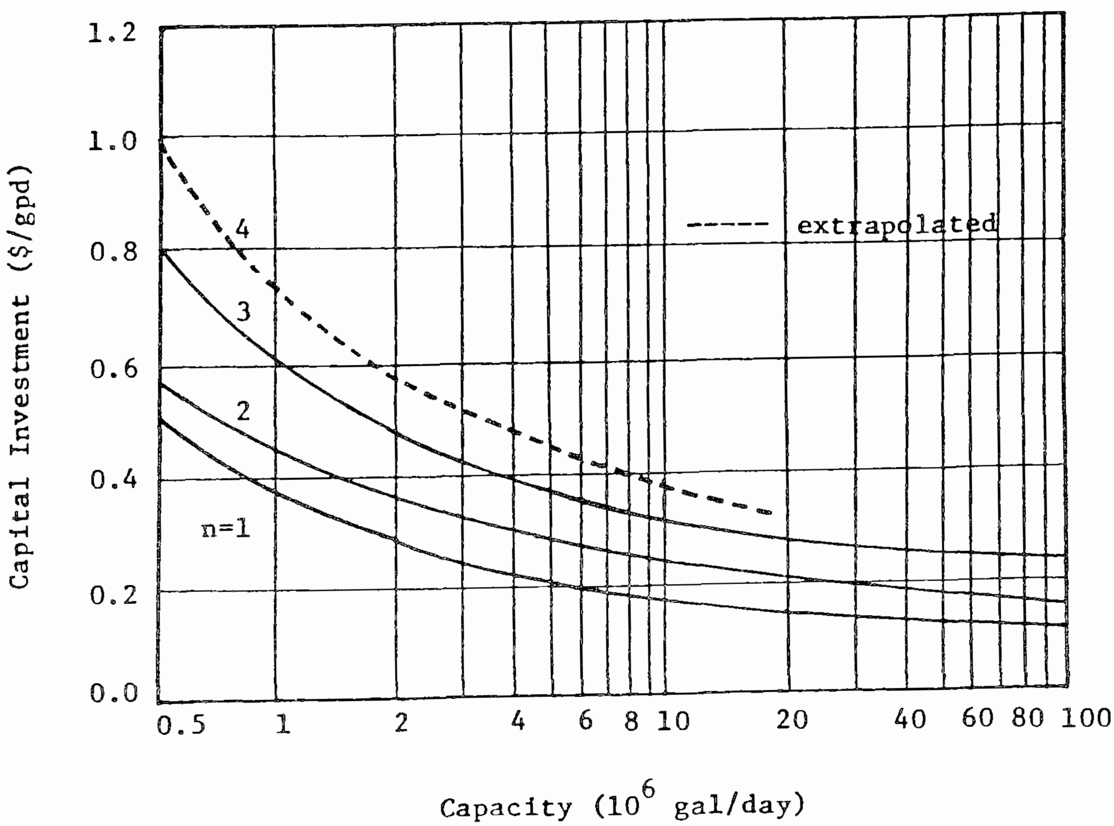


Figure A11-4 Approximate electrodialysis capital investment as a function of capacity for various numbers of stages. (Each stage removes approximately 50% of salts in its feed water).

TABLE A11-1. WATER TREATMENT BLOCKS AND OTHER COSTS

Lime Soda Softening

Cost: clarifiers: capital cost is taken from Figure 11-3 with the result multiplied by 2.0 for updating and spare capacity. To enter Figure 11-3, note that

$$10^3 \text{ lb water/hr} = 0.002 \times 10^3 \text{ gpm.}$$

Capital charges are 12%/yr for 7000 hours per year; so if

$$Y = \text{installed cost in } 10^3\$ \text{ from Figure 11-3}$$

charges are

$$2Y \times 10^3 \times 0.12/7000 \quad \$/\text{hr}$$
$$= 3.43Y\ ¢/\text{hr.}$$

chemicals: costs are given below.

Energy: negligible.

Waste: Based on dry weight of $CaCO_3$ precipitated with the sludge assumed to be 20% solids.

Electrodialysis

Cost: The cost is the sum of capital charges, membrane replacement, etc., and electricity.
Capital cost is taken from Figure 11-4 and multiplied by 1.35 to update. To enter Figure 11-4, note that

$$10^3 \text{ lb/hr} = 0.00288 \times 10^6 \text{ gal/day.}$$

Capital is charges at 17%/yr for 7000 hrs/yr and if

Y = capital investment shown on Figure 11-4
Q = flow rate, 10^3 lb water/hr.

charges are

$$(1.35Y)(Q/0.00288)(0.17)/7000 \ \$/\text{hr}$$
$$= 1.14\ YQ\ ¢/\text{hr.}$$

Membrane charges are 20¢/thousand gallons of throughput, or 2.40 Q ¢/hr.

Electricity charges are 0.8¢/(10^3 gallons)(100 mg/l removed), so if z is the reduction of TDS in mg/l, electricity charges are 0.000960 zQ ¢/hr.

Total charge in ¢/hr is

$$1.14\ YQ + 2.40\ Q + 0.000960\ zQ$$

Energy: 0.4 kw-hr/(10^3 gallons)(100 mg/l removed),
= 0.000480 z kw-hrs/10^3 lb water
= 5.62 zQ Btu/hr.

Waste: 10% of the feed flow

Ion Exchange (see Figure 11-2 for schemes)

Cost: Scheme 1: 10.5 Q ¢/hr for Hygas, Bigas & Synthane
9.5 Q ¢/hr for Lurgi, Synthoil & SRC
Where Q = flow rate, 10^3 lb water/hr

Scheme 2: 6.5 Q ¢/hr

Scheme 3: 11.5 Q ¢/hr not including the electrodialysis

Energy: Negligible

Waste: 6% of feed water

Phenol Extraction

Cost: 300 ¢/thousand gallons, 36¢/10^3 lb, 36Q ¢/hr where Q is the feed rate in 10^3 lb/hr. Sale of phenol yields 2.3¢/lb phenol. If y is phenol concentration in the feed stream in mg/l the rate of recovery of phenol is 0.95 y Q/1000 lb/hr. The net process cost, in ¢/hr, is

$$36\ Q - 0.00219\ yQ.$$

Energy: 10^6 Btu/thousand gallons; 120,000 Q Btu/hr.

Waste: negligible

Table A11-1 (continued)

Ammonia Separation

Cost: Gas plants: MGD < 1.5, cost = [4.75 - 0.5 MGD] $\$/10^3$ gals where MGD = 10^6 gallons feed/day.
That is, if Q = feed in 10^3 lb/hr.
Q < 520; cost = [57.0 - 0.0173 Q] Q ¢/hr.
If Q ≥ 520, cost = $\$4/10^3$ gallons,
that is 43 Q ¢/hr.

SRC & Synthoil: Q < 867; cost = [63.0 - 0.0173Q] Q ¢/hr.
Q ≥ 867; cost = 48 Q ¢/hr.

All plants: credit 7¢/lb ammonia recovered.

If y is the concentration of ammonia in the feed stream in mg/l, the rate of recovery of ammonia is

(y - 450) Q/1000 lb/hr,

The value of the recovered ammonia is

0.007 (y - 450)Q ¢/hr.

Energy: 1.7 x 10^6 Btu/thousand gallons; 204,000 Q Btu/hr.

Waste: Lose 2.3 lb water/lb ammonia recovered.

Biotreatment

Cost: All Hygas & bituminous coals in Lurgi and Synthane:

2.5¢/lb BOD removed, that is 0.0025 yQ ¢/hr, where
y = BOD concentration in mg/l and Q = feed rate in 10^3 lb/hr

All SRC & Synthoil, and subbituminous coals and lignites in Lurgi and Synthane:

2.1 ¢/lb BOD removed, that is 0.0021 yQ ¢/hr.

Energy: All plants: 4 Btu/lb BOD removed, that is 4 yQ Btu/hr.

Waste: 0.1 lb dry waste/lb BOD removed. Cost includes dissolved air flotation and vacuum filtration and sludge is discharged at 20% solids.

Filter

Cost: Capital cost is \$100/gpm = $\$200/10^3$ lb/hr. Charges are 12%/yr for 7000 hrs/yr, so operating cost is:

\$200 x 0.12/7000 = 0.343 ¢/hr for 10^3 lb/hr.

Energy: Negligible

Waste: None. Backwash is returned to clarifiers in biotreatment.

Acid Treatment of Cooling Water

Cost: If x = mg/l HCO_3 then x/61 = meq/l HCO_3. 100% replacement by H_2SO_4 (equivalent weight 49) means (49/61) x mg/l acid.
Cost:
0.00305 xQ ¢/hr where Q = flowrate in 10^3 lb/hr.

Chemicals

Cost:		
	H_2SO_4	3.8 ¢/lb
	$Ca(OH)_2$	2.7 ¢/lb
	Na_2CO_3	4.0 ¢/lb
	Magnesia	4.0 ¢/lb
	Alum	5.3 ¢/lb
	NaOH	8.3 ¢/lb
	NaCl	2.0 ¢/lb
	Cooling water biocide	6-12 $¢/10^3$ lb blowdown*
	Cooling water anti-corrosion chemicals	6 $¢/10^3$ lb blowdown
	Cooling water sus-suspending agents	0.3 $¢/10^3$ lb blowdown

*Non-oxidative biocides used to avoid production of chloro-organic molecules. Cost varied depending on the fraction of the makeup which is treated process effluent.

Table A11-1

<u>Reverse Osmosis</u>

<u>Cost</u>: ¢/10^3 water treated = 19.5 - 0.0043Q where Q is flowrate in 10^3 lb/hr; therefore

$$¢/hr = 19.5Q - 0.0043Q^2$$

Sequestering chemicals are included in the cost.

<u>Energy</u>: 0.864 kw-hr/10^3 lb water = 10,000 Q Btu/hr.

<u>Waste</u>: 10% of feed water.

<u>Activated Carbon Adsorption</u>

<u>Cost</u>: \$1/10^3 gallons treated = 12 Q ¢/hr.

<u>Energy</u>: 4,500 Btu/10^3 lb water treated = 4,500 Q Btu/hr.

<u>Waste</u>: Negligible.

TABLE A11-2. EFFLUENT WATER QUALITY

Concentrations in mg/l

	SRC & Synthoil Hydrogenation section condensate All Coals	Bigas condensate All Coals	SRC & Synthoil Gasification Condensate	Synthane & Lurgi Dirty condensate Bituminous Coals
Phenol as C_6H_5OH	6,000	s*	s	3,000
Ammonia as NH_3	13,000	4,500	s	7,000
BOD	30,000	s	s	10,000
Ca^{++}	∿ 20	∿ 120	∿ 120	∿ 20
Mg^{++}	∿ 15	∿ 50	∿ 50	∿ 15
HCO_3^-	4,000	∿ 100	∿ 100	14,000
Sulfide as S	14,000	s	s	1,000
$SO_4^=$	s	∿ 100	∿ 100	s

	Synthane & Lurgi Dirty condensate Subbituminous & Lignite	Synthane Medium quality condensate Bituminous Coals	Synthane Medium quality condensate Subbituminous & Lignite	Hygas Dirty condensate Bituminous Coals
Phenol as C_6H_5OH	6,000	300	600	300
Ammonia as NH_3	7,000	500	500	4,500
BOD	20,000	1,000	2,000	2,000
Ca^{++}	∿ 20	s	s	∿ 20
Mg^{++}	∿ 15	s	s	∿ 15
HCO_3^-	14,000	1,000	1,000	11,000
Sulfide as S	s	s	s	s
$SO_4^=$	s	s	s	s

	Hygas Dirty condensate Subbituminous & Lignite	Methanation water All Plants	Effluent from Phenol Extraction (see Note 1)	Effluent from Ammonia Separation
Phenol as C_6H_5OH	4,000	--	0.05p	--
Ammonia as NH_3	4,500	s	unchanged	450
BOD	14,000	--	b - 2.26p	--
Ca^{++}	∿ 20	--	--	--
Mg^{++}	∿ 15	--	--	--
HCO_3^-	11,000	s	--	--
Sulfide as S	s	--	--	--
$SO_4^=$	s	--	--	--

	Effluent from Biotreatment (see Note 2)
Phenol as C_6H_5OH	--
Ammonia as NH_3	--
BOD	--
Ca^{++}	∿ 60
Mg^{++}	--
HCO_3^-	∿ 40
Sulfide as S	--
$SO_4^=$	--
SiO_2	

Note 1. p = mg/l phenol in influent

b = mg/l BOD in influen

Note 2. Lime added to neutraliz and carbon dioxide added by treatment.

* s = small

TABLE A11-3. RAW WATER QUALITIES

Concentrations in mg/l

SOURCE	Tombigbee R. at Jackson, Ala.	Alabama R. at Selma, Ala.	Well water at Marengo, Ala.
PROCESS	Hygas, Lurgi, SRC	Hygas, Synthane, Synthoil	Hygas, Lurgi, SRC
SITE	Marengo, Ala.	Jefferson, Ala.	Marengo, Ala.
Ca^{++}	15	12	2.4
Mg^{++}	3.1	3.2	0.4
HCO_3^-	53	53	600
$SO_4^=$	18	92	17
TDS	91	76	880
SiO_2	9.1	7	9
pH (units)	6.9	7.3	8.3

SOURCE	Illinois R. at Marseilles, Ill.	Well water from Alluvial Ground at Bureau, Ill.	Ohio R. at Grand Chain, Ill.
PROCESS	Bigas	Bigas, Lurgi, SRC	Bigas, Lurgi, SRC
SITE	Bureau, Ill.	Bureau, Ill.	St. Clair, White, Saline, Shelby, Ill.
Ca^{++}	69	60	36
Mg^{++}	24	18	9
HCO_3^-	247	200	106
$SO_4^=$	102	90	60
TDS	466	360	209
SiO_2	7	7.5	6.5
pH (units)	7.5	7.4	7.4

Concentrations in mg/l

SOURCE	Green R. at Beech Grove, Ky.	Muskingum R. at McConnelsville, Ohio	Allegheny R. at Oakmont, Pa.
PROCESS	Lurgi	Hygas, Synthoil	Hygas, Synthane, Synthoil
SITE	Muhlenberg, Ky.	Tuscarawas, Ohio	Armstrong, Somerset, Pa. Monongalia, W.Va.
Ca^{++}	39	83	34
Mg^{++}	9	17	10
HCO_3^-	115	132	17
$SO_4^=$	54	145	108
TDS	191	582	215
SiO_2	5.9	6.3	7
pH (units)	6.9	7.2	6.2

SOURCE	Kanawha R. at Kanawha Falls, W.Va.	Well water from Alluvial Ground at Tuscarawas, Ohio	
PROCESS	Hygas, Synthane Synthoil	Hygas, Synthoil	
SITE	Fayette, Kanawha, Preston, Mingo, W.Va.	Tuscarawas, Ohio	
Ca^{++}	21	75	
Mg^{++}	5	20	
HCO_3^-	62	217	
$SO_4^=$	29	60	
TDS	134	363	
SiO_2	7.3	7	
pH (units)	7.1	7.5	

Table All-3. (continued)

Concentrations in mg/l

SOURCE	Ground water	White R. at Hazleton, Ind.	Ohio R. at Cannelton Dam, Ky.
PROCESS	Lurgi, SRC	Hygas, Synthane, Synthoil, Bigas	Hygas, Synthoil, Synthane
SITE	Fulton, Ill.	Gibson, Vigo, Sullivan, Ind.	Warrick, Ind., Floyd, Harlan, Pike, Ky. Gallia, Jefferson, Ohio
Ca^{++}	90	51	38
Mg^{++}	50	16	10
HCO_3^-	250	166	97
$SO_4^=$	1000	110	69
TDS	2000	269	216
SiO_2	9.0	5.7	4.6
pH (units)	7.7	7.7	7.1

Concentrations in mg/l

SOURCE	Tongue R. at Goose Creek below Sheridan, Wyo.	Medicine Bow R. above Seminee Res., near Hanna, Wyo.	Hams Fork near Granger, Wyo.
PROCESS	Synthoil	Hygas	Bigas, Lurgi
SITE	Lake de Smet, Wyo.	Hanna, Wyo.	Kemmerer, Wyo.
Ca^{++}	59	109	65
Mg^{++}	36	60	30
HCO_3^-	245	189	211
$SO_4^=$	137	537	171
TDS	451	945	429
SiO_2	8.3	7.4	4.2

SOURCE	Green R. below Green River, Wyo.	Beaver Creek near Newcastle, Wyo.	Ground water
PROCESS	Synthoil, Lurgi, SRC	Hygas, Synthane, SRC	SRC
SITE	Jim Bridger, Rainbow #8, Wyo.	Antelope Creek, Wyo.	Otter Creek, Mont.
Ca^{++}	55	446	70
Mg^{++}	21	156	100
HCO_3^-	175	183	600
$SO_4^=$	164	1802	1200
TDS	394	4667	2200
SiO_2	5.7	6.8	12

Table AII-3. (continued)

Concentrations in mg/l

SOURCE	Yellowstone R. at Terry, Mont.	Knife R. at Hazen, N.D.	Lake Sakakawea, N.D.
PROCESS	Bigas	Lurgi, Bigas, SRC	SRC
SITE	Slope, N.D.	Bently, Center, Knife River, N.D.	Underwood, Dickinson, N.D.
Ca^{++}	54	69	49
Mg^{++}	21	39	19
HCO_3^-	173	511	181
$SO_4^=$	187	419	170
TDS	424	1037	428
SiO_2	9.6	11	7

SOURCE	Missouri R. near Williston, N.D.	Grand River at Shadehill, S.D.	San Juan R. in N.M.
PROCESS	Lurgi	Bigas	Hygas, Lurgi
SITE	Williston, N.D.	Scranton, N.D.	Wesco, El Paso, N.M.
Ca^{++}	62	39	55
Mg^{++}	21	21	9
HCO_3^-	191	363	143
$SO_4^=$	176	412	114
TDS	436	931	300
SiO_2	9.3	5.6	12

Concentrations in mg/l

SOURCE	Yellowstone R. in Mont.	Powder R. at Arvada, Wyo.	Tongue R., average between Decker, Miles City, Mont.
PROCESS	Hygas, Synthane, SRC	Hygas, Synthane	Lurgi, SRC
SITE	Colstrip, Mont.	Spotted Horse, Wyo. East Moorehead, Mont.	Pumpkin Creek, Foster Creek, Mont.
Ca^{++}	40	138	52
Mg^{++}	14	69	36
HCO_3^-	138	247	222
$SO_4^=$	109	769	167
TDS	284	1580	328
SiO_2	10	9.5	8

SOURCE	Missouri R. at Culbertson, Mont.	Yellowstone R., average between Sidney, Terry, Mont.	Crazy Woman Creek at Upper Station near Arvada, Wyo.
PROCESS	SRC	Bigas	Hygas, SRC
SITE	Coalridge, Mont.	U.S. Steel, Mont.	Belle Ayr, Gillette, Wyo.
Ca^{++}	63	55	133
Mg^{++}	21	21	66
HCO_3^-	197	183	216
$SO_4^=$	168	197	620
TDS	427	439	1046
SiO_2	6.3	10	--

Table A11-3. (continued)

Concentrations in mg/l

SOURCE	Well water	Groundwater in N.M.	Colorado River near Glenwood Springs, Colo.
PROCESS	Hygas, Lurgi	Hygas, Lurgi, Synthoil	Paraho Direct, Paraho Indirect, TOSCO II
SITE	Decker, Mont.	Gallup, N.M.	Parachute Creek, Colo.
Ca^{++}	13	12	61
Mg^{++}	6	13	20
HCO_3^-	1700	408	137
$SO_4^=$	13	509	98
TDS	2400	2655	589
SiO_2	7	5.6	14

TABLE A11-4 WATER TREATMENT PLANTS

LURGI

TABLE A11-4. WATER TREATMENT PLANTS

Process Lurgi Site Williston, N.D.

Flow Diagram Figure A11-1A

Flow rates by stream number (10^3 lb/hr):

1. 2456	10. 1868	21. 847	31. 150
3. 1609	11. 1868	22. 8	32. 826
4. 1609	14. 1427	24. 0	33. 268
5. 1609	15. 75	25. 847	34. 268
6. 1512	16. 455	26. 0	36. 0
7. 1780	17. 264	27. 21	37. 150
8. 1897	18. 191	28. 21	39. 225
9. 1897	20. 2028	29. 14	40. 2464 RAW WATER

Treatment blocks:

	¢/hr	10^6 Btu/hr	waste (10^3 lb/hr) dry	waste (10^3 lb/hr) sludge or solution
Lime-Soda Softening - No. 1		NOT USED		
Lime-Soda Softening - No. 3	907		0.09	0.45
Ion Exchange - Scheme 1	15,300			97
Phenol Extraction	43,400	228		
Ammonia Separation	(-5,410)	387		
Biotreatment	25,300	48	1.20	4.8
Filter	489			
Acid addition to cooling water	655			
Other chemicals to cooling water	4,120			
Total	84,800	663		

TABLE A11-4. WATER TREATMENT PLANTS

Process Lurgi Site Decker, Mont.

Flow Diagram Figure A11-1A

Flow rates by stream number (10^3 lb/hr):

1. 2472	10. 1168	21. 0	31. 134
3. 2472	11. 1168	22. 9	32. 680
4. 2225	14. 987	24. 701	33. 265
5. 1524	15. 33	25. 701	34. 265
6. 1433	16. 195	26. 0	36. 0
7. 1698	17. 86	27. 21	37. 134
8. 1186	18. 109	28. 21	39. 167
9. 1186	20. 1500	29. 14	40. 2481 RAW WATER

Treatment blocks:

	¢/hr	10^6 Btu/hr	waste (10^3 lb/hr) dry	waste (10^3 lb/hr) sludge or solution
Lime-Soda Softening - No. 1		NOT USED		
Lime-Soda Softening - No. 3	905		0.08	0.40
Electrodialysis *	12,700	33.3		247
Ion Exchange - Scheme 3	17,500			91
Phenol Extraction	27,100	142		
Ammonia Separation	(-3,380)	242		
Biotreatment	16,000	30.6	0.75	3.8
Filter	339			
Acid addition to cooling water	1,200			
Other chemicals to cooling water	3,060			
Total	75,400	448		

*Located roughly in place of Softening No. 1.

TABLE A11-4. WATER TREATMENT PLANTS

Process Lurgi Site Foster Creek, Mont.

Flow Diagram Figure A11-1B

Flow rates by stream number (10^3 lb/hr):

1. 1307	10. 1353	20. 806	29. 14
2. 1286	11. 1353	21. 21	32. 170
3. 1286	12. 0	22. 5	33. 265
4. 1286	13. 1063	23. 153	34. 265
5. 1439	14. 1063	24. 0	36. 0
6. 1353	15. 87	25. 21	38. 0
7. 1618	16. 304	26. 0	39. 87
8. 1362	17. 166	27. 21	40. 1312 RAW WATER
9. 1362	18. 138	28. 21	

Treatment blocks:

	¢/hr	10^6 Btu/hr	waste (10^3 lb/hr) dry	sludge or solution
Lime-Soda Softening - No. 1		NOT USED		
Ion Exchange - Scheme 1	13,700			86
Phenol Extraction	31,100	163		
Ammonia Separation	(-3,880)	27.8		
Biotreatment	18,300	34.9	0.87	4.4
Filter	365			
Acid addition to cooling water	130			
Other chemicals to cooling water	1,590			
Reverse Osmosis	3,190	1.7		17
Activated Carbon Adsorbtion	1,840	0.69		
Total	66,300	228		

TABLE A11-4. WATER TREATMENT PLANTS

Process Lurgi Site El Paso, N.M.

Flow Diagram Figure A11-1A

Flow rates by stream number (10^3 lb/hr):

1. 1715	10. 1064	21. 258	31. 0
3. 1457	11. 1064	22. 10	32. 159
4. 1457	14. 699	24. 0	33. 270
5. 1457	15. 190	25. 258	34. 270
6. 1370	16. 375	26. 78	36. 0
7. 1640	17. 241	27. 21	37. 0
8. 1080	18. 134	28. 21	39. 189
9. 1080	20. 792	29. 14	40. 1725 RAW WATER

Treatment blocks:

	¢/hr	10^6 Btu/hr	waste (10^3 lb/hr) dry	sludge or solution
Lime-Soda Softening - No. 1		NOT USED		
Lime-Soda Softening - No. 3		NOT USED		
Ion Exchange - Scheme 1	13,900			88
Phenol Extraction	24,700	130		
Ammonia Separation	(-3,080)	220		
Biotreatment	14,600	27.8	0.69	3.5
Filter	240			
Acid addition to cooling water	154			
Other chemicals to cooling water	3,460			
Total	54,000	378		

TABLE A11-4. WATER TREATMENT PLANTS

Process Lurgi Site Wesco, N.M.

Flow Diagram Figure A11-1B

Flow rates by stream number (10^3 lb/hr):

1. 1854	10. 1468	20. 792	29. 14
2. 1754	11. 1468	21. 100	32. 37
3. 1754	12. 0	22. 11	33. 310
4. 1754	13. 1085	23. 33	34. 310
5. 1787	14. 1085	24. 0	36. 0
6. 1680	15. 256	25. 100	38. 0
7. 1990	16. 397	26. 79	39. 254
8. 1490	17. 261	27. 21	40. 1865 RAW WATER
9. 1490	18. 136	28. 21	

Treatment blocks:

			waste (10^3 lb/hr)	
	¢/hr	10^6 Btu/hr	dry	sludge or solution
Lime-Soda Softening - No. 1		NOT USED		
Ion Exchange - Scheme 1	17,000			107
Phenol Extraction	34,100	179		
Ammonia Separation	(-4,250)	304		
Biotreatment	19,900	37.8	0.95	4.8
Filter	372			
Acid addition to cooling water	132			
Other chemicals to cooling water	4,650			
Reverse Osmosis	716	0.37		3.7
Activated Carbon Adsorbtion	396	0.15		
Total	72,900	521		

TABLE A11-4. WATER TREATMENT PLANTS

Process Lurgi Site Gallup, N.M.

Flow Diagram Figure A11-1A

Flow rates by stream number (10^3 lb/hr):

1. 1768	10. 992	21. 0	31. 50
3. 1768	11. 992	22. 6	32. 164
4. 1654	14. 716	24. 244	33. 278
5. 1410	15. 38	25. 244	34. 278
6. 1325	16. 290	26. 59	36. 0
7. 1603	17. 188	27. 21	37. 50
8. 1007	18. 102	28. 21	39. 88
9. 1007	20. 792	29. 14	40. 1778 RAW WATER

Treatment blocks:

			waste (10^3 lb/hr)	
	¢/hr	10^6 Btu/hr	dry	sludge or solution
Lime-Soda Softening - No. 1		NOT USED		
Lime-Soda Softening - No. 3	892		0.03	0.15
Electrodialysis *	6,090	16.5		114
Ion Exchange - Scheme 3	16,200			85
Phenol Extraction	23,000	121		
Ammonia Separation	(-2,870)	205		
Biotreatment	13,400	25.6	0.64	3.2
Filter	246			
Acid addition to cooling water	226			
Other chemicals to cooling water	1,610			
Total	58,800	368		

*Located roughly in place of Softening No. 1.

TABLE A11-4. WATER TREATMENT PLANTS

Process Lurgi Site Marengo, Alabama (Surface water)

Flow Diagram Figure A11-1B

Flow rates by stream number (10^3 lb/hr):

1. 810	10. 2290	20. 980	29. 14
2. 789	11. 2290	21. 21	32. 904
3. 789	12. 874	22. 0	33. 260
4. 789	13. 1089	23. 814	34. 260
5. 1603	14. 1963	24. 0	36. 0
6. 1507	15. 79	25. 21	38. 30
7. 1767	16. 341	26. 0	39. 109
8. 2325	17. 211	27. 21	40. 810 RAW WATER
9. 2325	18. 130	28. 21	

Treatment blocks:

	¢/hr	10^6 Btu/hr	waste (10^3 lb/hr) dry	sludge or solution
Lime-Soda Softening - No. 1		NOT USED		
Ion Exchange - Scheme 1	15,200			96
Phenol Extraction	53,200	297		
Ammonia Separation	(-6,630)	474		
Biotreatment	36,900	59.0	1.47	7.4
Filter	670			
Acid addition to cooling water	130			
Other chemicals to cooling water	2,000			
Reverse Osmosis	14,100	9.04		90.4
Activated Carbon Adsorbtion	9,770	3.66		
Total	125,000	825		

TABLE A11-4. WATER TREATMENT PLANTS

Process Lurgi Site Marengo, Alabama (well water)

Flow Diagram Figure A11-1B

Flow rates by stream number (10^3 lb/hr):

1. 810	10. 2290	20. 980	29. 14
2. 789	11. 2290	21. 21	32. 904
3. 789	12. 874	22. 0	33. 260
4. 789	13. 1089	23. 814	34. 260
5. 1603	14. 1963	24. 0	36. 0
6. 1507	15. 79	25. 21	38. 30
7. 1767	16. 341	26. 0	39. 109
8. 2325	17. 211	27. 21	40. 810 RAW WATER
9. 2325	18. 130	28. 21	

Treatment blocks:

	¢/hr	10^6 Btu/hr	waste (10^3 lb/hr) dry	sludge or solution
Lime-Soda Softening - No. 1		NOT USED		
Ion Exchange - Scheme 2	10,400			96
Phenol Extraction	53,200	279		
Ammonia Separation	(-6,630)	474		
Biotreatment	36,900	59.0	1.47	7.4
Filter	670			
Acid addition to cooling water	130			
Other chemicals to cooling water	2,000			
Reverse Osmosis	14,100	9.04		90.4
Activated Carbon Adsorbtion	9,770	3.66		
Total	121,000	825		

TABLE A11-4. WATER TREATMENT PLANTS

Process Lurgi Site Fulton, Illinois

Flow Diagram Figure A11-1B

Flow rates by stream number (10^3 lb/hr):

1. 2058	10. 2125	20. 1034	29. 14
2. 1831	11. 727	21. 0	32. 762
3. 2058	12. 1149	22. 0	33. 277
4. 1852	13. 1149	23. 754	34. 277
5. 2585	14. 1876	24. 21	36. 0
6. 2430	15. 80	25. 21	38. 35
7. 2707	16. 263	26. 0	39. 115
8. 2158	17. 205	27. 21	40. 2058 RAW WATER
9. 2158	18. 58	28. 21	

Treatment blocks:

	¢/hr	10^6 Btu/hr	waste (10^3 lb/hr) dry	sludge or solution
Lime-Soda Softening - No. 1	Not Used			
Electrodialysis*	10,100	23		206
Ion Exchange - Scheme 3	29,700			155
Phenol Extraction	63,000	259		
Ammonia Separation	(-6,150)	440		
Biotreatment	17,100	55.6	0.68	3.42
Filter	654			
Acid addition to cooling water	154			
Other chemicals to cooling water	2,100			
Reverse Osmosis	12,400	7.62		7.6
Activated Carbon Adsorbtion	9,050	3.4		
Total	138,000	789		

*Located in place of Softening No. 1.

TABLE A11-4. WATER TREATMENT PLANTS

Process Lurgi Site Muhlenberg, Kentucky

Flow Diagram Figure A11-1B

Flow rates by stream number (10^3 lb/hr):

1. 1478	10. 1889	20. 533	29. 14
2. 1457	11. 1889	21. 21	32. 988
3. 1457	12. 979	22. 0	33. 291
4. 1457	13. 592	23. 889	34. 291
5. 2346	14. 1571	24. 0	36. 0
6. 2205	15. 50	25. 21	38. 9
7. 2496	16. 332	26. 0	39. 59
8. 1918	17. 280	27. 21	40. 1478 RAW WATER
9. 1918	18. 52	28. 21	

Treatment blocks:

	¢/hr	10^6 Btu/hr	waste (10^3 lb/hr) dry	sludge or solution
Lime-Soda Softening - No. 1		NOT USED		
Ion Exchange - Scheme 1	22,300			140
Phenol Extraction	43,800	230		
Ammonia Separation	(5,470)	391		
Biotreatment	25,900	49.4	0.61	3.1
Filter	539			
Acid addition to cooling water	300			
Other chemicals to cooling water	1,080			
Reverse Osmosis	15,100	9.88		99
Activated Carbon Adsorbtion	10,700	4.0		
Total	114,000	684		

TABLE A11-4. WATER TREATMENT PLANTS

Process Lurgi Site Bureau, Illinois

Flow Diagram Figure A11-1A

Flow rates by stream number (10^3 lb/hr):

1. 2628	10. 2117	21. 0	31. 138
3. 2628	11. 2117	22. 0	32. 39
4. 2628	14. 1913	24. 60	33. 279
5. 2568	15. 57	25. 60	34. 279
6. 2414	16. 218	26. 0	36. 0
7. 2693	17. 68	27. 21	37. 138
8. 2149	18. 150	28. 21	39. 195
9. 2149	20. 1757	29. 14	40. 2628 RAW WATER

Treatment blocks:

			waste (10^3 lb/hr)	
	¢/hr	10^6 Btu/hr	dry	sludge or solution
Lime-Soda Softening - No. 1	2,300		1.3	6.3
Lime-Soda Softening - No. 3	905		0.08	0.4
Ion Exchange - Scheme 2	16,700			150
Phenol Extraction	63,300	258		
Ammonia Separation	(-6,130)	438		
Biotreatment	17,100	27.3	0.68	3.4
Filter	656			
Acid addition to cooling water		NOT USED		
Other chemicals to cooling water	3,570			
Total	98,400	723		

TABLE A11-4. WATER TREATMENT PLANTS

Process Lurgi Site St. Clair, Illinois (surface mining)

Flow Diagram Figure A11-1A

Flow rates by stream number (10^3 lb/hr):

1. 2653	10. 2057	21. 70	31. 110
3. 2583	11. 2057	22. 0	32. 49
4. 2583	14. 1898	24. 0	33. 277
5. 2583	15. 85	25. 70	34. 277
6. 2428	16. 173	26. 0	36. 0
7. 2705	17. 117	27. 21	37. 110
8. 2089	18. 56	28. 21	39. 195
9. 2089	20. 1752	29. 14	40. 2653 RAW WATER

Treatment blocks:

			waste (10^3 lb/hr)	
	¢/hr	10^6 Btu/hr	dry	sludge or solution
Lime-Soda Softening - No. 1		NOT USED		
Lime-Soda Softening - No. 3	901		0.07	0.33
Ion Exchange - Scheme 1	24,500			160
Phenol Extraction	61,500	252		
Ammonia Separation	(-5,950)	426		
Biotreatment	16,600	26.5	0.66	3.3
Filter	651			
Acid addition to cooling water	247			
Other chemicals to cooling water	3,570			
Total	102,000	705		

TABLE A11-4. WATER TREATMENT PLANTS

Process Lurgi — Site St. Clair, Illinois (underground coal mine)

Flow Diagram Figure A11-1A

Flow rates by stream number (10^3 lb/hr):

1. 2736	10. 2057	21. 153	31. 110
3. 2583	11. 2057	22. 0	32. 132
4. 2583	14. 1815	24. 0	33. 277
5. 2583	15. 85	25. 153	34. 277
6. 2428	16. 256	26. 0	36. 0
7. 2705	17. 117	27. 21	37. 110
8. 2089	18. 149	28. 21	39. 195
9. 2089	20. 1752	29. 14	40. 2736 RAW WATER

Treatment blocks:

	¢/hr	10^6 Btu/hr	waste (10^3 lb/hr) dry	waste (10^3 lb/hr) sludge or solution
Lime-Soda Softening - No. 1		NOT USED		
Lime-Soda Softening - No. 3	901		0.07	0.33
Ion Exchange - Scheme 1	24,500			160
Phenol Extraction	61,500	252		
Ammonia Separation	(-5,950)	426		
Biotreatment	16,600	26.5	0.66	3.3
Filter	623			
Acid addition to cooling water	264			
Other chemicals to cooling water	3,570	—		
Total	102,000	705		

TABLE A11-4. WATER TREATMENT PLANTS

Process Lurgi — Site Jim Bridger, Wyo.

Flow Diagram Figure A11-1A

Flow rates by stream number (10^3 lb/hr):

1. 1541	10. 1104	21. 125	31. 0
3. 1416	11. 1104	22. 7	32. 104
4. 1416	14. 784	24. 0	33. 265
5. 1416	15. 81	25. 125	34. 265
6. 1331	16. 334	26. 0	36. 0
7. 1596	17. 234	27. 21	37. 0
8. 1121	18. 100	28. 21	39. 81
9. 1121	20. 807	29. 14	40. 1548 RAW WATER

Treatment blocks:

	¢/hr	10^6 Btu/hr	waste (10^3 lb/hr) dry	waste (10^3 lb/hr) sludge or solution
Lime-Soda Softening - No. 1		NOT USED		
Lime-Soda Softening - No. 3		NOT USED		
Ion Exchange - Scheme 1	13,500			85
Phenol Extraction	25,600	135		
Ammonia Separation	(-3,200)	229		
Biotreatment	14,900	28.4	0.71	3.6
Filter	269			
Acid addition to cooling water	151			
Other chemicals to cooling water	1,480	—		
Total	52,700	392		

TABLE A11-4. WATER TREATMENT PLANTS

Process Lurgi   Site Kemmerer, Wyo.

Flow Diagram Figure A11-1B

Flow rates by stream number (10^3 lb/hr):

1. 1917	10. 1905	20. 866	29. 14
2. 1896	11. 1905	21. 21	32. 711
3. 1896	12. 677	22. 8	33. 272
4. 1896	13. 962	23. 640	34. 272
5. 2536	14. 1639	24. 0	36. 0
6. 2384	15. 62	25. 21	38. 34
7. 2656	16. 280	26. 0	39. 96
8. 1934	17. 216	27. 21	40. 1925 RAW WATER
9. 1934	18. 64	28. 21	

Treatment blocks:

	¢/hr	10^6 Btu/hr	waste (10^3 lb/hr) dry	sludge or solution
Lime-Soda Softening - No. 1		NOT USED		
Ion Exchange - Scheme 1	24,100			152
Phenol Extraction		NOT USED		
Ammonia Separation	(-5,510)	395		
Biotreatment	47,600	76.2	1.91	9.5
Filter	562			
Acid addition to cooling water	200			
Other chemicals to cooling water	1,760			
Reverse Osmosis	11,700	7.1		71.0
Activated Carbon Adsorbtion	7,680	2.9		
Total	88,000	481		

TABLE A11-4. WATER TREATMENT PLANTS

Process Lurgi   Site Knife River, N.D.

Flow Diagram Figure A11-1B

Flow rates by stream number (10^3 lb/hr):

1. 1195	10. 1668	20. 838	29. 14
2. 1174	11. 1668	21. 21	32. 457
3. 1174	12. 435	22. 4	33. 264
4. 1174	13. 934	23. 411	34. 264
5. 1585	14. 1369	24. 0	36. 0
6. 1490	15. 74	25. 21	38. 22
7. 1754	16. 313	26. 0	39. 96
8. 1694	17. 141	27. 21	40. 1199 RAW WATER
9. 1694	18. 172	28. 21	

Treatment blocks:

	¢/hr	10^6 Btu/hr	waste (10^3 lb/hr) dry	sludge or solution
Lime-Soda Softening - No. 1		NOT USED		
Ion Exchange - Scheme 1	15,100			95
Phenol Extraction	38,700	203		
Ammonia Separation	(-4,830)	346		
Biotreatment	22,600	43.0	1.1	4.3
Filter	470			
Acid addition to cooling water	170			
Other chemicals to cooling water	1,760			
Reverse Osmosis	8,010	4.57		46
Activated Carbon Adsorbtion	4,930	1.85		
Total	86,900	598		

SOLVENT REFINED COAL

TABLE A11-4. WATER TREATMENT PLANTS

Process SRC Site Marengo, Ala. (surface water)

Flow Diagram Figure A11-1E

Flow rates by stream number (10^3 lb/hr):

1. 1354	9. 247	21. 1273	29. 14
3. 455	10. 247	22. 0	32. 1252
4. 455	14. 259	24. 0	33. 376
5. 455	15. 96	25. 1273	39. 208
7. 428	18. 112	27. 21	40. 1354 RAW WATER
8. 247	20. 1303	28. 21	

Treatment Blocks:

	¢/hr	10^6 Btu/hr	waste (10^3 lb/hr) dry	waste (10^3 lb/hr) sludge or solution
Lime-Soda Softening - No. 1	NOT USED			
Lime-Soda Softening - No. 2	1,300		0.3	1.7
Electrodialysis	NOT USED			
Ion Exchange - Scheme 1	4,320			27
Phenol Extraction	5,630	29.6		
Ammonia Separation	(-7,200)	50.4		
Biotreatment	8,540	16.2	0.4	2.0
Filter	89			
Acid addition to cooling water	234			
Other chemicals to cooling water	2,560	___		
Total	15,500	96.2		

TABLE A11-4. WATER TREATMENT PLANTS

Process SRC Site Marengo, Ala. (ground water)

Flow Diagram Figure A11-1E

Flow rates by stream number (10^3 lb/hr):

1. 1354	9. 247	21. 1273	29. 14
3. 455	10. 247	22. 0	32. 1252
4. 455	14. 259	24. 0	33. 376
5. 455	15. 96	25. 1273	39. 208
7. 428	18. 112	27. 21	40. 1354 RAW WATER
8. 247	20. 1303	28. 21	

Treatment Blocks:

	¢/hr	10^6 Btu/hr	waste (10^3 lb/hr) dry	waste (10^3 lb/hr) sludge or solution
Lime-Soda Softening - No. 1	NOT USED			
Lime-Soda Softening - No. 2	1,300		0.3	1.7
Electrodialysis	NOT USED			
Ion Exchange - Scheme 1	4,320			27
Phenol Extraction	5,650	29.6		
Ammonia Separation	(-7,200)	50.4		
Biotreatment	8,530	39.4	0.4	2.0
Filter	89			
Acid addition to cooling water	2,323			
Other chemicals to cooling water	2,560	___		
Total	17,600	119		

TABLE A11-4. WATER TREATMENT PLANTS

Process SRC Site Bureau, Ill. (well water)

Flow Diagram Figure A11-1E

Flow rates by stream number (10^3 lb/hr):

1. 1747	9. 81	21. 0	29. 14
3. 1853	10. 81	22. 0	32. 1518
4. 1846	14. 94	24. 1539	33. 106
5. 307	15. 69	25. 1539	39. 208
7. 290	18. 139	27. 21	40. 1747 RAW WATER
8. 81	20. 1406	28. 21	

Treatment Blocks:

	¢/hr	10^6 Btu/hr	waste (10^3 lb/hr) dry	waste (10^3 lb/hr) sludge or solution
Lime-Soda Softening - No. 1	2,670		1.5	7.0
Lime-Soda Softening - No. 2	NOT USED			
Electrodialysis	NOT USED			
Ion Exchange - Scheme 2	2,000			17
Phenol Extraction	1,850	9.7		
Ammonia Separation	(-2,130)	16.5		
Biotreatment	2,800	5.3	0.16	0.8
Filter	32			
Acid addition to cooling water	460			
Other chemicals to cooling water	2,560	___		
Total	10,200	31.5		

TABLE A11-4. WATER TREATMENT PLANTS

Process SRC Site White, Ill.

Flow Diagram Figure A11-1E

Flow rates by stream number (10^3 lb/hr):

1. 1617	9. 48	21. 0	29. 14
3. 1690	10. 48	22. 0	32. 1425
4. 1687	14. 62	24. 1445	33. 73
5. 242	15. 76	25. 1445	39. 202
7. 228	18. 126	27. 21	40. 1617 RAW WATER
8. 48	20. 1285	28. 28	

Treatment Blocks:

	¢/hr	10^6 Btu/hr	waste (10^3 lb/hr) dry	waste (10^3 lb/hr) sludge or solution
Lime-Soda Softening - No. 1	1,870		0.7	4
Lime-Soda Softening - No. 2	NOT USED			
Electrodialysis	NOT USED			
Ion Exchange - Scheme 2	1,490			14
Phenol Extraction	1,100	5.8		
Ammonia Separation	(-1,230)	9.8		
Biotreatment	1,660	3.2	0.08	0.4
Filter	21			
Acid addition to cooling water	180			
Other chemicals to cooling water	2,480	___		
Total	7,570	18.8		

TABLE A11-4. WATER TREATMENT PLANTS

Process SRC Site Fulton, Ill.

Flow Diagram Figure A11-1E

Flow rates by stream number (10^3 lb/hr):

1. 1297	9. 66	21. 0	29. 14
3. 1393	10. 66	22. 0	32. 853
4. 1156	14. 80	24. 874	33. 96
5. 282	15. 98	25. 874	39. 153
7. 271	18. 55	27. 21	40. 1297 RAW WATER
8. 66	20. 780	28. 21	

Treatment Blocks:

	¢/hr	10^6 Btu/hr	waste (10^3 lb/hr) dry	waste (10^3 lb/hr) sludge or solution
Lime-Soda Softening - No. 1		NOT USED		
Lime-Soda Softening - No. 2		NOT USED		
Electrodialysis*	11,600	26.6		237
Ion Exchange - Scheme 3	3,200			11
Phenol Extraction	1,510	7.9		
Ammonia Separation	(-1,720)	13.5		
Biotreatment	1,950	3.7	0.09	0.5
Filter	27			
Acid addition to cooling water	78			
Other chemicals to cooling water	2,200			
Total	18,800	52		

*located roughly in place of Softening No.1 .

TABLE A11-4. WATER TREATMENT PLANTS

Process SRC Site Saline, Ill.

Flow Diagram Figure A11-1E

Flow rates by stream number (10^3 lb/hr):

1. 1020	9. 42	21. 0	29. 14
3. 1110	10. 42	22. 0	32. 799
4. 1108	14. 56	24. 820	33. 90
5. 288	15. 81	25. 820	39. 128
7. 272	18. 47	27. 21	40. 1020 RAW WATER
8. 42	20. 727	28. 21	

Treatment Blocks:

	¢/hr	10^6 Btu/hr	waste (10^3 lb/hr) dry	waste (10^3 lb/hr) sludge or solution
Lime-Soda Softening - No. 1	1,390		0.4	2
Lime-Soda Softening - No. 2		NOT USED		
Electrodialysis		NOT USED		
Ion Exchange - Scheme 2	1,870			16
Phenol Extraction	960	5.04		
Ammonia Separation	(-1,070)	8.57		
Biotreatment	1,230	2.36	0.06	0.3
Filter	19			
Acid addition to cooling water	99			
Other chemicals to cooling water	1,570			
Total	6,100	16.0		

TABLE A11-4. WATER TREATMENT PLANTS

Process SRC Site Gillette, Wyo.

Flow Diagram Figure A11-1E

Flow rates by stream number (10^3 lb/hr):

1.	797	9.	186	21.	0	29.	14
3.	951	10.	181	22.	5	32.	599
4.	946	14.	195	24.	620	33.	154
5.	326	15.	101	25.	620	39.	193
7.	308	18.	92	27.	21	40.	802 RAW WATER
8.	186	20.	601	28.	21		

Treatment Blocks:

	¢/hr	10^6 Btu/hr	waste (10^3 lb/hr) dry	waste (10^3 lb/hr) sludge or solution
Lime-Soda Softening - No. 1	2,090		1.0	5.0
Lime-Soda Softening - No. 2	NOT USED			
Electrodialysis	NOT USED			
Ion Exchange - Scheme 2	2,120			18
Phenol Extraction	4,250	22.3		
Ammonia Separation	(-5,220)	37.9		
Biotreatment	6,250	11.9	0.30	1.5
Filter	67			
Acid addition to cooling water	small			
Other chemicals to cooling water	2,370	___		
Total	11,900	72.1		

TABLE A11-4. WATER TREATMENT PLANTS

Process SRC Site Antelope Creek, Wyo.

Flow Diagram Figure A11-1E

Flow rates by stream number (10^3 lb/hr):

1.	841	9.	166	21.	0	29.	14
3.	992	10.	161	22.	5	32.	510
4.	873	14.	175	24.	531	33.	151
5.	342	15.	51	25.	531	39.	132
7.	323	18.	81	27.	21	40.	846 RAW WATER
8.	166	20.	553	28.	21		

Treatment Blocks:

	¢/hr	10^6 Btu/hr	waste (10^3 lb/hr) dry	waste (10^3 lb/hr) sludge or solution
Lime-Soda Softening - No. 1	NOT USED			
Lime-Soda Softening - No. 2	NOT USED			
Electrodialysis*	8,120	25.7		120
Ion Exchange - Scheme 3	3,930			19
Phenol Extraction	3,800	19.9		
Ammonia Separation	(-4,600)	33.9		
Biotreatment	5,550	10.6	0.26	1.3
Filter	60			
Acid addition to cooling water	small			
Other chemicals to cooling water	1,620	___		
Total	18,500	90.1		

* Situated about where Softening No. 1 is shown on Figure A11-1E.

TABLE A11-4. WATER TREATMENT PLANTS

Process SRC Site Rainbow #8, Wyo.

Flow Diagram Figure A11-1E

Flow rates by stream number (10^3 lb/hr):

1. 1487	9. 111	21. 0	29. 14
3. 1602	10. 108	22. 12	32. 1244
4. 1596	14. 122	24. 1265	33. 115
5. 331	15. 48	25. 1265	39. 111
7. 312	18. 63	27. 21	40. 1499 RAW WATER
8. 111	20. 1255	28. 21	

Treatment Blocks:

	¢/hr	10^6 Btu/hr	waste (10^3 lb/hr) dry	sludge or solution
Lime-Soda Softening - No. 1	2,310		1.1	6.0
Lime-Soda Softening - No. 2		NOT USED		
Electrodialysis		NOT USED		
Ion Exchange - Scheme 2	2,150			19
Phenol Extraction	2,540	13.3		
Ammonia Separation	(-2,940)	22.6		
Biotreatment	3,730	7.1	0.18	0.90
Filter	42			
Acid addition to cooling water	268			
Other chemicals to cooling water	640	___		
Total	8,700	43.0		

TABLE A11-4. WATER TREATMENT PLANTS

Process SRC Site Dickinson, N.D.

Flow Diagram Figure A11-1E

Flow rates by stream number (10^3 lb/hr):

1. 903	9. 234	21. 761	29. 14
3. 396	10. 227	22. 4	32. 740
4. 396	14. 241	24. 0	33. 254
5. 396	15. 107	25. 761	39. 274
7. 374	18. 167	27. 21	40. 907 RAW WATER
8. 234	20. 707	28. 21	

Treatment Blocks:

	¢/hr	10^6 Btu/hr	waste (10^3 lb/hr) dry	sludge or solution
Lime-Soda Softening - No. 1		NOT USED		
Lime-Soda Softening - No. 2		NOT USED		
Electrodialysis		NOT USED		
Ion Exchange - Scheme 1	3,760			22
Phenol Extraction	5,350	28.1		
Ammonia Separation	(-6,760)	47.7		
Biotreatment	7,840	14.9	0.37	1.9
Filter	83			
Acid addition to cooling water	438			
Other chemicals to cooling water	3,370	___		
Total	14,100	90.7		

TABLE A11-4. WATER TREATMENT PLANTS

Process SRC Site Bentley, N.D.

Flow Diagram Figure A11-1E

Flow rates by stream number (10^3 lb/hr):

1. 943	9. 213	21. 0	29. 14
3. 1147	10. 207	22. 4	32. 755
4. 1143	14. 221	24. 776	33. 204
5. 367	15. 85	25. 776	39. 233
7. 346	18. 148	27. 21	40. 947 RAW WATER
8. 213	20. 743	28. 21	

Treatment Blocks:

			waste (10^3 lb/hr)	
	¢/hr	10^6 Btu/hr	dry	sludge or solution
Lime-Soda Softening - No. 1	1,900		0.8	4
Lime-Soda Softening - No. 2		NOT USED		
Electrodialysis		NOT USED		
Ion Exchange - Scheme 2	2,390			21
Phenol Extraction	4,870	25.6		
Ammonia Separation	(-6,080)	43.5		
Biotreatment	7,150	13.6	0.34	1.7
Filter	76			
Acid addition to cooling water	463			
Other chemicals to cooling water	2,870	—		
Total	13,600	82.7		

TABLE A11-4. WATER TREATMENT PLANTS

Process SRC Site Underwood, N.D.

Flow Diagram Figure A11-1E

Flow rates by stream number (10^3 lb/hr):

1. 1714	9. 226	21. 0	29. 14
3. 1945	10. 219	22. 10	32. 1512
4. 1939	14. 233	24. 1533	33. 231
5. 406	15. 81	25. 1533	39. 228
7. 383	18. 147	27. 21	40. 1724 RAW WATER
8. 226	20. 1517	28. 21	

Treatment Blocks:

			waste (10^3 lb/hr)	
	¢/hr	10^6 Btu/hr	dry	sludge or solution
Lime-Soda Softening - No. 1	2,670		1.2	6
Lime-Soda Softening - No. 2		NOT USED		
Electrodialysis		NOT USED		
Ion Exchange - Scheme 2	2,640			23
Phenol Extraction	5,170	27.1		
Ammonia Separation	(-6,500)	46.1		
Biotreatment	7,560	14.4	0.36	1.8
Filter	80			
Acid addition to cooling water		NOT USED		
Other chemicals to cooling water	2,800	—		
Total	14,400	87.6		

TABLE A11-4. WATER TREATMENT PLANTS

Process SRC   Site Otter Creek, Mont.

Flow Diagram Figure A11-1E

Flow rates by stream number (10^3 lb/hr):

1. 1186	9. 161	21. 0	29. 14
3. 1413	10. 156	22. 6	32. 736
4. 1230	14. 170	24. 757	33. 227
5. 473	15. 63	25. 757	39. 173
7. 445	18. 110	27. 21	40. 1192 RAW WATER
8. 161	20. 733	28. 21	

Treatment Blocks:

	¢/hr	10^6 Btu/hr	waste (10^3 lb/hr) dry	waste (10^3 lb/hr) sludge or solution
Lime-Soda Softening - No. 1		NOT USED		
Lime-Soda Softening - No. 2	1,300		0.2	1.0
Electrodialysis*	9,000	20.0		183
Ion Exchange - Scheme 3	5,400			28
Phenol Extraction	3,680	19.3		
Ammonia Separation	(-4,450)	32.8		
Biotreatment	5,390	10.3	0.26	1.3
Filter	58			
Acid addition to cooling water	453			
Other chemicals to cooling water	760			
Total	21,600	83		

*located roughly in place of Softening No.1 .

TABLE A11-4. WATER TREATMENT PLANTS

Process SRC   Site Pumpkin Creek, Mont.

Flow Diagram Figure A11-1E

Flow rates by stream number (10^3 lb/hr):

1. 947	9. 222	21. 750	29. 14
3. 420	10. 216	22. 5	32. 729
4. 420	14. 230	24. 0	33. 223
5. 420	15. 110	25. 750	39. 231
7. 396	18. 121	27. 21	40. 952 RAW WATER
8. 222	20. 728	28. 21	

Treatment Blocks:

	¢/hr	10^6 Btu/hr	waste (10^3 lb/hr) dry	waste (10^3 lb/hr) sludge or solution
Lime-Soda Softening - No. 1	NOT USED			
Lime-Soda Softening - No. 2	1,300		0.2	1.0
Electrodialysis	NOT USED			
Ion Exchange - Scheme 1	3,990			24
Phenol Extraction	5,080	26.6		
Ammonia Separation	(-6,370)	45.3		
Biotreatment	7,460	14.2	0.36	1.8
Filter	79			
Acid addition to cooling water	522			
Other chemicals to cooling water	2,840			
Total	14,900	86.1		

TABLE A11-4. WATER TREATMENT PLANTS

Process SRC   Site Coalridge, Mont.

Flow Diagram Figure A11-1E

Flow rates by stream number (10^3 lb/hr):

1.	1075	9.	330	21.	0	29.	14
3.	1514	10.	320	22.	6	32.	942
4.	1509	14.	334	24.	963	33.	440
5.	552	15.	144	25.	963	39.	311
7.	521	18.	167	27.	21	40.	1081 RAW WATER
8.	330	20.	965	28.	21		

Treatment Blocks:

	¢/hr	10^6 Btu/hr	waste (10^3 lb/hr) dry	sludge or solution
Lime-Soda Softening - No. 1	2,050		1.0	5.0
Lime-Soda Softening - No. 2	NOT USED			
Electrodialysis	NOT USED			
Ion Exchange - Scheme 2	3,590			31
Phenol Extraction	7,540	39.6		
Ammonia Separation	(-10,100)	67.3		
Biotreatment	11,000	21.0	0.53	2.7
Filter	115			
Acid addition to cooling water	NOT USED			
Other chemicals to cooling water	3,330	——		
Total	17,500	128		

TABLE A11-4. WATER TREATMENT PLANTS

Process SRC   Site Colstrip, Mont.

Flow Diagram Figure A11-1E

Flow rates by stream number (10^3 lb/hr):

1.	1045	9.	160	21.	827	29.	14
3.	386	10.	155	22.	6	32.	806
4.	386	14.	169	24.	0	33.	169
5.	386	15.	80	25.	827	39.	181
7.	364	18.	101	27.	21	40.	1051 RAW WATER
8.	160	20.	794	28.	21		

Treatment Blocks:

	¢/hr	10^6 Btu/hr	waste (10^3 lb/hr) dry	sludge or solution
Lime-Soda Softening - No. 1	NOT USED			
Lime-Soda Softening - No. 2	1,150		0.1	0.6
Electrodialysis	NOT USED			
Ion Exchange - Scheme 1	3,670			22
Phenol Extraction	3,660	19.2		
Ammonia Separation	(-4,420)	32.6		
Biotreatment	5,350	10.2	0.25	1.3
Filter	58			
Acid addition to cooling water	360			
Other chemicals to cooling water	2,230	——		
Total	12,100	62.0		

SYNTHANE

TABLE A11-4. WATER TREATMENT PLANTS

Process Synthane   Site Jefferson, Ala.

Flow Diagram Figure A11-1A

Flow rates by stream number (10^3 lb/hr):

1.	1981	10.	569	21.	827	32.	806
3.	1154	11.	684	22.	0	33.	245
4.	1154	14.	450	24.	0	34.	130
5.	1154	15.	26	25.	827	36.	115
6.	1085	16.	248	27.	21	37.	100
7.	1215	17.	130	28.	21	39.	126
8.	578	18.	118	29.	14	40.	1981 RAW WATER
9.	578	20.	1130	31.	100		

Treatment blocks:

			waste (10^3 lb/hr)	
	¢/hr	10^6 Btu/hr	dry	sludge or solution
Lime-Soda Softening - No. 1		NOT USED		
Lime-Soda Softening - No. 3	899		0.06	0.3
Ion Exchange - Scheme 1	12,100			69
Phenol Extraction		NOT USED		
Ammonia Separation	(-1,650)	118.0		
Biotreatment	17,100	27.0	0.68	3.4
Filter	154			
Acid addition to cooling water	185			
Other chemicals to cooling water	2,050	____		
Total	30,900	145		

TABLE A11-4. WATER TREATMENT PLANTS

Process Synthane   Site Gibson, Indiana

Flow Diagram Figure A11-1A

Flow rates by stream number (10^3 lb/hr):

1.	1926	10.	590	21.	0	32.	724
3.	1926	11.	705	22.	0	33.	245
4.	1923	14.	477	24.	745	34.	130
5.	1178	15.	8	25.	745	36.	115
6.	1107	16.	242	27.	21	37.	112
7.	1237	17.	125	28.	21	39.	120
8.	599	18.	117	29.	14	40.	1926 RAW WATER
9.	599	20.	1081	31.	112		

Treatment blocks:

			waste (10^3 lb/hr)	
	¢/hr	10^6 Btu/hr	dry	sludge or solution
Lime-Soda Softening - No. 1	1,690		0.69	3.45
Lime-Soda Softening - No. 3	901		0.08	0.40
Ion Exchange - Scheme 2	7,660			71
Phenol Extraction		NOT USED		
Ammonia Separation	(-1,710)	122		
Biotreatment	17,600	28.2	0.70	3.50
Filter	164			
Acid addition to cooling water		NOT USED		
Other chemicals to cooling water	1,960	____		
Total	28,300	150		

TABLE A11-4. WATER TREATMENT PLANTS

Process Synthane   Site Sullivan, Indiana

Flow Diagram Figure A11-1A

Flow rates by stream number (10^3 lb/hr):

1.	1847	10.	586	21.	0	32.	650	
3.	1847	11.	701	22.	0	33.	245	
4.	1845	14.	543	24.	671	34.	130	
5.	1174	15.	12	25.	671	36.	115	
6.	1104	16.	179	27.	21	37.	107	
7.	1234	17.	134	28.	21	39.	119	
8.	595	18.	45	29.	14	40.	1847	RAW WATER
9.	595	20.	1074	31.	107			

Treatment blocks:

	¢/hr	10^6 Btu/hr	waste (10^3 lb/hr) dry	waste (10^3 lb/hr) sludge or solution
Lime-Soda Softening - No. 1	1,600		0.4	2.0
Lime-Soda Softening - No. 3	1,200		0.06	0.3
Ion Exchange - Scheme 2	7,630			70
Phenol Extraction		NOT USED		
Ammonia Separation	(-1,700)	121		
Biotreatment	5,640	9.0	0.2	1.1
Filter	165			
Acid addition to cooling water		NOT USED		
Other chemicals to cooling water	1,940	___		
Total	16,500	130		

TABLE A11-4. WATER TREATMENT PLANTS

Process Synthane   Site Floyd, Ky.

Flow Diagram Figure A11-1A

Flow rates by stream number (10^3 lb/hr):

1.	1320	10.	600	21.	132	32.	111	
3.	1188	11.	715	22.	0	33.	245	
4.	1188	14.	442	24.	0	34.	130	
5.	1188	15.	4	25.	132	36.	115	
6.	1117	16.	287	27.	21	37.	51	
7.	1247	17.	179	28.	21	39.	55	
8.	609	18.	108	29.	14	40.	1320	RAW WATER
9.	609	20.	498	31.	51			

Treatment blocks:

	¢/hr	10^6 Btu/hr	waste (10^3 lb/hr) dry	waste (10^3 lb/hr) sludge or solution
Lime-Soda Softening - No. 1		NOT USED		
Lime-Soda Softening - No. 3	892		0.03	0.15
Ion Exchange - Scheme 1	12,500			71
Phenol Extraction		NOT USED		
Ammonia Separation	(-1,740)	124		
Biotreatment	17,900	29	0.72	3.6
Filter	152			
Acid addition to cooling water	140			
Other chemicals to cooling water	1,010	___		
Total	30,800	153		

TABLE A11-4. WATER TREATMENT PLANTS

Process Synthane Site Gallia, Ohio

Flow Diagram Figure A11-1A

Flow rates by stream number (10^3 lb/hr):

1. 1896	10. 581	21. 728	32. 707
3. 1168	11. 696	22. 0	33. 245
4. 1168	14. 451	24. 0	34. 130
5. 1168	15. 17	25. 728	36. 115
6. 1098	16. 259	27. 21	37. 99
7. 1228	17. 135	28. 21	39. 116
8. 590	18. 124	29. 14	40. 1896 RAW WATER
9. 590	20. 1042	31. 99	

Treatment blocks:

	¢/hr	10^6 Btu/hr	waste (10^3 lb/hr) dry	sludge or solution
Lime-Soda Softening - No. 1		NOT USED		
Lime-Soda Softening - No. 3	899		0.06	0.30
Ion Exchange - Scheme 1	12,300			70
Phenol Extraction		NOT USED		
Ammonia Separation	(-1,680)	120		
Biotreatment	5,600	9.0	0.2	1.1
Filter	155			
Acid addition to cooling water	264			
Other chemicals to cooling water	1,890			
Total	19,400	129		

TABLE A11-4. WATER TREATMENT PLANTS

Process Synthane Site Jefferson, Ohio

Flow Diagram Figure A11-1A

Flow rates by stream number (10^3 lb/hr):

1. 1810	10. 582	21. 641	32. 620
3. 1169	11. 697	22. 0	33. 245
4. 1169	14. 538	24. 0	34. 130
5. 1169	15. 16	25. 641	36. 115
6. 1099	16. 173	27. 21	37. 100
7. 1229	17. 130	28. 21	39. 116
8. 591	18. 43	29. 14	40. 1810 RAW WATER
9. 591	20. 1042	31. 100	

Treatment blocks:

	¢/hr	10^6 Btu/hr	waste (10^3 lb/hr) dry	sludge or solution
Lime-Soda Softening - No. 1		NOT USED		
Lime-Soda Softening - No. 3	899		0.06	0.3
Ion Exchange - Scheme 1	12,300			70
Phenol Extraction		NOT USED		
Ammonia Separation	(-1,680)	121		
Biotreatment	5,610	9.0	0.2	1.1
Filter	185			
Acid addition to cooling water	249			
Other chemicals to cooling water	2,120			
Total	19,700	130		

TABLE A11-4. WATER TREATMENT PLANTS

Process Synthane Site Armstrong, Pa.

Flow Diagram Figure A11-1A

Flow rates by stream number (10^3 lb/hr):

1.	1872	10.	584	21.	701	32.	680
3.	1171	11.	714	22.	0	33.	245
4.	1171	14.	487	24.	0	34.	115
5.	1171	15.	15	25.	701	36.	130
6.	1101	16.	241	27.	21	37.	102
7.	1231	17.	128	28.	21	39.	117
8.	593	18.	113	29.	14	40.	1872 RAW WATER
9.	593	20.	1050	31.	102		

Treatment blocks:

	¢/hr	10^6 Btu/hr	waste (10^3 lb/hr) dry	waste (10^3 lb/hr) sludge or solution
Lime-Soda Softening - No. 1		NOT USED		
Lime-Soda Softening - No. 3	900		0.06	0.31
Ion Exchange - Scheme 1	12,300			70
Phenol Extraction		NOT USED		
Ammonia Separation	(-1,690)	121		
Biotreatment	5,750	9.2	0.2	1.2
Filter	167			
Acid addition to cooling water	86			
Other chemicals to cooling water	2,140			
Total	19,600	130		

TABLE A11-4. WATER TREATMENT PLANTS

Process Synthane Site Kanawha, West Virginia

Flow Diagram Figure A11-1A

Flow rates by stream number (10^3 lb/hr):

1.	1865	10.	585	21.	693	32.	672
3.	1172	11.	700	22.	0	33.	245
4.	1172	14.	471	24.	0	34.	130
5.	1172	15.	14	25.	693	36.	115
6.	1102	16.	243	27.	21	37.	100
7.	1232	17.	130	28.	21	39.	114
8.	594	18.	113	29.	14	40.	1865 RAW WATER
9.	594	20.	1029	31.	100		

Treatment blocks:

	¢/hr	10^6 Btu/hr	waste (10^3 lb/hr) dry	waste (10^3 lb/hr) sludge or solution
Lime-Soda Softening - No. 1		NOT USED		
Lime-Soda Softening - No. 3	899		0.06	0.3
Ion Exchange - Scheme 1	12,300			70
Phenol Extraction		NOT USED		
Ammonia Separation	(-1,700)	121		
Biotreatment	5,640	9.0	0.1	1.1
Filter	162			
Acid addition to cooling water	185			
Other chemicals to cooling water	2,090			
Total	19,600	130		

TABLE A11-4. WATER TREATMENT PLANTS

Process Synthane Site Preston, West Virginia

Flow Diagram Figure A11-1A

Flow rates by stream number (10^3 lb/hr):

1. 1392	10. 582	21. 223	32. 202
3. 1169	11. 712	22. 0	33. 245
4. 1169	14. 431	24. 0	34. 130
5. 1169	15. 16	25. 223	36. 115
6. 1099	16. 295	27. 21	37. 47
7. 1229	17. 183	28. 21	39. 63
8. 591	18. 112	29. 14	40. 1392 RAW WATER
9. 591	20. 570	31. 47	

Treatment blocks:

	¢/hr	10^6 Btu/hr	waste (10^3 lb/hr) dry	sludge or solution
Lime-Soda Softening - No. 1		NOT USED		
Lime-Soda Softening - No. 3	891		0.03	0.15
Ion Exchange - Scheme 1	12,300			70
Phenol Extraction		NOT USED		
Ammonia Separation	(-1,680)	120.6		
Biotreatment	5,730	9.2	0.2	1.2
Filter	148			
Acid addition to cooling water	91			
Other chemicals to cooling water	1,150			
Total	18,600	130		

TABLE A11-4. WATER TREATMENT PLANTS

Process Synthane Site Antelope Creek, Wyo.

Flow Diagram Figure A11-1A

Flow rates by stream number (10^3 lb/hr):

1. 1426	10. 518	21. 0	32. 160
3. 1426	11. 687	22. 6	33. 310
4. 1283	14. 416	24. 181	34. 141
5. 1102	15. 11	25. 181	36. 169
6. 1036	16. 285	27. 21	37. 47
7. 1177	17. 227	28. 21	39. 58
8. 526	18. 58	29. 14	40. 1432 RAW WATER
9. 526	20. 518	31. 47	

Treatment blocks:

	¢/hr	10^6 Btu/hr	waste (10^3 lb/hr) dry	sludge or solution
Lime-Soda Softening - No. 1		NOT USED		
Lime-Soda Softening - No. 3	891		0.03	0.14
Electrodialysis *	9,550	32.1		143
Ion Exchange - Scheme 3	12,700			66
Phenol Extraction	12,000	63.1		
Ammonia Separation	(-1,500)	107.3		
Biotreatment	7,820	14.9	0.33	1.65
Filter	126			
Acid addition to cooling water		NOT USED		
Other chemicals to cooling water	1,060			
Total	42,600	217		

*Located roughly in the place of Softening No. 1.

TABLE A11-4. WATER TREATMENT PLANTS

Process Synthane Site Spotted Horse, Wyo.

Flow Diagram Figure A11-1A

Flow rates by stream number (10^3 lb/hr):

1. 1309	10. 503	21. 0	32. 196
3. 1309	11. 672	22. 6	33. 310
4. 1303	14. 378	24. 217	34. 141
5. 1086	15. 21	25. 217	36. 169
6. 1021	16. 308	27. 21	37. 36
7. 1162	17. 246	28. 21	39. 57
8. 511	18. 62	29. 14	40. 1315 RAW WATER
9. 511	20. 517	31. 36	

Treatment blocks:

	¢/hr	10^6 Btu/hr	waste (10^3 lb/hr) dry	waste (10^3 lb/hr) sludge or solution
Lime-Soda Softening - No. 1	2,140		1.3	6.3
Lime-Soda Softening - No. 3	890		0.02	0.11
Ion Exchange - Scheme 2	7,060			65
Phenol Extraction	11,700	61.3		
Ammonia Separation	(-1,460)	104.2		
Biotreatment	7,510	14.3	0.30	1.5
Filter	130			
Acid addition to cooling water		NOT USED		
Other chemicals to cooling water	1,040			
Total	29,000	180		

TABLE A11-4. WATER TREATMENT PLANTS

Process Synthane Site Colstrip, Montana

Flow Diagram Figure A11-1A

Flow rates by stream number (10^3 lb/hr):

1. 1415	10. 510	21. 322	32. 301
3. 1093	11. 679	22. 5	33. 310
4. 1093	14. 401	24. 0	34. 141
5. 1093	15. 17	25. 322	36. 169
6. 1027	16. 292	27. 21	37. 53
7. 1168	17. 219	28. 21	39. 70
8. 518	18. 73	29. 14	40. 1420 RAW WATER
9. 518	20. 632	31. 53	

Treatment blocks:

	¢/hr	10^6 Btu/hr	waste (10^3 lb/hr) dry	waste (10^3 lb/hr) sludge or solution
Lime-Soda Softening - No. 1		NOT USED		
Lime-Soda Softening - No. 3	892		0.03	0.16
Ion Exchange - Scheme 1	11,500			79
Phenol Extraction	11,800	62.2		
Ammonia Separation	(-1,470)	105.7		
Biotreatment	7,610	14.5	0.03	1.5
Filter	137			
Acid addition to cooling water	176			
Other chemicals to cooling water	1,280			
Total	31,900	182		

HYGAS

TABLE A11-4. WATER TREATMENT PLANTS

Process Hygas Site Jefferson, Ala.

Flow Diagram Figure A11-1A

Flow rates by stream number (10^3 lb/hr):

1.	2130	10.	532	21.	796	31.	9	
3.	1334	11.	532	22.	0	32.	775	
4.	1334	14.	344	24.	0	33.	180	
5.	1334	15.	103	25.	796	34.	180	
6.	1254	16.	202	26.	0	36.	0	
7.	1434	17.	101	27.	21	37.	9	
8.	537	18.	101	28.	21	39.	112	
9.	537	20.	1007	29.	14	40.	2130	RAW WATER

Treatment blocks:

			waste (10^3 lb/hr)	
	¢/hr	10^6 Btu/hr	dry	sludge or solution
Lime-Soda Softening - No. 1		NOT USED		
Lime-Soda Softening - No. 3	886		0.01	0.05
Ion Exchange - Scheme 1	14,000			80
Phenol Extraction		NOT USED		
Ammonia Separation	7,870	109		
Biotreatment	2,660	4.2	0.1	0.5
Filter	118			
Acid addition to cooling water	167			
Other chemicals to cooling water	1,830			
Total	27,600	113		

TABLE A11-4. WATER TREATMENT PLANTS

Process Hygas Site Marengo, Ala. (river water)

Flow Diagram Figure A11-1A

Flow rates by stream number (10^3 lb/hr):

1.	1298	10.	293	21.	431	31.	1	
3.	867	11.	293	22.	0	32.	410	
4.	867	14.	198	24.	0	33.	200	
5.	867	15.	60	25.	431	34.	200	
6.	815	16.	109	26.	0	36.	0	
7.	1015	17.	36	27.	21	37.	1	
8.	296	18.	73	28.	21	39.	61	
9.	296	20.	547	29.	14	40.	1298	RAW WATER

Treatment blocks:

			waste (10^3 lb/hr)	
	¢/hr	10^6 Btu/hr	dry	sludge or solution
Lime-Soda Softening - No. 1		NOT USED		
Lime-Soda Softening - No. 3	884		0.001	0.005
Ion Exchange - Scheme 1	9,100			52.
Phenol Extraction	7,220	35.5		
Ammonia Separation	6,960	60.4		
Biotreatment	3,630	8.2	0.2	1.0
Filter	68			
Acid addition to cooling water	90			
Other chemicals to cooling water	994			
Total	28,900	104		

TABLE A11-4. WATER TREATMENT PLANTS

Process Hygas Site Marengo, Ala. (well water)

Flow Diagram Figure A11-1A

Flow rates by stream number (10^3 lb/hr):

1.	1298	10.	293	21.	431	31.	1	
3.	867	11.	293	22.	0	32.	410	
4.	867	14.	198	24.	0	33.	200	
5.	867	15.	60	25.	431	34.	200	
6.	815	16.	109	26.	0	36.	0	
7.	1015	17.	36	27.	21	37.	1	
8.	296	18.	73	28.	21	39.	61	
9.	296	20.	547	29.	14	40.	1298	RAW WATER

Treatment blocks:

	¢/hr	10^6 Btu/hr	waste (10^3 lb/hr) dry	sludge or solution
Lime-Soda Softening - No. 1		NOT USED		
Lime-Soda Softening - No. 3	884		0.001	0.005
Ion Exchange - Scheme 1	9,100			52
Phenol Extraction	7,220	35.5		
Ammonia Separation	6,960	60.4		
Biotreatment	3,630	8.2	0.2	1.0
Filter	68			
Acid addition to cooling water	774			
Other chemicals to cooling water	994			
Total	29,600	104		

TABLE A11-4. WATER TREATMENT PLANTS

Process Hygas Site Gibson, Ind.

Flow Diagram Figure A11-1A

Flow rates by stream number (10^3 lb/hr):

1.	2048	10.	532	21.	0	31.	64	
3.	2048	11.	532	22.	0	32.	690	
4.	2045	14.	380	24.	711	33.	180	
5.	1334	15.	43	25.	711	34.	180	
6.	1254	16.	176	26.	0	36.	0	
7.	1434	17.	69	27.	21	37.	64	
8.	537	18.	107	28.	21	39.	107	
9.	537	20.	963	29.	14	40.	2048	RAW WATER

Treatment blocks:

	¢/hr	10^6 Btu/hr	waste (10^3 lb/hr) dry	sludge or solution
Lime-Soda Softening - No. 1	1,720		0.73	3.65
Lime-Soda Softening - No. 3	900		0.07	0.36
Ion Exchange - Scheme 2	8,670			80
Phenol Extraction		NOT USED		
Ammonia Separation	7,870	109		
Biotreatment	2,660	4.2	0.1	0.5
Filter	136			
Acid addition to cooling water		NOT USED		
Other chemicals to cooling water	1,530			
Total	23,500	113		

TABLE A11-4. WATER TREATMENT PLANTS

Process Hygas Site Warrwick, Indiana

Flow Diagram Figure A11-1A

Flow rates by stream number (10^3 lb/hr):

1. 2016	10. 532	21. 682	31. 48
3. 1334	11. 532	22. 0	32. 661
4. 1334	14. 409	24. 0	33. 180
5. 1334	15. 59	25. 682	34. 180
6. 1254	16. 132	26. 0	36. 0
7. 1434	17. 90	27. 21	37. 48
8. 537	18. 42	28. 21	39. 107
9. 537	20. 963	29. 14	40. 2016 RAW WATER

Treatment blocks:

	¢/hr	10^6 Btu/hr	waste (10^3 lb/hr) dry	waste (10^3 lb/hr) sludge or solution
Lime-Soda Softening - No. 1		NOT USED		
Lime-Soda Softening - No. 3	1,050		0.05	0.27
Ion Exchange - Scheme 1	14,000			80
Phenol Extraction		NOT USED		
Ammonia Separation	7,870	109		
Biotreatment	2,660	4.2	0.1	0.5
Filter	136			
Acid addition to cooling water	245			
Other chemicals to cooling water	1,740			
Total	27,700	113		

TABLE A11-4. WATER TREATMENT PLANTS

Process Hygas Site Tuscaramas, Ohio (surface water)

Flow Diagram Figure A11-1A

Flow rates by stream number (10^3 lb/hr):

1. 1600	10. 532	21. 0	31. 21
3. 1600	11. 532	22. 0	32. 240
4. 1595	14. 327	24. 261	33. 180
5. 1334	15. 36	25. 261	34. 180
6. 1254	16. 214	26. 0	36. 0
7. 1434	17. 113	27. 21	37. 21
8. 537	18. 101	28. 21	39. 57
9. 537	20. 510	29. 14	40. 1600 RAW WATER

Treatment blocks:

	¢/hr	10^6 Btu/hr	waste (10^3 lb/hr) dry	waste (10^3 lb/hr) sludge or solution
Lime-Soda Softening - No. 1	1,890		0.93	4.7
Lime-Soda Softening - No. 3	900		0.02	0.11
Ion Exchange - Scheme 2	8,670			80
Phenol Extraction		NOT USED		
Ammonia Separation	7,870	109		
Biotreatment	2,660	4.2	0.1	0.5
Filter	112			
Acid addition to cooling water		NOT USED		
Other chemicals to cooling water	1,040			
Total	23,200	113		

TABLE A11-4. WATER TREATMENT PLANTS

Process Hygas Site Tuscarawas, Ohio (ground water)

Flow Diagram Figure A11-1A

Flow rates by stream number (10^3 lb/hr):

1. 1599	10. 532	21. 0	31. 21
3. 1599	11. 532	22. 0	32. 240
4. 1595	14. 327	24. 261	33. 180
5. 1334	15. 36	25. 261	34. 180
6. 1254	16. 214	26. 0	36. 0
7. 1434	17. 113	27. 21	37. 21
8. 537	18. 101	28. 21	39. 57
9. 537	20. 510	29. 14	40. 1599 RAW WATER

Treatment blocks:

	¢/hr	10^6 Btu/hr	waste (10^3 lb/hr) dry	sludge or solution
Lime-Soda Softening - No. 1	1,820		0.84	4.2
Lime-Soda Softening - No. 3	900		0.02	0.11
Ion Exchange - Scheme 2	8,670			80
Phenol Extraction		NOT USED		
Ammonia Separation	7,870	109		
Biotreatment	2,660	4.2	0.1	0.5
Filter	112			
Acid addition to cooling water		NOT USED		
Other chemicals to cooling water	1,040			
Total	23,100	113		

TABLE A11-4. WATER TREATMENT PLANTS

Process Hygas Site Jefferson, Ohio

Flow Diagram Figure A11-1A

Flow rates by stream number (10^3 lb/hr):

1. 2031	10. 532	21. 697	31. 42
3. 1334	11. 532	22. 0	32. 676
4. 1334	14. 372	24. 0	33. 180
5. 1334	15. 63	25. 697	34. 180
6. 1254	16. 169	26. 0	36. 0
7. 1434	17. 132	27. 21	37. 42
8. 537	18. 37	28. 21	39. 105
9. 537	20. 943	29. 14	40. 2031 RAW WATER

Treatment blocks:

	¢/hr	10^6 Btu/hr	waste (10^3 lb/hr) dry	sludge or solution
Lime-Soda Softening - No. 1		NOT USED		
Lime-Soda Softening - No. 3	895		0.06	0.3
Ion Exchange - Scheme 1	14,000			80
Phenol Extraction		NOT USED		
Ammonia Separation	7,870	109		
Biotreatment	2,660	4.2	0.1	0.5
Filter	128			
Acid addition to cooling water	197			
Other chemicals to cooling water	58			
Total	25,800	113		

TABLE A11-4. WATER TREATMENT PLANTS

Process Hygas Site Armstrong, Pa.

Flow Diagram Figure A11-1A

Flow rates by stream number (10^3 lb/hr):

1. 2046	10. 532	21. 712	31. 45
3. 1334	11. 532	22. 0	32. 691
4. 1334	14. 350	24. 0	33. 180
5. 1334	15. 59	25. 712	34. 180
6. 1254	16. 191	26. 0	36. 0
7. 1434	17. 94	27. 21	37. 45
8. 537	18. 97	28. 21	39. 104
9. 537	20. 937	29. 14	40. 2046 RAW WATER

Treatment blocks:

	¢/hr	10^6 Btu/hr	waste (10^3 lb/hr) dry	waste (10^3 lb/hr) sludge or solution
Lime-Soda Softening - No. 1		NOT USED		
Lime-Soda Softening - No. 3	1,020		0.1	0.5
Ion Exchange - Scheme 1	14,000			80
Phenol Extraction		NOT USED		
Ammonia Separation	7,870	109		
Biotreatment	2,660	4.2	0.1	0.5
Filter	120			
Acid addition to cooling water	35			
Other chemicals to cooling water	1,900			
Total	27,700	113		

TABLE A11-4. WATER TREATMENT PLANTS

Process Hygas Site Fayette, W. Va.

Flow Diagram Figure A11-1A

Flow rates by stream number (10^3 lb/hr):

1. 2032	10. 532	21. 698	31. 61
3. 1334	11. 532	22. 0	32. 677
4. 1334	14. 402	24. 0	33. 180
5. 1334	15. 47	25. 698	34. 180
6. 1254	16. 139	26. 0	36. 0
7. 1434	17. 47	27. 21	37. 61
8. 537	18. 92	28. 21	39. 108
9. 537	20. 971	29. 14	40. 2032 RAW WATER

Treatment blocks:

	¢/hr	10^6 Btu/hr	waste (10^3 lb/hr) dry	waste (10^3 lb/hr) sludge or solution
Lime-Soda Softening - No. 1		NOT USED		
Lime-Soda Softening - No. 3	950		0.1	0.3
Ion Exchange - Scheme 1	14,000			80
Phenol Extraction		NOT USED		
Ammonia Separation	7,870	109		
Biotreatment	2,660	4.2	0.1	0.5
Filter	138			
Acid addition to cooling water	177			
Other chemicals to cooling water	1,760			
Total	27,600	113		

TABLE A11-4. WATER TREATMENT PLANTS

Process Hygas

Site Monongalia, W. Va.

Flow Diagram Figure A11-1A

Flow rates by stream number (10^3 lb/hr):

1.	1577	10.	532	21.	243	31.	21	
3.	1334	11.	532	22.	0	32.	222	
4.	1334	14.	356	24.	0	33.	180	
5.	1334	15.	37	25.	243	34.	180	
6.	1254	16.	185	26.	0	36.	0	
7.	1434	17.	91	27.	21	37.	21	
8.	537	18.	94	28.	21	39.	58	
9.	537	20.	520	29.	14	40.	1577	RAW WATER

Treatment blocks:

	¢/hr	10^6 Btu/hr	waste (10^3 lb/hr) dry	sludge or solution
Lime-Soda Softening - No. 1		NOT USED		
Lime-Soda Softening - No. 3	900		0.02	0.11
Ion Exchange - Scheme 1	14,000			80
Phenol Extraction		NOT USED		
Ammonia Separation	7,870	109		
Biotreatment	2,660	4.2	0.1	0.5
Filter	122			
Acid addition to cooling water	11			
Other chemicals to cooling water	950			
Total	26,600	113		

TABLE A11-4. WATER TREATMENT PLANTS

Process Hygas

Site Mingo, W. Va.

Flow Diagram Figure A11-1A

Flow rates by stream number (10^3 lb/hr):

1.	1507	10.	532	21.	173	31.	30	
3.	1334	11.	532	22.	0	32.	152	
4.	1334	14.	433	24.	0	33.	180	
5.	1334	15.	28	25.	173	34.	180	
6.	1254	16.	113	26.	0	36.	0	
7.	1434	17.	79	27.	21	37.	30	
8.	537	18.	34	28.	21	39.	58	
9.	537	20.	527	29.	14	40.	1507	RAW WATER

Treatment blocks:

	¢/hr	10^6 Btu/hr	waste (10^3 lb/hr) dry	sludge or solution
Lime-Soda Softening - No. 1		NOT USED		
Lime-Soda Softening - No. 3	900		0.03	0.17
Ion Exchange - Scheme 1	14,000			80
Phenol Extraction		NOT USED		
Ammonia Separation	7,870	109		
Biotreatment	2,660	4.2	0.1	0.5
Filter	148			
Acid addition to cooling water	28			
Other chemicals to cooling water	1,060			
Total	26,700	113		

TABLE A11-4. WATER TREATMENT PLANTS

Process Hygas Site Gillette, Wyo.

Flow Diagram Figure A11-1A

Flow rates by stream number (10^3 lb/hr):

1.	1261	10.	293	21.	0	31.	0
3.	1261	11.	293	22.	6	32.	367
4.	1255	14.	154	24.	388	33.	200
5.	867	15.	69	25.	388	34.	200
6.	815	16.	153	26.	0	36.	0
7.	1015	17.	85	27.	21	37.	0
8.	296	18.	68	28.	21	39.	69
9.	296	20.	452	29.	14	40.	1267 RAW WATER

Treatment blocks:

			waste (10^3 lb/hr)	
	¢/hr	10^6 Btu/hr	dry	sludge or solution
Lime-Soda Softening - No. 1	2,060		1.2	6.0
Lime-Soda Softening - No. 3		NOT USED		
Ion Exchange - Scheme 2	5,640			52
Phenol Extraction	7,220	35.5		
Ammonia Separation	6,960	60.4		
Biotreatment	3,630	5.8	0.2	1.0
Filter	53			
Acid addition to cooling water		NOT USED		
Other chemicals to cooling water	1,130			
Total	26,700	102		

TABLE A11-4. WATER TREATMENT PLANTS

Process Hygas Site Antelope Creek, Wyo.

Flow Diagram Figure A11-1A

Flow rates by stream number (10^3 lb/hr):

1.	1353	10.	293	21.	0	31.	15
3.	1353	11.	293	22.	6	32.	330
4.	1218	14.	172	24.	351	33.	200
5.	867	15.	35	25.	351	34.	200
6.	815	16.	135	26.	0	36.	0
7.	1015	17.	76	27.	21	37.	15
8.	296	18.	59	28.	21	39.	50
9.	296	20.	452	29.	14	40.	1359 RAW WATER

Treatment blocks:

			waste (10^3 lb/hr)	
	¢/hr	10^6 Btu/hr	dry	sludge or solution
Lime-Soda Softening - No. 1		NOT USED		
Lime-Soda Softening - No. 3	887		0.02	0.08
Electrodialysis *	11,300	292		135
Ion Exchange - Scheme 3	9,970			52
Phenol Extraction	7,220	35.5		
Ammonia Separation	6,960	60.4		
Biotreatment	3,630	5.8	0.2	1.0
Filter	58			
Acid addition to cooling water	156			
Other chemicals to cooling water	815			
Total	41,000	394		

* Situated roughly in place of softener No. 1.

TABLE A11-4. WATER TREATMENT PLANTS

Process Hygas   Site Belle Ayr, Wyo.

Flow Diagram Figure A11-1A

Flow rates by stream number (10^3 lb/hr):

1. 1374	10. 293	21. 0	31. 0
3. 1374	11. 293	22. 6	32. 479
4. 1367	14. 44	24. 500	33. 200
5. 867	15. 71	25. 500	34. 200
6. 815	16. 263	26. 0	36. 0
7. 1015	17. 206	27. 21	37. 0
8. 296	18. 57	28. 21	39. 71
9. 296	20. 452	29. 14	40. 1380 RAW WATER

Treatment blocks:

	¢/hr	10^6 Btu/hr	waste (10^3 lb/hr) dry	sludge or solution
Lime-Soda Softening - No. 1	2,170		1.3	6.5
Lime-Soda Softening - No. 3	NOT USED			
Ion Exchange - Scheme 2	5,640			52
Phenol Extraction	7,220	35.5		
Ammonia Separation	6,960	60.4		
Biotreatment	3,630	5.8	0.2	1.0
Filter	15			
Acid addition to cooling water	NOT USED			
Other chemicals to cooling water	873			
Total	26,500	102		

TABLE A11-4. WATER TREATMENT PLANTS

Process Hygas   Site Hanna Coal Fld., Wyo.

Flow Diagram Figure A11-1A

Flow rates by stream number (10^3 lb/hr):

1. 1742	10. 293	21. 0	31. 53
3. 1742	11. 293	22. 8	32. 847
4. 1735	14. 203	24. 868	33. 200
5. 867	15. 52	25. 868	34. 200
6. 815	16. 104	26. 0	36. 0
7. 1015	17. 55	27. 21	37. 53
8. 296	18. 49	28. 21	39. 105
9. 296	20. 945	29. 14	40. 1750 RAW WATER

Treatment blocks:

	¢/hr	10^6 Btu/hr	waste (10^3 lb/hr) dry	sludge or solution
Lime-Soda Softening - No. 1	2,220		1.3	6.5
Lime-Soda Softening - No. 3	892		0.3	0.15
Ion Exchange - Scheme 2	5,640			52
Phenol Extraction	7,220	35.5		
Ammonia Separation	6,960	60.4		
Biotreatment	3,630	5.8	0.2	1.0
Filter	70			
Acid addition to cooling water	NOT USED			
Other chemicals to cooling water	1,500			
Total	28,100	102		

TABLE A11-4. WATER TREATMENT PLANTS

Process Hygas Site Decker, Mont.

Flow Diagram Figure A11-1A

Flow rates by stream number (10^3 lb/hr):

1.	1893	10.	293	21.	0	31.	77
3.	1893	11.	293	22.	7	32.	816
4.	1704	14.	226	24.	837	33.	200
5.	867	15.	27	25.	837	34.	200
6.	815	16.	81	26.	0	36.	0
7.	1015	17.	14	27.	21	37.	77
8.	296	18.	67	28.	21	39.	104
9.	296	20.	938	29.	14	40.	1900 RAW WATER

Treatment blocks:

	¢/hr	10^6 Btu/hr	waste (10^3 lb/hr) dry	waste (10^3 lb/hr) sludge or solution
Lime-Soda Softening - No. 1	NOT USED			
Lime-Soda Softening - No. 3	896		0.05	0.25
Electrodialysis*	9,720	25.5		189
Ion Exchange - Scheme 3	9,970			52
Phenol Extraction	7,220	35.5		
Ammonia Separation	6,960	60.4		
Biotreatment	3,630	5.8	0.2	1.0
Filter	77			
Acid addition to cooling water	1,200			
Other chemicals to cooling water	1,660			
Total	41,300	127		

* Located roughly in place of lime-soda softening No. 1.

TABLE A11-4. WATER TREATMENT PLANTS

Process Hygas Site East Moorehead, Mont.

Flow Diagram Figure A11-1A

Flow rates by stream number (10^3 lb/hr):

1.	1258	10.	293	21.	0	31.	0
3.	1258	11.	293	22.	5	32.	364
4.	1252	14.	147	24.	385	33.	200
5.	867	15.	62	25.	385	34.	200
6.	815	16.	160	26.	0	36.	0
7.	1015	17.	65	27.	21	37.	0
8.	296	18.	95	28.	21	39.	62
9.	296	20.	449	29.	14	40.	1263 RAW WATER

Treatment blocks:

	¢/hr	10^6 Btu/hr	waste (10^3 lb/hr) dry	waste (10^3 lb/hr) sludge or solution
Lime-Soda Softening - No. 1	2,100		1.2	6.0
Lime-Soda Softening - No. 3	NOT USED			
Ion Exchange - Scheme 2	5,640			52
Phenol Extraction	7,220	35.5		
Ammonia Separation	6,960	60.4		
Biotreatment	3,630	5.8	0.2	1.0
Filter	50			
Acid addition to cooling water	NOT USED			
Other chemicals to cooling water	1,020			
Total	26,600	102		

TABLE A11-4. WATER TREATMENT PLANTS

Process Hygas Site Colstrip, Mont.

Flow Diagram Figure A11-1A

Flow rates by stream number (10^3 lb/hr):

1. 1301	10. 293	21. 434	31. 3
3. 867	11. 293	22. 5	32. 413
4. 867	14. 150	24. 0	33. 200
5. 867	15. 53	25. 434	34. 200
6. 815	16. 157	26. 0	36. 0
7. 1015	17. 84	27. 21	37. 3
8. 296	18. 73	28. 21	39. 56
9. 296	20. 507	29. 14	40. 1306 RAW WATER

Treatment blocks:

	¢/hr	10^6 Btu/hr	waste (10^3 lb/hr) dry	sludge or solution
Lime-Soda Softening - No. 1	NOT USED			
Lime-Soda Softening - No. 3	885		0.003	0.02
Ion Exchange - Scheme 1	9,100			52
Phenol Extraction	7,220	35.5		
Ammonia Separation	6,960	60.4		
Biotreatment	3,630	5.8	0.2	1.0
Filter	51			
Acid addition to cooling water	192			
Other chemicals to cooling water	913			
Total	29,000	102		

TABLE A11-4. WATER TREATMENT PLANTS

Process Hygas Site El Paso, N.M.

Flow Diagram Figure A11-1A

Flow rates by stream number (10^3 lb/hr):

1. 1428	10. 293	21. 561	31. 0
3. 867	11. 293	22. 8	32. 491
4. 867	14. 122	24. 0	33. 200
5. 867	15. 153	25. 561	34. 200
6. 815	16. 184	26. 49	36. 0
7. 1015	17. 100	27. 21	37. 0
8. 296	18. 84	28. 21	39. 153
9. 296	20. 460	29. 14	40. 1436 RAW WATER

Treatment blocks:

	¢/hr	10^6 Btu/hr	waste (10^3 lb/hr) dry	sludge or solution
Lime-Soda Softening - No. 1	NOT USED			
Lime-Soda Softening - No. 3	NOT USED			
Ion Exchange - Scheme 1	9,100			52
Phenol Extraction	7,220	35.5		
Ammonia Separation	6,960	60.4		
Biotreatment	3,630	5.8	0.2	1.0
Filter	58			
Acid addition to cooling water	229			
Other chemicals to cooling water	2,190			
Total	29,400	102		

TABLE A11-4. WATER TREATMENT PLANTS

Process Hygas Site Gallup, N.M. (ground water)

Flow Diagram Figure A11-1A

Flow rates by stream number (10^3 lb/hr):

1.	1404	10.	293	21.	400	31.	20	
3.	1004	11.	293	22.	8	32.	342	
4.	867	14.	168	24.	0	33.	200	
5.	867	15.	31	25.	400	34.	200	
6.	815	16.	138	26.	37	36.	0	
7.	1015	17.	74	27.	21	37.	20	
8.	296	18.	64	28.	21	39.	51	
9.	296	20.	460	29.	14	40.	1412	RAW WATER

Treatment blocks:

	¢/hr	10^6 Btu/hr	waste (10^3 lb/hr) dry	sludge or solution
Lime-Soda Softening - No. 1	NOT USED			
Lime-Soda Softening - No. 3	900		0.02	0.11
Electrodialysis*	6,530	15.4		137
Ion Exchange - Scheme 3	9,970			52
Phenol Extraction	7,220	35.5		
Ammonia Separation	6,960	60.4		
Biotreatment	3,630	5.8	0.2	1.0
Filter	58			
Acid addition to cooling water	410			
Other chemicals to cooling water	730			
Total	36,400	117		

* Located roughly in place of softening No. 1.

BIGAS

TABLE A11-4. WATER TREATMENT PLANTS

Process Bigas Site Bureau, Ill. (Illinois River water)

Flow Diagram Figure A11-1C

Flow rates by stream number (10^3 lb/hr):

1. 2151	12. 14	24. 0	34. 234
3. 187	14. 0	25. 1646	35. 138
4. 187	15. 49	27. 21	36. 1198
5. 187	16. 14	28. 21	37. 238
6. 176	17. 146	29. 14	38. 100
7. 410	18. 106	30. 1625	39. 149
8. 890	20. 1338	31. 100	40. 2151 RAW WATER
10. 880	21. 1646	32. 1487	
11. 0	22. 0	33. 318	

Treatment blocks:

	¢/hr	10^6 Btu/hr	waste (10^3 lb/hr) dry	waste (10^3 lb/hr) sludge or solution
Lime-Soda Softening - No. 1	NOT USED			
Lime-Soda Softening - No. 3	899		0.06	0.3
Ion Exchange - Scheme 2	1,220			11
Ammonia Separation	13,040	181		
Acid addition to cooling water	1,830			
Other chemicals to cooling water	939	—		
Total	17,900	181		

TABLE A11-4. WATER TREATMENT PLANTS

Process Bigas Site Bureau, Ill. (well water)

Flow Diagram Figure A11-1C

Flow rates by stream number (10^3 lb/hr):

1. 2152	12. 14	24. 1646	34. 234
3. 1834	14. 0	25. 1646	35. 138
4. 1833	15. 49	27. 21	36. 1198
5. 187	16. 14	28. 21	37. 238
6. 176	17. 146	29. 14	38. 100
7. 410	18. 106	30. 1625	39. 149
8. 890	20. 1338	31. 100	40. 2152 RAW WATER
10. 880	21. 0	32. 1487	
11. 0	22. 0	33. 318	

Treatment blocks:

	¢/hr	10^6 Btu/hr	waste (10^3 lb/hr) dry	waste (10^3 lb/hr) sludge or solution
Lime-Soda Softening - No. 1	1,930		0.9	4.5
Lime-Soda Softening - No. 3	900		0.06	0.3
Ion Exchange - Scheme 2	1,220			11
Ammonia Separation	13,040	181		
Acid addition to cooling water	NOT USED			
Other chemicals to cooling water	1,830	—		
Total	18,900	181		

TABLE A11-4. WATER TREATMENT PLANTS

Process Bigas Site Shelby, Ill.

Flow Diagram Figure A11-1C

Flow rates by stream number (10^3 lb/hr):

1. 1355	12. 14	24. 0	34. 234
3. 187	14. 0	25. 866	35. 242
4. 187	15. 100	27. 21	36. 1273
5. 187	16. 14	28. 21	37. 242
6. 176	17. 155	29. 14	38. 0
7. 410	18. 111	30. 845	39. 100
8. 980	20. 503	31. 0	40. 1355 RAW WATER
10. 971	21. 866	32. 603	
11. 0	22. 0	33. 302	

Treatment blocks:

	¢/hr	10^6 Btu/hr	waste (10^3 lb/hr) dry	sludge or solution
Lime-Soda Softening - No. 1	NOT USED			
Lime-Soda Softening - No. 3	NOT USED			
Ion Exchange - Scheme 1	1,960			11
Ammonia Separation	14,400	200		
Acid addition to cooling water	163			
Other chemicals to cooling water	1,230	—		
Total	17,800	200		

TABLE A11-4. WATER TREATMENT PLANTS

Process Bigas Site Vigo, Ind.

Flow Diagram Figure A11-1C

Flow rates by stream number (10^3 lb/hr):

1. 2092	12. 14	24. 1590	34. 234
3. 1778	14. 0	25. 1590	35. 82
4. 1777	15. 48	27. 21	36. 1147
5. 187	16. 14	28. 21	37. 183
6. 176	17. 97	29. 14	38. 101
7. 410	18. 100	30. 1569	39. 149
8. 841	20. 1338	31. 101	40. 2092 RAW WATER
10. 833	21. 0	32. 1487	
11. 0	22. 0	33. 314	

Treatment blocks:

	¢/hr	10^6 Btu/hr	waste (10^3 lb/hr) dry	sludge or solution
Lime-Soda Softening - No. 1	1,790		0.7	3.7
Lime-Soda Softening - No. 3	980		0.06	0.3
Ion Exchange - Scheme 2	1,220			11
Ammonia Separation	12,300	172		
Acid addition to cooling water	NOT USED			
Other chemicals to cooling water	1,830	—		
Total	18,100	172		

TABLE A11-4. WATER TREATMENT PLANTS

Process Bigas Site Kemmerer, Wyo.

Flow Diagram Figure A11-1C

Flow rates by stream number (10^3 lb/hr):

1.	1308	12.	14	24.	0	34.	234
3.	187	14.	0	25.	808	35.	139
4.	187	15.	51	27.	21	36.	1168
5.	187	16.	14	28.	21	37.	139
6.	176	17.	111	29.	14	38.	0
7.	410	18.	42	30.	787	39.	51
8.	863	20.	597	31.	0	40.	1308 RAW WATER
10.	855	21.	808	32.	648		
11.	0	22.	4	33.	313		

Treatment blocks:

	¢/hr	10^6 Btu/hr	waste (10^3 lb/hr) dry	waste (10^3 lb/hr) sludge or solution
Lime-Soda Softening - No. 1	NOT USED			
Lime-Soda Softening - No. 3	NOT USED			
Ion Exchange - Scheme 1	1,960			11
Ammonia Separation	12,600	176		
Acid addition to cooling water	450			
Other chemicals to cooling water	630	—		
Total	15,600	176		

TABLE A11-4. WATER TREATMENT PLANTS

Process Bigas Site Slope, N.D.

Flow Diagram Figure A11-1C

Flow rates by stream number (10^3 lb/hr):

1.	1405	12.	54	24.	0	34.	234
3.	486	14.	0	25.	919	35.	221
4.	486	15.	85	27.	21	36.	1424
5.	486	16.	54	28.	21	37.	221
6.	457	17.	129	29.	14	38.	0
7.	691	18.	146	30.	898	39.	85
8.	1478	20.	592	31.	0	40.	1410 RAW WATER
10.	1464	21.	919	32.	677		
11.	40	22.	5	33.	0		

Treatment blocks:

	¢/hr	10^6 Btu/hr	waste (10^3 lb/hr) dry	waste (10^3 lb/hr) sludge or solution
Lime-Soda Softening - No. 1	NOT USED			
Lime-Soda Softening - No. 3	NOT USED			
Ion Exchange - Scheme 1	5,100			29
Ammonia Separation	21,650	302		
Acid addition to cooling water	241			
Other chemicals to cooling water	1,050	—		
Total	28,000	302		

TABLE A11-4. WATER TREATMENT PLANTS

Process Bigas Site Center, N.D.

Flow Diagram Figure A11-1C

Flow rates by stream number (10^3 lb/hr):

1. 1397	12. 14	24. 0	34. 234
3. 486	14. 0	25. 889	35. 188
4. 486	15. 90	27. 21	36. 1377
5. 486	16. 14	28. 21	37. 186
6. 457	17. 83	29. 14	38. 0
7. 691	18. 119	30. 868	39. 90
8. 1368	20. 590	31. 0	40. 1401 RAW WATER
10. 1355	21. 889	32. 680	
11. 0	22. 4	33. 22	

Treatment blocks:

	¢/hr	10^6 Btu/hr	waste (10^3 lb/hr) dry	sludge or solution
Lime-Soda Softening - No. 1		NOT USED		
Lime-Soda Softening - No. 3		NOT USED		
Ion Exchange - Scheme 1	5,100			29
Ammonia Separation	20,040	279		
Acid addition to cooling water	1,200			
Other chemicals to cooling water	1,110	___		
Total	27,500	279		

TABLE A11-4. WATER TREATMENT PLANTS

Process Bigas Site Scranton, N.D.

Flow Diagram Figure A11-1C

Flow rates by stream number (10^3 lb/hr):

1. 1415	12. 14	24. 899	34. 234
3. 1386	14. 0	25. 899	35. 203
4. 1385	15. 83	27. 21	36. 1355
5. 486	16. 14	28. 21	37. 203
6. 457	17. 91	29. 14	38. 0
7. 691	18. 126	30. 878	39. 83
8. 1338	20. 592	31. 0	40. 1419 RAW WATER
10. 1326	21. 0	32. 675	
11. 0	22. 4	33. 29	

Treatment blocks:

	¢/hr	10^6 Btu/hr	waste (10^3 lb/hr) dry	sludge or solution
Lime-Soda Softening - No. 1	1,420		0.3	1.4
Lime-Soda Softening - No. 3		NOT USED		
Ion Exchange - Scheme 2	3,160			29
Ammonia Separation	19,600	273		
Acid addition to cooling water		NOT USED		
Other chemicals to cooling water	1,020	___		
Total	25,200	273		

TABLE A11-4. WATER TREATMENT PLANTS

Process Bigas Site Chupp Mine, Mont.

Flow Diagram Figure A11-1C

Flow rates by stream number (10^3 lb/hr):

1. 2215	12. 14	24. 0	34. 234
3. 486	14. 0	25. 1669	35. 137
4. 486	15. 78	27. 21	36. 1355
5. 486	16. 14	28. 21	37. 137
6. 457	17. 47	29. 14	38. 0
7. 691	18. 104	30. 1648	39. 78
8. 1307	20. 1433	31. 0	40. 2224 RAW WATER
10. 1295	21. 1669	32. 1511	
11. 0	22. 9	33. 60	

Treatment blocks:

	¢/hr	10^6 Btu/hr	waste (10^3 lb/hr) dry	waste (10^3 lb/hr) sludge or solution
Lime-Soda Softening - No. 1	NOT USED			
Lime-Soda Softening - No. 3	NOT USED			
Ion Exchange - Scheme 1	5,100			29
Ammonia Separation	19,200	267		
Acid addition to cooling water	725			
Other chemicals to cooling water	960			
Total	26,000	267		

SYNTHOIL

TABLE A11-4. WATER TREATMENT PLANTS

Process Synthoil Site Jefferson, Ala.

Flow Diagram Figure A11-1D

Flow rates by stream number (10^3 lb/hr):

1. 2237	14. 0	23. 0	31. 60
3. 247	15. 121	24. 0	32. 1814
4. 247	16. 111	25. 1990	33. 140
5. 247	18. 111	26. 0	35. 15
7. 232	19. 75	27. 21	39. 181
8. 23	20. 1633	28. 21	40. 2237 RAW WATER
9. 23	21. 1990	29. 14	
10. 22	22. 0	30. 1829	

Treatment blocks:

	¢/hr	10^6 Btu/hr	waste (10^3 lb/hr) dry	sludge or solution
Lime-Soda Softening - No. 1	NOT USED			
Ion Exchange - Scheme 1	2,350			15
Phenol Extraction	526	2.7		
Ammonia Separation	(-581)	4.7		
Biotreatment	760	1.4	0.04	0.18
Filter	NOT USED			
Acid addition to cooling water	289			
Other chemicals to cooling water	2,230	___		
Total	5,570	8.8		

TABLE A11-4. WATER TREATMENT PLANTS

Process Synthoil Site Gibson, Ind.

Flow Diagram Figure A11-1D

Flow rates by stream number (10^3 lb/hr):

1. 2028	14. 0	23. 91	31. 124
3. 2028	15. 50	24. 1797	32. 1735
4. 2025	16. 116	25. 1797	33. 132
5. 229	18. 116	26. 0	35. 0
7. 215	19. 33	27. 21	39. 174
8. 71	20. 1562	28. 21	40. 2028 RAW WATER
9. 71	21. 0	29. 14	
10. 69	22. 0	30. 1735	

Treatment blocks:

	¢/hr	10^6 Btu/hr	waste (10^3 lb/hr) dry	sludge or solution
Lime-Soda Softening - No. 1	1,700		0.6	3
Ion Exchange - Scheme 2	1,490			14
Phenol Extraction	1,620	8.5		
Ammonia Separation	(-1,850)	14.5		
Biotreatment	2,380	4.5	0.11	0.57
Filter	NOT USED			
Acid addition to cooling water	NOT USED			
Other chemicals to cooling water	2,140	___		
Total	7,470	27.5		

TABLE A11-4. WATER TREATMENT PLANTS

Process Synthoil Site Warrick, Ind.

Plow Diagram Figure A11-1D

Flow rates by stream number (10^3 lb/hr):

1. 2126	14. 0	23. 48	31. 112
3. 224	15. 68	24. 0	32. 1800
4. 224	16. 46	25. 1902	33. 129
5. 224	18. 46	26. 0	35. 0
7. 211	19. 64	27. 21	39. 180
8. 99	20. 1620	28. 21	40. 2126 RAW WATER
9. 99	21. 1902	29. 14	
10. 96	22. 0	30. 1800	

Treatment blocks:

	¢/hr	10^6 Btu/hr	waste (10^3 lb/hr) dry	sludge or solution
Lime-Soda Softening - No. 1	NOT USED			
Ion Exchange - Scheme 1	2,130			13
Phenol Extraction	2,260	11.9		
Ammonia Separation	(-2,630)	20.2		
Biotreatment	3,310	6.3	0.02	0.08
Filter	NOT USED			
Acid addition to cooling water	489			
Other chemicals to cooling water	2,210	___		
Total	7,770	38.4		

TABLE A11-4. WATER TREATMENT PLANTS

Process Synthoil Site Harlan, Ky.

Plow Diagram Figure A11-1D

Flow rates by stream number (10^3 lb/hr):

1. 1406	14. 0	23. 38	31. 69
3. 243	15. 26	24. 0	32. 948
4. 243	16. 102	25. 1163	33. 137
5. 243	18. 102	26. 0	35. 0
7. 228	19. 31	27. 21	39. 95
8. 59	20. 853	28. 21	40. 1406 RAW WATER
9. 59	21. 1163	29. 14	
10. 57	22. 0	30. 1043	

Treatment blocks:

	¢/hr	10^6 Btu/hr	waste (10^3 lb/hr) dry	sludge or solution
Lime-Soda Softening - No. 1	NOT USED			
Ion Exchange - Scheme 1	2,310			15
Phenol Extraction	1,350	7.1		
Ammonia Separation	(-1,530)	12.0		
Biotreatment	2,040	3.9	0.01	0.05
Filter	NOT USED			
Acid addition to cooling water	250			
Other chemicals to cooling water	1,170	___		
Total	5,590	23.0		

TABLE A11-4. WATER TREATMENT PLANTS

Process Synthoil Site Pike, Ky.

Flow Diagram Figure A11-1D

Flow rates by stream number (10^3 lb/hr):

1. 1359	14. 41	23. 71	31. 71
3. 244	15. 32	24. 0	32. 993
4. 244	16. 37	25. 1115	33. 172
5. 244	18. 37	26. 0	35. 0
7. 229	19. 0	27. 21	39. 103
8. 66	20. 931	28. 21	40. 1359 RAW WATER
9. 66	21. 1115	29. 14	
10. 64	22. 0	30. 993	

Treatment blocks:

	¢/hr	10^6 Btu/hr	waste (10^3 lb/hr) dry	sludge or solution
Lime-Soda Softening - No. 1	NOT USED			
Ion Exchange - Scheme 1	2,320			15
Phenol Extraction	1,510	7.9		
Ammonia Separation	(-1,720)	13.5		
Biotreatment	2,210	4.2	0.01	0.05
Filter	14			
Acid addition to cooling water	265			
Other chemicals to cooling water	1,270	___		
Total	5,870	25.6		

TABLE A11-4. WATER TREATMENT PLANTS

Process Synthoil Site Tuscarawas, Ohio (surface water)

Flow Diagram Figure A11-1D

Flow rates by stream number (10^3 lb/hr):

1. 1493	14. 0	23. 47	31. 73
3. 1493	15. 42	24. 1256	32. 1148
4. 1489	16. 111	25. 1256	33. 134
5. 233	18. 111	26. 0	35. 0
7. 219	19. 26	27. 21	39. 115
8. 73	20. 1033	28. 21	40. 1493 RAW WATER
9. 73	21. 0	29. 14	
10. 71	22. 0	30. 1148	

Treatment blocks:

	¢/hr	10^6 Btu/hr	waste (10^3 lb/hr) dry	sludge or solution
Lime-Soda Softening - No. 1	1,800		0.8	4.3
Ion Exchange - Scheme 1	2,210			14
Phenol Extraction	1,670	8.8		
Ammonia Separation	(-1,920)	14.9		
Biotreatment	2,450	4.7	0.01	0.06
Filter		NOT USED		
Acid addition to cooling water		NOT USED		
Other chemicals to cooling water	1,420	___		
Total	7,630	28.4		

TABLE A11-4. WATER TREATMENT PLANTS

Process Synthoil   Site Tuscarawas, Ohio (ground water)

Flow'Diagram Figure A11-1D

Flow rates by stream number (10^3 lb/hr):

1. 1493	14. 0	23. 47	31. 73
3. 1493	15. 42	24. 1256	32. 1148
4. 1489	16. 111	25. 1256	33. 134
5. 233	18. 111	26. 0	35. 0
7. 219	19. 26	27. 21	39. 115
8. 73	20. 1033	28. 21	40. 1493 RAW WATER
9. 73	21. 0	29. 14	
10. 71	22. 0	30. 1148	

Treatment blocks:

	¢/hr	10^6 Btu/hr	waste (10^3 lb/hr) dry	sludge or solution
Lime-Soda Softening - No. 1	1,750		0.7	3.5
Ion Exchange - Scheme 2	1,520			14
Phenol Extraction	1,670	8.8		
Ammonia Separation	(-1,910)	14.9		
Biotreatment	2,450	4.7	0.01	0.06
Filter	NOT USED			
Acid addition to cooling water	NOT USED			
Other chemicals to cooling water	1,420	___		
Total	6,900	28.4		

TABLE A11-4. WATER TREATMENT PLANTS

Process Synthoil   Site Jefferson, Ohio

Flow'Diagram Figure A11-1D

Flow rates by stream number (10^3 lb/hr):

1. 2064	14. 11	23. 103	31. 103
3. 239	15. 75	24. 0	32. 1767
4. 239	16. 42	25. 1825	33. 140
5. 239	18. 42	26. 0	35. 0
7. 225	19. 0	27. 21	39. 178
8. 40	20. 1600	28. 21	40. 2064 RAW WATER
9. 40	21. 1825	29. 14	
10. 39	22. 0	30. 1767	

Treatment blocks:

	¢/hr	10^6 Btu/hr	waste (10^3 lb/hr) dry	sludge or solution
Lime-Soda Softening - No. 1	NOT USED			
Ion Exchange - Scheme 1	2,270			14
Phenol Extraction	914	4.8		
Ammonia Separation	(-1,020)	8.2		
Biotreatment	1,350	2.6	0.01	0.03
Filter	4			
Acid addition to cooling water	486			
Other chemicals to cooling water	2,190	___		
Total	6,190	15.6		

TABLE A11-4. WATER TREATMENT PLANTS

Process Synthoil Site Mingo, W. Va.

Flow Diagram Figure A11-1D

Flow rates by stream number (10^3 lb/hr):

1. 1352	14. 15	23. 70	31. 70
3. 243	15. 33	24. 0	32. 1019
4. 243	16. 37	25. 1109	33. 139
5. 243	18. 37	26. 0	35. 0
7. 228	19. 0	27. 21	39. 103
8. 40	20. 931	28. 21	40. 1352 RAW WATER
9. 40	21. 1109	29. 14	
10. 38	22. 0	30. 1019	

Treatment blocks:

	¢/hr	10^6 Btu/hr	waste (10^3 lb/hr) dry	waste (10^3 lb/hr) sludge or solution
Lime-Soda Softening - No. 1	NOT USED			
Ion Exchange - Scheme 1	2,310			15
Phenol Extraction	914	4.8		
Ammonia Separation	(-1,020)	8.2		
Biotreatment	1,310	2.5	0.01	0.03
Filter	5			
Acid addition to cooling water	180			
Other chemicals to cooling water	1,270	___		
Total	4,970	15.5		

TABLE A11-4. WATER TREATMENT PLANTS

Process Synthoil Site Somerset, Pa.

Flow Diagram Figure A11-1D

Flow rates by stream number (10^3 lb/hr):

1. 1581	14. 0	23. 0	31. 11
3. 261	15. 98	24. 0	32. 1091
4. 261	16. 107	25. 1320	33. 139
5. 261	18. 107	26. 0	35. 69
7. 245	19. 80	27. 21	39. 109
8. 13	20. 982	28. 21	40. 1581 RAW WATER
9. 13	21. 1320	29. 14	
10. 13	22. 0	30. 1160	

Treatment blocks:

	¢/hr	10^6 Btu/hr	waste (10^3 lb/hr) dry	waste (10^3 lb/hr) sludge or solution
Lime-Soda Softening - No. 1	NOT USED			
Ion Exchange - Scheme 1	2,480			16
Phenol Extraction	297	1.6		
Ammonia Separation	(-326)	2.7		
Biotreatment	449	0.9	0.002	0.01
Filter	NOT USED			
Acid addition to cooling water	68			
Other chemicals to cooling water	1,340	___		
Total	4,310	5.2		

TABLE A11-4. WATER TREATMENT PLANTS

Process Synthoil Site Lake de Smet, Wyo.

Flow Diagram Figure A11-1D

Flow rates by stream number (10^3 lb/hr):

1. 1797	14. 130	23. 57	31. 57
3. 210	15. 112	24. 0	32. 1559
4. 210	16. 82	25. 1587	33. 64
5. 210	18. 82	26. 0	35. 0
7. 197	19. 0	27. 21	39. 169
8. 206	20. 1520	28. 21	40. 1805 RAW WATER
9. 206	21. 1587	29. 14	
10. 200	22. 8	30. 1559	

Treatment blocks:

	¢/hr	10^6 Btu/hr	waste (10^3 lb/hr) dry	waste (10^3 lb/hr) sludge or solution
Lime-Soda Softening - No. 1	NOT USED			
Ion Exchange - Scheme 1	2,000			13
Phenol Extraction	4,710	24.7		
Ammonia Separation	(-7,090)	42.0		
Biotreatment	6,910	13.2	0.33	1.7
Filter	40			
Acid addition to cooling water	1,180			
Other chemicals to cooling water	1,330	___		
Total	9,080	79.9		

TABLE A11-4. WATER TREATMENT PLANTS

Process Synthoil Site Jim Bridger, Wyo.

Flow Diagram Figure A11-1D

Flow rates by stream number (10^3 lb/hr):

1. 1200	14. 129	23. 11	31. 11
3. 227	15. 91	24. 0	32. 889
4. 227	16. 78	25. 973	33. 74
5. 227	18. 78	26. 0	35. 0
7. 213	19. 0	27. 21	39. 102
8. 201	20. 916	28. 21	40. 1205 RAW WATER
9. 201	21. 973	29. 14	
10. 195	22. 5	30. 889	

Treatment blocks:

	¢/hr	10^6 Btu/hr	waste (10^3 lb/hr) dry	waste (10^3 lb/hr) sludge or solution
Lime-Soda Softening - No. 1	NOT USED			
Ion Exchange - Scheme 1	2,160			14
Phenol Extraction	4,590	24.1		
Ammonia Separation	(-6,900)	41.0		
Biotreatment	6,730	12.8	0.32	1.6
Filter	40			
Acid addition to cooling water	489			
Other chemicals to cooling water	1,250	___		
Total	8,360	77.9		

TABLE A11-4. WATER TREATMENT PLANTS

Process Synthoil Site Gallup, N.M.

Flow Diagram Figure A11-1D

Flow rates by stream number (10^3 lb/hr):

1.	1305	14.	42	23.	53	31.	53	
3.	1305	15.	43	24.	965	32.	878	
4.	1175	16.	83	25.	965	33.	119	
5.	210	18.	83	26.	48	35.	0	
7.	197	19.	0	27.	21	39.	96	
8.	115	20.	863	28.	21	40.	1313	RAW WATER
9.	115	21.	0	29.	14			
10.	112	22.	8	30.	878			

Treatment blocks:

	¢/hr	10^6 Btu/hr	waste (10^3 lb/hr) dry	sludge or solution
Lime-Soda Softening - No. 1	NOT USED			
Electrodialysis*	6,230	14.7		130
Ion Exchange - Scheme 3	2,420			13
Phenol Extraction	2,630	13.8		
Ammonia Separation	(-3,780)	23.5		
Biotreatment	3,870	7.4	0.19	0.95
Filter	10			
Acid addition to cooling water	1,050			
Other chemicals to cooling water	1,180			
Total	13,600	59.4		

* Located roughly in place of Softening No. 1

APPENDIX 12

CALCULATIONS ON OIL SHALE

Oil shale conversion plant designs are required at Parachute Creek, Colorado for both directly and indirectly heated retorts. The Paraho Direct and Indirect processes and the TOSCO II process illustrate the basic types of surface retorting procedures. They were selected based not only on the commercial potential of the process, but also on the availability of published information. The Paraho designs for an integrated oil shale plant are given in Ref. 1 while the TOSCO II design is given in Refs. 2 and 3. These designs have been summarized in Ref. 4. The calculations presented in this section are for an integrated plant designed to produce 50,000 barrels/day of synthetic crude plus any by-products not utilized as plant fuel. The total heating value of the synthetic crude is 2.9×10^{11} Btu/day. If the by-products are taken together with the synthetic crude, the output is directly comparable to the output of 3.1×10^{11} Btu/day for the standard size coal liquefaction plants examined in Appendix 2. Table 12A-1 gives the net input and output quantities for a 50,000 barrels/day plant based on the designs given in Refs. 1 and 3. The properties of the raw shale and the products are given in Table 12A-2[1,2]. Part of the difference in the mining rates between the Paraho and TOSCO II processes is a consequence of the difference in the grade of shale assumed to be mined. The Paraho designs use 30 gal/ton shale while the TOSCO II design uses 35 gal/ton shale. In addition, since the Paraho retort cannot accept fines, about 5 percent more shale must be mined than can be used[1].

A flow diagram for the surface processing of oil shale is shown in Figure 12A-1. All surface processing operations involve mining, crushing and then retorting to produce the shale oil. The product of the retorting is generally too viscous to be piped and is put through an upgrading process to remove nitrogen and sulfur. The spent shale from the retorting must be disposed. Figures 12A-2, 12A-3 and 12A-4 show the three different retorts considered in this section. Figure 12A-5 is a diagram of the upgrading process slightly modified from the commercial plant design suggested for a commercial plant employing the TOSCO II retort[2].

TABLE A12-1. NET INPUT AND OUTPUT QUANTITIES FOR AN INTEGRATED OIL SHALE PLANT PRODUCING 50,000 BARRELS/DAY OF SYNTHETIC CRUDE

	Paraho Direct[1]	Paraho Indirect[1]	TOSCO II[3]
Raw shale grade (gal/ton)	30	30	35
Mined shale (tons/day)	92,000	105,000	73,000
Sized shale (tons/day)	88,000	100,000	73,000
Purchased power (megawatts)	0	0	95
Liquified petroleum gas (barrels/day)	-	1970	3300
Coke (tons/day)	*	430	890
Ammonia (tons/day)	170	190	170
Sulfur (tons/day)	80	90	200

*Specified as the sum of heat output of coke and low-Btu gas equal to 54×10^9 Btu/day.

TABLE A12-2. RAW SHALE AND PRODUCT OUTPUT PROPERTIES

Material	Property	Heating Value (Btu/lb)
Raw shale	30 gal/ton	2,750
Raw shale	35 gal/ton	3,208
Crude shale oil	0.928 spec. grav.	18,550
Synthetic crude	0.825 spec. grav.	20,150
Liquified petroleum gas	0.900 spec. grav.	21,200
Coke	-	13,850
Ammonia	-	8,620

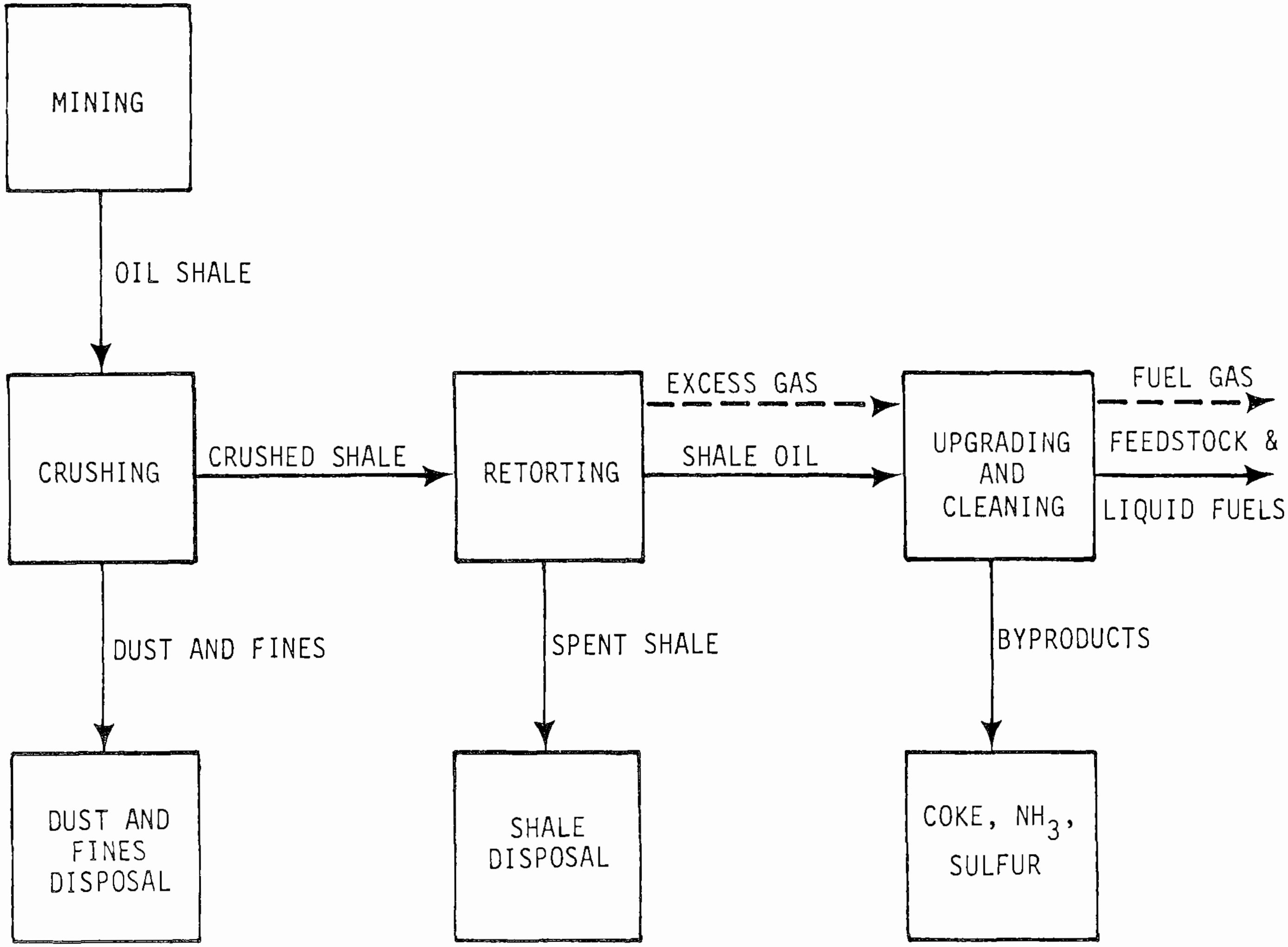


Figure A12-1. Flow diagram for surface processing of oil shale. (Reprinted from Ref. 4 with the permission of the MIT Press, Copyright 1978 by the Massachusetts Institute of Technology).

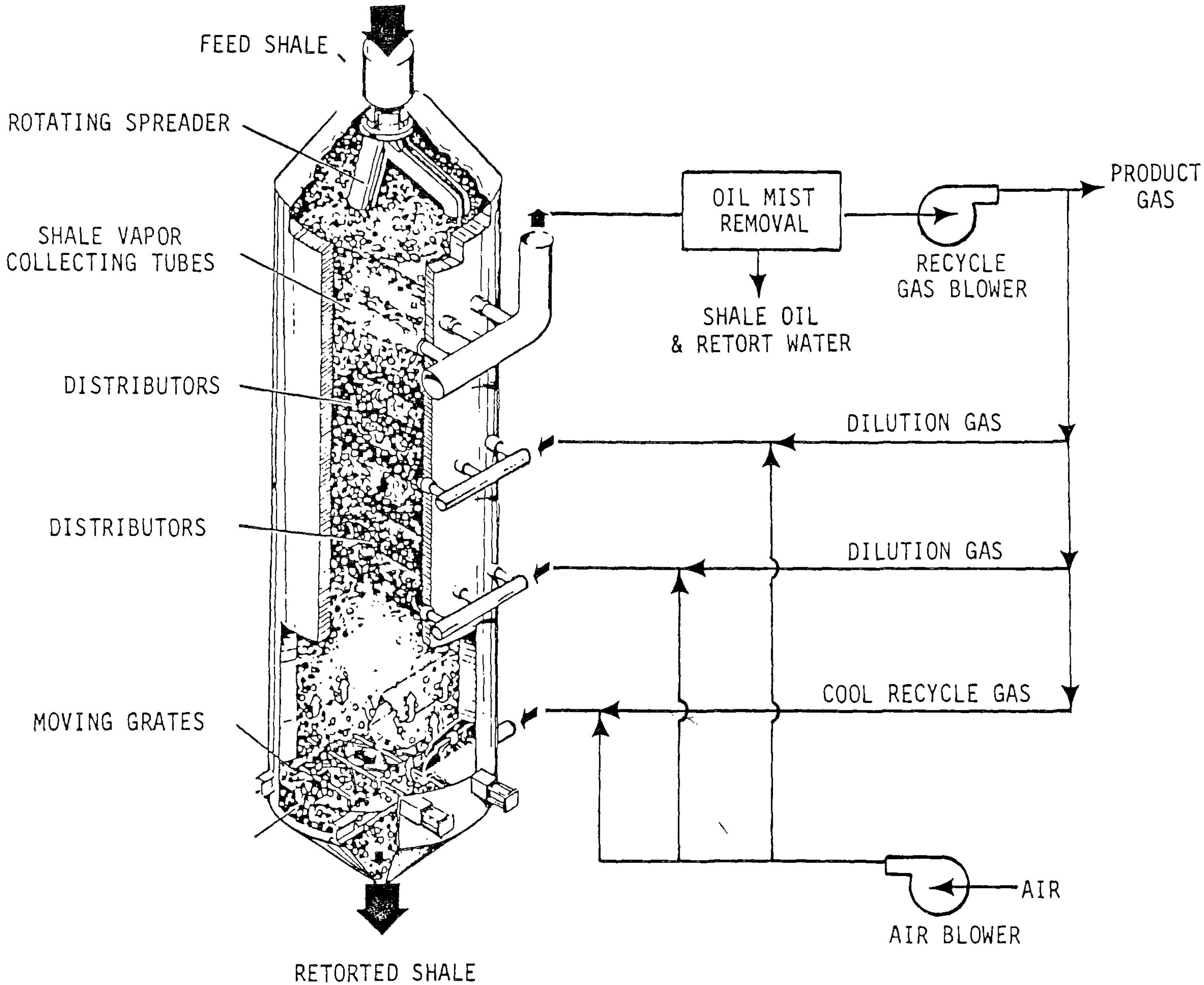


Figure A12-2. Paraho retorting process - direct mode. (Reprinted from Ref. 4 with the permission of the MIT Press, Copyright 1978 by the Massachusetts Institute of Technology).

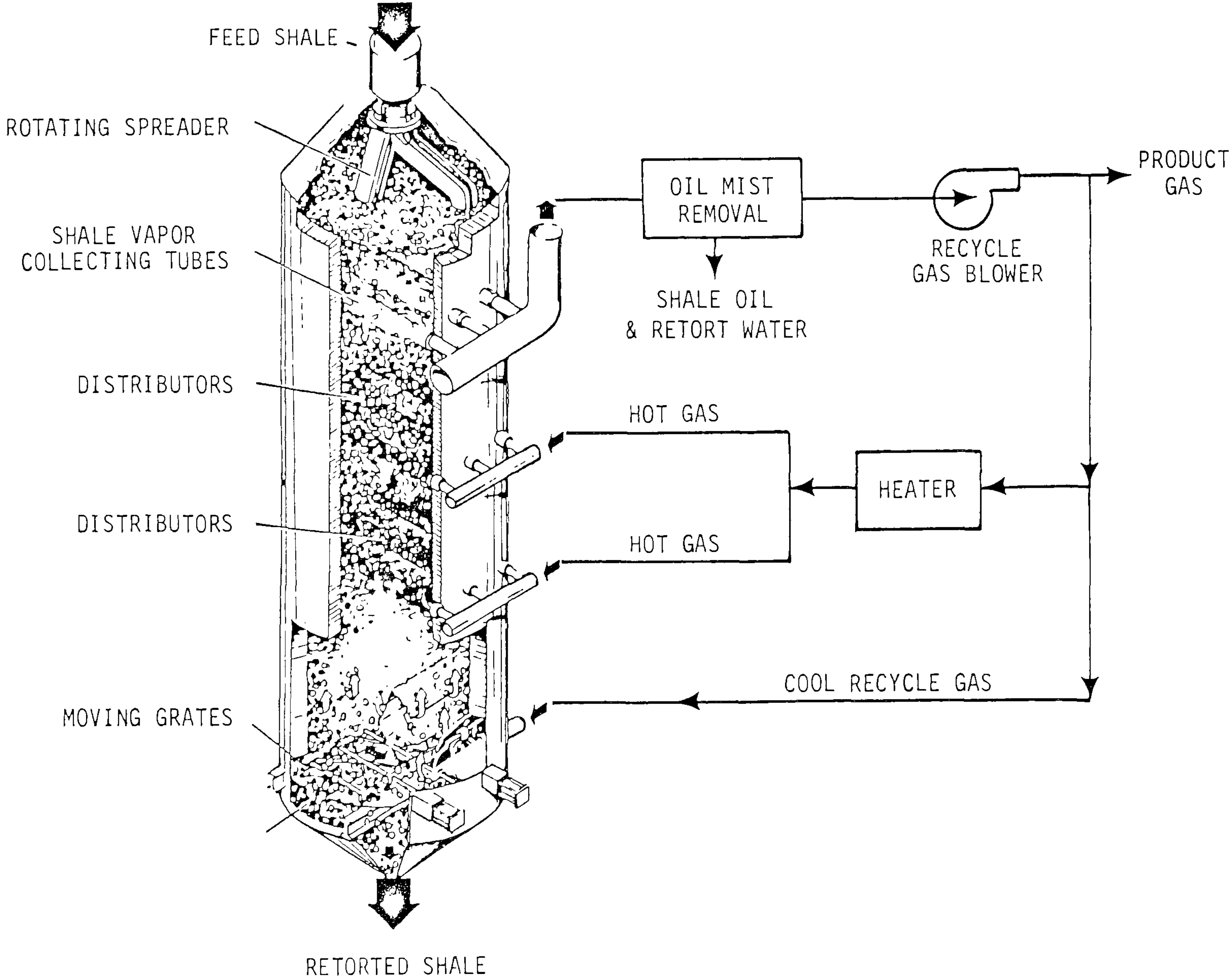


Figure A12-3. Paraho retorting process - indirect mode. (Reprinted from Ref. 4 with the permission of the MIT Press, Copyright 1978 by the Massachusetts Institute of Technology).

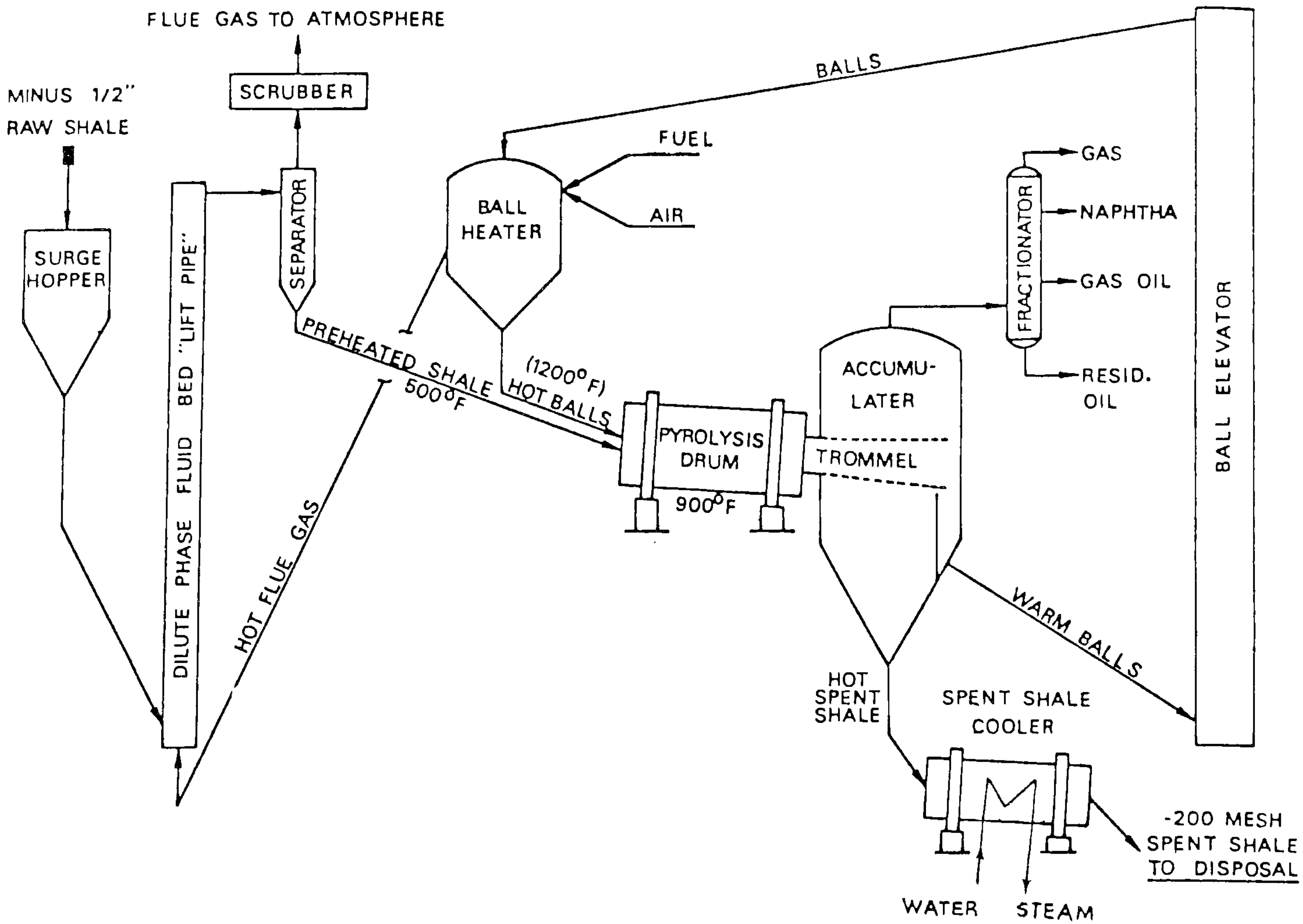


Figure A12-4. TOSCO II retorting process.

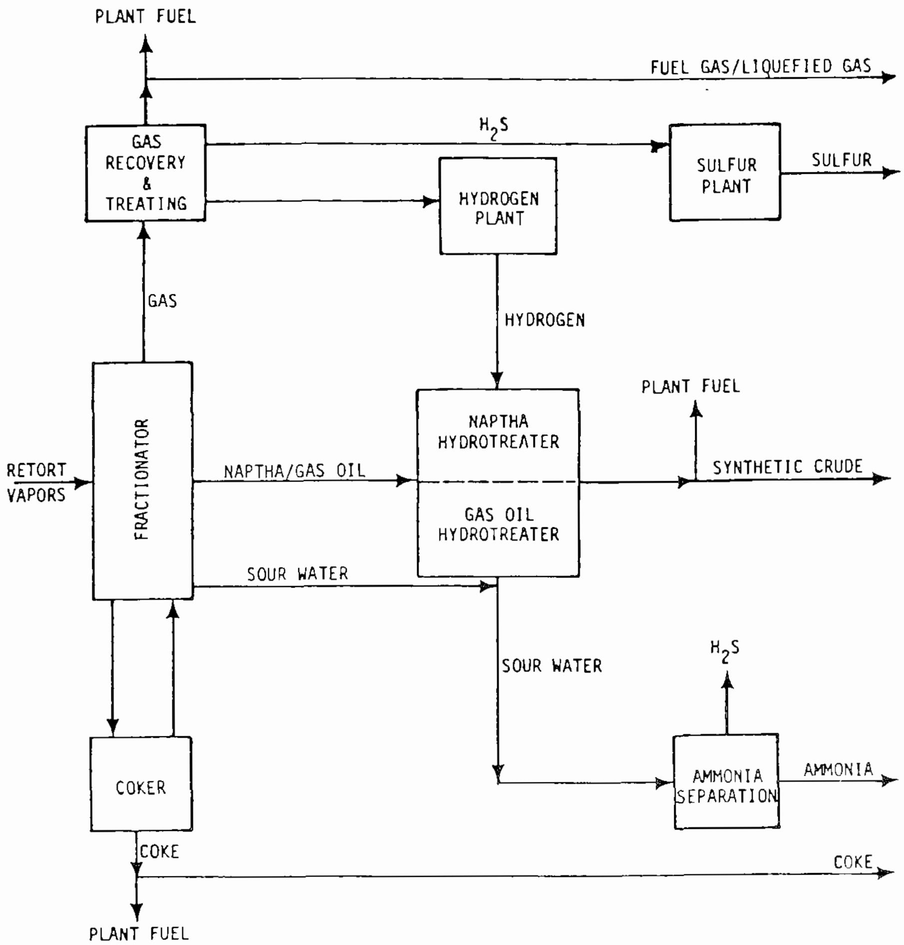


Figure A12-5. Shale oil upgrading plant. (Reprinted from Ref. 4 with the permission of the MIT Press, Copyright 1978 by the Massachusetts Institute of Technology)

The water streams for retorting and upgrading are summarized in Table 12A-3 for a 50,000 barrel/day synthetic crude output. The different quantities of water streams are related to whether pyrolysis is a result of direct heating in an inert atmosphere or indirect heating by combustion gases[4]. The TOSCO II process is a net consumer of water compared to the Paraho processes because the particular design uses wet venturi scrubbers for off-gas cleaning. In the upgrading section of the plant, the makeup water is the water consumed in the hydrogen plant as well as the water consumed in gas treating, in coking and in other process steps. The foul water, from which ammonia and hydrogen sulfide are stripped out, is made up principally of the retort water and the foul water from the gas treating unit and the coker. Most of the designs have assumed that this foul water will be used for spent shale disposal. The water requirements for upgrading operations are fairly close for the three designs because of the similar nature of the pre-refinery upgrading processes. The Paraho Direct process is a net producer of water for both the retorting and upgrading sections, while the TOSCO II water consumes the most water. However, in any event, the process water requirements are very small compared to both the cooling water and shale disposal water.

The thermal balances for each of the three 50,000 barrel/day oil shale plants are shown in Table 12A-3 for the retort and in Table 12A-4 for the integrated plant[4]. The highest retort efficiency is attained by the direct combustion process where no intermediate medium is used to transfer heat for the pyrolysis. The slightly higher efficiency for the TOSCO II process is the result of solid-to-solid heat transfer as compared to the less efficient gas-to-solid heat transfer used in the Paraho Indirect retort. The thermal efficiency to produce crude shale oil is quite high. However, the thermal efficiency for the integrated plant is of primary interest since the important product is upgraded synthetic crude. The thermal efficiency and evaporated water of the Paraho Indirect process are comparable with coal liquefaction. However, the fraction of unrecovered heat dissipated by wet cooling in the indirect process is somewhat lower because part of the unrecovered heat is lost up a furnace stack, which is not lost that way in the direct process.

The underground mining of shale is similar to that for coal. Table 12A-6 summarizes the water consumed for dust control in the underground mining of shale[1,2]. Since the Paraho designs do not differentiate between the requirements for mining and crushing[1], we have assumed, based on the requirements as given

TABLE A12-3. RETORTING AND UPGRADING PROCESS WATER STREAMS FOR OIL SHALE PLANTS PRODUCING 50,000 BARRELS/DAY OF SYNTHETIC CRUDE

	10^3 lb/hr*		
	Paraho Direct	Paraho Indirect	TOSCO II
RETORTING			
IN			
Water addition to shale	28	32	50
Water into venturi scrubbers	--	--	172
	28	32	222
OUT			
Water out in effluent sludge	--	--	53**
Water of retorting	272	159	83
	272	159	136
Net water product	244	127	(139)
UPGRADING			
IN			
Retort water	272	159	83
Makeup water	378	433	444
	650	592	527
OUT			
Foul water for reuse	439	350	266
Boiler blowdown	83	95	119
	522	445	385
Net water consumed	128	147	142
Net water consumed in retorting and upgrading	(116)	20	281

*10^5 lb/hr = 1 gal/10^6 Btu of synthetic crude output.
**This water is assumed lost from the plant and is not counted as a product.

TABLE A12-4. RETORT THERMAL BALANCES FOR 50,000 BARREL/DAY OIL SHALE PLANTS

	10^9 Btu/hr		
Heating Value	Paraho Direct	Paraho Indirect	TOSCO II
Sized shale feed	20.0	22.9	19.6
Retorting heat	-	1.8	1.6
Power for retorting*	0.4	0.5	0.5
Crude shale oil	(14.5)	(16.6)	(14.3)
Untreated product gas	(3.1)	(1.9)	(2.2)
Unrecovered heat	2.8	6.7	5.2
Overall conversion efficiency	86%	73%	76%

* 10,000 Btu/kwh (34% conversion efficiency).

TABLE A12-5. THERMAL BALANCES, UNRECOVERED HEAT REMOVED BY WET COOLING AND WATER EVAPORATED IN 50,000 BARREL/DAY OIL SHALE PLANTS

	10^9 Btu/hr		
Heating Value	Paraho Direct	Paraho Indirect	TOSCO II
Sized shale feed	20.0	22.9	19.6
Purchased electricity*	-	-	0.9
Power to mine and size*	0.3	0.3	0.2
Synthetic crude	(12.1)	(12.1)	(12.1)
Liquefied gas	-	(0.6)	(0.9)
Coke	(2.3)+	(0.5)	(1.0)
Ammonia	(0.1)	(0.1)	(0.1)
Unrecovered heat	5.8	9.9	6.6
Overall conversion efficiency	71%	57%	68%
Fraction of unrecovered heat to evaporate water	28%	19%	18%
Water evaporated for cooling (10^3 lb/hr)	1,160	1,330	850

* 10,000 Btu/kwh (34% conversions efficiency).

\+ Heating value of coke and low-Btu gas.

in the TOSCO II design[2] that 70 percent of the dust control water is for the mine and the remaining 30 percent is for crushing and other dust control operations. There is about a 30 percent difference in the unit water requirements between the two designs, although the absolute requirements are about the same. Table 12A-6 also summarizes the water requirements for dust control in preparing the shale for delivery to the conversion plant and for storage within the mine.

Approximately 80-85 percent of high grade raw shale remains as spent shale after retorting. If the oil shale grade is specified, the fraction of the raw shale to be disposed may be estimated from the following equation.

$$\text{Yield (gal/ton)} = 1.97 \times \text{Organic Matter (wt \%)} - 2.59$$

Table 12A-6 summarizes the quantities mined, retorted and disposed for a 50,000 barrels/day integrated mine-plant complex. The processed shale from the TOSCO II retorting process is a fine, black, sandy material[2], while the processed shale for the Paraho retorts are lumps[5].

Different procedures with considerably different water needs have been proposed for the disposal of the TOSCO and Paraho spent shales. In the TOSCO II design shown in Figure 12A-7, the spent shale leaving the cooler is moisturized to approximately 15 percent moisture content in a rotating drum moisturizer. Steam and processed shale dust produced in the moisturizing procedure are passed through a venturi wet scrubber to remove the dust before discharge to the atmosphere. The moisturized spent shale is transported by a covered conveyor belt to the disposal area, and then spread and compacted to a density of about 90 pounds of dry spent shale per cubic foot. During the transport, spreading and compaction operations, about 13 percent of the added moisture evaporates. This leaves about a 13 percent in-place moisture content, defined as an optimum for compaction and setting purposes[6].

The importance of the moisturizing is that the addition of the water to the TOSCO II type processed shale, at a predetermined shale temperature, leads to cementation of the shale after compaction. This cemented shale appears to permanently "freeze in" the moisture that was added[2], much of which was dirty process water. Moreover, the shale becomes effectively impermeable and resists

TABLE A12-6. WATER CONSUMED IN DUST CONTROL FOR MINING AND FUEL PREPARATION FOR UNDERGROUND SHALE MINES INTEGRATED WITH SHALE OIL PLANTS PRODUCING 50,000 BARRELS/DAY OF SYNTHETIC CRUDE

	Paraho Direct	Paraho Indirect	TOSCO II
Shale mined (tons/day)	92,000*	105,000*	73,300
Water consumed in mining			
10^3 lb/hr	176+	202+	195
lb water/10^3 lb shale	23	23	32
Water consumed in fuel preparation			
10^3 lb/hr	76	87	83
lb water/10^3 lb shale	10	10	14

* 5 percent more than used

+ Based on 70 percent to mining, 30 percent to crushing

TABLE A12-7 OIL SHALE QUANTITIES IN TONS/DAY FOR INTEGRATED PLANTS PRODUCING 50,000 BARRELS/DAY OF SYNTHETIC CRUDE

Process	Grade (gal/ton)	Mined	Fines	Spent Shale	Disposal
TOSCO II	35	73,000	-	60,000	60,000
Paraho Direct	30	92,000	4,000	71,000	75,000
Paraho Indirect	30	105,000	5,000	85,000	90,000

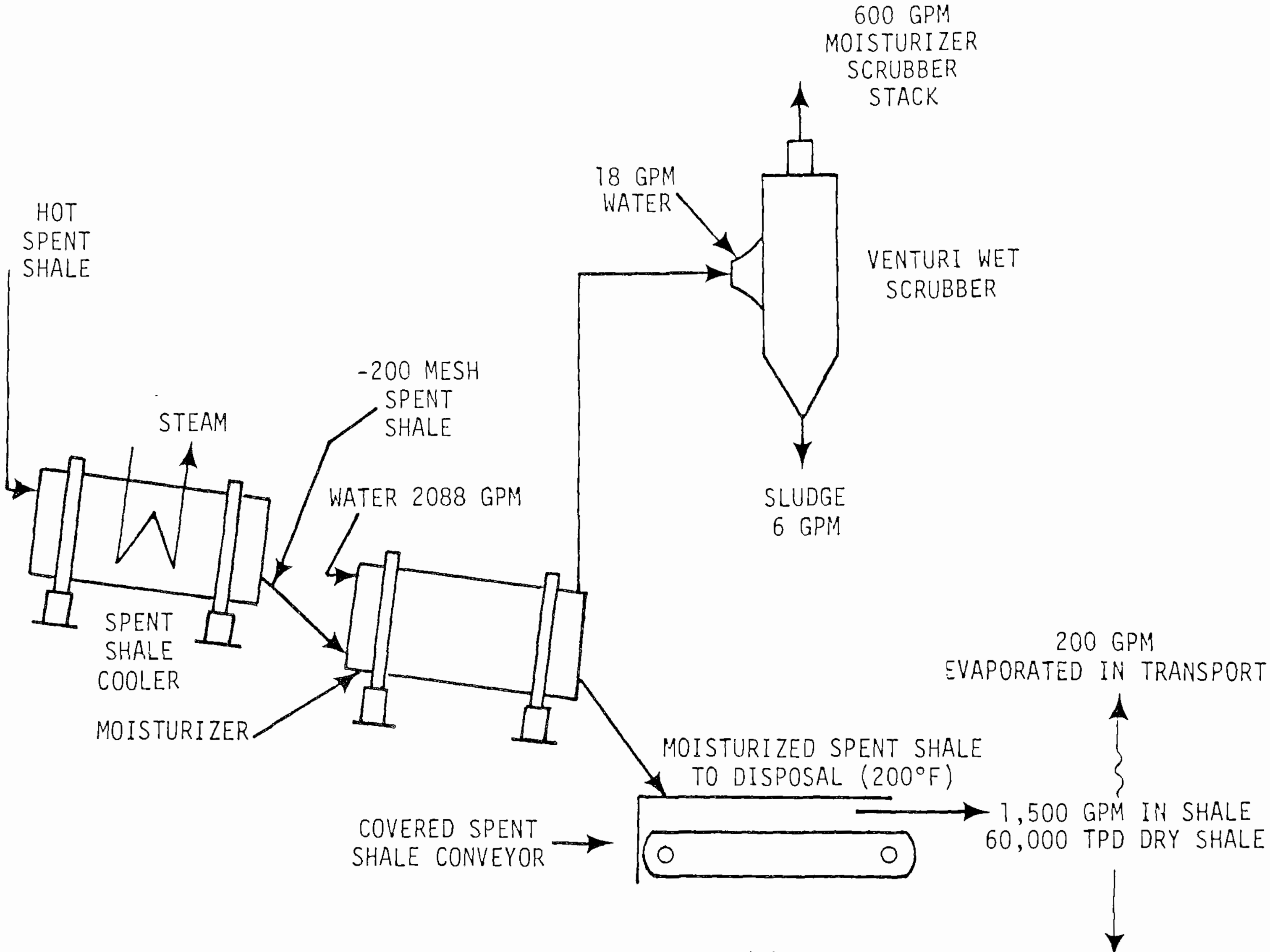


Figure A12-6. TOSCO II spent shale disposal process with quantities appropriate to an integrated plant producing 50,000 barrels/day of synthetic crude. (Reprinted from Ref. 4 with the permission of the MIT Press, Copyright 1978 by the Massachusetts Institute of Technology).

percolation so that soluble salts cannot be leached out[6] Processed shale piles in a TOSCO II commercial embankment are designed for a maximum depth of 700 to 800 ft and an average depth of about 250 ft.

In the TOSCO II design of Ref. 2 the spent shale is to be disposed of in a canyon. The shale is compacted into a shallow embankment and benched to decrease erosion. A flood control reservoir is located above the canyon to divert water from the canyon. Any runoff from the embankment is diverted back to the plant for use as moisturizer water.

After 20 years of operation of a 50,000 barrel/day plant the compacted spent shale would cover an area of approximately 800 acres[2]. This is an average of about 40 acres/yr and for a compaction density of 90 lbs/ft^3 would correspond to a mean height of 250 ft. Irrigated revegetation will be undertaken as permanent surfaces are created by the fill. Prior to revegetation, water spraying will be used to control dust.

In the Paraho design concept for spent shale disposal[5], an "earth" dam constructed of retorted shale would be built at the mouth of a valley selected for a disposal area. The valley itself would be lined with a heavy compacted, impervious layer of retorted shale. By adding about 20 weight percent water prior to compaction, the shale cements up and the shale layer would thus be made impermeable. The valley would then form a lined basin ("bath tub") into which the retorted shale could be deposited. It is assumed that any precipitation leaching through the spent shale would be held within the basin. The important point here is that the spent shale would be compacted but not be wetted down, except for controlling dust and for revegetation. Tests have shown a compaction density of about 90 lbs/ft^3 can be obtained, which is similar to that obtained for spent shale that has been wetted down. It is estimated that less than one percent of the total volume of the shale disposed would have to be wetted to obtain a material of high strength and low permeability. Such a disposal scheme would substantially reduce the water requirements for oil shale plants. On the other hand, the TOSCO procedure, although more water consuming, has had sufficient long-term testing to be reasonably assured that serious environmental problems will not be encountered.

Estimates of the water needed to revegetate and to control dust prior to revegetation must rely solely on results of tests on the specific processed shale in the particular disposal area. In any case, the amount of water required will be relatively large compared, for example, to reclaiming strip mined coal lands in an arid region. At least 4 ft of water are required for leaching the salt from the spoils. Additionally, two to three times this amount could be required over, say, a five year period to ensure a successful cover. To some extent, the amount of water needed for dust control will depend on how rapidly a vegetative cover is established.

Table 12A-8 summarizes the reported data on the water requirements for spent shale disposal. The Paraho requirements as reported did not distinguish between that water needed for dust control and that for vegetation. The estimate for the revegetation water for the TOSCO II spent shale piles was derived from averaging 78 gal/min for years 1 to 11 of the plant and 780 gal/min for years 12 to 20. These figures have been scaled upward somewhat from the values quoted for the plant size in Reference 2.

There are within an integrated mine-plant synthetic fuel complex a number of consumptive uses of water other than those already considered which should be considered in any water balance. These uses include sanitary, potable, service and fire water needs in both the plant and the mine, water for dust control within the boundaries of the conversion plant itself and evaporation from on-site reservoirs and settling basins. The calculation of these consumptive water uses is given in Appendix 9 for coal conversion. Table 12A-9 summarizes these requirements for integrated oil shale plants.

Table 12A-10 summarizes the net water consumed and wet-solid residuals generated for all three processes for integrated oil shale plants producing 50,000 barrels/day of synthetic crude. The absolute quantities have also been normalized with respect to the heating value of the product fuel.

TABLE A12-8. WATER REQUIREMENTS FOR SPENT SHALE DISPOSAL FROM INTEGRATED PLANTS PRODUCING 50,000 BARRELS/DAY OF SYNTHETIC CRUDE

	Water (10^3 lb/hr)			
Process	Moisturizing	Dust Control & Revegetation	Total	lb water per 10^3 lb spent shale
TOSCO II	1,003	336*	1,389	278
Paraho Indirect	-	1,160	1,160	155
Paraho Direct	-	443	443	71

*Dust control 139 X 10^3 lb/hr. Revegetation of 197 X 10^3 lb/hr is 20 year average.

TABLE A12-9. SERVICE AND OTHER WATER REQUIREMENTS FOR INTEGRATED OIL SHALE PLANTS PRODUCING 50,000 BARRELS/DAY OF SYNTHETIC CRUDE

	(10^3 lb/hr)		
Purpose	Paraho Direct	Paraho Indirect	TOSCO II
Sanitary. potable, service usage	10	13	10
Plant dust control	30	32	60
Evaporation	10	18	17
Total	50	63	87

TABLE A12-10. SUMMARY OF WATER CONSUMED AND WET SOLIDS RESIDUALS GENERATED FOR INTEGRATED OIL SHALE PLANTS PRODUCING 50,000 BARRELS/DAY OF SYNTHETIC CRUDE

	Paraho Direct	Paraho Indirect	TOSCO II
Net water consumed in retorting and upgrading (10^3 lb/hr)	(116)	20	281
Water evaporated for cooling (10^3 lb/hr)	1160	1330	850
Water consumed for dust control in mining (10^3 lb/hr)	176	202	195
Water consumed for dust control in fuel preparation (10^3 lb/hr)	76	87	83
Water consumed for spent shale disposal (10^3 lb/hr)	443	1160	1389
Water consumed for other plant uses (10^3 lb/hr)	50	63	87
Total water consumed (10^3 lb/hr)	1789	2862	2885
Total water consumed (gal/10^6 Btu)	18	28	29
Spent Shale (tons/day)	75,000	90,000	60,000
Water (tons/day)	--*	--*	7,800
Total wet-solids residuals (tons/day)	75,000	90,000	60,000
Total wet-solids residuals (lb/10^6 Btu)	520	620	470

*Negligible

REFERENCES - APPENDIX 12

1. McKee, J.M. and Kunchal, S.K., "Energy and Water Requirements for an Oil Shale Plant Based on Paraho Processes," Quarterly Colorado School of Mines 71 (4), 49-64, Oct 1976.

2. Colony Development Operation, "An Environmental Impact Analysis for a Shale Oil Complex at Parachute Creek, Colorado, Part I - Plant Complex and Service Corridor," (also corrected water system flow diagram, personal communication), Atlantic Richfield Co., Denver, Colorado, 1974.

3. Whitcombe, J.A. and Vawter, R.G., "The TOSCO-II Shale Process," Paper No. 40a, AIChE 79th National Meeting, March 1975.

4. Probstein, R.F. and Gold, H., Water in Synthetic Fuel Production - The Technology and Alternatives. The MIT Press, Cambridge, Mass., 1978.

5. Development Engineering, Inc., "Field Compaction Tests, Research and Development Program on the Disposal of Retorted Oil Shale Paraho Oil Shale Project," Report No. OFR78-76, Bureau of Mines, Dept. of the Interior, Washington, D.C., Feb 1976.

6. Metcalf & Eddy Engineers, "Water Pollution Potential from Surface Disposal of Processed Oil Shale from the TOSCO II Process," Vol. I, Report to Colony Development Operation, Atlantic Richfield Co., Grand Valley, Colorado, Oct 1975.

APPENDIX 13

WATER AVAILABILITY AND DEMAND IN EASTERN AND CENTRAL REGIONS

Resource Analysis, Inc., under subcontract to Water Purification Associates, prepared a general assessment of the water resources data in the major coal and oil shale bearing regions of the United States. Water resources data was collected and used as a basis for determining the availability of surface and groundwater resources at specific coal and oil shale conversion plant sites in the Eastern and Central coal bearing regions and the Western coal and oil shale bearing regions. The draft report on the Eastern and Central regions that was submitted as part of their study is included in its entirety in this Appendix.

Resource Analysis, Inc.
1050 MASSACHUSETTS AVENUE
CAMBRIDGE, MASSACHUSETTS 02138
617-354-1922

EAST/CENTRAL WATER SUPPLY DATA

FOR

A STUDY OF WATER RELATED SITE AND PLANT
DESIGN CRITERIA TO DETERMINE FEASIBILITY OF SYNTHETIC FUEL
PLANT SITING AND LOCAL ENVIRONMENTAL IMPACTS

Prepared under subcontract to

WATER PURIFICATION ASSOCIATES
238 Main Street
Cambridge, Massachusetts 02142

August,1978

TABLE OF CONTENTS

LIST OF TABLES

LIST OF FIGURES

1. INTRODUCTION

1.1 Study Objectives

This draft report presents a general assessment of the water resources data that has been reviewed as a part of the East/Central synthetic fuel plant siting study being performed under subcontract to Water Purification Associates, Cambridge, Massachusetts for the Energy Research and Development Administration. The objective of the water resources portion of the overall study is to define the availability of surface and groundwater resources at each specific site in terms of other competing water users.

In order to investigate water related aspects of the feasibility of synthetic fuel plant siting in the Eastern and Central states, Water Purification Associates selected approximately 30 primary specific site locations throughout the region, each having sufficient coal reserves in the immediate area to justify a conversion plant. These sites were selected in such a way as to cover a diverse mix of geographical and climatological characteristics of the coal producing regions.

Sufficient and reliable water supplies are essential to the siting and operation of the synthetic fuel production processes under study. Significant quantities of water are consumed as a raw material on a continuous basis in the liquefaction and the gasification processes

Where the wet cooling process is used, large amounts of water are lost to evaporation. Large quantities of water can also be required where slurry pipelines are used to transport coal from the source to the actual conversion site. The supply of water for these purposes must be available on a continuous 24-hour basis. The economics of shutdowns due to water supply shortages are such, that the reliability of water supplies are a major consideration in establishing the overall feasibility of siting at a particular location. This report presents the basic water resources information that can be used as a basis for determining the feasibility in terms of water availability at the specific sites under study.

1.2 Scope of Studies

The water resources information included in this report consists of the data necessary to establish the surface and groundwater supplies actually available for use in the coal conversion process at each prospective site. Factors entering into this determination are the extent and variability of nearby streamflows or groundwater aquifers, legal institutions regulating the use of these waters, and the implications of competing users for limited supplies in certain areas. Data on the quality of water in terms of constitutents detrimental to the coal conversion process have been compiled for each water source for which such data was available. Also included is a general assessment of potential environmental impacts of energy development in the Eastern and Central coal regions. These potential impacts fall into two general categories: the environmental impacts due to the actual coal mining or conversion activities, and the hydrologic impacts associated with the withdrawal of surface or groundwater supplies.

In assessing the water resources situation at each designated site, no attempt has been made to generate new field data. All data used in the investigations was previously collected by various Federal and state governmental agencies, universities, or local groups. This study serves primarily to compile the existing data into a form most useful for establishing the water related aspects of synthetic fuel plant siting. During this process all data used was reviewed for consistency with other data or basic hydrologic principles. Conclusions were then drawn from the available data as to the existence of favorable or unfavorable water resources conditions at the various locations under consideration as synthetic fuel plant sites.

1.3 Study Region and Specific Sites

The specific sites selected for detailed feasibility analysis are located in seven states in the Eastern and Central coal resource regions of the United States. The site locations were specified as county-sized areas in the states of Alabama, Illinois, Indiana, Kentucky, Ohio, Pennsylvania, and West Virginia. The matrix of primary site locations, type of mining activity, and designated water source presented in Table 1.1 is intended to cover a representative sampling of the geographic location, coal reserve characteristics, climate, and topography likely to be used as sites for synthetic fuel plants. A number of secondary sites as shown in Table 1.2 were also considered to determine the overall water availability in the coal regions as a whole, but were not considered per se in the detailed analysis of specific

Table 1.1

LIST OF PRIMARY COAL CONVERSION PLANT SITES FOR CENTRAL AND EASTERN STUDY

STATE	COUNTY	MINING[1]	COAL[2]	WATER SOURCE
Alabama	Jefferson	U	B	Coosa River
	Morengo	S	L	Tombigbee River or Groundwater
Illinois	Bureau	U	B	Ground Water
	Shelby	U	B	Kaskaskia River
	St. Clair	U	B	Mississippi River
	White	U	B	Wabash River
	Bureau	S	B	Illinois River
	Fulton	S	B	Ground Water
	St. Clair	S	B	Mississippi River
	Saline	S	B	Saline River
Indiana	Gibson	U	B	White River
	Vigo	U	B	Wabash River
	Sullivan	S	B	Wabash River
	Warrick	S	B	Ohio River
Kentucky	Floyd	U	B	Big Sandy River
	Harlan	U	B	Cumberland River
	Henderson	S	B	Ohio
	Muhlenberg	S	B	Green River
	Pike	S	B	Surface Water
Ohio	Gallia	U	B	Ohio River
	Tuscarawas	U	B	Tuscarawas River
	Tuscarawas	U	B	Ground Water
	Jefferson	S	B	Ohio River
Pennsylvania	Allegheny	U	B (HV)	Allegheny River
	Somerset	U	B (MV,LV)	Surface Water
West Virginia	Fayette	U	B (MV,LV)	New River
	Kanawha	U	B (HV)	Kanawha River
	Marshall	U	B (HV)	Ohio River
	Monongalia	U	B (HV)	Monongahela River
	Preston	U	B (HV,MV,LV)	Cheat River
	Mingo	S	B (HV)	Big Sandy River

[1] U = underground mining; S = surface mining.

[2] A = Anthracite; B = bituminous; HV = high volatility, MV = medium volatility, LV = low volatility; L = lignite.

Table 1.2

LIST OF ADDITIONAL COAL CONVERSION PLANT SITES

State	County	Water Source
Alabama	Fayette	Warrior (R)
	Marion	Tennessee (R)
	Jackson	Tennessee (R)
	DeKalb	Tennessee (R)
Illinois	Mercer	Mississippi (R)
	McLean	Illinois (R)
Kentucky	Hopkins	Green (R)
	McCreary	Cumberland
	Lee	Kentucky
	Lawrence	Big Sandy (R)
Ohio	Morgan	Muskingum
Pennsylvania	Venango	Allegheny (R)
	Clearfield	West Branch
	Cambria	Conemaugh
West Virginia	Randolph	Tygart
	Greenbrier	Greenbrier

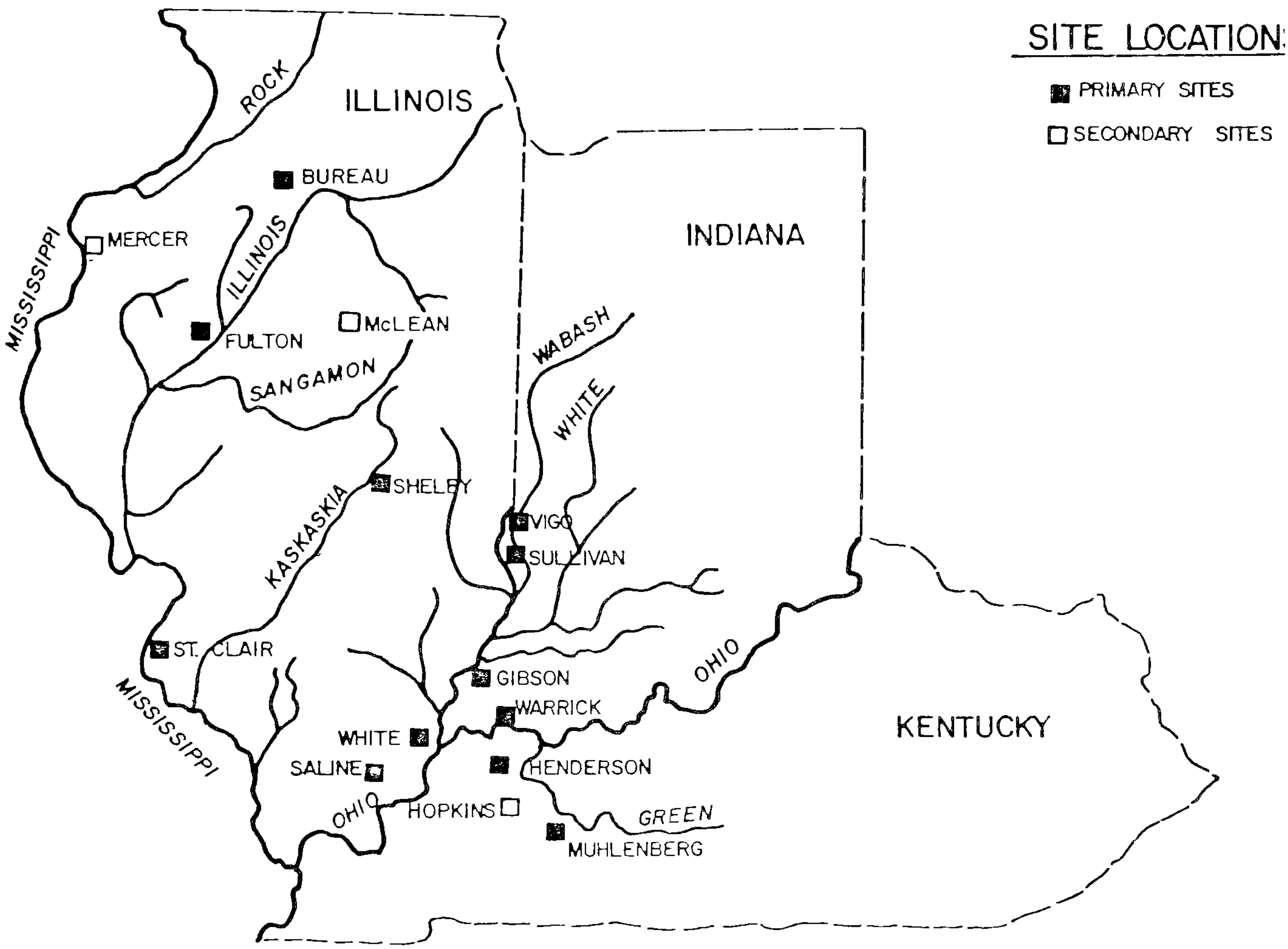
sites. Figure 1.1 shows the primary and secondary site location with respect to the coal reserves and major water resources features of the study region.

Several aspects of the actual design and operation of a coal conversion plant are of importance in evaluating the relationship of the plant to the water resources of the area. It has been assumed for the purposes of this study that the consumptive use requirement for process and cooling water, and all associated uses at each plant would be about 4500 gallons per minute or an equivalent streamflow of about 10 cfs. In order to provide a stand-by water supply for times of water shortage, a holding pond system having a reserve supply of one week's water requirement was assumed to be typical. It was also assumed that water treatment costs are such that lower quality water supplies such as brackish groundwater or municipal treatment plant effluents would be acceptable water sources. Conversion plants are expected to be designed to make maximum use of water recycling within the plant and return no flows or waste residues to the receiving waters.

The coal conversion plants under consideration, in some instances where terrain and water supplies permit, may be located at the mine mouth. Water use regulations prohibiting non-riparian† water use as discussed in this report, or adverse terrain features may at many locations require the actual conversion plant to be located some distance away from the mine. Unit train or coal slurry transport of the coal from mine to conversion plant will be required in these instances.

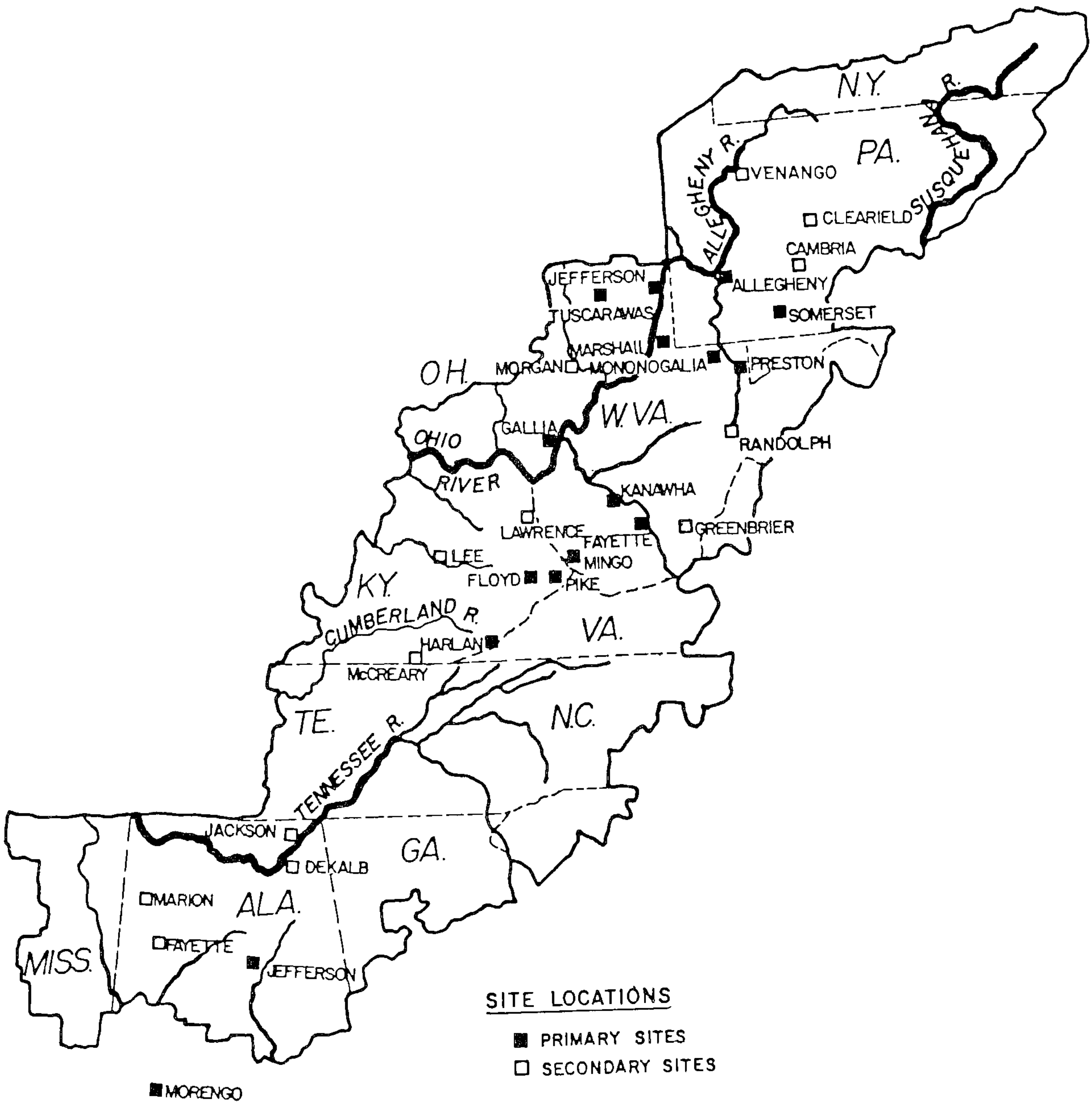
---

†A Riparian water right is defined as a right derived from ownership of land adjacent to a natural watercourse.



ILLINOIS BASIN

Figure 1.1 Coal Conversion Site Locations and Surface Water Features(continued)



APPALACHIAN BASIN

Figure 1.1 Coal Conversion Site Locations and Surface Water Features

2. SUMMARY OF RESULTS AND CONCLUSIONS

The most significant findings of the water resources investigations to-date may be summarized as follows.

1. Surface water supply sources were specified for most of the sites to be studied. Sufficient reliable supplies to support one or more coal conversion plants exist close to many of the sites, especially those with a major regulated river flowing through or adjacent to the study area. This applies to all sites in the vicinity of the following major rivers:

Mississippi
Ohio
Wabash-White
Kanawha-New
Allegheny
Tennessee
Tombigbee

In most of these instances present water use data and future demand projections indicate a significant surplus streamflow beyond expected use, even under low-flow conditions. For the few cases where data on other demands is not readily available, the conversion plant demand is generally in the order of less than one percent of the seven-day, twenty-year low-flow.[†] Uses of this magnitude would appear to safely satisfy the common law requirement of being reasonable relative to other users.

2. Surface water supplies are much less reliable in the smaller streams in the upper water courses. The eastern Kentucky and adjacent

[†]The seven day, twenty-year low flow is defined as the minimum average flow over seven consecutive days that is expected to occur with an average frequency of once in twenty years.

West Virginia coal regions in the Big Sandy River Basin; the upper Cumberland, Kentucky, and Green River basins in eastern Kentucky; and the northern West Virginia coal region in the Monongahelia Basin fall into this category. In these areas extreme low-flows are practically zero. A coal conversion plant demand could easily represent a very significant portion of the seasonal low-flow in many of these areas, and therefore be judged to be an unreasonably large use. In order for a plant to be sited in these regions an alternative or supplemental supply to streamflows must be assured. In some cases the construction of sizable surface water impoundments may be practical, while in other cases this would be prohibited by topographical constraints. Groundwater supplies to supplement surface supplies during times of scarcity look favorable in several cases as described below.

3. The riparian land requirement in many instances will discourage the transfer of surface water over even a short distance from small streams to coal reserves on a non-riparian site. Historically industries using significant amounts of water have located on major rivers with surplus water supplies for this very reason. Although several states are presently considering statutory modifications to the Riparian Doctrine which might eventually allow users (including non-riparian users) to reserve definite supplies of surface flows, none of the seven states in the study region have enacted an effective permit system to-date. A non-riparian use of large volumes of water would currently be feasible from an institutional point of view only from a major river (those cited in item 1) with large water surpluses.

4. In addition to the 30 or so primary plant sites, several other regions were considered to determine the overall water availability of the coal regions as a whole. These regions were not considered as such in the detailed analysis of specific sites. Locations considered in this vein found to have surface supplies generally favorable for energy development include: several potential sites in northern Alabama supplied from the Tennessee River, in north-central Illinois supplied from the Mississippi or Illinois Rivers, in Kentucky from the mid-Green River, in Ohio from the Lower Muskinghum River, and additional sites in northwest Pennsylvania from the Allegheny River. Groundwater supplies in west-central Alabama also appear to be favorable. Regions generally found to have limited water supplies for energy development include: the upper watersheds of the Cumberland, Kentucky, Green, and Big Sandy Rivers in eastern Kentucky; the coal areas of western Pennsylvania except those that can be supplied from the Allegheny, Ohio, or Susquehanna Rivers; and the east-central West Virginia region.

5. Groundwater was specified as a primary source of supply at a few locations which include Bureau and Fulton Counties in Illinois and Tuscarawas County, Ohio. Indications are that there would be no problem in developing the many high-yield wells that would be required to provide the reliable supplies at these sites. Groundwater also looks promising as a conjunctive supply in certain areas where surface supplies are seasonally questionable. Unfortunately, the groundwater situation is most favorable from alluvial aquifers recharged by major streams in the valley bottoms where surface supplies are best, and

least favorable from less transmissive consolidated aquifers higher in the watersheds where surface supplies tend to be poorest. Since the aquifer structure is highly fractured in many areas under study, expected well yields can vary tremendously over a county-sized area.

6. Since the rights of a landowner to use groundwater are generally more absolute than those concerning surface water use, the development of groundwater supplies as a primary or supplemental source for energy-related uses requiring large capital investments may be preferable to surface water on the basis of institutional feasibility.

7. Water quality data on a number of constituents having potentially detrimental effects on coal conversion processes were compiled for many water supply sources. In surface waters, concentrations of various constituents were found to vary from location to location depending on the local geology, population density, and industrial development. Even more significant variations over time are evident at certain locations with major sources of industrial pollution or where the effects of varying dilution rates are particularly severe. The Muskingum, White, and Illinois Rivers exhibit this tendency. The quality of groundwater supplies is similar to that of surface waters where alluvial aquifers are used as a source. Groundwater from deep consolidated aquifers on the other hand may be brackish and highly mineralized. The chemical composition of water from a given well at a particular location generally will show very little variation over time. as compared to a surface water source.

8. Potential hydrologic impacts are associated with both the coal mining operation and the process of converting the coal to synthetic fuels The mining operation, whether it be underground or strip mining,

creates the potential for environmental problems resulting from the earthmoving operation (erosion, sedimentation of stream channels, and scarring the land) and the mine dewatering process (acid mine drainage and depletion of groundwater supplies). Modern mining techniques and reclamation when properly employed can minimize or eliminate the problems associated with earthmoving. Impounding mine drainage for subsequent evaporation or treatment and proper underground mining methods have been used to successfully handle the acid mine drainage problem. The possibility that a mining operation will lower nearby well yields or cause small locally-used shallow aquifers to be depleted is common to nearly all coal bearing regions. Because this problem is very localized and site dependent the problem must be considered on a site by site basis at a much smaller scale than present site definitions allow.

The synthetic fuel conversion process has several potential hydrologic impacts associated with it as well. Since no return flows or waste residues are to be returned to the receiving waters the potential for environmental degradation are minimized. The major potential impact, therefore,is that associated with the use of groundwater as a source of water supply. The feasibility of using groundwater as a water supply source must be evaluated based on the ability of the local aquifers to supply the required yields without widespread lowering of the water table or other impairments of existing users in the area.

3. SURFACE WATER RESOURCES

3.1 General

The synthetic fuel plant sites in the East/Central portion of the United States are located in two major coal regions. The Appalachian Region extends from eastern Pennsylvania through eastern Ohio, western Kentucky, West Virginia, and into northern Alabama. The Illinois Region includes the deposits in Illinois, southern Indiana, and western Kentucky. The Appalachian Region is characterized by highly variable terrain resulting from extensive geologic folding and faulting,while the Illinois Region is underlain by a smoother much more consistent geologic framework.

The majority of the study sites are located within the limits of the Ohio River Basin. A few others are located in the Upper Mississippi Basin in north-central Illinois and the Mobile River Basin in central Alabama. Annual precipitation and runoff exceeds the national average throughout the region and water supplies are generally plentiful. Monthly and seasonal variability in precipitation is greatest in the northwest portion of the region and least in the southern part.

Water supply sources associated with each specific site were designated for the purposes of this study. These sources are for the most part major streams in the vicinity of each site. Groundwater was specified as a primary source in several instances. The discussion below considers various aspects related to the availability of surface water supplies for coal conversion. Further on in Section 4 the ground water resources of the region are discussed.

3.2 Water Supply Availability

The adequacy of the water supply at each primary site having a river or stream as its water source was assessed through a comparison of a typical plant use with expected low-flows in the stream. As is described more fully in Section 3.3., the Riparian Doctrine governing water use in the Eastern States requires that each use be reasonable in relation to other riparian uses. For preliminary screening purposes, plant use at each site was compared to the low-flow in the associated water source to establish whether the use would probably be reasonable, possibly be reasonable or probably be unreasonable. The criteria used in judging the situation at each site were the following:

1) Favorable. Site use is less than about 5 percent of the estimated seven-day, twenty-year low-flow

2) Questionable. Site use is about 10 percent of the estimated seven-day, twenty-year low-flow

3) Unreliable. Site use is more than 20 percent of the estimated seven-day, twenty-year low-flow.

In this analysis the water use associated with a typical plant was assumed to be approximately 4,500 gpm (about 10.0 cfs, or 7,000 acre-ft/year).

The seven-day, twenty-year low-flow used in the comparison is defined to be the minimum average flow over seven consecutive days that is expected to occur with an average frequency of once in twenty years. This is an appropriate criteria for sites having a useful life of about twenty years and holding ponds with a reserve capacity of about a seven-day water supply. Low-flow values were determined from Streamflow Data Program Reports for each state (USGS, 1970), various state or regional agencies, or were estimated from historical low-flows at nearby gauging stations. Low-flows from major streams affected by regulation are very difficult to establish accurately. In many of these instances, however, flows are relatively high and the objective of regulation is to achieve higher low-flows.

Table 3.1 lists the runoff characteristics of each primary supply source and the results of the assessment based on local low-flows. The analysis shows that surface supplies are most favorable for those sites having the main stream of a major regulated river near by. These include all of the sites having the following rivers as designated sources:

Mississippi
Ohio
Kanawha-New
Wabash-White
Allegheny

Surface water supplies are shown to be much less reliable for many of the smaller streams away from the major rivers. In many of these streams low-flows may in fact be less than the typical coal conversion plant requirement. In other cases a plant water requirement would represent a large portion of the flow and such a use would probably interfere with other small existing users.

The analysis described above clearly suggests that there are sites having abundant supplies at hand where meeting the water requirements

TABLE 3.1

ASSESSMENT OF POTENTIAL SURFACE WATER SOURCES

State	County	Source	Drainage Area (SM)	USGS Gauge No.	Mean Flow (CFS)	Historical Low-Flow (CFS)	7 day - 20 Yr. Low-Flow (CFS)	Situation (1)	Possible Alternate Source
Alabama	Jefferson	Coosa	8,390	4070	13,790	370	---	F	---
	Morengo	Tombigbee	5,900	4450	8,631	165	---	F	---
Illinois	Bureau	Groundwater	---	---	---	---	---	See Table 4.1	---
	Bureau	Illinois	12,040	---	12,500(E)	1,800(E)	800(2)	F	---
	Fulton	Groundwater	---	---	---	---	---	See Table 4.1	---
	St. Clair	Mississippi(R)	700,000	0100	177,000	18,000	10,000	F	---
	Saline	Saline	---	None	---	10(E)	(NA)	U	Ohio or Prop. Res.
	Shelby	Kaskaskia(R)	1,054	5920	788	0	(NA)	U	Lake Shelbyville
	White	Wabash	28,635	3775	27,030	1,650	800(2)	F	---
Indiana	Gibson	White(R)	11,125	3740	11,540	573	610(4)	F	---
	Sullivan	Wabash(R)	13,161	3420	11,600	858	350(2)	F	---
	Vigo	Wabash(R)	12,265	3415	10,660	701	300(2)	F	---
	Warrick	Ohio(R)	107,000	3220	113,700	NA	2,000(2) (13,000(5))	F	---
Kentucky	Floyd	Levisa Fork	1,701	2098	2,104	20	(NA)	U	Dewey Lake
	Harlan	Cumberland(R)	374	4010	689	3	(NA)	U	Surface Storage
	Henderson	Ohio(R)	107,000	3220	133,900	NA	15,400(5)	F	---
	Muhlenburg	Green Pond(R)	6,182	3165	9,201	250	(NA)	Q	Groundwater
	Pike	Levisa Fork	1,237	2015	1,458	2	(NA)	U	Fishtrap Lake or Groundwater
Ohio	Galia	Ohio(R)	---	---	77,600	---	8,600(5)	F	---
	Jefferson	Ohio(R)	---	---	40,900	---	5,600(5)	F	---
	Tuscarawas	Tuscarawas(R)	2,443	1290	2,453	170	215(7)	Q	Groundwater
	Tuscarawas	Groundwater	---	---	---	---	---	See Table 4.1	---
Pennsylvania	Allegheny	Allegheny(R)	12,500	---	19,500(E)	900(E)	(NA)	F	---
	Somerset	Casselman	382	0790	655	10	12(4)	U	Quemahoning Res.
West Virginia	Fayette	New(R)	9,000	1930	10,500	950(3)	1,184	F	---
	Kanawha	Kanawha(R)	10,419	1980	14,480	2,360	1,750	F	---
	Marshall	Ohio(R)	---	---	40,900	---	5,600(5)	F	---
	Mingo	Tug Ford(R)	850	2140	1,351	17(3)	30	U	Groundwater
	Monongalia	Monongahela(R)	4,407	0725	8,137	20	248	Q	Surface Storage
	Preston	Cheat	972	0700	2,239	10	95	U	Lake Lynn or Groundwater

(1) Situation assessment: F=Favorable, Q=Questionable, U=Unreliable

(2) Low-flow (1 day, 50 year) data from Illinois State Water Survey (1975)

(3) Estimated from nearby gauges

(4) Estimated using regression equations in Streamflow Data Program Reports (USGS, 1970)

(5) Low flow (7 day, 10 year) from ORBC Table of Instream Flows

(6) Pennsylvania Department of Forests and Waters, Bulletin No. 1 (1966)

(7) Ohio Department of Natural Resources Bulletin 40 (1965)

(E) Estimated from best available information

(R) River substantially regulated at source location

(NA) Data not available at present, or nonapplicable of one or more conversion plants would be no problem. There are others where supplies are such that the designated supply source could not be relied on during very dry periods and where alternative or supplemental source should be developed. The supplies available at several other sources are in between the extremes. The adequacy of these sources depends in large part on the extent of other competing uses or the likelihood that competing demands will develop in the future. Following a discussion of institutional factors controlling the use of surface supplies, the available data on present uses and projected future demand is presented in Section 3.4.

As indicated earlier, in addition to the 30 or 50 primary specific sites, additional sites in several other regions were considered in a general sense to complete the assessment of overall water availability throughout the coal regions. Using the same analytical criteria as described earlier, these additional sites are listed in Table 3.2 with their associated water source and a general assessment of the water supply availability at each site. These results indicate that several sites in northern Alabama could be supplied from the Tennessee River; that sites in north-central Illinois could be supplied from either the Mississippi or Illinois Rivers; and that additional sites could be supplied from the Green River in Kentucky, the Muskingum River in Ohio, or the Allegheny River in Pennsylvania. The region found to have the least favorable water supplies for coal conversion is that at the upper reaches of the Cumberland, Kentucky and Big Sandy Rivers in Kentucky.

TABLE 3.2

ASSESSMENT OF ADDITIONAL SURFACE WATER SOURCES

State	County	Source	Drainage Area (SM)	USGS Gauge No.	Mean Flow (CFS)	Historical Low Flow (CFS)	7 day, 20 Yr. Low Flow (CFS)	Situation (1)	Possible Alternate Source
Alabama	Fayette	Warrior(R)	4828	4650	7822	37	N.A.	Q	Groundwater
	Marion	Tennessee(R)	30810	5895	51610	105	N.A.	F	---
	Jackson	Tennessee(R)	25610	5755	43760	400	N.A.	F	---
	De Kalb	Tennessee(R)	25610	5755	43760	400	N.A.	F	---
Illinois	Mercer	Mississippi(R)	119000	4745	62570	5000	6500(2)	F	---
	McLean	Illinois(R)	15819	5685	14529	1810	N.A.	F	---
Kentucky	Hopkins	Green(R)	7564	3200	10960	280	N.A.	F	---
	McCreary	Cumberland	1977	4045	3199	4	12(3)	U	Lake Cumberland
	Lee	Kentucky	2657	2820	3638	4	8.6(3)	U	Unknown
	Lawrence	Big Sandy(R)	2143	2150	2480	8.4	74(3)	Q	Ohio River
Ohio	Morgan	Muskingum	7422	1500	7247	218	565(5)	F	---
Pennsylvania	Venango	Allegheny(R)	5982	02550	10330	334	N.A.	F	---
	Clearfield	West Branch	1462	5425	2467	100	115(4)	Q	Unknown
	Cambria	Conemaugh	715	04150	1269	105	155(4)	Q	Unknown
W. Virginia	Randolph	Tygart	408	0510	800	0.1	0.4(3)	U	Tygart Lake
	Greenbrier	Greenbrier	1835	1835	1980	24	43(3)	Q	Bluestone Res.

(1) Situation assessment: F=Favorable; Q=Questionable; U=Unreliable

(2) Low-Flow (1 day, 50 year) from Illinois State Water Survey Report No. 4 (1975)

(3) *Estimated using regression equations in USGS Streamflow Data Program Reports* (1970)

(4) Pennsylvania Department of Forests and Waters Bulletin No. 1 (1966)

(5) Ohio Department of Natural Resources Bulletin 40 (1965)

(R) River substantially regulated from source location

(NA) Data not available at present or non-applicable

3.3 Surface Water Doctrines

Most regions in the east and central portions of the United States receive sufficient rainfall, so that surface supplies in many areas are plentiful. Relatively high population densities in certain areas, and great seasonal variabilities in runoff rates, however, result in many situations where the demand for the use of water creates competition for the available supplies. The industrial use of water for energy development is often, one of many competing uses to which limited water supplies must be allocated.

The majority of the sites under consideration in this study involve river or stream flow as a primary source of water for the conversion process. Where such supplies are somewhat limited, the required water may be available from existing or future reservoirs or from groundwater systems. Each of these potential sources is subject to general legal principles as to how the water may be used. Local statutory enactments may also affect use in several states. For the purposes of this report, the general aspects of water use regulations were reviewed primarily as applicable to the surface water supply assessments described in the previous Section. Specific state qualifications are also discussed.

The use of surface flows in the Eastern United States has traditionally been subject to a judicially developed set of legal principles known as the Riparian Doctrine which define water rights as an incidence of ownership of land that adjoins or is traversed by a natural stream (Cox, 1975). Two separate applications of the doctrine have been recognized at one time or another. The natural flow concept is the older of these and has been replaced generally by the concept of reasonable use. The natural flow concept was based on the theory that the objective of water use regulations was to maintain the natural flow in a stream and was more restrictive, particularly for industrial applications involving the consumption of water. The reasonable use interpretation of the Riparian Doctrine is now widely accepted and states that each owner of riparian land (i.e., traversed by or adjoining a natural stream) has the right to make any use of the water in connection with the use of the riparian land as long as such use is reasonable with respect to others' having a similar right. This statement of the reasonable use concept of the doctrine suggests three important considerations related to the use of water for energy development:

1) Reasonable Use. The question of reasonableness is a rather vague requirement primarily determined by the impact of the use in question on other valid users. This is a relative matter dependent on a particular set of circumstances and generally more dependent on the magnitude of the proposed use than the nature of it. The basic requirement is that some degree of sharing of available supplies must take place among the various demands.

2) Riparian Land Use Limitation. This important aspect of the doctrine requires that water use be restricted to the riparian land upon which the right is derived. The basic requirement for land to be riparian is physical contact with the water source. This can be a significant limitation on the availability of an otherwise adequate water supply source where energy reserves are located some distance

away from the water. Certain state regulations allow use on non-riparian land where supplies are sufficient, so that no riparian user is injured by such a use. Thus, non-riparian use is generally dependent on the existence of surplus water after all riparian use has been satisfied--a very restrictive condition (Cox, 1975). Only the major rivers of the region such as the Kanawha, Allegheny, and Ohio can satisfy this condition reliably enough to justify the large capital investments involved in the construction of coal conversion plants

3) Variability Over Time. An important limitation in the doctrine to significant users requiring dependable, long-term availability such as synthetic fuel plants is that a reasonable use at one point in time may become unreasonable at some unknown future time. Other riparian owners do not lose their right through disuse. Also, riparian water rights generally are not quantified and recorded but simply must remain reasonable with respect to all other users.

In addition to the above, the Riparian Doctrine establishes an order of preference among various categories of users for determining a reasonable share with domestic uses having the highest priority and industrial users a relatively low ranking. It is possible, however, that should the national energy situation continue on its present course, energy development users in the future may have a high social priority.

Several Eastern states have recently adopted statutory modifications to the Common Law Doctrine that allow some degree of water appropriation by permit. These states are Kentucky, Indiana, Iowa, and North Carolina. Since a number of other states are considering or moving towards similar enactments the nature of these statutes is discussed below even though only Indiana and Kentucky are actually included in this study.

Kentucky: Statutes have been enacted which cover water use throughout the state. The impact of these statutes has been very limited since they do nothing to either regulate water use or assure a reliable supply to users. Basically anyone requesting a permit to use water has been able to obtain one whether or not sufficient water is available. The right by permit to use water is not assured during times of reduced supplies.

Indiana: Present statutes regulate the use of groundwater only. Under these laws the Department of Conservation seeks to restrict withdrawals where other users would be affected. New users of more than 100 gpd must obtain a permit.

Iowa: Forceful statutes are in effect which allow the allocation of water through an effective permit system.

North Carolina: Statutes have been enacted to control water use in designated problem areas only. Other states are considering this approach.

These statutory modifications are generally aimed at allowing potential users, including in some instances non-riparian users, to obtain the legal right to use a specified quantity of water. At the same time they attempt to insure that no existing user would be harmed and all riparian rights are preserved. The effect of such legislation would be to encourage high investment type industries requiring firm and reliable sources of water to locate in other areas than they could presently. Historically the vague requirements of the Riparian Doctrine have forced significant water using industries to locate primary on the major rivers of the region that have surplus flows.

According to a recent survey (Ausness, 1976) of legal aspects of water use in the East the states of Alabama, Illinois, Ohio, Pennsylvania, and West Virginia, among others, currently adhere to the Common Laws of water use with no significant statutory modifications. Although future legislation may eventually alter this situation, present planning for major new water use should be in accordance with existing laws.

3.4 Competing Water Use

Previous sections have discussed overall surface water availability at the specific study sites and the legal considerations that have an effect on the manner in which the water supplies can be used. Throughout the East/Central study region an essential determinant of a given user's right to a certain quantity of water is whether or not that use would be reasonable with respect to other users. An assessment of surface water sources in terms of the relative amount of streamflow at low-flow conditions that would be required for a coal conversion plant was presented in Section 3.2 and Tables 3.1 and 3.2. This approach provides a good basis for identifying sites where the water requirements of a typical coal conversion plant would be a reasonably small fraction of the total surface water flow under drought conditions and therefore could be reliably maintained. It also clearly points out sites where the plant requirements probably or might not always be maintained since another provision of the law is that users must also share in cutting back their use when supplies are low.

Although this approach gives a valid indication of the relative reasonableness of a typical conversion plant use, another factor that might be considered in plant siting is the amount of competing use in a particular location from such other water demands as municipal, industrial, power production, etc. The difference between the low flow in a stream or river and the total present or projected water use is the surplus flow available for coal conversion, or a deficit indicating that supplies are insufficient even for the other uses. This information would be of particular importance where coal resources are located some distance away from a water source and a non-riparian use of the water is being considered. Such a use might be feasible if a significant surplus supply exists at the source and therefore no other user would be harmed by the withdrawal.

Although data on other competing uses is not available for all sites, some preliminary, unpublished data compiled by the Ohio River Basin Commission (1977) gives estimated consumptive water use for 1975 and 2000 for the Ohio River main stem and its larger tributaries. This data was used to compute surplus (or deficit) water supplies available under critical low-flow conditions for many of the specific sites being studied. Water use quantities for the tributary basins were given for the entire basin. For sites located some distance into these basins, water use quantities were estimated as being proportional to the ratio of drainage areas. The estimated present and future consumptive water use for other uses, and the results of the supply surplus calculations for a number of sites are presented in Table 3.3.

TABLE 3.3

ESTIMATED CONSUMPTIVE WATER USE AND SURPLUS SUPPLIES IN THE OHIO RIVER BASIN FOR 1975 AND 2000

Location	Mean Annual(4) Flow (cfs)	Low Flow 7 Day, 20 Yr Except as Noted (cfs)	Estimated Present 1975 Use (5) (cfs)	Available Quantity With Present Use at Low Flow Conditions (cfs)	Estimated Future 2000 Use (5) (cfs)	Available Quantity With Future Use At Low Flow Conditions (cfs)
Allegheny R. (Allegheny Co. Pa.)	19,500	1,000 (1)	280	720	350	650
Monongahela R. (Monongalia Co. W. Va.)	8,137	248	110	138	310	-62
Ohio R. (Jefferson Co. Ohio)	40,900	5,600 (2)	695	4,905	1,129	4,471
Ohio R. (Marshall Co. W. Va.)	40,900	5,600 (2)	700	4,900	1,306	4,294
Muskingum (Tuscarawas) R. (Tuscarawas Co. Ohio)	2,453	215	45	170	85	130
Kanawha R. (Kanawha Co. W. Va.)	14,480	1,750	130	1,620	240	1,510
Ohio R. (Gallia Co. Ohio)	77,600	8,600 (2)	1,010	7,590	1,980	6,620
Ohio R. (Warrick Co. Ohio)	113,700	13,000 (2)	1,420	11,580	3,220	9,780
Green R. (Muhlenburg Co. Ky.)	9,201	500 (1)	55	445	60	440
Ohio R. (Henderson Co. Ky.)	133,900	15,400 (2)	1,500	13,900	3,310	12,090
Wabash R. (White Co. Ill.)	11,540	610 (3)	330	280	1,120	-510

NOTES:

(1) Estimated from available information

(2) Ohio River Basin Commission (1977) estimates

(3) Low-flow (1 day, 50 year) from Illinois State Water Survey Report No. 4 (1975)

(4) Mean flow from U.S.G.S. Data

(5) Estimated uses are accumulated consumptive use for the Ohio Main Stem, or on its tributaries, use at the named location determined from the total tributary basin use from the ratio of drainage areas (ORBC 1977)

It is apparent from these results that significant water surpluses exist even at low-flow conditions all along the Ohio main stem both now (1975) and in the future. In fact at least some surplus under present use conditions exists at all sites listed. Under future (2000) condi tions deficit supplies are indicated for the Monongahelia River at Monongalia County, W. Virginia and the Wabash River at White County, Illinois, and only a relatively minor surplus will exist for the Tuscarawas River at Tuscarawas County, Ohio. Most of the other sites too far removed from the Ohio main stem for meaningful use estimates would also be expected to show supply deficits under these conditions.

3.5 Surface Water Quality

Water quality data on a number of chemical properties having potentially detrimental effects on coal conversion processes were compiled for many of the designated water supply sources. This information is of interest to provide some indication of the type and extent of pre-treatment facilities that must be installed at the plant sites. The properties considered in this analysis, generally because of their tendency to contribute to fouling or corrosion of the process equipment, are the following:

Silica SiO_2
Calcium - Ca
Magnesium - Mg
Bicarbonate - HCO_3
Sulfate - SO_4
Sodium Na
Chloride Cl
Total Dissolved Solids - TDS
Carbonate Hardness

Non-Carbonate Hardness
Hydrogen Ion Concentration - pH

The significance of these properties and their source or cause are described more fully in Table 3.4.

U.S. Geological Society water quality data was obtained for stations on many of the rivers specified as water sources for coal conversion sites. Up to 10 years of this data, generally monthly samples, for each water property was stored on computer files and then processed to determine the average value and range (minimum and maximum observed values) of each property at each location. The results of this analysis are given in Table 3.5. The number of samples used in these determinations and therefore the accuracy of the results in representing the actual average and expected range varied from site to site. Several years of data were used and therefore the stated values are most accurate for the following sources:

Tombigbee River, Alabama
Ohio River, Illinois
Muskingum River, Ohio
Allegheny River, Pennsylvania
Monongahelia River, West Virginia

Only one year of data was used for the following sources:

Illinois River, Illinois
White River, Indiana
Green River, Kentucky
Ohio River, Kentucky
Kanawha and New Rivers, W. Virginia

TABLE 3.4

SIGNIFICANCE OF THE CHEMICAL AND PHYSICAL PROPERTIES OF WATER

CONSTITUENT OR PHYSICAL PROPERTY	SOURCE OR CAUSE	SIGNIFICANCE
Silica (SiO_2)	Dissolved from practically all rocks and soils, usually in small amounts up to about 25 ppm. However water draining from deposits high in silicate minerals particularly feldspars often contain up to 60 ppm.	Forms hard scale in pipes and boilers. Carried over in steam of high pressure boilers to form deposits on blades of steam turbines. Inhibits deterioration of zeolite-type water softeners.
Calcium (Ca) and Magnesium (Mg)	Dissolved from practically all rocks and soils, but especially from limestone, dolomite, gypsum, and gypsiferous shale.	Causes most of the hardness and scale-forming properties of water; soap consuming (see hardness).
Sodium (Na) and Potassium (K)	Dissolved from practically all rocks and soils. Found also in sewage industrial waste and waste brines.	Moderate quantities have little effect on the usefulness of water for most purposes. Sodium salts may cause foaming in steam boilers.
Bicarbonate (HCO_3) and Carbonate (CO_3)	Action of carbon dioxide in water on carbonate rocks and soil minerals such as limestone and dolomite.	Bicarbonate and carbonate produce alkalinity. Bicarbonate of calcium and magnesium decompose in steam boilers and hot water facilities to form scale and release corrosive carbon-dioxide gas. In combination with calcium and magnesium cause carbonate hardness.
Sulfate (SO_4)	Dissolved from rocks and soils containing gypsum, iron sulfides, and other sulfur compounds. Usually present in drainage from mines and in some industrial wastes.	Sulfate in water containing calcium forms hard scale in steam boilers. In large amounts, sulfate in combination with other ions gives a bitter taste to water. Federal drinking water standards recommend that sulfate content should not exceed 250 ppm.
Chloride (Cl)	Dissolved from rocks and soils. Present in sewage and found in large amounts in waste brines and some other industrial wastes.	In large quantities increases the corrosiveness of water. Federal drinking water standards recommend that the chloride content should not exceed 250 ppm.
Dissolved Solids	Chiefly mineral constituents dissolved from rocks and soils. Includes any organic matter and some water of crystallization.	Federal drinking water standards recommend that the dissolved solids should not exceed 500 ppm. Waters containing more than 1,000 ppm of dissolved solids are unsuitable for many purposes.
Hardness as $CaCO_3$	In most waters nearly all the hardness is due to calcium and magnesium. All of the metallic cations other than the alkali metals also cause hardness.	Hard water forms scale in boilers, water heaters, and pipes. Hardness equivalent to the bicarbonate and carbonate is called carbonate hardness. Any hardness in excess of this is called noncarbonate hardness. Waters of hardness up to 60 ppm are considered soft; 61 to 120 ppm, moderately hard; 121 to 200 ppm, hard; more than 200 ppm, very hard.
Hydrogen ion Concentration (pH)	Acids, acid-generating salts, and dissolved carbon dioxide lower the pH. Carbonates, bicarbonates, hydroxides, phosphates, silicates, and borates raise the pH.	A pH of 7.0 indicates neutrality of a solution. Values higher than 7.0 denote increasing alkalinity; values lower than 7.0 indicate increasing acidity. pH is a measure of the activity of the hydrogen ions. Corrosiveness of water generally increases with decreasing pH. However, excessively alkaline waters may also attack metals.

Table 3.5

CHEMICAL CHARACTERISTICS OF THE SURFACE WATER SOURCES
(Average Concentration and Range in mg/l)

Source Location	Silica SiO_2 (as $CaCO_3$)	Calcium Ca (as $CaCO_3$)	Magnesium Mg (as $CaCO_3$)	Bicarbonate HCO_3 (as $CaCO_3$)	Sulfate SO_4 (as $CACO_3$)	Sodium Na (as $CaCO_3$)	Chloride Cl (as $CACO_3$)	Total Diss. Solids TDS	Carbonate Hardness	Non-Carbonate Hardness	pH
Alabama											
Tombigbee R. at Jackson, Ala.	9.1 (3.2-18)	37.8 (20-50)	12.9 (4.1-22.9)	43.7 (31.7-55.9)	19.4 (6.9-40.6)	22.9 (4.1-52.1)	16.7 (5.6-44.3)	91.4 (55.0-138.0)	50.6 (34.0-68.0)	14.1 (7.0-24.0)	6.9 (6.4-7.4)
Illinois											
Illinois R. at Marseilles Ill.	6.9 (4.7-8.2)	171.6 (140.0-207.5)	100.6 (82.0-131.2)	202.6 (179.3-225.4)	106.4 (83.2-135.2)	94.9 (60.8-134.5)	90.7 (60.1-140.1)	466.4 (411.0-519.0)	271.8 (222.0-340.0)	102.6 (65.0-160.0)	7.5 (7.1-7.9)
Ohio R. at Grand Chain Ill.	6.5 (3.7-9.3)	89.5 (57.5-137.5)	37.7 (21.3-57.4)	87.4 (47.0-125.4)	61.9 (26.0-163.3)	28.5 (12.2-60.8)	36.2 (10.7-100.1)	209.0 (87.0-382.0)	140.4 (86.0-248.0)	62.9 (26.0-146.0)	7.4 (6.6-8.3)
Indiana											
White R. at Hazleton, Ind.	5.7 (0.3-7.5)	128.6 (100.0-152.5)	65.6 (45.1-98.4)	202.6 (179.3-225.4)	106.4 (83.2-135.2)	94.9 (60.8-134.5)	22.9 (14.3-37.2)	268.5 (202.0-345.0)	195.5 (150.0-240.0)	51.0 (43.0-70.0)	7.7 (7.0-8.6)
Kentucky											
Green R. at Beech Grove Ky.	5.9 (5.0-6.7)	97.7 (75.0-135.0)	36.5 (27.9-65.6)	94.5 (70.6-119.6)	55.7 (19.8-114.4)	12.6 (6.7-23.9)	8.3 (4.3-18.5)	191.4 (130.0-288.0)	134.5 (100.0-200.0)	55.3 (29.0-110.0)	6.9 (6.0-8.5)
Ohio R. at Cannelton Dam, Ky.	4.6 (0.2-6.5)	95.7 (75.0-112.5)	41.9 (32.8-49.2)	79.4 (63.7-93.1)	71.8 (53.0-99.8)	37.3 (23.9-54.3)	32.8 (22.9-50.1)	215.6 (176.0-268.0)	137.3 (110.0-160.0)	72.0 (53.0-100.0)	7.1 (6.5-8.1)
Ohio											
Muskingum R. at McConnelsville	6.3 (0.0-11.0)	209.8 (95.0-385.0)	68.3 (36.1-106.1)	107.9 (35.3-161.7)	151.3 (68.6-220.5)	101.4 (21.3-258.2)	207.2 (31.5-614.9)	582.4 (196.0-1240.0)	316.7 (136.0-543.0)	226.0 (78.0-425.0)	7.2 (6.0-8.2)
Pennsylvania											
Allegheny at Oakmont, Pa.	-	84.3 (35.0-150.0)	42.9 (15.9-77.9)	14.2 (0.0-78,4)	113.5 (47.8-287.0)	-	29.9 (11.4-74.4)	215.6 (95.0-434.0)	127.9 (56.0-418.0)	102.6 (45.0-230.0)	6.2 (4.0-8.0)
W. Virginia											
Kanawha at Kanawha Falls	7.3 (1.8-14.0)	52.5 (27.5-92.5)	20.5 (12.3-31.9)	50.9 (25.5-100.0)	30.1 (18.7-57.2)	28.2 (8.3-76.0)	31.5 (5.0-85.8)	134.0 (82.0-252.0)	73.0 (43.0-122.0)	30.0 (17.0-44.0)	- (6.6-7.3)
Monongahela Fairmont W.Va.	-	-	-	-	169.5 (44.7-169.5)	36.5 (3.9-108.5)	8.6 (2.8-15.7)	324.0 (129.0-821.0)	102.0 (40.0-198.0)	-	- (3.6-6.0)

For these sources although the tabulated values give some indication of levels of the various constituents to be expected the true range of values that could occur might be quite different.

No data is reported for surface water quality from the Coosa (Alabama), Mississippi and Kaskaskia (Illinois), or Wabash (Indiana) Rivers. U.S.G.S. chemical quality monitoring stations apparently have not or have only recently been installed at these locations. The scarce quality data located in other governmental or regional reports for these sources was not suitable for inclusion with this data either because the properties of interest were not sampled or the sampling was not done on a systematic basis.

4. GROUNDWATER RESOURCES

4.1 General

Groundwater was specified as a primary supply for certain sites located in Illinois and Ohio. In several other regions, conditions appear to be favorable for the development of groundwater as an alternative source to unreliable surface supplies or as a supplemental source. As further described in Section 4.3, groundwater sources may have institutional advantages in some instances even though they would generally be more expensive to develop than surface supplies.

Situations favorable to groundwater development as supply sources for coal conversion plants generally meet the following conditions: expected well yields of 500 gpm or more; extensive, highly permeable aquifers; or recharge occurring through induced infiltration from nearby rivers. Rather extensive and costly well fields will normally have to be developed where groundwater is considered as a primary supply source. In order to provide the typical plant water requirement of 4000 gpm, a field consisting of at least 8 wells would have to be provided, even in areas producing high well yields of 500 gpm. The spacing of wells in such a field will have to be carefully controlled depending on the aquifer extent and permeability characteristics to avoid impacts on other local users through drawdown of the water table. In many areas having seasonally questionable surface water resources, development of less extensive or lower yielding wells may be important as a supplemental source.

4.2 Groundwater Availability

Groundwater in the East/Central coal region states is a large and important water resource that may have a significant role in development of the coal resource. In the Ohio River Basin which encompasses much of the study area, present groundwater development plans do not nearly utilize the full potential of the resource. It has been estimated (U.S.G.S. 1974) that the average annual groundwater recharge of the region is about 35 billion gallons per day. Annual groundwater use in 1960 by municipal and rural users was estimated to be about one billion gallons per day or only about 3 percent of recharge. Although not all of the groundwater is recoverable or located so as to be of value in energy development, much of it is.

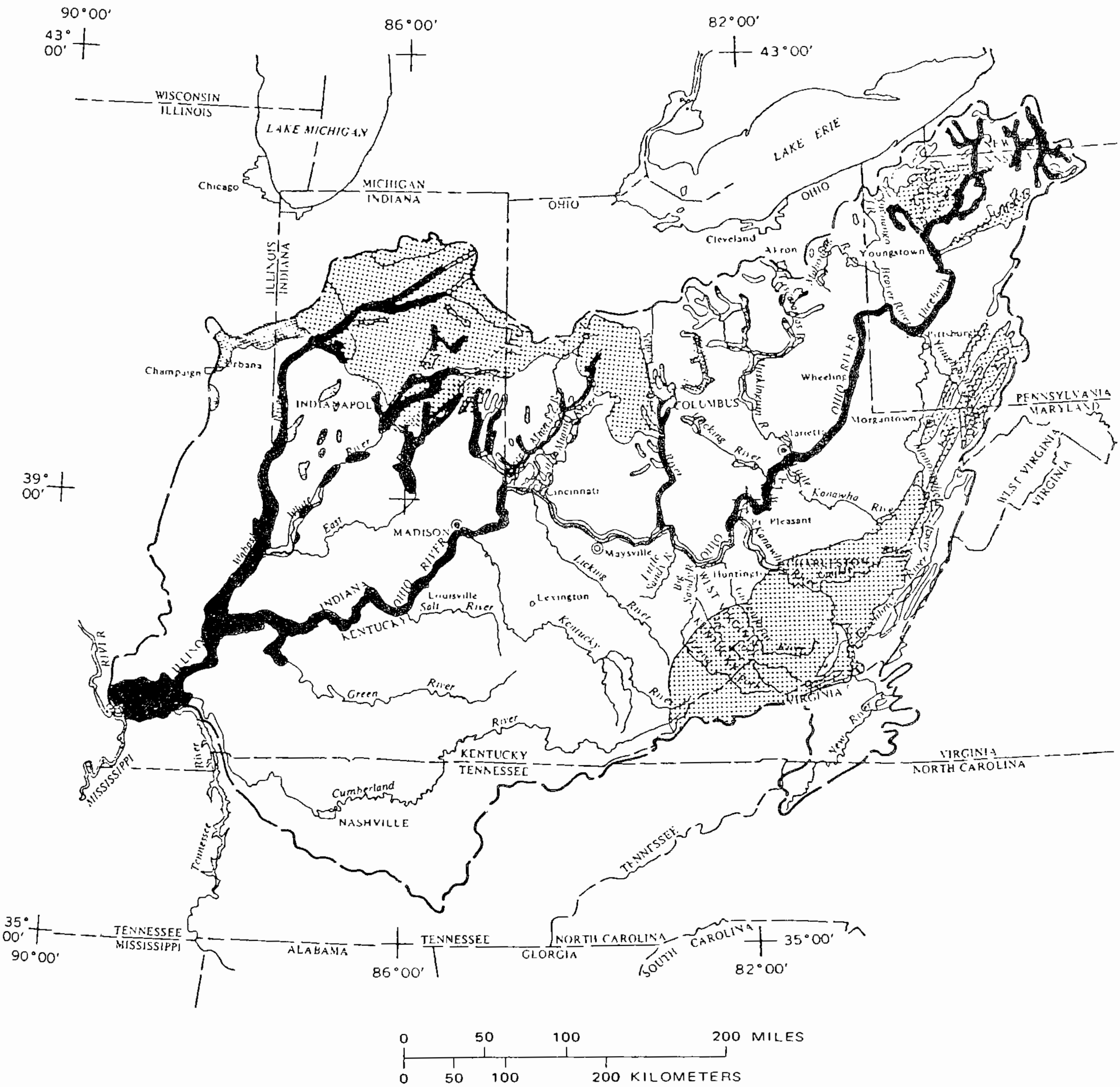
Alluvium, outwash, and glaciofluvial deposits constitute the most productive part of the region's groundwater system. Well sorted glacial sediments redeposited by streams above the southernmost glacial encroachment (roughly along the path of the Allegheny-Ohio Rivers), have helped to create highly permeable aquifers in widespread parts of the region. Alluvial deposits consisting of silt, sand, and gravel, present in the major tributary valleys south of the Ohio River, generally are finer grained and less permeable than the glaciofluvial deposits. Alluvial aquifers are usually shallow and unconfined. As a result drilling for alluvial groundwater is relatively inexpensive and simply drilled through the unconsolidated medium of gravel and/or sand.

In consolidated aquifers (limestone, sandstone, etc.) the ability of water to flow through is reduced as permeability decreases. Although high porosities may be present as in clays, the very low permeabilities prevent movement of water down the hydraulic gradient to a well. Therefore, even if large quantities of water are available the yields may be low due to the low rate of replenishment of water through the aquifer.

Therefore, in a consolidated aquifer yields exceeding 100 gpm are considered very good. Solution cracks which occur in limestones can greatly increase permeabilities, effectively forming an underground conduit where discharges can reach 2,500 gpm (as in, for example, certain areas in Pennsylvania). The incidence of such yields is, however, rare.

Figure 4.1 shows the general locations of high-yield sources of groundwater in the region.

Primary groundwater sources and all surface sources classified as unreliable in the assessment of surface supplies (Table 3.1) were considered in an initial review of groundwater availability. A screening process similar to that used for surface sources was utilized to establish whether or not it would be feasible to develop groundwater as sources of supply. The following criteria were used in assessing the situation at each site:



EXPLANATION

Potential yields to individual wells

From: Bloyd (1974)

- Unconsolidated aquifers, greater than 500 gpm
- Unconsolidated aquifers, 100-500 gpm
- Consolidated aquifers, 100-500 gpm

Figure 4.1 High-yield Sources of Groundwater

Yield Characteristics

A. Favorable. Well yields are expected to approach 500 gpm or more.

B. Possible. Well yields are expected to exceed 100 gpm.

C. Unfavorable. Well yields are generally less than 50 gpm.

Accessibility

A. On-site

B. Near by

C. Distant

Table 4.1 lists the primary sites considered in the groundwater analysis and the results of the assessment. Many of the sites show good potential for groundwater development.

The Wabash and White subbasins probably have the highest potential of all Ohio River subbasins for additional groundwater development. It is estimated (USGS, 1974) that about 30,000 billion gallons, or nearly 30 percent of the total potable groundwater available from storage in the Ohio Region, is stored in these subbasins. Estimated average annual groundwater recharge in these basins is 7.3 billion gallons per day while 1960 groundwater withdrawal estimates are only about 0.22 billion gallons per day (about 3 percent of recharge) which is only about 0.3 percent of potable groundwater storage. Many very high yield aquifers offer excellent possibilities for use to supply energy development programs. A further discussion of the groundwater situation at the sites having groundwater designated as a possible primary source follows.

Table 4.1

Assessment of Groundwater Availability at Sites with Insufficient Surface Supplies

State	County	Presently Designated Source	Potential Groundwater Yield*	Groundwater Accessibility	Groundwater Feasibility
Alabama	Jefferson	Coosa	Favorable	On-Site	Yes
Illinois	Bureau	Groundwater	Favorable	On-Site	Yes
	Fulton	Groundwater	Favorable	On-Site	Yes
	Saline	Saline	Unfavorable	Near by	No
	Shelby	Kaskaskia	Possible	Distant	Possible
Indiana	------------------ all okay ------------------				
Kentucky	Floyd	Levisa Fork	Unfavorable	Distant	No
	Harlan	Cumberland	Unfavorable	Distant	No
	Muhlenberg	Green	Possible	Near by	Possible
	Pike	Levisa Fork	Favorable	On-Site	Yes
Ohio	Tuscarawas	Tuscarawas & Groundwater	Favorable	On-Site	Yes
Pennsylvania	Somerset	Casselman	Favorable	On-Site	Yes
West Virginia	Mingo	Tug Fork	Favorable	On-Site	Yes
	Monongalia	Monongahela	Unfavorable	Distant	No
	Preston	Cheat	Favorable	On-Site	Yes

*Favorable = >100 gpm and likely to approach or exceed 500 gpm
Possible = generally >100 gpm
Unfavorable = <50 gpm

Bureau County, Illinois

The county sits on perhaps the most productive aquifer of the state. This aquifier is composed of coarse glacial outwash material along the Illinois River and spreads well laterally from the river channel. Due to the consistency of the aquifer material, transmissivity and rate of recharge are very high. Expected yields are in excess of 500 gpm (72 mgd).

Fulton County, Illinois

The squifer is of the same geologic age as that in Bureau County (Quarternary glacial deposits); however, it is of finer consistency and better sorted. As a result recharge rates and consequently the available well yields are lower. Its suitability for development is, therefore, not as great as in Bureau County.

Large yields are available in Mason County across the Illinois River. It is conceivable that this source could be used as a supply in conjunction with the available yields in Fulton County of more than 250 gpm.

Tuscarawas County, Ohio

The Muskingham River glacial outwash deposits form the aquifer in this area. It has been exploited for a considerable time. Outwash deposits, which are not directly recharged by the Muskingum and its tributaries, exist and are potentially good high yield aquifers. Yields of greater than 500 gpm are available in the valley train deposits of the Muskingum and potential for further development is good. Competing users, however, have large developments at the present time.

Marengo County, Alabama

Marengo County aquifers are extensive and consolidated. The structure is Cretaceous in age consisting of sands, marls, chalks and clays. None of these form excellent aquifers with only a few areas providing high yields. The majority range in yield from 25 to 100 gpm.

Serious drawdown has occurred in the city of Demopolis where yields of 400 gpm are maintained for the municipal water supply. Therefore, it is obvious that further exploitation of high yield aquifers may cause serious damage to the county's groundwater supplies

In a number of other areas having questionable surface supplies, groundwater many serve as a supplementary source or a temporary source to augment surface supplies during low flow. The general situation at these sites is as follows:

Saline County, Illinois

Conditions are unfavorable for groundwater development with highest yields of about 20 gpm from either the unconsolidated aquifer or from the consolidated limestone aquifers.

Shelby County, Illinois

Sandy aquifer along the Kaskaskia has predicted yields of 100 gpm but reliable long term yields may be less because the available recharge is restricted by the limited extent of the aquifer. However, the suitability for augmentation of low flows is favorable.

Floyd, Harlan, and Pike Counties, Kentucky

Sediments in the Levisa Fork Basin have low yields ranging from 10-25 gpm. The consolidated rocks of the county yield little water (< 25 gpm) and are brackish at shallow depths. These low yields are due in part to the incision of the area by a high density of valleys, consequently, breaking potential aquifiers and causing them to drain.

Somerset County, Pennsylvania

Yields as great as 1000 gpm are available in the limestone structures of Somerset County. However, the majority of wells yield 25-50 gpm. Due to the extreme variability of the consolidated aquifer yields in the limestone, it is difficult to reliably comment on its use for supplemental supplies without on-site test wells.

Mingo County, West Virginia

Within this county the best potential for groundwater sources exists in the valley deposits of the Tug Fork. Yields approach 50 gpm but the suitability as a continuous supply to augment surface supplies may be poor because of the restricted recharge characteristics of the relatively limited aquifers.

Monongolia and Preston Counties, West Virginia

The Monongahela River sediments have reasonable aquifers yielding as much as 75 gpm. Typical yields are 25 gpm for the majority of the consolidated aquifer, however, the deep sandstone aquifer have yields as high as 400 gpm. It is apparent that detailed surveying is needed to assess if well densities can provide the required yields for supplemental supplies.

An assessment of the additional secondary sites is given in Table 4.2. Of these, conditions appear to be most favorable for groundwater development in Fayette County, Alabama. With the exception of McCreary and Lee Counties, where little potential appears to exist for large groundwater supplies, development is a possibility at the other sites, depending on actual location.

4.3 Groundwater Doctrines

The principal groundwater doctrines affecting the use of groundwater involve the concepts of absolute ownership and that of reasonable use. Absolute ownership (or the English Rule) recognizes a landowner as the owner of all groundwater beneath his land and allows him to use it or interfere with it in any way without being accountable to other uses which may be affected. Although this interpretation is somewhat archaic, it still receives some continued acceptance.

The concept of reasonable use (or American Rule) of groundwater is most widely accepted and involves a definition of reasonable use significantly different than that under the Riparian Doctrine of surface supplies discussed in Section 3.3. As applied to groundwater, any reasonable use in connection with the land from which the groundwater is taken is allowed without regard to impacts the withdrawal may have on other users. Since the rights of property owners are clearly more absolute with regard to groundwater use than in the case of surface water, the development of reliable groundwater supplies for energy production may be preferable in certain areas on the basis of institutional feasibility.

Table 4.2

Assessment of Groundwater Availability
at the Secondary Sites

State	County	Present Source	Potential Ground-water Yield*	Groundwater Accessibility	Preliminary Groundwater Feasibility
Alabama	Fayette	Warrior	Favorable	On-Site	Yes
	Marion	Tennessee	Possible	On-Site	Possible
	Jackson	Tennessee	Possible	On-Site	Possible
	DeKalb	Tennessee	Possible	On-Site	Possible
Kentucky	McCreary	Cumberland	Unfavorable	Distant	No
	Lee	Kentucky	Unfavorable	Distant	No
Penn.	Clearfield	West Branch	Possible	On-Site	Possible
	Cambria	Conemaugh	Possible	On-Site	Possible
W. Va.	Randolph	Tygart	Possible	On-Site	Possible
	Greenbrier	Greenbrier	Possible	On-Site	Possible

*Favorable = >100 gpm and likely to approach or exceed 500 gpm
Possible = generally > 100 gpm
Unfavorable = < 50 gpm

As discussed in Section 3.3 certain Eastern states are beginning to depart from strict adherence to the common laws of water use by considering statutory modifications to, in some way, regulate use. Of the states included in this study, only Kentucky and Indiana have enacted such statutes to-date. In Indiana where statutes involve only groundwater use, the Department of Conservation has authority to restrict withdrawals where other users would be affected. New users of more than 100 gpd are required to obtain a permit. Other states, North Carolina for example, have moved to control groundwater use in designated problem areas only.

Although disruption of groundwater systems by valid users is in some instances allowable from a purely legal point of view, minimizing impacts by use or mining operations should be an important consideration in the siting, design, and/or operation of conversion plants. The potential effects of mining and water withdrawal on groundwater systems are discussed in Section 5 of this report.

4.4 Groundwater Quality

As discussed earlier in Section 3.5, data on the chemical quality of water to be supplied to conversion plants is of interest due to the detrimental effects certain constituents can have on the process equipment. The properties of interest and the reasons for their importance are shown in Table 3.4.

The effects of man-made pollutants or constituents on the variability of groundwater quality is generally considerably less than for surface waters. From location to location, however, groundwater quality can vary greatly due primarily to geologic differences. The influence of anhydrite and calcareous lenses, and fractured planes of various other minerals can alter the physical properties of groundwater significantly over small distances. Throughout the region of interest, brackish water (high total Dissolved Solids) exists generally within 500 feet of the surface and closer in many instances.

The valley fill or unconsolidated alluvial aquifers are products of the last ice age being derived mainly from outwash material off of the retreating ice sheets. The material in the valleys along the Ohio River and mouth of it is considerably coarser and of greater extent than the deposits to the south. In general, the coarser deposits are more readily recharged and give higher yields and better quality than the fine sands and gravels of some valley fill deposits. Consequently, the yields are greater and the quality is better on the northern side of the Ohio River Valley.

The sedimentary rocks of the Appalachian Chain (consolidated aquifers) contain vast quantities of potable (non brackish) water. Yields from these aquifers rarely exceed 100 gpm and are, therefore, of limited use for coal conversion purposes. The density of wells needed to provide the required yields from consolidated aquifers may be restrictive. In some cases yields as great as 2,500 gpm occur in consolidated aquifers in the region but are not near proposed sites for coal conversion plants. Such high yields eminate primarily from limestone solution cracks (caves) where the entire flow of an aquifer becomes concentrated at one point.

The quality of consolidated aquifers is generally better than that of unconsolidated aquifers, particularly from sandstone beds. As a result they could become important as supplemental suppliers during periods of low flow.

Alluvial aquifers rarely have brackish conditions. This is primarily due to direct recharge from the valley stream or from rainfall infiltration. The recharge contribution to alluvial aquifers from consolidated aquifers is small compared to these sources

Because groundwater quality is so spacially variable in most areas, the chemical properties of water from a given location are rather unique to the well from which the sample was taken. It is therefore meaningless to present extensive groundwater sampling data as an indication of what conditions might be like in any particular county in the study area. The groundwater quality data in Table 4.3 is presented simply to illustrate the conditions at a few selected sites.

Table 4.3

CHEMICAL CHARACTERISTICS OF GROUNDWATER SOURCES
(Source: U.S.G.S. Well Records)

	Aquifer Location and Type				
Property[†]	Marengo, Al. Consolidated	Jefferson, Al. Consolidated	Bureau, Ill. Alluvial	Muhlenburg, Ky. Alluvial	Tuscarawas, Oh. Alluvial
Fe	1.1	< 0.3	3.3	-	-
F	-	-	0.4	-	-
SiO_2	-	-	-	3.7-22	-
Ca	2.4	-	-	41-152	75
Ma	0.4	-	-	5.8-50	20
Na	-	-	-	3.8-88	-
HCO_2	489	-	-	104-639	217
SO_4	-	< 17	0.2	8-155	-
Cl	58	-	1.6	2.1-84	6.7
T.D.S.	-	120-210	360	174-691	363
Hardness CO_3	8	-	263	126-564	275
Hardness Non CO_3	-	-	-	0-209	-
pH	8.3	-	-	6.4-8.0	7.5

[†]Concentration in mg/l.

5. POTENTIAL ENVIRONMENTAL IMPACTS

A number of potential hydrologic and environmental impacts are associated with both the traditional coal mining operation and the process of converting the coal produced to synthetic fuels. The potential impacts due to either action generally fall into three categories: impacts on the land, impacts on surface water quality, and impacts on groundwater systems. In many instances these effects can be minimized or avoided through controlled siting, design and operation of the facilities. Some impacts, at least temporary, can be expected simply due to the large scale of the operation.

5.1 Impacts on the Land

Potential impacts on the land are the result of the massive earth-moving operation involve in coal mining, particularly strip mining. The problems of erosion resulting from land clearing and grading activities may be effectively handled by measures taken to control surface drainage on the site. A major concern about strip mining has been the scaring of the land that has often resulted in the past. Modern mining techniques and tough new Federal and State reclamation standards should reduce this problem.

5.2 Water Quality Impacts

A water quality problem associated with the erosion effects mentioned above, is that of sediment loadings and siltation of stream channels.

Effective control of these problems depends on proper handling of mine spoils and overburden to prevent surface drainage from flowing down steep slopes over loose exposed earth.

Synthetic fuel plants may produce a number of waste residues that could be detrimental to water quality if discharged into surface waters. Planning for the safe disposal of all waste residues is an important consideration of plant development and design. In many instances, where the plants consume all water taken in and no return flow possibly contaning residues is returned to the receiving waters, the potential for environmental degradation is minimized.

In certain coal mining areas, particularly the northern Appalachian region of West Virginia and eastern Pennsylvania, acid mine drainage is a significant problem. Acid water conditions are most likely to occur where a combination of three factors exists:(1) extensive surface or subsurface mining in strata which contain iron sulfide minerals, (2) abundant rainfall and runoff on steep slopes; and (3) low natural alkalinity in natural watersheds. The results of acid water conditions may be corrosive damage to concrete and metals, increased treatment costs for municipal and industrial supplies, altered ecological systems, and reduced recreational values. Although no single procedure has been developed to effectively deal with the acid mine drainage problem, a variety of corrective measures are being promoted by State and Federal agencies. These measures generally fall into the following categories (USGS, 1965):

1) minimizing the contact between water and acid-producing materials,

2) regulating the flow of mine wastewater to nearby streams,

3) neutralizing acid wastewater with Alkaline compounds, and

4) protecting acid-producing materials from weathering and erosion at the end of mining operations.

Water quality of streams can also be affected by the withdrawal of significant amounts of water to supply the needs of the conversion process. Such withdrawals from the smaller streams reduce the total flow available for dilution of man-made pollutants. The potential impact of this action can be overcome by augmenting conversion plant supplies to the fullest extent possible with lesser quality water from such sources as treated municipal or industrial wastewater effluents or brackish groundwater supplies.

5.3 Impacts on Groundwater Systems

A major potential impact of the coal mining operation common to nearly all coal bearing regions is that the mining will disturb existing aquifers and result in the lowering of nearby well yields or cause small locally used aquifers to be depleted. When a productive aquifer is cut by the mining operation, a large free-surface discharge into the mine way be created which can significantly lower the hydraulic gradient (i.e., water table) of the aquifer in the vicinity of the mine.

Typically unconsolidated deposits lie on the surface and extend to a few hundred feet (at most) below the surface. Potentially unconsolidated aquifers offer large yields (in excess of 500 gpm) in Bureau County, Illinois and along the Muskingum River in Tuscarawas County, Ohio. In Tuscarawas County the aquifer would be unaffected as the coal is located at higher elevations than the river recharge area. In Bureau County, however, the present potential aquifer lies above the coal and would thus be regarded as "overburden" and consequently removed. The local effects in Bureau County could be, for example, significant local lowering of the water table. Because this problem is very localized and dependent on the underlying aquifer structure, the situation can only be accurately evaluated on a site by site basis at a much smaller scale than present site definitions allow.

Another potential impact on groundwater systems is the effect of large withdrawal rates for conversion plant supplies. If these withdrawals exceed aquifer recharge or transmissibility rates, they to can lower the local groundwater table. Therefore, the feasibility of using groundwater as a water supply source must be carefully evaluated based on the ability of the local aquifers to supply the required yields without widespread lowering of the water table or other impairments of existing users in the area.

Based on the above considerations a brief qualitative evaluation of potential groundwater impacts was conducted for the primary groundwater supply sites and several other sites where groundwater looks promising as a supplemental source. These assessments are presented in Tables 5.1 and 5.2.

TABLE 5.1

ASSESSMENT OF POTENTIAL IMPACTS AT DESIGNATED GROUNDWATER SITES

Site Location	Mining Type	Aquifers Disturbed	Problems
Marengo, Al.	Surface	Sandstone above coal. Our source is cretaceous sandstone aquifers and may be unaffected. Lignite (paleocene) overlies main aquifers -- no problem for supply to coal conversion plants.	Acid mine drainage; lowering of local well levels; possible aquifer destruction.
Bureau, Ill.	Surface/ Underground	Unconsolidated glacial outwash aquifers considered as source of water. Significant disturbance if a strip mine, less of a problem if an underground mine.	Large volumes of drainage from overlying aquifer. Aquifer material would be overburden to a strip mine. Subsequent high discharges into mine would be an operational problem. Underground mine preferable here if possible.
Fulton, Ill.	Surface	Structure very similar to Bureau Company. Aquifer disturbance could be greater here as it is a proposed surface mining area.	Large volumes of drainage from overlying aquifer. Aquifer material would be overburden to a strip mine. Subsequent high discharges into mine would be an operational problem. Underground mine preferable here if possible.
Tuscarawas, Ohio	Underground	Deep mining will have little affect on alluvial aquifers along Muskingum River. Aquifers above coal will be disturbed.	Mine drainage from sandstone aquifers above coal. Little affect as few users of this water.

TABLE 5.2

ASSESSMENT OF POTENTIAL IMPACTS AT SUPPLEMENTAL GROUNDWATER SITES

Site Location	Mining Type	Aquifers Disturbed	Problems
Saline, Ill.	Surface	Only unconsolidated aquifer in area. Low yields. High disturbance.	Definite problem to present users.
Shelby, Ill.	Underground	Unconsolidated aquifer of Kaskaskia River Basin unaffected, aquifers in coal series less than 20 gpm. No problem	No significant problems.
Floyd & Harlan, Ky.	Underground	All aquifers are brackish at shallow depth. Impact on present aquifers small as they are near surface. Very low yield aquifers only provide domestic water.	No significant problems.
Pike, Ky.	Surface	Likely removal and consequent drainage of shallow sandstone. Aquifers of low yield.	Domestic users heavily affected since deeper sypplies would be brackish.
Somerset, Pa.	Underground	Good aquifers in sandstone, are below coals. Aquifers above coal subject to drainage.	Alternative domestic supplies might have to be provided for aquifers disturbed.
Mingo, W. Virginia	Surface	Valley deposits will be unaffected.	No significant problems.
Monongalia & Preston, Ky.	Underground	Main coals at top of Pennsylvanian. High yield aquifers below coals. Domestic aquifers of Permian (above coal) will be affected.	Alternative domestic supplies might have to be provided for aquifers disturbed.

6. SITE SPECIFIC SUMMARY

This section presents a general summary of the water resources situation at the proposed coal conversion plant sites in each state. Separate tables for each state list first the primary specific sites studied in detail and then the additional secondary sites investigated in a general sense only. The water supply source designated for each site in the coal reserve-water supply matrix is listed along with a qualitative (good, fair, or poor) evaluation of the adequacy of the source. This assessment is based on a comparison of plant requirements with low streamflow conditions and other considerations as described fully in the earlier text.

Alternative sources are suggested where designated sources are not rated "good", and the adequacy of these alternatives is rated based on a brief review of the associated supply condition. Since groundwater may be considered as a supplemental or conjunctive supply in many instances, groundwater availability in the vicinity of each site is rated based on the general aquifer structure in that area. It must be recognized that actual well yields that may be realized at a given location, particularly those from fractured consolidated aquifers in the Appalachian region, are very site dependent.

Based on the results of the overall investigations conducted, a water supply source or combination of sources is suggested that would appear to best meet the water supply needs at each site. The originally designated sources are used for this purpose to the fullest extent feasible. This evaluation is based on water supply considerations only accounting for the required reasonable sharing of available supplies, but not considering the many other institutional (such as the non-riparian use restriction), political, or environmental considerations that may enter into the final selection of the water supply make-up at a particular location. Some indication of the likelihood of environmental impacts at a specific site is given in the last column. This is a qualitative assessment of potential environmental impacts based on the factors discussed in Section 5 and the general area of the site. It must be emphasized that actual environmental effects associated with coal mining and conversion are very site and design/operation dependent, and can not be reliably evaluated without specific site and design data.

Table 6.1

WATER RESOURCES SUMMARY FOR ALABAMA

Location	Designated Source	Adequacy of Source	Alternate Source	Adequacy of Alternate	Groundwater Availability	Recommended Supply	Environmental Impact
Primary Sites							
Jefferson	Coosa R.	Good	-	-	Fair	Coosa	Moderate
Marengo	Tombigbee R.	Fair	Groundwater	Fair	Fair	Tombigbee & G.W. Augment	Significant
Secondary Sites							
Fayette	Warrior R.	Fair	Groundwater	Fair	Fair	Warrior & G.W.	Moderate
Marion	Tennessee R.	Good	-	-	Fair	Tennessee	Minimal
Jackson	Tennessee R.	Good	-	-	Fair	Tennessee	Minimal
DeKalb	Tennessee R.	Good	-	-	Fair	Tennessee	Minimal

Table 6.2

WATER RESOURCES SUMMARY FOR ILLINOIS

Location	Designated Source	Adequacy of Source	Alternate Source	Adequacy of Alternate	Groundwater Availability	Recommended Supply	Environmental Impact
Primary Sites							
Bureau	Illinois R.	Fair	Groundwater	Very Good	Very Good	Groundwater	Moderate
Fulton	Groundwater	Good	-	-	Good	Groundwater	Moderate
St. Clair	Mississippi River	Very Good	Groundwater	Very Good	Very Good	Mississippi R.	Minimal
Saline	Saline R.	Very Poor	Ohio	Good	Very Poor	Ohio R.	Significant
Shelby	Kaskaskia R.	Poor	Lake Shelbyville	Fair	Fair	Kaskaskia & G.W.	Moderate
White	Wabash R.	Good	-	-	Fair	Wabash	Moderate
Secondary Sites							
McLean	Illinois R.	Fair	Groundwater	Fair	Fair	Illinois & G.W.	Moderate
Mercer	Mississippi R.	Very Good	Groundwater	Very Good	Very Good	Mississippi	Minimal

Table 6.3

WATER RESOURCES SUMMARY FOR INDIANA

Location	Designated Source	Adequacy of Source	Alternate Source	Adequacy of Alternate	Groundwater Availability	Recommended Supply	Environmental Impact
Primary Sites							
Gibson	White R.	Good	Groundwater	Fair	Fair	White & G.W.	Moderate
Sullivan	Wabash R.	Good	Groundwater	Good	Good	Wabash R.	Moderate
Vigo	Wabash R.	Good	Groundwater	Good	Good	Wabash R.	Moderate
Warrick	Ohio R.	Very Good	Groundwater	Very Good	Very Good	Ohio R.	Minimal

Table 6.4

WATER RESOURCES SUMMARY FOR KENTUCKY

Location	Designated Source	Adequacy of Source	Alternate Source	Adequacy of Alternate	Groundwater Availability	Recommended Supply	Environmental Impact
Primary Sites							
Floyd	Levisa Fork	Very Poor	Unknown	-	Very Poor	Unknown	Significant
Harlan	Cumberland R.	Very Poor	Surface	-	Very Poor	Unknown	Significant
Henderson	Ohio R.	Very Good	-	-	Good	Ohio R.	Minimal
Muhlenburg	Green R.	Fair	Groundwater	Fair	Fair	Green & G.W.	Moderate
Pike	Levisa Fork	Very Poor	Unknown	-	Very Poor	Unknown	Significant
Secondary Sites							
Hopkins	Green R.	Fair	Groundwater	Fair	Fair	Green & G.W.	-
Lawrence	Big Sandy R.	Fair	Groundwater	Fair	Fair	Big Sandy & G.W.	Moderate
Lee	Kentucky R.	Poor	Unknown	-	Poor	Unknown	-
McCreary	Cumberland R.	Poor	L. Cumberland	Good	Poor	Unknown	-

Table 6.5

WATER RESOURCES SUMMARY FOR OHIO

Location	Designated Source	Adequacy of Source	Alternate Source	Adequacy of Alternate	Groundwater Availability	Recommended Supply	Environmental Impact
Primary Sites							
Galia	Ohio R.	Very Good	-	-	Very Good	Ohio R.	Minimal
Jefferson	Ohio R.	Very Good	-	-	Very Good	Ohio R.	Minimal
Tuscarawas	Tuscarawas	Fair	Groundwater	Very Good	Very Good	Groundwater	Moderate
Secondary Sites							
Morgan	Muskingum	Good	Groundwater	Very Good	Very Good	Muskingum & G.W.	Moderate

Table 6.6

WATER RESOURCES SUMMARY FOR PENNSYLVANIA

Location	Designated Source	Adequacy of Source	Alternate Source	Adequacy of Alternate	Groundwater Availability	Recommended Supply	Environmental Impact
Primary Sites							
Allegheny	Allegheny R.	Good	-	-	Good	Allegheny	Moderate
Luzerne	Susquehanna R.	Good	-	-	Good	Susquehanna	Moderate
Schuylkill	Susquehanna R.	Good	-	-	Good	Susquehanna	Moderate
Somerset	Casselman R.	Poor	Quemahoning Res.	-	Good (Highly Variable)	Casselman & G.W.	Significant
Secondary Sites							
Venango	Allegheny R.	Good	Unknown	-	Fair	Allegheny	Moderate
Clearfield	West Branch	Fair	Unknown	-	Fair	Unknown	-
Cambria	Conenaugh R.	Poor	Unknown	-	Poor	Unknown	-

Table 6.7

WATER RESOURCES SUMMARY FOR WEST VIRGINIA

Location	Designated Source	Adequacy of Source	Alternate Source	Adequacy of Alternate	Groundwater Availability	Recommended Supply	Environemtnal Impact
Primary Sites							
Fayette	New R.	Good	-	-	Poor	New	Moderate
Kanawha	Kanawha R.	Good	-	-	Fair	Kanawha	Moderate
Marshall	Ohio R.	Very Good	-	-	Good	Ohio	Minimal
Mingo	Tug Fork	Poor	Groundwater	Fair	Fair	Tug & G.W.	Moderate
Monongalia	Monongahela R.	Fair	Groundwater	Fair-Good	Fair-Good	Monongahela & Groundwater	Moderate
Preston	Cheat R.	Poor	Groundwater	Poor	Poor	Unknown	Significant
Secondary Sites							
Randolph	Tygart R.	Poor	Unknown	-	Very Poor	Unknown	-
Greenbrier	Greenbrier R.	Fair-Poor	Unknown	-	Very Poor	Unknown	-

REFERENCES AND DATA SOURCES

References

Ausness, R., Legal Institutions for the Allocation of Water and their Impact on Coal Conversion Operations in Kentucky., Research Report No. 95, University of Kentucky Water Resources Research Institute, 1976.

Bloyd, R.M., Jr., Summary Appraisals of the Nation's Ground-Water Resources-Ohio Region, U.S.G.S., Professional Paper 813-A, 1974.

Cox, W.E., and Walker, W.R., Energy Self-sufficiency: Are Eastern Water Rights a Serious Constraint?, 1975.

Illinois State Water Survey, Coal and Water Resources for Coal Conversion in Illinois, Cooperative Resources Report, No. 4, 1975.

Ohio River Basin Commission, Preliminary Unpublished Data on - Ohio River Instream Flows and Consumptive Water Use, 1977.

Schneider, W.J., et. al., Water Resources of the Appalachian Region, Pennsylvania to Alabama, USGS, HA 198, 1965.

U.S.G.S., Proposed Surface Data Programs in (each state), 1970.

Data Sources

Geological Survey of Alabama, Water Availability of Jefferson County, Alabama, 1976.

Geological Survey of Alabama, Newton J.G., et. al., Geology and Ground-Water Resources of Marengo County, Alabama, County Report 5, 1961.

Carlston, C.W., Groundwater Resources of Monongalia County, West Virginia, USGS, Bull. 15, 1958.

Doll, W.L., Water Resources of Kanawha County, West Virginia, USGS, Bull. 20, 1960.

Hyman, D.J., and Pettijohn, R.A., Wabash River Basin Comprehensive Study, 1971.

Maxwell, B.W. and Devaul, R.W., Reconnaissance of Groundwater Resources in the Western Coal Field Region, Kentucky, USGS, Water Supply Paper 1599, 1962.

McGuinness, C.L., The Role of Ground Water in the National Water Situation, USGS, Water Supply Paper 1800, 1963.

Ohio Department of Natural Resources, Low Flow Frequencies and Storage Requirements for Selected Ohio Streams, Bull 37, 1963; Bulletin 40, 1965.

Price, W.E., et. al., Reconnaissance of Ground-Water Resources in the Eastern Coal Field Region, Kentucky, U.S.G.S., Water Supply Paper 1607, 1962.

Resource Analysis, Inc., Hydrologic Analysis of Low-Flow Conditions for Water Quality Management in the Kanawha River Basin, 1976.

U.S.G.S., Availability of Groundwater in McLean and Muhlenburg Counties, Kentucky, 1962.

U.S.G.S., Availability of Groundwater in Floyd, Harlan, Pike (and others) Counties, Kentucky, HA-36, 1962.

U.S.G.S., Water Resource Investigations (each state) Maps.

U.S.G.S., Water Resources Data for (each state), Water Year 1975.

Ward, P.E. and Wilmouth, B.M., Ground-Water Hydrology of the Monongahela River Basin in West Virginia, U.S.G.S., River Bull. 1, 1968.

APPENDIX 14

WATER AVAILABILITY AND DEMAND IN WESTERN REGION

Resource Analysis, Inc., under subcontract to Water Purification Associates, prepared a general assessment of the water resources data in the major coal and oil shale bearing regions of the United States. Water resources data was collected and used as a basis for determining the availability of surface and groundwater resources at specific coal and oil shale conversion plant sites in the Eastern and Central coal bearing regions and the Western coal and oil shale bearing regions. The draft report on the Western region that was submitted as part of their study is included in its entirety in this Appendix.

Resource Analysis, Inc.
235 WYMAN STREET
WALTHAM, MASSACHUSETTS 02154
617-890-1201

WATER SUPPLY DATA FOR THE WESTERN COAL AND OIL SHALE REGION FOR AN ASSESSMENT OF WESTERN REGIONAL WATER SUPPLY AND DEMAND REQUIREMENTS FOR SYNTHETIC FUEL PRODUCTION

Prepared under subcontract to

WATER PURIFICATION ASSOCIATES
238 Main Street
Cambridge, Massachusetts 02142

August, 1978

TABLE OF CONTENTS

LIST OF FIGURES

LIST OF TABLES

1. INTRODUCTION

1.1 Study Objectives

This draft report presents the results of an evaluation of water supply availability for synthetic fuel production in the easily mined coal and oil shale regions of the Western United States. This study is being performed under subcontract to Water Purification Associates, Cambridge, Massachusetts, as a part of an investigation entitled, "An Assessment of Western Regional Water Supply and Demand Requirements for Synthetic Fuel Production" for the U.S. Environmental Protection Agency.

The need for such an assessment exists because of the limited water supplies that are available throughout much of the area in which the vast coal and oil shale reserves are located. An adequate and dependable water supply is essential to the siting and operation of the synthetic fuel production processes under study. Significant quantities of water are consumed as a raw material on a continuous basis in the liquefaction and the gasification processes of converting the raw material into more easily used forms. Water may also be required for cooling, land reclamation, and a variety of ancilliary uses. Large quantities of water are also required where slurry pipelines are used to transport coal from the source to the actual conversion site.

Prior studies of the water situation in the West have generally indicated that either on a regional basis there is enough water to meet the projected needs, or that on a specific local basis there exists over-commitments and shortages. The fact is that although surface and groundwater supplies vary tremendously with location and complex regulations may govern the use of water, significant water sources exist within reasonable distances to most coal reserves.

The overall objectives of the water resources portion of this study are therefore to identify reliable surface and/or groundwater supplies that would be available or could be made available for future energy development at each site under study. Potential water supply sources for each site are evaluated on a site specific basis in terms of the total available water supply, the needs and rights of other competing water users, and the quality of the alternative water supplies. This report presents some of the water availability data that can serve as a basis for determining the relative feasibility of certain specific sites that were selected for study.

1.2 Study Region and Specific Sites

The specific sites selected for detailed feasibility analysis with regard to water availability and requirements are located in the six western states having the most readily accessible coal and oil shale deposits.

The vast Fort Union and Powder River coal formations cover large areas of the states of Wyoming, Montana, and North Dakota in the Upper Missouri River Basin. Other significant coal and oil shale deposits are situated in the Upper Colorado River Basin in the states of Wyoming, Colorado, Utah, and New Mexico. Table 1.1 presents a list of 32 specific site locations that were selected for study based on their proximity to readily developable energy reserves. The locations of these sites with respect to the major energy reserves and the primary water resources characteristics are shown in Figure 1.1.

1.3 Scope of Studies

The approach taken in this study was to first conduct a review of existing literature on the water situation in the West to develop a thorough qualitative understanding of the water resources and hydrology of the regions of interest; regulations effecting the allocation of water among competing users; present water use; and projections of future needs for existing users and energy development During the course of this review these issues were discussed at length with numerous local, state, and federal planners and officials

Table 1.1

PLANT SITE LOCATIONS IN THE WESTERN STUDY REGION

State	Mine	County	Deposit	Hydrologic Sub-Region
UPPER MISSOURI RIVER BASIN				
Wyoming	Gillette	Campbell	Subbituminous	Belle Fourche-Cheyenne
	Spotted Horse	Campbell	Subbituminous	Powder
	Belle Ayr	Campbell	Subbituminous	Belle Fourche-Cheyenne
	Antelope Creek	Converse	Subbituminous	Belle Fourche-Cheyenne
	Lake de Smet-Banner	Johnson	Subbituminous	Powder
	Hannah Coal Field	Carbon	Subbituminous	North Platte
Montana	Decker	Big Horn	Lignite	Tongue-Rosebud
	Otter Creek	Powder River	Lignite	Tongue-Rosebud
	Pumpkin Creek	Powder River	Lignite	Tongue-Rosebud
	Moorhead	Powder River	Lignite	Powder
	Foster Creek	Powder River	Lignite	Tongue-Rosebud
	U.S. Steel-Chupp	Dawson	Lignite	Missouri Mainstem
	Coalridge	Sheridan	Lignite	Missouri Mainstem
	Colstrip	Rosebud	Subbituminous	Tongue-Rosebud
North Dakota	Slope	Slope	Lignite	Heart-Cannonball
	Dickenson	Stark	Lignite	Heart-Cannonball
	Bently	Hettinger	Lignite	Heart-Cannonball
	Scranton	Bowman	Lignite	Heart-Cannonball
	Williston	Williams	Lignite	Missouri Mainstem
	Knife River	Mercer	Lignite	Missouri Mainstem
	Underwood	McLean	Lignite	Missouri Mainstem
	Center	Oliver	Lignite	Missouri Mainstem
UPPER COLORADO RIVER BASIN				
Wyoming	Kemmerer	Lincoln	Bituminous	Upper Green
	Jim Bridger	Sweetwater	Subbituminous	Upper Green
	Rainbow #8	Sweetwater	Bituminous	Upper Green
	Tract W-9/W-b	Sweetwater	Oil Shale	Upper Green
Colorado	Tract C-a/C-b	Rio Blanco	Oil Shale	Lower Green
	Colony Development	Garfield	Oil Shale	Upper Colorado
Utah	Tract U-a/U-b	Unitah	Oil Shale	Lower Green
New Mexico	El Paso	San Juan	Subbituminous	San Juan
	Wesco	San Juan	Subbituminous	San Juan
	Gallup	McKinley	Subbituminous	San Juan

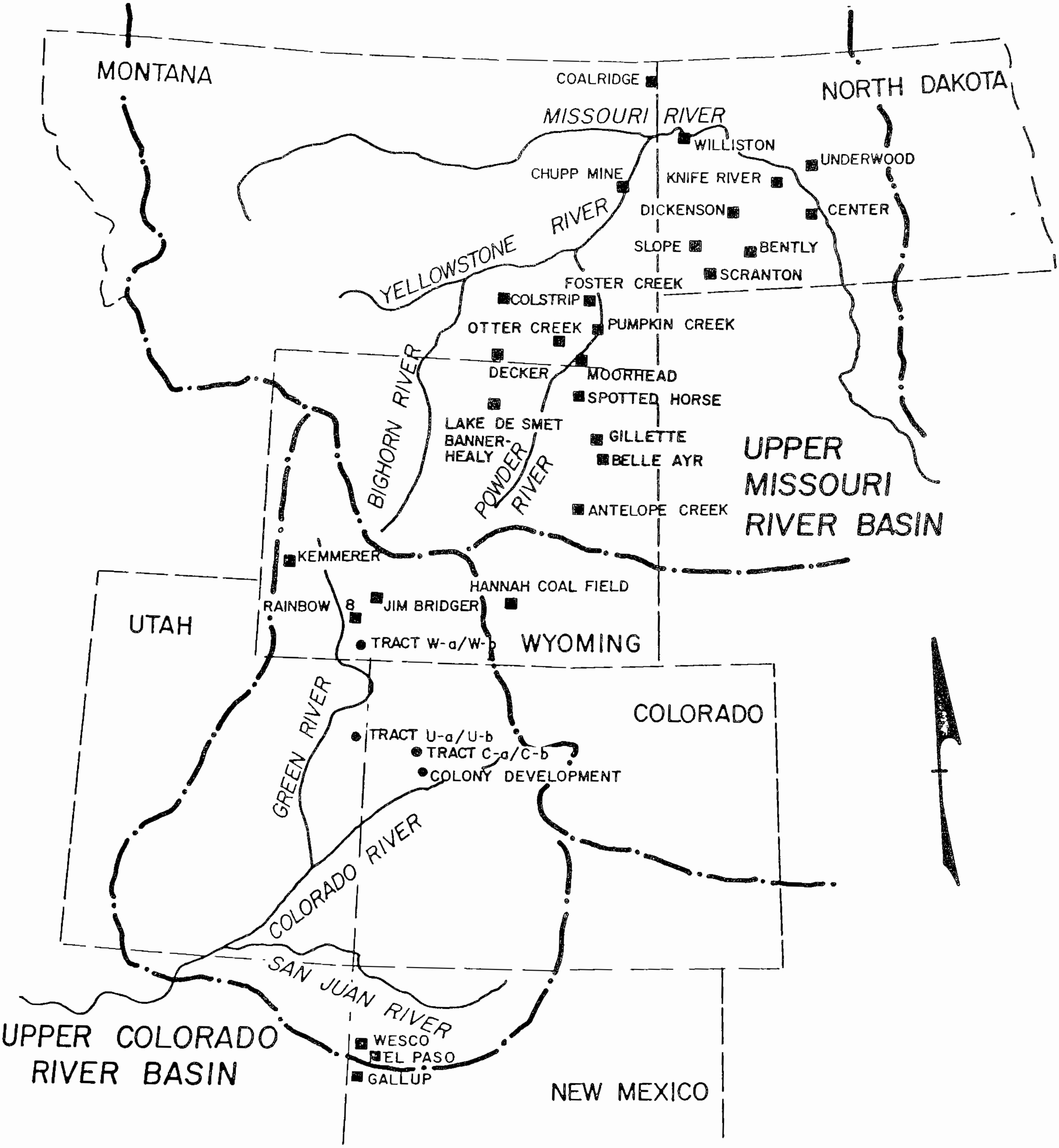


FIGURE I.1 SPECIFIC SITE LOCATIONS

The information gained from this continuing review process formed the basis for a quantitative assessment to establish the areas where water availability and energy reserve deposit locations are most conducive to conversion plan siting. A summary of the results of these findings are given in Section 2 of this report. The data leading to these conclusions is then presented in Sections 3 through 6.

Section 3 discusses the overall water supply situation in the study area in terms of the total quantities of surface and groundwater available to all users. The constraints of how these basic supplies may be used are considered in Section 4. In a region where water scarcity is often a limiting growth factor, a very explicit set of priorities has evolved over the years to regulate how and by whom the water can be used. Section 5 discusses the present water use situation and the factors that may alter these uses or otherwise effect water demands in the future.

This information and data is all brought together in Section 6 to estimate the levels of water availability for future energy development at the sites in question. This is accomplished by comparing the basic water yields on a sub-regional basis with present and projected future demands exclusive of the desired water needs for synthetic fuel production. This indicates the extent if any to which energy development can occur at various locations without further water resources development projects or disruption of the local way of life due to transfers of water rights to energy development use from other sectors of demand. Based on several scenarios of future energy development published by different sources, alternative methods of meeting the water supply needs for energy may be identified. Finally, some conclusions can be made on a site specific basis as to the relative costs and socio-economic impacts associated with supplying various levels of water for energy needs at different sites.

2. SUMMARY OF RESULTS AND CONCLUSIONS

This report presents the results of investigations to establish water availability for synthetic fuel production in the major hydrologic sub-regions of the Western U.S. which have significant recoverable energy reserves. Associated with this use in the same general areas are projections of significant increases in conventional thermal power generation. Water requirements and water availability for this total future energy development need is therefore considered in this report for each of the study sub-regions.

In the West the adequacy of a water supply can be evaluated on the basis of two factors - the total water supply produced, and the extent to which the water is used (or committed to use through a prior appropriation). On a sub-regional basis, total average annual water yields often greatly exceeds actual use. In many cases, however, legally recognized rights to use water (in many cases the right granted is not fully utilized) exceed the available supplies during low flow periods. Supplying water for future energy use in these many of these cases will require the implementation of one or more of the following developments:

1. Additional storage facilities to more evenly distribute the available supplies over the year and from wet to dry years.

2. Importation of surplus supplies from regions with more abundant water yields.

3. Transfer of water use to the industrial sector by the purchase of existing agricultural water rights.

4. Development of the region's extensive fresh and brackish groundwater resources.

The results and recommendations of these investigations are discussed briefly below for each of the major sub-regions in terms of three levels (low, most likely, and high) of energy development scenarios.

Powder River Basin. A low level energy demand of 40,000 AF/yr could be met locally through either the purchase of existing agricultural rights or the development of one of several proposed storage reservoirs. Higher energy demands of up to 230,000 AF/yr would best be met by a comprehensive transbasin diversion plan from the Bighorn or Yellowstone Rivers.

Tongue-Rosebud Basins. High energy demands in relation to the available supplies indicate that all of the future scenarios can best be supplied by diversions from the Yellowstone.

Yellowstone and Missouri River Mainstems. Future energy development sites in the mainstem sub-regions of the Northern Plains can easily be met by the abundant supplies available from the mainstem rivers and reservoirs.

Belle Fourche/Cheyenne. The low energy demand scenario of 20,000 AF/yr can be met locally by a program of conjunctive surface and groundwater development. High level demands of up to 50,000 AF/yr would be difficult to meet without comprehensive program of agricultural right aquisitions and/or transbasin diversions. Institutional constraints presently favor a diversion from the Green River basin via the Platte River.

North Platte Basin. Small energy demands relative to the overall supply situation are projected for the North Platte basin, although the supply is already fully allocated, primarily for agricultural uses. Development of additional surfaces supplies within the basin is difficult due to institutional constraints. The modest energy demand requirements can be met in any of the following three ways:

1. Purchase of existing agricultural rights.
2. Development of the extensive favorable groundwater reserves.
3. Importation from the Green River basin.

Heart/Cannonball Basins. The low level energy demand scenarios of 10,000 AF/yr can be satisfied locally by developing several proposed storage reservoirs. Higher demand levels can best be met by multipurpose diversions from the Missouri mainstem reservoirs.

Upper Green Basin. Little development in the Upper Green River basin leaves much of Wyoming's allotment under the Upper Colorado Compact unused and available for future energy development. The existing storage capacity of Fontenelle and Flaming Gorge reservoirs is sufficient to supply all projected energy development scenarios.

Lower Green. Extensive developable oil shale deposits in the Uintah and Piceance basins could lead to very significant water requirements for synthetic fuel production in this region. The Uintah portion of this requirement can readily be satisfied from the Green River by Utah's Colorado River opportionment. Developments in the Piceance Creek basin can best be supplied from the White River which presently has adequate supplies in relation to development.

Upper Colorado Mainstem. Abundant flows from the headwater of the Colorado River are sufficient to supply the water requirements projected for oil shale developments in the western Colorado portion of the sub-basin. At some locations the purchase of existing water rights may be desirable to achieve the necessary dependability. Rapidly increasing water demand in this region may alter this situation in the not too distant future.

San Juan Basin. Major supplies from Navajo Reservoir which have been allotted for industrial purposes could used low and moderate energy development scenarios. The high development scenarios would require the transfer of Indian water allocations to industrial uses and/or extensive local groundwater development.

3. WATER RESOURCES OF THE REGION

3.1 Climate and Physiography

The water resources aspects of this study may be conveniently separated for consideration into the two major watershed regions shown previously in Figure 1.1. The climate of these regions is somewhat different due to differences in longitude and orientation with respect to the mountains of the Continental Divide.

The Upper Missouri River Basin, on the eastern slopes of the Rocky Mountains, has two major sub-regions with respect to climate. The mountanous regions of Western Montana and Central Wyoming receive annual rainfalls of up to 40 inches and generate most of the runoff within the basin. Much of the remainder of the basin has the characteristic flat terrain of the Northern Great Plains. This area has a semi-arid climate and annual precipitation ranging from about 12 to 24 inches. Throughout the basin most of the precipitation occurs as snowfall during the winter as the result of orographic cooling of the prevailing westerly air flow. The result is that most of the annual runoff occurs in late spring as the mountain snowpack melts. This serves to create short periods of high streamflows and to recharge the alluvial groundwater system. From late summer through winter, there is very little natural surface runoff. Annual evaporation rates range from about 28 inches at the higher elevations to about 44 inches on the plains (NOAA, 1977)

The Upper Colorado River Basin covers a region on the western slope of the Continental Divide that is located further to the south than the Missouri Basin. Although the Colorado River Basin has a somewhat more arid climate due to its more southerly position and because much of the western portion of the basin does not benefit from the orographic precipitation caused by the Rockies, the seasonal distribution of overall precipitation is similar to that in the Upper Missouri Basin. Throughout the basin annual precipitation varies from lows of about 8 inches at numerous locations in the Basin to a maximum of about 40 inches at higher elevations in portions of north eastern Utah. Most of the annual surface runoff results from melting mountain snow-packs in the spring and early summer with much lower flows occurring over the remainder of the year. Annual evaporation rates over most of the basin are quite high, ranging from about 32 inches to about 54 inches, (NOAA, 1977).

The geographic variability of the climate is an important aspect of the assessment of potential water supplies for use in energy development. As indicated above this variability indirectly affects the seasonal distribution of water supplies throughout most of the study area. The variation of average annual precipitation in both study regions is shown in Figure 3.1. Evaporation is also a vital parameter to the water resources of the region since it affects two of the most significant water uses irrigation requirements and reservoir evaporation losses. Figure 3.2 shows the geographic variation of lake evaporation over the study area.

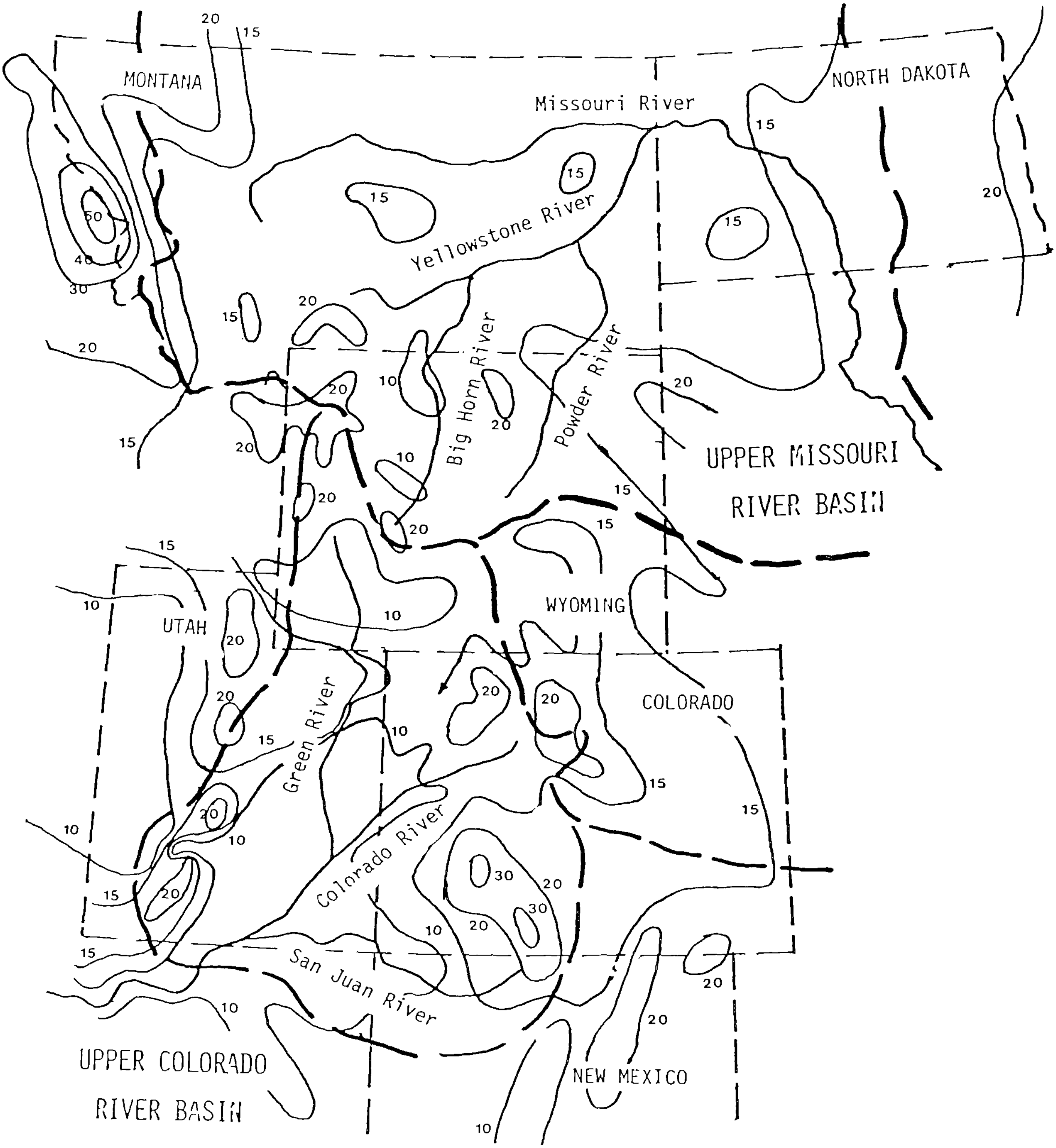


Figure 3.1 Average Annual Precipitation (Contours of Precipitation in inches)

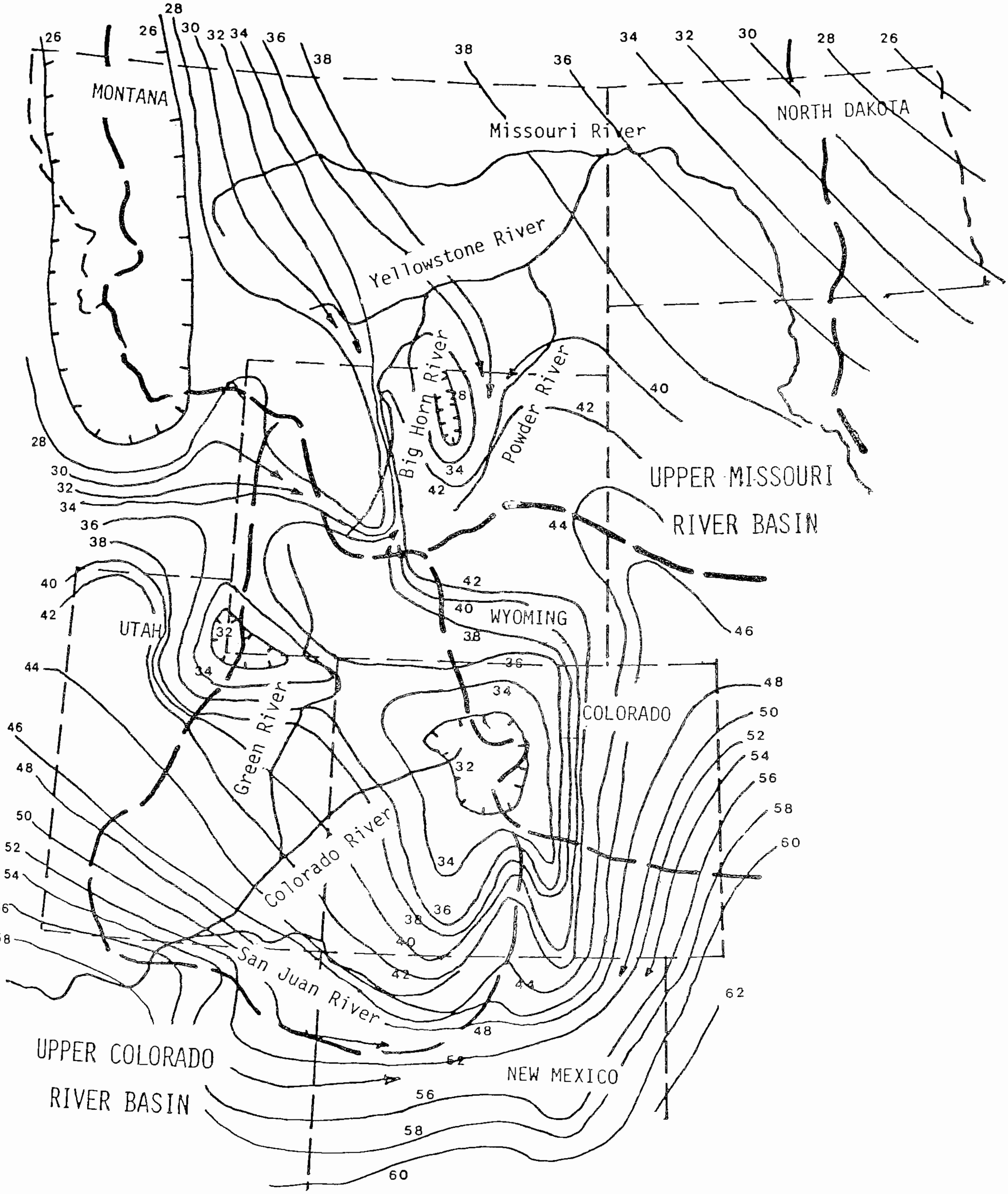


Figure 3.2 Average Annual Lake Evaporation (Contours of Evaporation in inches)

3.2 Surface Water Resources

Upper Missouri River Basin

The Upper Missouri River Basin may be divided into several hydrologic sub-regions of interest with respect to water availability for energy development. As shown on Figure 3.3, these study regions may be identified as follows:

1. Upper Missouri River Mainstem (Montana, North Dakota)
2. Yellowstone River Mainstem (Wyoming, Montana)
3. Powder River Basin (Wyoming, Montana)
4. Tongue-Rosebud Basins (Wyoming, Montana)
5. Heart-Cannonball Basins (North Dakota)
6. Bell Fourche-Cheyenne Basins (Wyoming)
7. North Platte Basin (Wyoming)

This section discusses these sub-regions with respect to the total surface water resources generated with the regions that is available to all users. Subsequent sections discuss the nature of the groundwater resources and how the total supply is distributed among the competing demands.

Most of the annual runoff produced in the Upper Missouri Basin originates in the mountainous headwaters of the Yellowstone and Missouri sub-regions in western Montana and Wyoming. The Yellowstone River Basin is of special interest in this study because much of the most easily retrievable coal is located within its drainage basin, making it a likely source of supply for future development. The Yellowstone Basin covers a drainage area of about 70,000 square miles which is divided nearly equally between Montana and Wyoming, and joins the Missouri River just east of the Montana-North Dakota

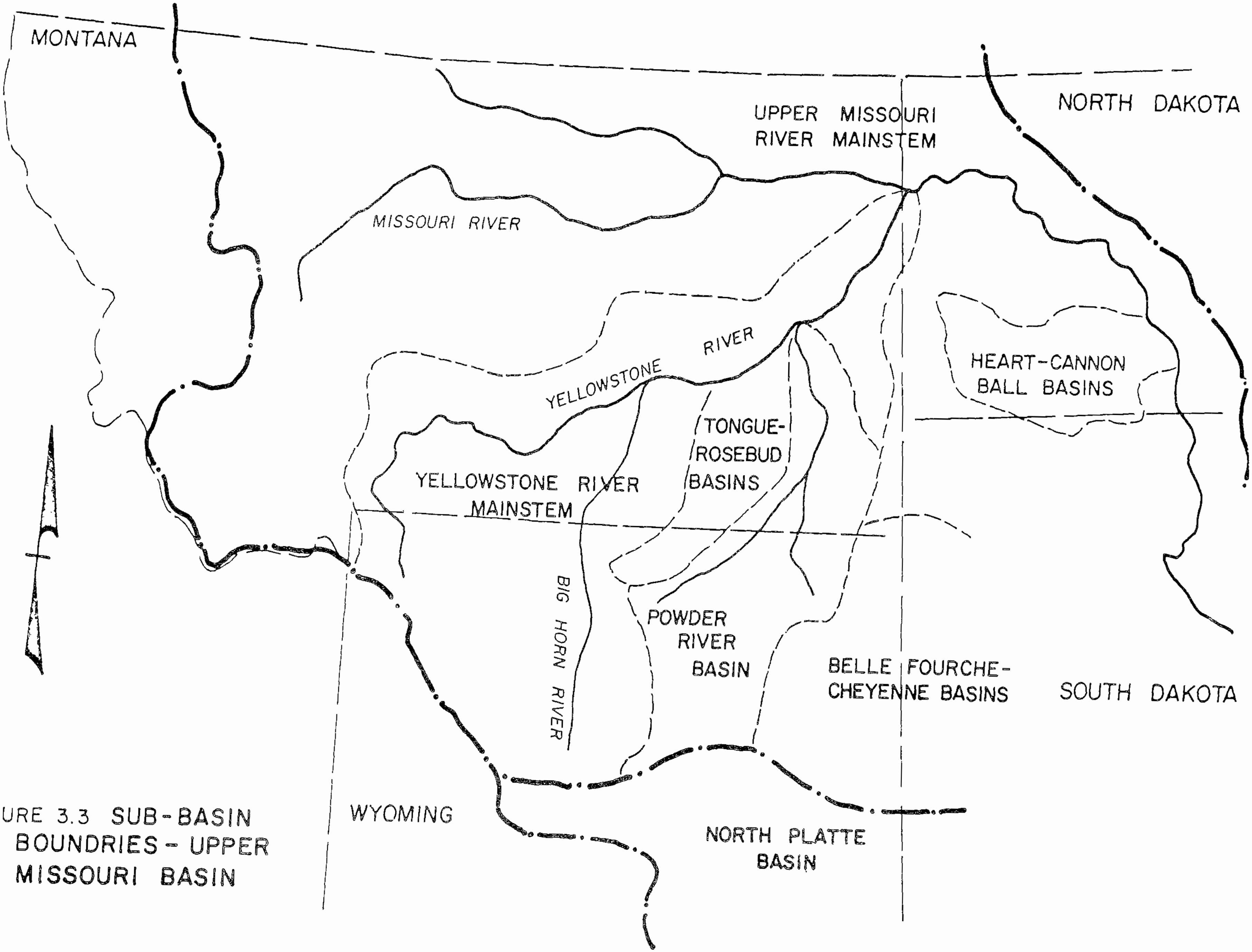
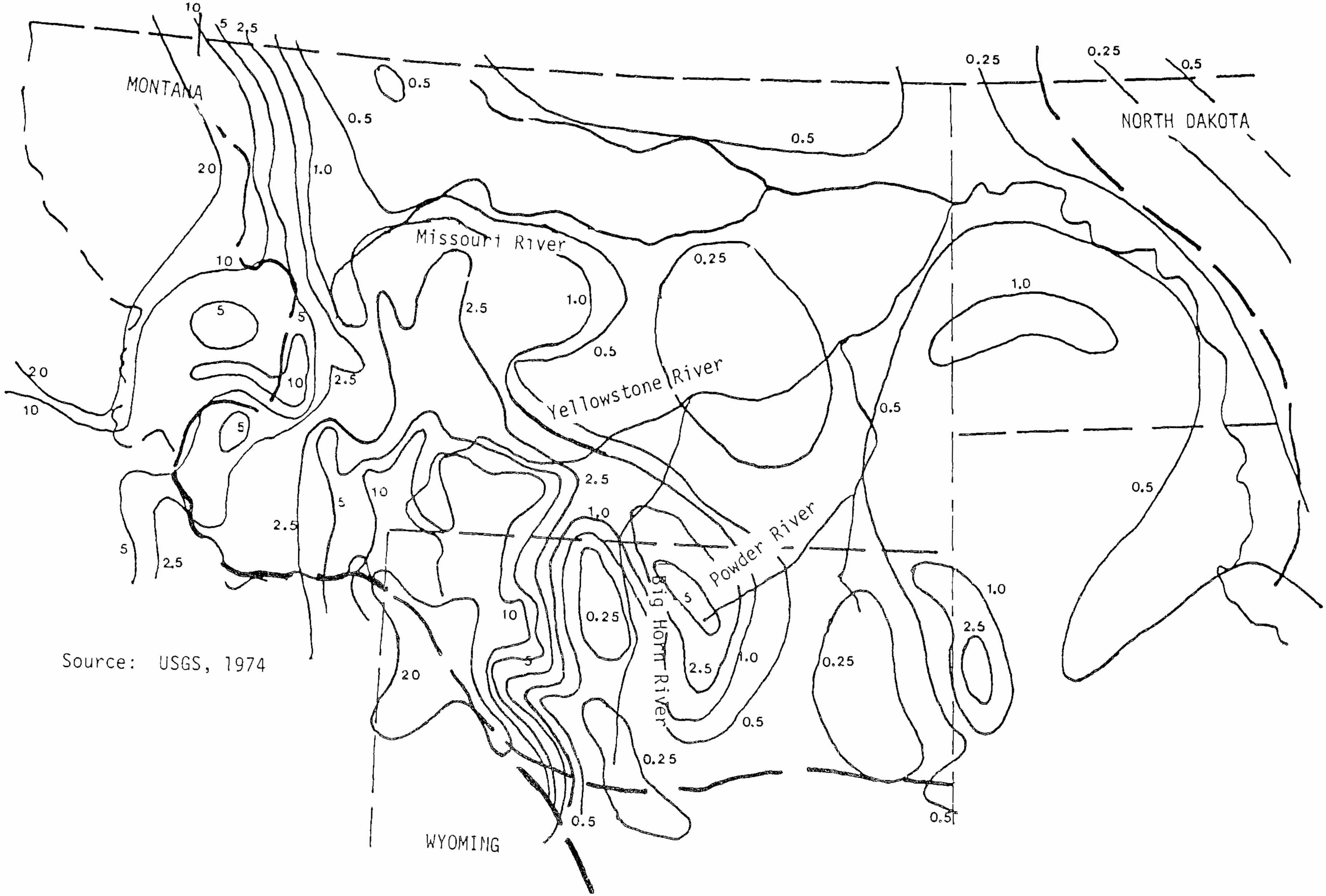


FIGURE 3.3 SUB-BASIN BOUNDRIES - UPPER MISSOURI BASIN

border. At their confluence the Yellowstone yields an annual flow of about 9.5 million acre-feet/year which is 22 percent more than the average flow than the Missouri, although it drains 14 percent less area (Montana DNRC, 1976). The Yellowstone River receives more than one-half of its total yield from waters rising in the mountain ranges upstream of Billings, Montana. The majority of the remaining yield is from the Wind-Bighorn River Basin in north-central Wyoming.

The hydrologic characteristics vary within the Upper Missouri Basin, primarily between the mountain and plains regions. Water yield from the high mountain region in the western basin ranges to over 20 inches per year, while the semi-arid plains covering much of the basin contribute less than one inch of runoff. The general geographical variability of water yield within the basin is shown in Figure 3.4. The total water yields on a sub-regional basis are shown in Table 3.1.

The seasonal distribution of runoff also varies throughout the basin with most of the annual runoff occurring in the spring and early summer due to the melting of the accumulated snowpack. The largest variation in flow is evidenced in streams in the plains regions where very high flows are typically experienced over a short spring melt season, but where flows often diminish to zero at times during the year because of depletions and little rainfall input. Because of this seasonal variability numerous storage reservoirs have been built over the years to retain the spring runoff for use during the remainder of the year. This has been particularly important to the development of the region's agricultural base, since the controls make for more water availability for irrigation during the growing season



Source: USGS, 1974

Figure 3.4 Annual Runoff Characteristics - Upper Missouri River Basin (Contours of Runoff in inches)

Table 3.1

AVERAGE ANNUAL WATER YIELD - UPPER MISSOURI BASIN

Sub-Region	Drainage Area (sq. mi)	Average Water Yield in Sub-Region[1] (AF/year)	Average Area Yield (AF/year/sq. mi)
Tongue-Rosebud	6,660	467,000	70
Powder	13,420	501,900	37
Yellowstone Mainstem	50,040	10,488,100	210
Belle Fourche-Cheyenne (Wyoming Only)	11,000	182,400	17
Heart-Cannonball	7,620	337,500	44
Upper Missouri Mainstem (At Oahe Dam)	185,840	23,625,000	127
North Platte (Colorado & Wyoming Only)	26,660	1,223,100	46

[1] Sources: Wyoming State Water Plan, 1972.
Critical Water Problems Facing the Eleven Western States, 1975
U.S. Geological Survey, 1964

than would be available under natural flow conditions.

Within the Yellowstone River portion of the basin, the reservoirs are located primarily on the tributaries in northern Wyoming and southeastern Montana. The mainstem of the Yellowstone is presently unregulated and is valued as one of the few remaining major free-flowing rivers in the West. It is doubtful if any future impoundments on the mainstem would be allowed.

The Missouri River mainstem major coal reserve region is highly regulated by a series of large, multi-purpose reservoirs built and operated by the Bureau of Reclamation and the U.S. Army Corps of Engineers. These are as follows:

Reservoir	Location	Active Storage
Fort Peck	Montana	10,900,000 AF
Lake Sakakawea	North Dakota	13,400,000 AF
Oahe	North and South Dakota	13,700,000 AF

These reservoirs form the basis for a reliable and abundant water supply to serve a variety of energy development activities in northeastern Montana and along the mainstem in North Dakota.

The quality of surface waters in the Upper Missouri River Basin may be categorized as being from good to excellent and suitable for most uses. In general, the highest quality water is found at the headwaters of the streams near the mountain divides. As the streams progress downstream, the quality generally deteriorates somewhat due to a variety of natural processes such as erosion and leaching, and man-made influences such as agricultural practices and waste discharges. Throughout the region except in a few localized areas the quality is satisfactory for most irrigation, stock watering, recreation, fish and wildlife, and municipal and industrial purposes.

Water quality data for the streams in this region are generally analyzed to establish the physical characteristics such as pH, temperature, color, etc. and the chemical characteristics such as salinity, alkalinity, trace elements, etc., of the water. This data is available at selected locations and for selected parameters from the U.S. Geological Survey, the Environmental Protection Agency, and various state agencies. Unfortunately, the present distribution of measuring stations is not sufficient to adequately establish the current water quality situation in all areas.

One of the few water quality parameters for which substantial amounts of data has been taken for a number of years is total dissolved solids (TDS). This has long been used as a measure of water salinity which is a parameter that is important in the use of water for irrigation. Another parameter that is of particular significance in the region is suspended sediment levels. Although TDS concentrations are lowest during the high flow periods of the year when dilution effects are most significant, sediment levels due to erosion tend to be highest during these periods.

Water quality in the headwaters of the Yellowstone and Missouri River Basins is generally excellent with only localized or seasonal problems involving sedimentation, heavy metals and acidity (Montana DNRC, 1976). Water chemistry which began as sodium bicarbonate in the mountains soon changes to calcium bicarbonate. In central

Montana the presence of the sulfate ion becomes more important except during the high flow period from May through July. In the lower reaches of these basins near the confluence of the Yellowstone with the Missouri, median TDS and sulfate concentrations sometimes exceed the recommended guidelines of 500 mg/l and 250 mg/l for drinking water during the low flow period from November to April. These levels are not however high enough to interfere with most beneficial uses of the water in the mainstems.

Water quality in the eastern Wyoming and western North Dakota tributaries that lie entirely on the high plains and derive their flows mainly from rainfall or groundwater rather than snowmelt have somewhat poorer water quality. Dissolved solids near the mouth of the Yellowstone, for example, range from about 230 mg/l to 660 mg/l with an average of 460 mg/l, whereas solids in the Powder River at Moorhead, Montana average 1550 mg/l with a range of 680 to 4080 mg/l (NGPRP, 1974)

Upper Colorado River Basin

The Upper Colorado River basin may also be divided into several hydrologic sub-regions with respect to water availability for energy development. As shown in Figure 3.5, these study regions may be identified as follows:

1. Upper Green River (primarily Wyoming)
2. Lower Green River (Colorado and Utah)
3. Upper Colorado Mainstem (Colorado and Utah)
4. Lower Colorado Mainstem (primarily Utah)

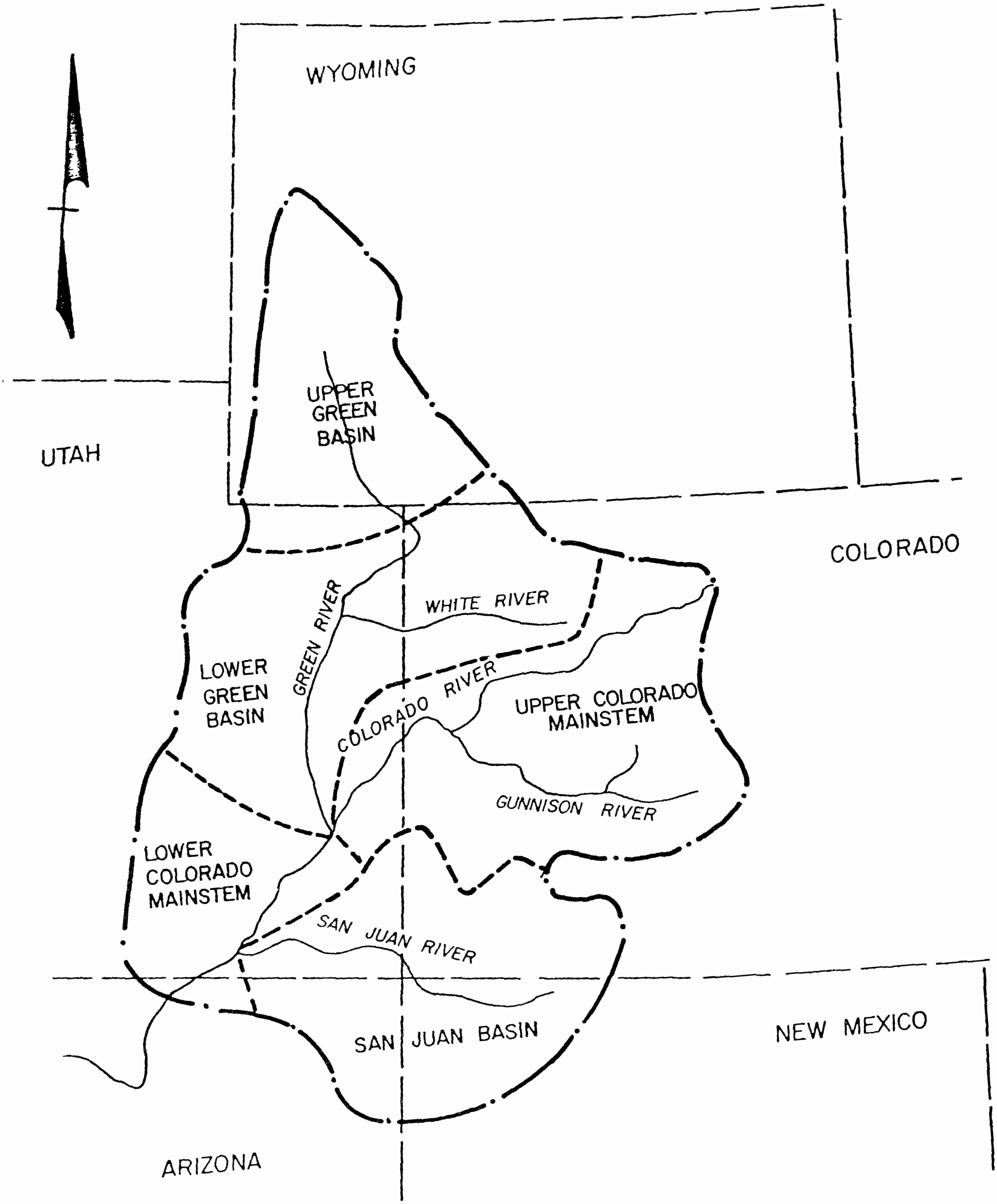


FIGURE 3.5 SUB-BASIN BOUNDRIES
UPPER COLORADO BASIN

5. San Juan River (Colorado, New Mexico, Utah and Arizona)

As with the Upper Missouri Basin, this section discusses these sub-regions only with respect to the total water generated that is available to all users.

Most of the annual runoff produced in the Upper Colorado River originates in the western slope mountain headwaters of the basin in Colorado. The mainstem of the Colorado River and two of its major tributaries, the Green River and the San Juan River, drain portions of the headwaters, but the Colorado produces by far the most runoff. Although the Green River Basin drains about 44,000 square miles or about 70 percent more area than theColorado River above their junction, the Colorado yields about 25 percent more water. Much of the remainder of the basin at lower elevations has an arid to semi-arid climate and produces very little additional yield. This geographic variability of water yield is shown in Figure 3.6 which shows water yields ranging to over 20 inches in the high mountain regions, but consisting of less than 0.5 inches over most of the basin. The total water yields on a sub-regional basis are shown in Table 3.3.

The seasonal variability of runoff is also a very significant aspect of the overall water resources situation in the basin. Most of the annual runoff occurs during the late spring as a result of melting snow. During the remainder of the year most of the smaller tributary streams receive little additional rainfall input and flows frequently diminish to zero. Because agriculture has long been an important part of the regions economy, water resources developments have been developed over the years to more evenly distribute the

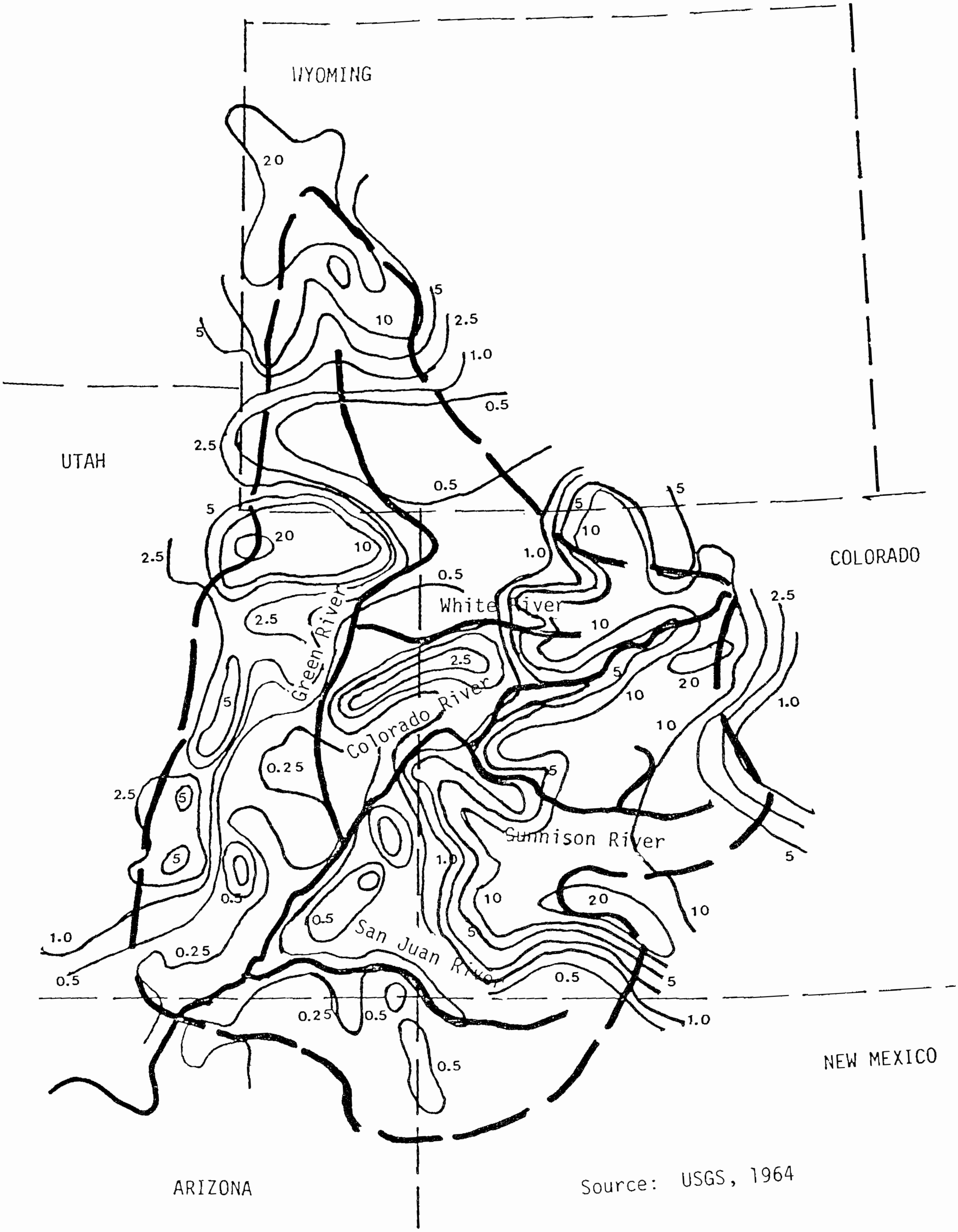


Figure 3.6 Annual Runoff Characteristics - Upper Colorado River Basin (Contours of Runoff in inches)

Table 3.2

AVERAGE ANNUAL WATER YIELD - UPPER COLORADO BASIN

Sub-Region	Drainage Area (sq. mi)	Average Water Yield in Sub-Region[1] (AF/year)	Average Area Yield (AF/year/sq. mi)
Upper Green	14,300	1,926,000	135
Lower Green	29,700	3,534,000	119
Upper Mainstem	26,000	6,838,000	263
Lower Mainstem	20,500	451,000	22
San Juan	23,000	2,387,000	104

Sources: Wyoming State Water Plan, 1972
Critical Water Problems Facing the Eleven Western States, 1975
Upper Colorado Region Comprehensive Framework Study, 1971
U.S. Geological Survey, 1964

excess spring runoff over the year, particularly during the growing season. These developments include storage reservoirs, flow diversions, and a variety of irrigation works. The result is that the Colorado River System has become one of the most highly regulated river systems in the country.

The major storage reservoirs in the Upper Colorado Basin are the following:

Reservoir	Location	Active Storage
Fontenelle	Green River, Wyoming	190,000 AF
Flaming Gorge	Green River, Wyoming-Utah	3,749,000 AF
Blue Mesa	Gunnison River, Colorado	830,000 AF
Navajo	San Juan River, New Mexico	1,696,000 AF
Lake Powell	Colorado River, Utah-Arizona	25,002,000 AF

Although these facilities and a number of significant flow diversions make more water available along the major interstate rivers than can presently be used, a specific set of legal considerations govern how the water may be used. These factors are considered in detail in Sections 4 and 5.

Water quality is a more significant issue in the Upper Colorado River Basin than in the Upper Missouri Basin. Although the water in the upper reaches of the major streams is of high quality the quality deteriorates as the water moves downstream. By far the most significant water quality concern in the basin is mineral pollution, commonly known as salinity. Salinity of surface waters refers to their content of soluble salts which include mainly chlorides, sulfates, and bicarbonates of calcium, magnesium, and sodium. Salinity is often measured in terms of total dissolved solids (TDS) without further identifying the levels of specific constituents.

As water flows downstream in the Colorado River Basin, salt concentrations increase due to a variety of natural and man-made influences. Throughout most of the length of the river, salinity has also been increasing with time. The factors that cause the salinity problems in the basin may be classified into two basic categories. These may be referred to as salt loading and salt concentrating effects. Salt loading refers to the addition of mineral salts into a stream from natural sources (runoff, springs, etc.) or from man-made causes such as industrial wastes or leaching of salts from soils during irrigation. Salt concentrating effects involve no change in the amount of salt present, but result in higher concentrations as a consequence of removal of water from the stream system through consumptive use, or transfers of high quality water out of the basin.

The salinity problem is presently most severe in the Lower Colorado Basin. It has been estimated annual economic losses of $230,000 per mg/l increase in salinity at Imperial Dam just above the Mexican border (Dept. of Interior, 1974). Although the problem is less critical in the Upper Colorado Basin, changes in water use here can effect salinity levels in both the upper basins streams and in the lower Colorado River.

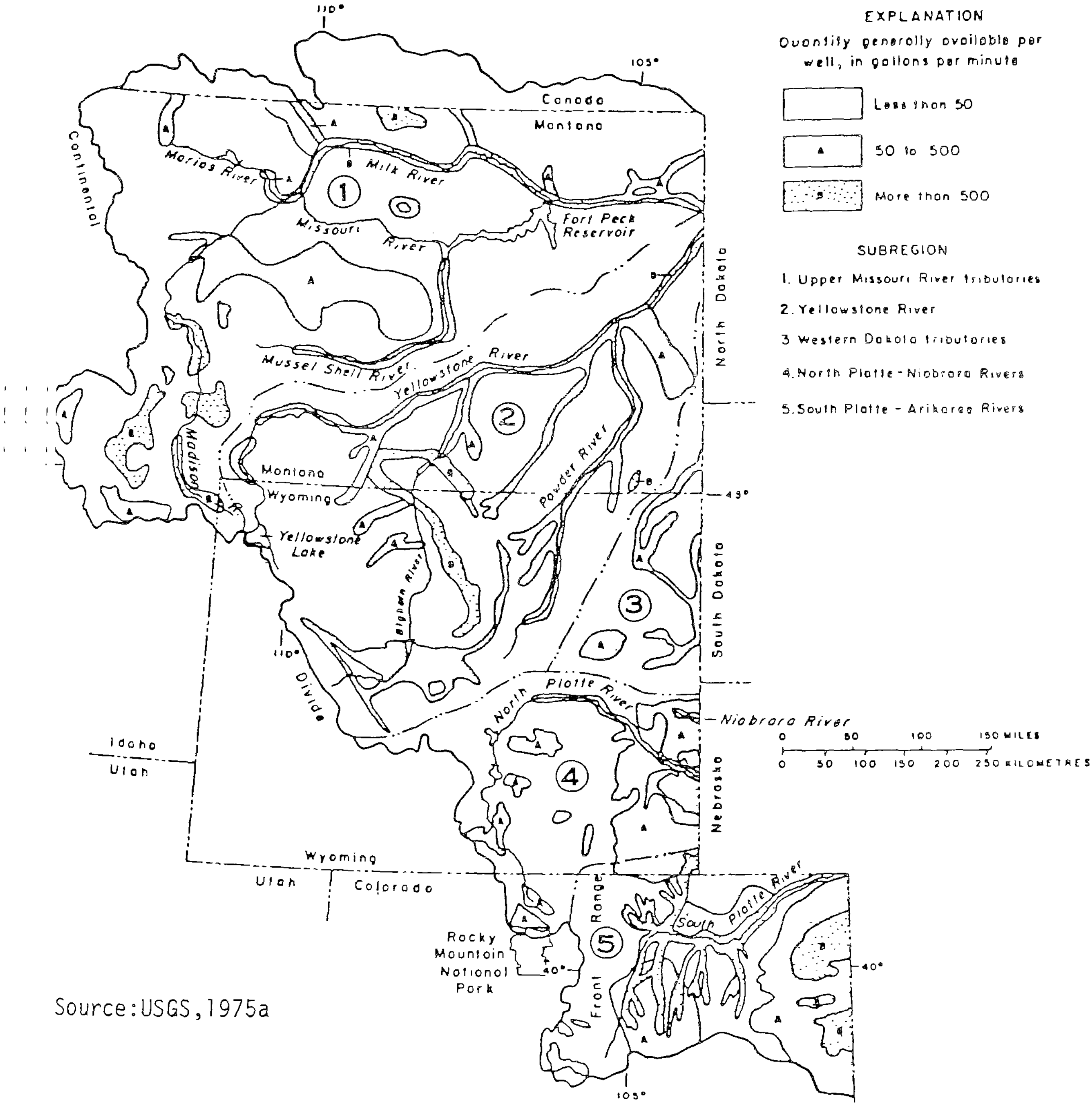
Surface water quality in the Upper Colorado Basin will be an important consideration for future energy development for two reasons. The presence of high concentrations of certain salts may be a factor affecting the feasibility of using various sources as a water supply source for energy conversion, and therefore may be a siting consideration At the same time, the consumption of high quality supplies in the upper basin region may reduce the dilution water available and therefore increase salinity downstream.

3.3 Groundwater Resources

Groundwater is an important but often overlooked water supply source throughout much of the coal region of the West. It is estimated that there is approximately 120 million acre-feet of water stored in natural underground reservoirs at depths within only 200 feet of the surface (Dept. of Interior, 1975). This volume is several times the storage capacity of all of the surface reservoirs in the region, yet present groundwater useage accounts for only a relatively small percentage of total water use. The reasons for this are varied but include: the costs to locate and develop groundwater supplies, poor groundwater quality in some areas, and the preference of certain users to utilize surface supplies. Groundwater supplies may however have certain advantages over surface supplies in that they are often more widely distributed and more dependable throughout the year. As competition for available surface supplies increases in the future, it is anticipated that groundwater will play a larger role in the overall water supply picture in the West.

Groundwater aquifers in the study area fall into two general categories. Shallow (tributary) aquifers consist of coalbeds, sandstones, and the unconsolidated alluvium along major rivers and their principle tributaries in buried preglacial valleys. Deeper strata (non-tributary aquifers) of limestone and associated carbonate rocks have also shown promise as potential water supply sources, particularly in the Northern Great Plains region. General areas underlain by aquifers capable of well yields of 50 gpm or more are shown in Figure 3.7.

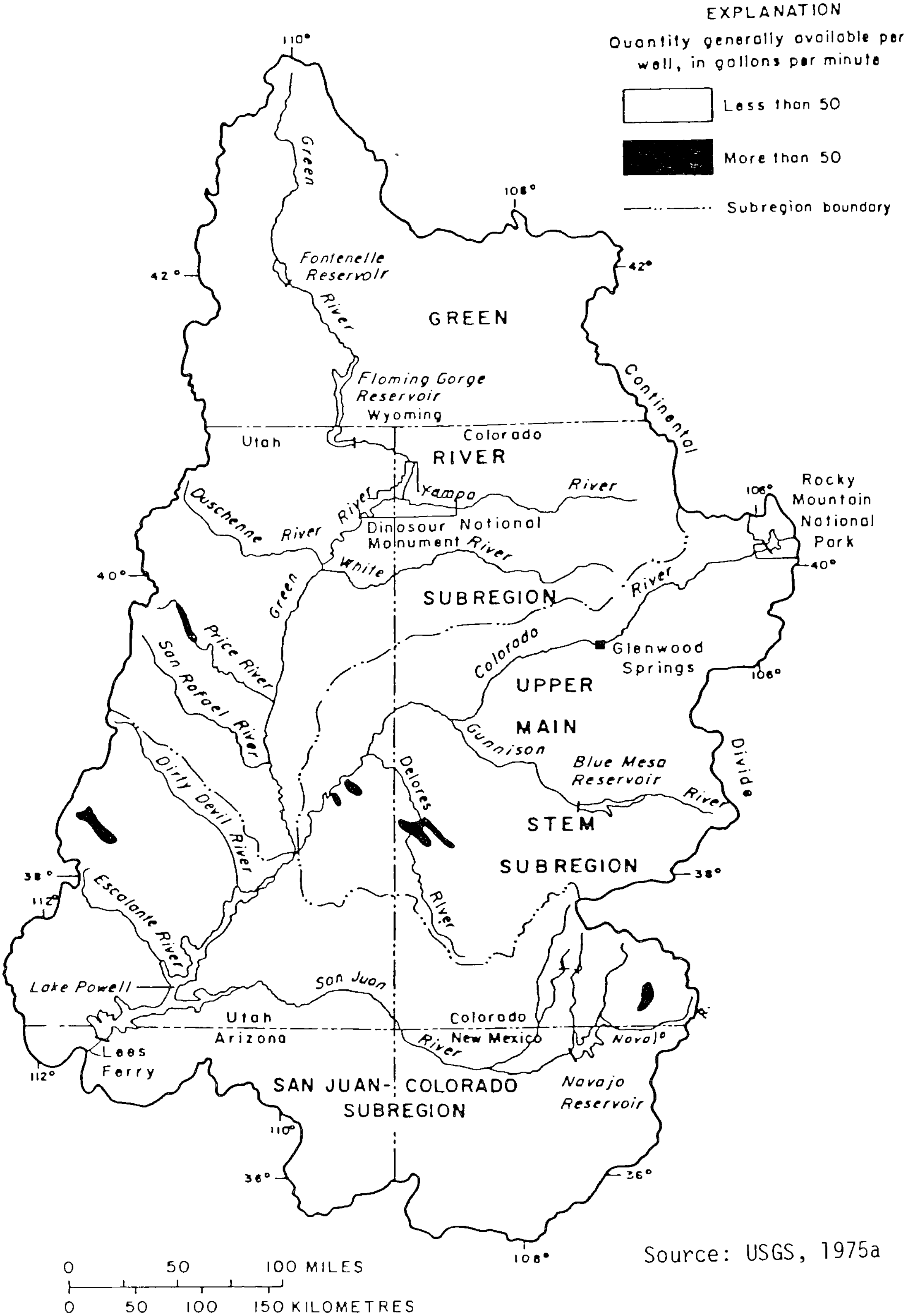
The lack of wide-spread groundwater data at a sufficient level of detail has limited the analyses that could be carried out on a site



Source:USGS,1975a

WESTERN MISSOURI RIVER REGION

Figure 3.7 Groundwater Supply Availability(continued).



UPPER COLORADO RIVER BASIN

Figure 3.7 (concluded)

specific basis in this report. It is recognized however that ground-water will be important as a primary or conjunctive supply in several areas and that further field study is necessary to identify local availability. Some general characteristics of these supplies in the region of interest are given in the following paragraphs.

Upper Missouri River Basin

Shallow aquifers are present throughout much of the Upper Missouri Basin except in the Bighorn Mountains and Black Hills, where the older Madison Limestone and associated carbonate rocks are exposed. These aquifers generally vary in depth from the surface to a few thousand feet. Most existing wells are less than about 300 feet deep although some alluvial wells less than 100 feet deep yield as much as 500 gpm (Dept. of Interior, 1976). Most present shallow aquifer wells yield less than 50 gpm, but this appears to be a limitation related to typical water requirements rather than the capacities of the aquifers. Available data indicates that the sandstone units and associated coal beds in the Fox Hills-Hell Creek-Fort Union-Wasatch sequence may yield up to 500 gpm in appropriately constructed individual wells.

The Madison aquifer underlies most of the Northern Great Plains coal region except for the Bighorn, Pryor and Snowy mountains and the Black Hills where it is exposed or absent. Varying in depth from about 5000 feet in the coal region of Montana to about 10,000 feet in portions of the Powder River Basin in Wyoming, this aquifer has produced a few high yielding wells yielding up to several thousand gallons per minute. However, yields are highly variable, and since the cost involved in tapping this source is so great, data on the potential of the Madison is presently quite limited. Significant studies of the Madison aquifer are presently being carried out by the U.S. Geological Survey.

Upper Colorado River Basin

The aquifers that underlie the Upper Colorado River region consist mostly of consolidated and semi-consolidated sedimentary strata with unconsolidated alluvial deposits along reaches of major stream valleys. It has been estimated (Dept. of Interior, 1975) that the volume of recoverable groundwater within 200 feet of the surface is about 88 million acre-feet which is nearly three times the active storage in all of the surface reservoirs in the Colorado River System and that the amount stored in the deeper rocks is several times that within the initial 200 feet zone. It is also estimated that about 4 million acre-feet of groundwater recharge occurs annually (USGS, 1974) from rainfall, principally in the higher mountains and plateaus where rainfall is the highest.

Although the total volume of recoverable groundwater storage is great, the water cannot always be obtained at the desired rates in all places. About 85 percent of the stored groundwater occurs in sedimentary rocks which have relatively low permeability and yield water slowly. Wells yielding more than 50 gpm generally can be expected only in areas consisting of permeable alluvium which accounts for only about 5 percent of the groundwater reserves.

Groundwater Quality

The general chemical quality of groundwater with regard to its dissolved solids content according to a classification system used by the U.S. Geological Survey (1974) is as follows:

Class	TDS (mg/l)
Fresh	<1000
Slightly Saline	1000-3000
Moderately Saline	3000-10,000
Very Saline	10,000-35,000
Briny	>35,000

Fresh water is generally found in shallow aquifers of most rock units in areas above an elevation of about 7000 feet and in certain sandstones and carbonate rocks which have good hydrologic connection with the principle recharge areas in the mountains. The chemical quality in most shallow and alluvial aquifers is slightly to moderately saline with dissolved solids ranging from about 1000 mg/l to 5000 mg/l.

In general salinity increases with depth beneath the surface, except as noted where the aquifer has a good connection with its recharge area. The Madison aquifer for example shows very good quality in certain locations, considering its depth. Dissolved solids in this aquifer varies from less than 1000 mg/l near the Black Hills to about 2000 mg/l throughout the Powder River Basin, but is known to exceed 100,000 mg/l in some areas of western North Dakota (Dept. of Interior, 1975).

4. WATER USE CONSTRAINTS

4.1 Codes of Water Law

There are two major doctrines of water law found in the United States, each stemming from a different background and used to different extents in areas with differing hydrologic characteristics. They are known as the Riparian Code and the Appropriation Doctrine, and in order to understand them it is necessary to review the circumstances and conditions in which they were formed. With this knowledge, it will be possible to assess on an institutional basis the water supply conditions found in the western states for energy development.

The Riparian Code descends from English Common Law developed in the relatively water-rich English Isles. It is based on two principles - that of "reasonable use"; and the notion that the only person with any water rights are those who own property adjacent to the watercourse. The idea of "reasonable use" is relatively ill-defined; in many cases this has been understood to mean that any use of the water is permissible so long as no other user of the water is harmed. Clearly, the Riparian Code is the result of experience gained from areas in which water is relatively plentiful, and, in its present form, is suited only to areas with those characteristics. It is practiced in the states east of the Mississippi River, although certain characteristics of the Riparian Code are found in some other states as well.

The Appropriation Doctrine differs significantly in both background and purpose from the Riparian Doctrine. Used to some extent in most of the relatively arid western states, where water is frequently a limiting factor, it has evolved since the time of the first development of the areas in approximately the middle of the 19th century. It is based on the seniority principle of "first in time, first in right." This means that a senior right has diversion priority over a junior right, i.e., in times of limited water availability, the senior diversion right can be completely satisfied before any diversion for the junior right is permitted.

Most systems have two important requirements which must be met before any water right can be established. These are (1) diversion of the water from the stream, and (2) application of the water to beneficial use. In some of the states these requirements are being altered; this is discussed in greater detail in the Appendix on the water administration systems of the individual states.

It is important to note the difference in the original intention of the two doctrines. The Riparian Code tends to have as its purpose the maintenance of satisfactory conditions in the river for all adjoining landowners, and often has the effect of discouraging out-of-stream diversions. The Appropriation Doctrine on the other hand encouragements the use of water, often at the expense of satisfactory streamflow conditions. It was established to assure the senior appropriator that he has a reliable supply of water, inasfar as no other water user is permitted to take any action which could in any way injure the senior appropriator. Thus, the water is often regarded as a property right in and of itself. Junior water rights are in most cases also protected against injury from any manipulation or change in use of senior water rights, as they are generally entitled to the maintenance of stream conditions as they existed when their junior appropriation was granted.

The basic concepts enumerated above form the foundation for the water administration found in each of the states which concern this discussion. The manner of administration differs considerably from state to state, but the concepts are found in each of them.

4.2 Administrative Procedures

This section discusses the administrative procedures that generally must be followed and problems which may be encountered in attempts to supply water from alternative sources, without respect to the use for which it is intended.

Typically, each state has a water administration system with characteristics distinct from those in the other western states. A characteristic common to all of the systems of the states under consideration include some degree of appropriation doctrine, a system designed primarily to encourage the efficient beneficial use of water, in an economic sense, while at the same time minimizing conflicts with other water users. This system permits, and in many cases, requires, the diversion of water from a stream bed or watercourse to establish a water right. Recently, though, the administrative procedures have been changed in several of the states regarding instream appropriations of water; these have been instituted primarily for the purpose of minimizing environmental degradation, e.g., maintaining a minimum streamflow for fish life and recreational purposes.

There has been considerable pressure from a variety of sources to alter administrative procedures in order to make them more responsive to changes in both economic and socio-political priorities, and major changes appear possible in the next few years. From many points of view, stability is a positive aspect of the system: a slow response implies that matters are much more predictable, permitting much more certainty in prognostications for planning aspects. Also, however, the feeling of many of those concerned with water resources management are that of the goal of efficiency is not served by relatively slow-moving administrative efforts. Some of the proposals voiced have centered upon the possibility of having an annual rent to be paid to the state, as owner of all waters flowing within the state. In some cases, the rate might be set at the maximum price at which water could be used by anybody, thus ensuring the maximum return per unit of water, and the maximum efficiency of water use. However, legislation and administrative changes based on these concepts is not likely in the near future.

The appropriation system finds its apotheosis in the water administration practices used in the states of Colorado, New Mexico, Utah, and Wyoming. Typically, many of the water administration schemes are extensions of systems started from a number of different sources. These include early Spanish and Mexican law codes, Mormon water codes, as well as mining codes developed at the time of the first gold rushes which were the original impetus for migration of large numbers of people into part of the area in the second half of the nineteenth centry.

The procedures by which water rights can be transferred in title, manner of use, and place of use vary widely from state to state. In some states, irrigation water is tied to the land upon which it is used, and can be transferred only with somewhat greater effort than in those systems in which it is recognized that the water is indeed separable from the land. In all cases, however, the prevention of adverse effects of the transfer on other water uses, junior and senior, is of paramount importance. In fact, this is, in most cases, the only restriction on transfers of water on an individual basis. It is typically the case that the burden of proof lies upon those wishing to effect the transfer, whether the change must be adjudicated, or approved by an administrator.

Development of storage rights is generally encouraged in the area of interest by water administration systems. Again, they are permitted only when other water users are not materially injured, or when they can be induced to withdraw objection to the project. In general, temporal aspects (e.g., time of year in which water is used) play a large role in the value of the right. Consequently, water storage plays a correspondingly large role in the transfer of water rights. For instance, when an irrigation right which is used in the period May - October each year is transferred to an industrial use which requires a year-round water supply, some storage must be used, even when the total annual volume of the industrial use is equal to or less than that of the irrigation use. This is done primarily to ensure that the hydrologic regime of the river does not change as a result of the change in use and harm a junior appropriator by causing water which was formerly available to him to become unavailable.

Transbasin diversions can be handled in many ways as simply a conventional change in use and location. However, the consequences of transbasin diversions tend to have somewhat greater impact on the hydrologic regimes of rivers; hence, they are much more complicated in the political aspects. This is largely a result of the interstate compacts which exist on most of the major interstate rivers. These compacts will be individually discussed later. Generally, the interstate compacts tend to come about only after conflicts between the states arise concerning the flows. Since they are a result of tensions between the states, the states watch closely to ensure that they do not get shortchanged by other states. Consequently, trans-basin diversions concerning these streams, conditions for which are customarily included in the compact, must satisfy very stringent conditions.

Groundwater is another resource subject to a variety of differing administrative policies in different states and regions. In most states, permits from the statewide administrative agency are required. Typically, one of the main requirements has been that of not adversely affecting the groundwater situation of adjoining landowners, e.g., the cone of depression may not extend beyond the boundaries of the land owned by the divertor for alluvial systems. In most cases the deep, i.e., non-alluvial, aquifers with limited recharge capabilities may only be "mined" at a rate usually set by the state administrator responsible for such matters.

For large diversions from tributary alluvial aquifers, augmentation arrangements are frequently necessitated for the surface waters affected. The augmentation plans are, however, quite subjective on the part of the State Engineers Office, due to the lack of information available on most specific surface-ground water interactions.

Frequently, the administration and regulation of groundwater activities is handled by the same state agencies which administer the surface waters. Although the history of groundwater management is relatively short, significant changes have been made in several states in the recent past. They have moved primarily in the direction of recognizing the hydraulic connections between surface water and tributary groundwater sources. Thus, increasing interaction is taking place between the surface water management system and the groundwater management systems.

The procedure by which water can be allocated from the different possible sources to energy uses is, in the eyes of existing law, exactly the same as procedures followed by allocation to any other use. It should be kept in mind, however, that because of the nature and extent of energy conversion activities, the political and social forces extent will necessarily have some bearing on the manner in which the development proceeds.

4.3 Interstate Compacts

One of the most important institutional considerations affecting the utilization, administration, and management of the water resource in the area of concern lies in the effects of interstate water compacts. These compacts came about as a result of the need for clarification of the amounts of water each state could rely upon from shared water sources. Since most of the important rivers flow through two or more states, there are a number of interstate river compacts, which allocate the river's water among the signatory states. Because they are interstate, they must be approved by the president and the U.S. Congress before they become effective. Typically, the negotiations involved in these compacts involve many years and much discussion, and are jealously guarded by the states involved.

Yellowstone River Compact

In the three northern states of the study area, Wyoming, Montana, and North Dakota, an interstate compact of major importance is the Yellowstone River Compact. Since the Yellowstone River and its tributaries represent the largest potential source of water in much of the Northern Great Plains Coal Area, the stipulations of this Compact signed in 1950, provide important guidelines for water supply possibilities. Four articles of this compact have particular bearing on the question of water supply and are worth enumerating. These are Articles V, VII, VIII, and X.

Article V is concerned with the allocation of Yellowstone tributary water between Wyoming and Montana. This is performed on a percentage of available flow basis, and is relatively uncontroversial. Rights and diversions existing at the date of compact signing were recognized.

Articles VII and VIII deal with the permissibility of facility construction in one state for use of water in another state.

Article X is important because it treats the question of out-of-basin transfers of water from any of the Yellowstone River Drainage Basin. Essentially, it requires unanimous consent from the three signatory states before any out-of-basin diversions. This is a serious constraint on water resource development in the area, for the reason that some of the major easily-retrievable coal lies just outside the Yellowstone Drainage Basin, in the area near Gillette, Wyoming of the Belle Fourche River Basin. As water supplies are particularly limited in the Belle Fourche River Basin, a likely possibility for a source of large-scale water importations would have been the tributaries of the Yellowstone River. However, the problems associated with gaining the requisite unanimous approval of the signatory states are sufficient to cause a serious (some believe insurmountable) obstacle to transferring the water from this source. This is currently being tested in court by the Intake Water Company vs. Yellowstone River Compact Commission case, mentioned elsewhere. Provision does exist in the Yellowstone River Compact for the transfer of water from one tributary of the Yellowstone River to another tributary, such that the water is not exported from the Yellowstone Basin.

Belle Fourche River Compact

The Belle Fourche River Compact concerns the entire drainage basin of the Belle Fourche River in Wyoming and South Dakota. The two states are participants in the compact, which divides the limited quantity of water in the basin between Wyoming and South Dakota.

While recognizing the existing water rights on the river, it strictly controls what use and facilities may occur in Wyoming after the signing of the pact. Generally, the Belle Fourche Compact does not appear to affect water development plans significantly, as it deals with relatively small amounts of water.

Platte River

No Platte River Compact as such exists. Several court cases have been decided in the Supreme Court regarding the division of the North Platte River and its tributaries between Wyoming and Colorado. These decisions presently constitute the guidelines by which the North Platte River is divided between Wyoming and Colorado. There also exists a stipulation, approved by the Supreme Court, between the states of Nebraska, Colorado, and Wyoming regarding the allocation and use of Platte River water between them.

These documents result in a situation such that the water of the Platte River is almost fully allocated. This implies the potential sources of water required for energy use will be the following: 1. Purchase of existing agricultural rights, 2. Construction of new storage facilities, 3. Importation of water to the Platte River Basin.

Because of the long history of litigation between Wyoming, Colorado, and Nebraska, each of the states guards its water carefully. In the past the downstream states have often sued the upstream states to prevent actions which might remove too much water from the stream. Thus Nebraska might be expected to be the plaintiff in any action resulting from the construction of additional storage capacity in Wyoming for energy use.

Colorado River Basin Institutional Aspects

The Colorado River, the most important river in its region, has had its water allocated among the seven states of the Colorado River Basin and Mexico by a series of compacts, following lengthy and acrimonious discussions. In 1922, the Colorado River Compact was concluded; in essence, this divided the river into an Upper Basin consisting of Colorado, Wyoming, Utah, New Mexico, and a small area of Arizona. The lower Basin was made up of the remainder of Arizona, California and Nevada, and the dividing point between the Upper and Lower Basin is at Lee's Ferry, Arizona, directly below the Glen Canyon Dam. With this compact, it was decided that the lower basin was to receive 75 million acre-feet every ten years, or an average of 7.5 million acre-feet per year. At that time, it was thought that the average annual flow of the Colorado River was 15 million acre-feet per year, so the flow was intended to be evenly split between the Upper and Lower Basins.

In 1928, the Boulder Canyon Act was concluded by the Lower Basin States, in order to proceed with the construction of Hoover Dam and the All-American Canal. This Act apportioned water between the Lower Basin

States on the basis of 4.4 million acre-feet per year to California, 0.8 million acre-feet to Arizona, and 0.3 million acre-feet for Nevada.

In 1945, as part of a treaty between the U.S. and Mexico apportioning water of the Rio Grande, Tijuana, and Colorado Rivers, it was agreed that Mexico would receive 1.5 million acre-feet annually from the Colorado River. This was to be increased to 1.7 million AF/yr in years of surplus and decreased in proportion to the decrease of consumptive use in the United States. It was later determined that the 1.5 million acre feet annually owed to Mexico was a burden to be shared equally by the Upper and Lower Basins.

In 1949 the Upper Colorado Basin Compact was concluded, resulting in apportionment of the Upper Basin Allotment of Colorado River water. These are as follows: (in terms of total beneficial consumptive use of available water to the Upper Basin):

Arizona:	50,000 AF/yr
Colorado:	51.75%
New Mexico:	11.25%
Utah:	23%
Wyoming:	14%

The apportionments were made in terms of flow percentage in part, because of the awareness of the variation in river flows, combined with the Lower Basin commitment of a fairly constant amount. Included in this Compact were the details of how state water apportionment cutbacks are to be determined, with respect to the existing interstate river compacts on the San Juan and other tributaries of the Colorado, if a "compact call" occurs under the terms of the Colorado River Compact.

The Upper Colorado River Storage Project Act of 1956 had the construction of water storage facilities in the Upper Basin of the Colorado River as its purpose. Most of these projects are presently completed with a storage capacity of over 24 million acre-feet. This means that the flow at Lee's Ferry can now be completely controlled, thus allowing the Upper Basin to make efficient use of their allotment.

A later development on the Colorado River was Minute 242 of the International Boundary Waters Commission, in which the U.S. agreed to deliver water of a certain quality (in terms of Total Dissolved Solids (TDS)) to Mexico, as part of the conditions by which the water would be delivered to Mexico. This was significant change in the administration of water in the Colorado Basin, as quality, although long recognized as a problem in the Basin, had never been covered in any sort of compact or treaty.

The problem of salt loading is severe in the Colorado River for a variety of causes. There are many natural sources of salt in the basin, taking the form of springs and salt beds, and they contribute a high percentage of the total salt load. However, the problem is magnified because of the purposes for which the water is used. The greatest use is for irrigation, in which water is diverted from the river and applied to land. Generally, a return flow to the river results from irrigation, and the return flow tends to have a higher TDS concentration than the original water for two reasons: a portion of the water is lost to evapotranspiration, thus leaving a greater concentration of salt in the remaining water, and the return flow then travels through the soil and rock, dissolving and carrying away the salt in the soil and rocks. A consequence of the salt loading from both natural and artificial causes in such high concentrations of TDS in the lower Colorado is to make the water worth much less for practically all purposes. There is currently some uncertainty in the Colorado River Basin about the measures which will be taken about the salt loading. A large portion of the salt loading in the river from both natural and artificial causes occurs in the Upper Basin. One problem lies in the fact that the water from high on the river is typically quite pure, thus diluting the concentration of TDS in the lower portions. Any decrease in the flow of this due either to out-of-basin diversions or consumptive use has the effect of increasing the TDS concentration in the lower part of the basin. Since much of the salt load caused by irrigation also occurs in the Upper Basin, and because almost every water development has the effect of increasing TDS concentrations, those involved with water use in the upper basin are understandably concerned about the measures taken to alleviate the problem. One action which has already begun is the construction of a large desalination plant at Yuma, Arizona, near the Mexican border. This facility is being constructed for the purpose of improving the quality of water delivered to Mexico, and is only part of a larger plan to control salinity. The EPA is also currently being sued to play a greater role in the water quality management of the Colorado River, which may have significant consequences in development and water supply situations in the area.

Although the 1922 Colorado River Compact had intended to divide the available Colorado River Water evenly between the Upper and Lower Basin, the result has not met the intention. This is because, in the years since 1922, the flow of the Colorado has been considerably less than 15 million acre feet per year. Since the language of the compact guaranteed the Lower Basin States an average of 7.5 million acre-feet per year, without regard to the flow, the Upper Basin has received correspondingly less water. Until the present this has not been a problem, because the entire allotment to the Upper Basin has not been used. With new developments, there will be increasing dissatisfaction with this situation, for which no immediate resolution is likely. There is some pressure in the Upper Basin to seek a reallocation of Colorado River water between the Upper and Lower Basins for this reason.

Another aspect of water management in the Colorado River Basin lies in the controversy surrounding out-of-basin diversions. There currently are a number of these in Colorado, transporting water from the Colorado or its tributaries to the Rio Grande, South Platte, or Arkansas River basins on the Eastern slope. Since these diversions take very high quality water far up in the river basin, they have the result of contributing to the salinity problem in the lower reaches of the Colorado River, because of the removal of what is largely dilution water. Although there is sentiment against the out-of-basin diversions for this reason, as well as the desire of the sparsely populated Western Slope area of Colorado to keep its water, the political strength of Eastern Colorado is such that it continues to divert water from the Colorado River, and to plan for future transmountain diversions. However, this is becoming increasingly difficult, and few more transmountain diversions should be expected as opposition from a variety of groups increases.

One possible alternative for water supply in the Powder Basin, Wyoming, area is the transmountain diversion of Green River water to the North Platte River, and thence a diversion to the Powder River. This would be the second transmountain diversion from the Colorado River Basin in Wyoming, and might meet with less opposition than any similar proposal in Colorado, because it would allow Wyoming to more fully use its Colorado River opportionment. Again, however, this would have the effect of increasing salinity in the lower reaches of the Colorado.

Several streams in Wyoming, Utah, Colorado, and New Mexico are subjects of interstate compacts, and convered by the Upper Colorado River Basin Compact of 1948. These compacts covering La Plata Creek, Little Snake Creek, Yampa River, San Juan River, Henry's Fork, Beaver Creek, Burnt Fork, Birch Creek, and Sheep Creek, still have the conditions of the Upper Colorado River Basin Compact of 1948 as their major limits, and will therefore not be discussed individually.

One potential problem lies in the lack of any compact or agreement between the states of Colorado and Utah concerning the use of water of the White River. Commonly regarded as one of the most likely sources of water for oil shale development, the absence of any agreement on the disposition of White River water almost guarantees an eventual clash between the states of Colorado and Utah when an attempt is made in either state to put a significant amount of water to use. Currently, the river remains largely undeveloped.

4.4 Federal Water Policy

An important factor in the consideration of the Water supply possibilities in the area lies in the claims of the Federal Government for its reservations of different types. As discussed below the Reserved Rights Doctrine allows the federal government to reserve sufficient water for whatever use is made of federally reserved lands, which include Indian Reservations and Bureau of Land Management Land among other types. Consequently, there has been considerable litigation to force the federal government to quantify these claims and file for them through the State Water Administrations.

Federal Reserved Rights are based upon the notion that sufficient water from adjoining watercourses was reserved for watever use the Federal lands should be put to when the land was claimed by the Federal Government. Since many of these lands were put aside before private water development took place, the priority of the Federally reserved water is better than the other water rights on the river. Generally, this concept has been tested in the courts and upheld firmly. The problem associated with the Federally reserved water rights is that they have not been quantified or even identified, resulting in uncertainty on the past of other water users. Because the Indian Reservations fall into this category, and because they are the Federally reserved lands most likely to be developed, much of the concern has focused upon them - hence the proliferation of court cases concerning them. There has been no resolution of this problem, and the uncertainty may well drag on for several years.

An outcome of the trials known as the "Eagle County Cases" and the McCarran Amendment of the 1952 U.S. Congress was the decision that Federal claims to water would be made within the state systems for general adjudications of water rights. As a result of these cases, the Federal Government must move to establish its claims in the State Legislatures; however, this has been proceeding quite slowly because the government is seeking to determine the maximum use for any of the possible futures which might take place on its reservations. Some claims have been established in the Colorado River Basin; for example, the amount of water claimed for the Naval Oil Shale Reserves has been designated as 200,000 Acre-Feet, although the Federal Government in Colorado still does not agree that its claims under the Reserve Rights Doctrine must be quantified.

Another consideration of Federal Water Policy is the development of the Wild and Scenic Rivers in the region of concern. When a river is designated as wild or scenic, development along the river is severely restricted in order to maintain the desirable condition of the river. Among the rivers being considered for designation are parts of the Yellowstone, Missouri, Green, Yampa, Dolores, and Colorado in the study area.

5. COMPETING WATER DEMANDS

5.1 General

In assessing water availability for synthetic fuel production in the western states an important consideration is how other alternative uses will compete for the available water at any particular supply source. The future water supply and demand interaction in any region is virtually impossible to accurately predict because of potential and often likely changes in the seasonal distribution of water supplies through new control/diversion facilities or changes in institutional constraints affecting how the water can be used. The best available indicator of how water supplies in any region will be distributed among the various demand sectors is the present way in which the water is used. This chapter deals first with the present use of water in the various regions of interest to this study, then discusses the factors that may lead to changes in the demand structure, and finally suggests a number of potential future demand scenarios.

An important aspect of any discussion of present or future water use in the arid western regions considered here is that the limited geographical and seasonal distribution of water supplies has greatly effected the development of these regions and how water is used. Most of the water supply generated in the region as a whole occurs, as winter snowfall at higher elevations in the upper watersheds. Melting of the extensive mountain snowpeaks results in high rates of spring stream runoff and groundwater recharge, but throughout much of the summer and fall seasons, very little additional runoff is produced. This leaves large portions of the region with very little water throughout much of the year except along the major streams. Since most potential water users require a steady and reliable supply, most of the region's development has occurred where natural supplies are most reliable or where man-made control projects have improved the seasonable variability of supplies to an acceptable level.

Historically the primary use of water throughout the region has been for a variety on agricultural uses. Since the growing season extends over much of the dry summer period, continuing water resources developments have been directed at storage impoundments which more evenly distribute the spring runoff throughout the year. Even though the reservoir evaporation losses associated with this may represent a substantial depletion, the total value of the annual runoff is increased since more summer water is available at a substantially higher value per unit than spring water. Many reservoirs have been built and are operating throughout the west for this purpose. As water from these sources has become available in any given area, the demand for the relatively inexpensive water generally increases. This is an indication of the fact that the level of various alternative water uses is highly dependent on the reliability of the supply as well as its economic cost.

As pointed out in Chapter 4, the legal right to use water is a more important consideration in the west than is the mere presence of an available supply that is not being fully utilized. In this context it is important to note that although a certain free market transfer of supplies between various individuals or sectors of demand is possible within the system, the provisions of the intra-state compacts and in state regulation may in fact be an increasingly significa factor as supplies become more fully allocated. Concern over conflicting plans for future use of the water in the Yellowstone River Basin, for example, recently led Montana to enact a temporary moratorium on an major new appropriations within its portion of the basin. Also, individual states are increasingly recognizing instream flow needs as a beneficial and therefore reservable use.

Generalizations concerning the major water use categories that apply throughout the western study region are presented in the following paragraphs. The discussion then focuses on the specific water use situation in the individual sub-regions of primary interest.

Irrigation

The use of water for agricultural purposes which consists primarily of the irrigation of cropland or pasture is by far the largest water use in the west, accounting for an average of 70-80 percent of total present depletions. This depletion in most cases represents only a portion of the water actually withdrawn from a source and applied to the cropland. The net depletion of irrigation water comes about from evaporation or transpiration losses, seepage into the deep groundwater system, and water incorporated into growing plants. The amount of water applied per acre is quite variable with location, depending on the age and condition of the project, the technology of application, the type of crop grown, the local geology, and the cost/availability of water Normal irrigation practice usually results in return flows (either directly or through the shallow groundwater system) that may be reused for irrigation or other applications. Multiple reuse of irrigation water has resulted in adverse water quality impacts through the accumulation of dissolved salts that are particularly severe in the Southwestern states.

Water quality requirements for irrigation are dependent on a number of factors including salinity, sodium adsorption ratio, crop type, quality of the soil, the amount of rainfall and the total amount of rainfall applied. Although absolute limits cannot be set for irrigation water quality, the U.S. Department of Agriculture has established some general classifications for the salinity hazard which may be used as a guide where there are no particular soil problems (Upper Colorado Region State-Federal Interagency Group, 1971). These categories are as follows:

Salinity Hazard	TDS (mg/l)
Low	< 160
Medium	160 - 480
High	480 - 1440
Very High	> 1440

Reservoir Evaporation

As indicated earlier an extensive system of reservoir storage has been developed throughout the West to more uniformly distribute the spring runoff over the year and particularly through the growing season. These reservoirs often serve multipurpose functions including irrigation, flood control, power generation, municipal and industrial supplies, and recreation. Although these developments make far more water available for use when the water is most valuable, on an annual basis the large water surface areas associated with the reservoirs result in substantial water depletions through evaporation.

Instream Flow Needs

It has been increasingly recognized during recent years that maintaining streamflows above certain minimum levels that vary according to season is necessary to preserve the habitat for fish and stream-related wildlife. Free-flowing streams also create opportunities for recreation and increase environmental quality in several ways.

For the most part however, the appropriate water laws in effect in the Western States are weak or lacking in provisions that would insure minimum sustained streamflows. Under present laws streamflows can be and in many cases are appropriated to a level that exceeds the available water supply. A result of this is that theoretically streams can be completely depleted and have no remaining flow during dry months or years. This obviously has serious impacts on local fish and wildlife populations.

Several states presently recognize minimum flows for maintaining fish and wildlife as a beneficial use and therefore a use that can be specifically reserved in its own right. Other states are contemplating similar legislation. Studies to more adequately establish the minimum flow regime needed to sustain given stream ecosystem without appreciable degradation will be required as a part of the development and perfection of future instream flow appropriations. In many cases the result may be instream flow requirements that are a major portion of existing low flows.

Municipal

The sparse population throughout most of the study region results in municipal and industrial water demand sectors being very low by comparison with the agricultural sector. Domestic and industrial users supplied by municipal systems are frequently considered together under the category of Municipal and Industrial (M&I). On the whole, M&I use presently accounts for less that 5% of overall water use and an even smaller fraction of total depletions.

Water quality requirements for municipal systems are quite high. The U.S. Public Health Standard recommended guideline for drinking water specifies a maximum TDS level of 500 mg/l (U.S.P.H.S., 1962). Many smaller communities in the West, however, have supplies containing over 1000 mg/l TDS for lack of better quality supplies.

Industrial

Self supplied industrial users are generally considered separately. The major industrial uses in this category are the mining and minerals industry which uses water primarily in the cleaning and processing of ores, and the power industry which uses water in thermal electric plant for cooling. These major industries as well as many other less significant water users offer fully deplete their water withdrawals because any wastewater produced would be detrimental to the environment if returned to the streams.

The water quality requirements for industrial uses vary widely according to the industry served. Much of the water used in the mining and materials industry can be highly brackish without affecting its utility. Industries using cooling water require fairly high quality water to prevent fouling of the facilities. Where water quality requirements are high, treatment prior to use may be practical for some industrial applications. Fresh and brackish groundwater supplies for industrial use have been developed in many locations where there is a suitable match between the quality of available supplies and the needs of the industry.

5.2 Present Water Use

Upper Missouri River Basin

Water use in the Upper Missouri Basin is committed largely to agricultural pruposes. It has been estimated that fully 80 percent of present use goes towards crop or range irrigation and related uses. Development of the region in fact has depended on reliable water supplies and as such has occurred mostly along the inter-state rivers and their major tributaries. Good water availability in western Montana and the Upper Yellowstone Basin in north central Wyoming and south central Montana has led to the development of numerous irrigation projects and associated water control facilities such as reservoirs, irrigation channels, and distribution systems. Most of the population centers, power generation facilities, and other industrial development are also located in these regions. Much more limited water supplies are available for development in the plains regions of eastern Montana and Wyoming and western North Dakota, and as a result, these regions have been developed to a far lesser extent.

As previously described in Section 4, the way water is presently being used in this region is largely determined by legal considerations as to the right to use the water. This is particularly true in the portions of the Yellowstone River Basin and the Belle Fourche-Cheyenne Basins where some of the most easily retrievable coal reserves are located, but where water is already in very short supply. Within each of the major tributaries, various inter-state compacts define how much of the available supplies may be used within each state, allowing for reservations recognized prior to the compact dates. Each state's share then is allocated according to existing appropriative rights.

Although the Northern Great Plains States do have a formal agreement as to how much of the available water is allocated to each state under the compacts, the Wyoming State Water Plan (Wyoming Water Planning Program, 1973) provides a breakdown that appears to be the best available at the present time. Allocations among the states according to the plan are as follows:

Tributary	Total Subject to Compact (AF)	Wyoming (%)	Wyoming (AF)	Montana (%)	Montana (AF)
Bighorn	1,800,000	80	1,800,000	20	400,000
Tongue	241,100	40	96,400	60	144,700
Powder	287,300	42	120,700	58	166,600

The way in which water is presently used in the Upper Missouri coal regions is shown in Table 5.1. For each of the study sub-regions defined earlier, water use estimates under the categories of irrigation, municipal and industrial (including rural domestic), self-supplied industrial, and reservoir evaporation are given. The water use values given here are for total depletions of the water supplies. Irrigation and municipal use generally would involve larger actual withdrawals with return flows to the waterways, and hence reuse. Industrial and reservoir evaporation involve full depletion of the water utilized in these sectors.

Table 5.1

PRESENT WATER USE - UPPER MISSOURI BASIN
(Depletions - Acre-Feet/Year

Sub-Region	Irrigation	M&I and Rural Domestic	Industrial	Reservoir Evaporation	Total
Tongue-Rosebud	187,200	5,000	1,600	8,000	201,800
Powder	181,600	4,400	1,600	29,000	216,700
Yellowstone Mainstem	1,561,200	79,400	24,600	331,900	1,997,100
Belle Fourche-Cheyenne (Wyoming Only)	6,000	2,000	3,000	31,000	41,000
Heart-Cannonball	24,300	6,500	2,400	8,000	41,200
Upper Missouri Mainstem (To Oahe Dam)	1,335,300	159,600	(including all Industrial)	1,445,000	2,939,900
North Platte (Wyoming Only)	574,000	7,000	9,000	177,000	766,000

Sources: Wyoming Framework Water Plan (Wyoming Water Planning Program, 1972)
Water Use in Montana (MT. DNRC, 1975)
Water for Energy (U.S. Dept. of Interior, 1975)
Critical Water Problems Facing the Eleven Western States (U.S. Dept. of Interior, 1975)
North Dakota Water Resources Development Plan (N.D. State Water Commission, 1968)

Upper Colorado River Basin

The Upper Colorado region also has agriculture as an important part of the economy. Because much of the basin has a semi-arid climate, and little precipitation over most of the year, most of the region's growth has occurred along the Colorado River and its major tributaries. Since even these major rivers naturally would have large seasonal fluctuations in flow, numerous storage reservoirs have been built throughout the Colorado Basin to more evenly distribute the water supply. Today the Colorado River is one of the most regulated rivers in the country and a uniform, reliable flow can be produced over the entire year.

This has led to the development of many irrigation projects at locations throughout the basin. Presently, water use for irrigation accounts for by far the largest depletions of the available supply. The reservoirs that make this water available for use, however, also cause significant depletions through evaporation. A summary of present water use within each of the study sub-regions according to the various demand sectors is given in Table 5.2.

Table 5.2

PRESENT WATER USE - UPPER COLORADO BASIN
(Depletions - Acre-Feet/Year)

Sub-Basin	Irrigation	M&I and Rural Domestic	Industrial	Reservoir Evaporation	Other[1]	Total
Upper Green	242,000	12,000	16,000	26,000	-	296,000
Lower Green	550,000	6,000	28,000	31,000	154,000	769,000
Upper Mainstem	775,000	15,000	13,000	79,000	194,000	1,096,000
Lower Mainstem	33,000	1,500	1,500	2,000	-	38,000
San Juan	286,000	11,500	31,500	95,000	48,000	472,000

[1] Other losses are consumptive conveyance losses and evaporation attributed to recreation, wildlife, and wetlands

Sources: Wyoming Frameowrk Water Plan (Wyoming Water Planning Program, 1972)
Critical Water Problems Facing the Eleven Western States (U.S. Dept. of Interior, 1975)
Water for Energy (U.S. Dept. of Interior, 1974)

5.3 Demand Variability

The utility of water for certain uses varies considerably from season to season throughout the year. This is particularly true of agricultural uses which account for a very large portion of total water use in the western study region and which occur primarily during the summer and fall growing seasons. The average duration of the growing season extends from about mid-May through September in the Upper Missouri Basin and from about May through mid-September in the Upper Colorado Basin. Demands for irrigation water therefore begin in April, gradually increase to peak requirements in July, and then taper off until about October. The winter months of November through March have no irrigation water requirements (U.S. Department of Commerce, NOAA, 1977).

The amount of irrigation water required from year to year also varies, depending on a number of factors among which is the amount of natural rainfall. During dry periods or drought years when the available water supplies are at their lowest levels, irrigation demands tent to be highest. During these periods demands of many of the junior water rights in certain areas cannot be met.

Reservoirs built to carry spring runoff over to the peak agricultural need during the growing season and to some extent from wet years to dry years also account for a water depletion that varies seasonally. Although storage impoundments help to even out the seasonal fluctuation in runoff, the significant evaporation water losses result in net decreases in the water available to downstream areas. The variation of reservoir evaporation losses closely resembles that for irrigation demands with evaporation being highest during July/August and diminishing to zero during the winter months when the reservoirs are frozen.

Municipal and particularly industrial demands tend to be much more constant over time. These demands, however, are generally much more dependent on reliable supplies and therefore require priority rights during low flow periods.

5.4 Potential Demand Changes

Any discussion of potential demand changes must recognize that the limited water supply and associated high economic cost of water in the West have directly influenced growth and development in many areas. Since water demand is a sensitive function of cost for many uses, the overall demand structure in any locale at one unit cost (i.e., supply level) may be very different than the structure at a higher unit cost. This is an important consideration in assessing any potential demand changes affecting the future supply/demand picture, particularly in the primary energy regions of the West, since the value of water for energy production is likely to be higher than the value for agricultural uses. This could result in a significant shift in water use as a result of industrial users acquiring agricultural rights to use water.

As energy and other industrial developments occur in the future, institutional constraints may play a key role in the way water may be distributed or used. As described in Section 4, constraints or inter-basin transfers, particularly in the Yellowstone River Basin, presently make development of some prime coal deposits just outside the basin boundary difficult. Also, present priority schedules in some states give a low preference to industrial uses of water.

Changes in institutional constraints are impossible to predict at the present time and will not be attempted within the context of this study. It will be assumed that present institutional constraints will continue into the future. It is important to bear in mind however that this aspect of the supply/demand interaction will remain in a state of flux. Several important areas where institutional changes could be of particular importance are regulations to protect the existing agricultural socio-economic character of the region, as presently advocated by certain groups, to recognition of instream flows as a beneficial use as presently being studied by several states, and the quantification of Indian water rights.

The primary demand sectors which are expected to have an impact tending to increase water use in the future are increased irrigation use for food and fiber production and an increased role of the region in providing for the nation's energy needs.

With regard to the future course of agricultural development in the energy resources regions of the country, there is considerable disagreement as to whether there will be a net increase or decrease in irrigated agriculture in the study area, and the magnitude of any such change. The relative portion of agriculture in the future competition for water between energy and agriculture because the demand for food and fiber production depends, to a great degree on national policies and market conditions, which will affect the degree of Federal financing of irrigation development such as Bureau of Reclamation storage projects (W.F.E., 1975).

The nature of future energy development and the water required to support it also depends in large part on national policy and international developments. Depending on the extent to which the nation decides to develop a self-sufficient energy policy and the extent to which nuclear energy is utilized in the program will greatly affect the level of coal and oil shale development occurring in the study area in the near to intermediate future. The mix between coal-fired thermal electric power generation and synthetic fuel production will also affect the overall water requirements for future energy development.

As the competition for the increasing scarce water supplies becomes more intense, a number of developments could tend to change the nature of use in several demand sectors. These generally involve the conservation and reuse of water through better management practices. Major concerns in the area of agricultural usage have led to a number of recent studies which have shown that significant improvements in the efficiency of irrigated agriculture water use can be attained. Recommended procedures include improvements in the design and layout of existing distribution systems to reduce seepage and salt loadings, and use of drip irrigation systems to reduce evaporation losses (C.W.P., 1975). In industrial applications, including energy production, studies have indicated that air cooling processes, although more expensive initially, are as effective as water-cooled systems, but use little water. Significant saving in industrial water use could be realized if dry cooling systems are installed more frequently in the future. The use of poorer quality supplies or reuse of wastewater supplies rather than high quality surface supplies represents another avenue that could affect the future industrial demand situation. Many indus+rial and maining processes such as slag quenching, ore rinsing, dust control, and stack gas scrubbing can utilize water that would not be suitable for many other uses.

5.5 Future Demand Projections

As discussed in the previous section, many factors that cannot presently be determined will affect levels of future demands. Many other studies have reported estimates of future water demand for different uses and the results vary considerably, indicating that there is no general agreement as to how future uses will shape up. The available data has been reviewed during the course of this study and summarized by sub-region according to use.

Upper Missouri River Basin

Estimates of water use in the year 2000 in the Upper Missouri River Basin portion of the study area are given in Table 5.3. Projections for portions of the Sub-Regions in the State of Wyoming are taken from the Wyoming Framework Water Plan (Wyoming Water Planning Program, 1973) which projects moderate increases in irrigation depletions for food and fiber production, but relatively larger increases in industrial use. Projected Montana water use is from the Montana Department of Natural Resources and Conservation (1977). Figures for the Yellowstone Mainstem and the Heart-Cannonball Sub-Regions were disaggregated from estimates for the total Yellowstone Basin and the Western Dakota tributaries of the Upper Missouri Basin. No use projections were made for the Upper Missouri Mainstem sub-region because it is anticipated that the abundant water supplied available in the Fort Peck reservoir and Lakes Sakakawea and Oahe will be more than adequate to meet the energy and all other water needs of that area will into the future.

Table 5.3

PROJECTED FUTURE (YEAR 2000) WATER USE - UPPER MISSOURI REGION
(Depletions - Acre-Feet/Year)

Sub-Region	Irrigation	M&I and Rural Domestic	Industrial	Reservoir Evaporation	Total
Tongue-Rosebud	238,000	11,000	124,000	9,000	382,000
Powder	285,000	10,000	62,000	29,000	386,000
Yellowstone Mainstem	1,785,000	128,000	25,000	332,000	2,270,000
Belle Fourche-Cheyenne (Wyoming Only)	7,000	5,000	45,000	31,000	88,000
Heart-Cannonball	61,000	8,000	3,000	17,000	89,000
Upper Missouri Mainstem (To Oahe Dam)		Note (1)			
North Platte (Wyoming Only)	918,000	36,000	47,000	180,000	1,181,000

[1] Major water demands in this region will be supplied out of the Mainstem reservoirs which have a supply that greatly exceeds any projected uses.

Sources: Water for Energy (U.S. Dept. of Interior, 1975)
Future of the Yellowstone River (MT. DNRC, 1977)
Wyoming Framework Water Plan (Wyoming Water Planning Program, 1972)

In Table 5.3, the figures given for industrial usage include self-supplied industrial uses (municipally-supplied industrial water is included under M&I/Domestic) which are primarily the mining/minerals industry and thermal power generation. Projections for synthetic fuel production are not included in this category, but are discussed later in Section 6. Data on future reservoir evaporation losses is not available so it has been assumed for the purposes of Table 5.3 that these depletions will be the same in the future as at present.

Upper Colorado River Basin

Upper Colorado River Basin water use estimates for the year 2000 are given in Table 5.4. Projections of irrigation depletions are based on OBERS (Office of Business Economics, U.S. Department of Commerce and the Economic Research Service, U.S. Department of Agriculture) projections of agricultural data as disaggregated from figures given for the individual states (Upper Colorado Region Comprehensive Framework Study, 1971). M&I and self-supplied industrial (exclusive of synthetic fuel production) projections were derived from figures given in "Water for Energy in the Upper Colorado River Basin" (U.S. Department of Interior, 1974). By the year 2000, it was assumed that each state will be utilizing their allowable share of the mainstem reservoir evaporation which is apportioned to the states based on the Upper Colorado Compact share allotments.
Data for future levels of "Other" uses is not available so it was assumed there would be a fifty percent increase in this category over present depletions, primarily for fish, wildlife, and other recreational developments.

Table 5.4

PROJECTED FUTURE (YEAR 2000) WATER USE - UPPER COLORADO REGION
(Depletions - Acre-Feet/Year)

Sub-Basin	Irrigation	M&I and Rural Domestic	Industrial	Reservoir Evaporation	Other	Total
Upper Green	407,000	6,000	104,000	73,000	24,000	618,000
Lower Green	655,000	15,000	146,000	144,000	231,000	1,191,000
Upper Mainstem	1,166,000	20,000	108,000	168,000	291,000	1,753,000
Lower Mainstem	58,000	2,000	23,000	18,000		101,000
San Juan	696,000	27,000	188,000	117,000	72,000	1,100,000

Sources: Wyoming Framework Water Plan (Wyoming Water Planning Program, 1972)
Critical Water Problems Facint the Eleven Western States (U.S. Dept. of Interior, 1975)
Water for Energy (U.S. Dept. of Interior, 1974)

6. WATER SUPPLY AVAILABILITY FOR ENERGY DEVELOPMENT

6.1 Regional Water Availability

Previous sections of this report have dealt with annual water yields and water usage in each of the hydrologic sub-regions selected for study because of the presence of significant coal or oil shale energy reserves. This section combines the total annual water supply data with water use projections for uses other than energy development to estimate total future unallocated surface water supplies in each region. These results give an indication of the net water supply that could be expected to be available for energy production without the transfer (acquisition) of existing water rights from present uses to energy use. Section 6.2 then discusses the range of likely energy development scenarios and Section 6.3 considers alternative ways in which the energy water requirements might be met.

A summary of projected regional water availability for energy use in the year 2000 in the Upper Missouri River Basin is given in Table 6.1. A similar summary is given in Table 6.2 for the Upper Colorado River Basin.

These summaries consist of three parts for each region: the overall water supply, water use and commitments, and the net remaining water supply. The overall water supply in a sub-region consists of the natural water yield within the sub-region (as previously given in Tables 3.1 and 3.3), the depleted stream inflows from other sub-regions, and any water imports from other sub-regions. Data on

Table 6.1

PROJECTED FUTURE WATER AVAILABILITY - UPPER MISSOURI BASIN
(1000 AF/YR)

Sub-Region	Annual Water Supply				Water Use and Commitments				
	Natural Yield	Depleted Inflow	Imports	Total Supply	Projected Depletions	Instream Flows	Exports	Total Use	Net Water Availability
Tongue-Rosebud	467	0	0	467	382	148	0	530	(63)
Powder	502	0	0	502	386	162	0	548	(46)
Yellowstone Mainstem	10,488	0	0	10,488	2,270	4,070	0	6,340	4,148
Belle Fourche-Cheyenne	182	0	0	182	88	75	0	163	19
Heart-Cannonball	338	0	0	338	89	138	0	227	111
North Platte	1,223	520	10	1,753	1,181	501	0	1,682	71

Table 6.2

PROJECTED FUTURE WATER AVAILABILITY - UPPER COLORADO BASIN
(1000 AF/YR)

	Annual Water Supply				Water Use and Commitments				
Sub-Region	Natural Yield	Depleted Inflow	Imports	Total Supply	Projected Depletions	Instream Flows	Exports	Total Use	Net Water Availability
Upper Green	1926	0	0	1926	618	960	10	1,588	338
Lower Green	3534	1,300	0	4834	1191	2,400	112	3,703	1,129
Upper Mainstem	6838	0	0	6838	1753	3,400	620	5,773	1,065
Lower Mainstem	451	9,298	0	9749	101	4,900	0	5,001	4,748
San Juan	2387	0	130	2517	1100	1,260	113	2,473	44

possible future intra-basin transfers (imports/exports) are not specific enough to allow reliable projections of these quantities, so present water transfers have been used in these tables. Water use and commitments are made up of projected future depletions (as previously given Tables 5.3 and 5.4), estimated present unused water commitments and instream flow requirements, any any water exports from out of the sub-region. The difference between the total available water supply and the total water use and commitments is the net water supply available for future depletion.

6.2 Energy Development Scenarios

A number of prior studies have considered and described various energy development scenarios that may occur depending on several underlying factors such as the availability and cost of nuclear, foreign oil, or other forms of energy. The purpose of the work reported on here is to establish, based on a number of existing energy scenario projections, a range (minimum, likely, and maximum levels) of water needs in each sub-region that may be required for energy purposes. Sources of water supply for these water requirements are discussed in the next section.

Summaries of the expected ranges of water requirements for the year 2000 from several sources are presented in Tables 6.3 and 6.4 for the Upper Missouri and Upper Colorado Basins. Because the interaction of water requirements for energy development other than synthetic fuel production (primarily electric generation) are significant to the overall water availability outlook, separate figures are given for synthetic fuel production and the total coal industry. In general, the sub-areas used to report energy development and water requirement projections under various scenarios were different in these studies than the drainage sub-areas used in our investigations. As a result some adjustment of the values was necessary to make the figures consistent with our study basins. Although these adjustments are in accordance with the general availability and accessibility of the coal reserves from region to region, they are somewhat arbitrary in cases where the data is lacking or not specific. The overall range of water requirements however is probably reasonably representative.

Table 6.3

ENERGY WATER REQUIREMENT SCENARIOS - UPPER MISSOURI BASIN
(1000 AF/YR)

	Powder	Tongue-Rosebud	Belle-Fourche Cheyenne	Yellowstone-Missouri Mainstem	Heart-Cannonball
WPA Syn. Fuel Sites	3	5	3	6	4
Harza Energy Study					
Syn. Fuel Plants	0-6-9	0-0-0	0-1-2	0-4-5	0-4-5
Syn. Fuel, AF/YR	0-36.1-189.0	0-0-0	0-18.8-31.3	0-44.5-73.7	0-49.7-63.7
Total Coal Ind. AF/YR	48.2-65.1-195.2	15.7-32.7-55.6	9.8-21.9-45.6	11.1-105.8-126.9	10.3-101.9-112.4
Wyoming Water Plan					
Syn. Fuel Plants	4	-	3	-	-
Syn. Fuel, AF/YR	55	-	50	-	-
Total Coal Ind., AF/YR	114	-	114	-	-
Univ. OK/EPA					
Syn. Fuel AF/YR	46.3-63.6-57.5	39.7-58.9-53.5	12.7-16.2-10.2	39.6-60.4-49.5	17.6-24.2-39.5
Total Coal Ind. AF/YR	134.0-151.3-145.3	136.8-179.9-240.1	38.6-42.1-46.5	95.6-191.2-214.8	65.4-48.0-121.5
Natural Petroleum Council					
Syn. Fuel Units	2-4-13	1-2-5	1-2-8	1-5-10	1-1-2
Syn. Fuel, AF/YR	14.5-33.5-127.2	7-20.0-44.5	10.5-23.5-97.5	7.5-46.0-103.0	7.5-10.0-23.0
Total Coal Ind.,AF/YR	121.2-140.2-233.8	60.4-73.4-113.4	90.5-103.5-177.5	124.5-163.0-220.0	56.5-59.0-72.0
Composit Range					
Syn. Fuel, AF/YR	15-40-190	5-15-55	10-20-30	5-45-75	5-25-60
Total Coal Ind., AF/YR	50-140-230	15-100-240	20-35-50	10-150-220	10-60-120

Table 6.4

ENERGY WATER REQUIREMENT SCENARIOS - UPPER COLORADO BASIN (1000 AF/YR)

Source	Upper Green	Lower Green	Upper Colorado Mainstem	San Juan
WPA Sites	4	1	2	3
UCRB Report (2000)				
Syn Fuel, Plants	2	4	7	2
Syn Fuel, AF/Yr	37.0	98.5	191.0	72.0
Total Energy, AF/Yr	116.5	243.5	325.0	154.0
Wyoming Water Plan (2020)				
Syn Fuel, AF/Yr	-	-	-	-
Total Energy, AF/Yr	204.8	-	-	-
Univ of OK/EPA (2000)				
Syn Fuel, AR/Yr	-	38.8-51.7-51.7	-	5.6-14.3-14.3
Total Energy	-	38.8-51.7-51.7	-	34.8-43.5-101.9
National Petroleum Council (1985)				
Syn Fuel, Plants	-	2	13	1
Syn Fuel, AF/Yr	-	18-18-18	112-112-112	20-48-60
Total Energy	-	42-42-42	112-112-112	140-168-180
COMPOSIT RANGE				
Syn Fuel, AF/Yr				
Total Energy, AF/Yr	50-100-200	40-60-100	110-110-325	40-60-180

Composite ranges and intermediate energy water requirements selected from the available sources for use within the context of our present study are further summarized in Table 6.5. Comparison of these figures with the water availability results from Tables 6.1 and 6.2 gives an indication of the relative adequacy of water supplies for energy production in the study sub-regions. These results show that the projected levels on energy development cannot be accommodated by the available supplies in most sub-regions. Only in the Yellowstone, Upper Missouri, Upper Green, and Upper Colorado mainstem sub-regions does it appear that sufficient unreserved supplies are available for the expected levels of energy production. In all other regions, lack of sufficient water could be a limiting factor unless additional supplies can be made available through surface and/or groundwater development or through the acquisition of existing rights.

Table 6.5

SUMMARY OF ENERGY WATER REQUIREMENTS
(1000 AF/YR)

Sub-Region	Synthetic Fuel Min.	Synthetic Fuel Inter.	Synthetic Fuel Max.	Total Coal/Shale Min.	Total Coal/Shale Inter.	Total Coal/Shale Max
UPPER MISSOURI						
Powder	15	40	190	50	140	230
Tongue-Rosebud	5	15	55	15	100	240
Yellowstone Mainstem						
Belle Fourche-Cheyenne	10	20	30	20	35	50
Heart-Cannonball	5	25	60	10	60	120
Upper Missouri						
North Platte						
UPPER COLORADO						
Upper Green	-	-	-	50	100	200
Lower Green	20		50	40	60	100
Upper Mainstem	-	-	0	110	-	325
Lower Mainstem	-	-	0	-	-	-
San Juan	10	-	60	40	60	180

6.3 Alternative Water Supply Sources

In this section, we attempt to present some of the possibilities for water supply for energy conversion. All possibilities have not been fully evaluated, or even identified, and since the study has been performed at long distance, there may be some inaccuracies in the broad-level analysis. We hope that these will not affect the conclusions in any significant manner. The evaluation of water rights is difficult without extensive field work, and for this reason, the purchase of water rights is acknowledged in many of the water supply alternatives, although no estimates are made of the prices or the different manipulations of water rights which would be necessary in any such program.

In general, there are several sources of water for large demands including groundwater, purchase of water used for irrigation, construction of storage facilities, purchase of water from existing storage facilities, and inter-basin transfers of water. Each of the alternatives given below is comprised of one or more of these water sources.

Different alternatives appear in the various scenarios of water demand, for two reasons:

a. the alternative supplied either too little or too much water (i.e., economic reasons), or

b. the alternative would not be acceptable for institutional reasons (e.g., it is permissible to dry up a small portion of farmland, but not an entire area).

The alternatives presented are compatible with those for the other river basins, event when inter-basin water transfers are involved. Thus, it is possible to combine any alternative from one river basin with any project from another river basin. In several cases, projects for more than one river basin could be combined and cost efficiency increased.

A summary of the water supply alternatives for the sub-regions in the Upper Missouri Basin is presented in Table 6.6. Alternatives for the Upper Colorado Basin are given in Table 6.7. A few additional comments on each sub-region are given in the following paragraphs.

TONGUE ROSEBUD RIVER BASINS

The Tongue River and Rosebud Creek drainage basins, adjacent to the Powder River Basin, have a high demand for the scant available water in the drainage basin. Because these rivers are both tributary to the Yellowston River, importations to the Tongue and Rosebud basin from other parts of the Yellowstone Basin are expessly permitted by the Yellowstone River Compact. These are several sites in the basin for which reservoirs have been proposed, and these are included as possible alternatives for water supply.

POWDER RIVER BASIN

Large amounts of coal have been found in the Yellowstone River Basin, including the drainages of the Powder, Tongue, and Bighorn Rivers, which are tributaries of the Yellowstone. In general, the Yellowstone and Bighorn have sufficient water supplies for all

Table 6.6

SUMMARY OF WATER SUPPLY ALTERNATIVES - UPPER MISSOURI BASIN

Sub-Region	Scenario I Low Demand	Scenario II Moderate Demand	Scenario III High Demand
Tongue-Rosebud	Additional storage alone, or with water rights acquisition	Additional storage, or aqueduct from Bighorn or Yellowstone	Aqueduct from Bighorn or Yellowstone
Powder	Acquisition of water rights, or construct Moorhead or Lower Clear Creek Reservoir	Ultimate Powder River development, or aqueduct from Bighorn or Yellowstone	Aqueduct alone, or with reservoir development
Yellowstone Mainstem	Mainstem diversion	Mainstem diversion to offline storage	Missouri Mainstem, or Fort Peck Reservoir
Belle Fourche-Cheyenne	Reservoir development, or groundwater development	Reservoir and groundwater development, or aqueduct	Aqueduct from Bighorn, or Yellowstone Rivers
Heart-Cannonball	Reservoir development	Aqueduct from Sakakawea or Oahe Reservoir	Same as II
Upper Missouri Mainstem	Mainstem diversion	Aqueduct from Fort Peck, Sakakawea or Oahe Reservoir	Same as II
North Platte	Acquisition of water rights and/or groundwater development	Same as I, or importation from Green Basin	Same as II

Table 6.7

SUMMARY OF WATER SUPPLY ALTERNATIVES - UPPER COLORADO BASIN

Sub-Region	Scenario I Low Demand	Scenario II Moderate Demand	Scenario III High Demand
Upper Green	Additional local storage facilities	Aqueducts from Fontenelle and/or Flaming Gorge	Same as II
Lower Green	Reservoir development on the White River	Reservoir development on the White River	White River storage plus diversion from the Green River
Upper Mainstem	Diversion from the main stem to utilize existing storage	Same as I	Same as I
Lower Mainstem	Although no significant energy development has been projected for the Lower Mainstem hydrologic sub-region, large supplies are available from Lake Powell.		
San Juan	Groundwater development and/or diversion using Navajo Reservoir storage	Same as I	Diversion using all available Navajo Reservoir storage and extensive groundwater development

anticipated in-basin requirements, whereas the Tongue and Powder drainage basins, with the largest supplies of coal, have a more limited supply of water relative to the total demand.

Large amounts of coal lie very near the indistinct drainage divide between the Powder River and the Belle Fourche River, in the Belle Fourche River drainage basin. The water supply of the Belle Fourche is very limited, thus forcing investigation of trans-basin imports of water. However, the nearest sources of water are tributaries of the Yellowstone, subject to constraints imposed by the Yellowstone River Compact upon the export of water from the Yellowstone River.

YELLOWSTONE AND MISSOURI RIVER BASINS

The Yellowstone and Missouri Rivers are unique in this study, as they have ample water supplies for any of the projected water demand scenarios for their entire length. Although the Yellowstone River is free-flowing for its entire length, there are two very large reservoirs on the Missouri in the area of interest, Fort Peck Reservoir and Lake Sakakawea. Additionally, there are two reservoirs on the Bighorn River, a major tributary to the Yellowstone River, which can provide storage for water along the stretch of concern of the Yellowstone River.

The Yellowstone River is presently being stuided for inclusion in the Wild and Scenic Rivers Section, because it is still free-flowing. It if is so designated, severe restrictions will be placed on the construction of storage and water use facilities of the mainstem river.

HEART AND CANNONBALL RIVER BASINS

The Heart and Cannonball Rivers both lie completely within the State of South Dakota and art tributary to the Missouri River. Due to their relatively small watershed area, they both have limited streamflow. Since the drainages are adjacent and parallel to each other, with a low drainage divide between them, it is assumed the transfer of water between the basins is possible without major problems. There are no compacts concerning either of these rivers which would hinder their development from institutional considerations

PLATTE RIVER BASIN

While there is a large amount of water in the Platte River Basin, it is presently being used for a variety of uses, with agriculture being the largest user. In this situation, there are two directions in which one can proceed to obtain the water necessary for new purposes: 1. develop new sources of water, and 2. purchase and transfer of water presently being used for other purposes. The possibility of groundwater development remains, but will not be further discussed here.

Importation of water from the Green River Basin is one of the most likely possibilities for the development of new water in the Platte Basin. There exists a large amount of storage in the North Platte Drainage Basin, but it is all currently used, primarily for agricultural purposes.

Developments in the water use of Platte River water will be closely monitored by Nebraska, and significant increases in consumptive use will probably be protested.

UPPER GREEN RIVER BASIN

The Green River in Wyoming is that state's major contributor to the Colorado River drainage. There is currently very little development in the region, and most of the water allotted to Wyoming under the terms of the Upper Colorado River Basin Compact flows unused out of the State. This means that large amounts of water in the Green River are available for development and beneficial use.

There are two reservoirs on the Green River in Wyoming, Fontanelle and Flaming Gorge, both of which are part of the Upper Colorado River Basin Storage Project. With the storage capacity of these reservoirs, adequate water supplies are available for the energy demands presently envisioned for the Green River Basin in Wyoming.

For these reasons, the anticipated source for all of the scenarios would be the Green River, with its storage capabilities in the Fontanelle and Flaming Gorge Reservoirs.

LOWER GREEN RIVER BASIN

For each of the demand scenarios, the same sources of water exist. These are the Green River, the White River, the Colorado River, and possibly Strawberry - Duchesne Rivers. In general, the Green River is seen as a probable source of water for the Utah energy requirement, with excellent storage capacity in Fontanelle and Flaming Gorge Reservoirs.

The White River is also a very good potential source of water for the Utah demand. However, the lack of a White River Compact between Utah and Colorado combined with the potential utilization of White River water in Colorado make it risky to depend on this source without assurance of continued supply in Utah.

The Colorado is seen as an unlikely source of water because of its distance from the proposed sites. The proposed Starvation Reservoir on the Strawberry River could supply a portion (about 30,000 AF) of the required amount. This would be carried by the Duchesne River, whence an aqueduct would carry to the point of use.

UPPER COLORADO MAINSTEM

There are two major surface water sources which are being considered seriously. They are the White River and the Colorado River. Either one has sufficient average annual flow to supply the major portion of the requirement. It is anticipated, however, that both rivers will be used, as the sites vary in their proximity to each river. There exists currently a large amount of storage capacity in the Colorado River, but very little in the White River. There have been several dam sites identified, but none of them are expected to be built by Federal agencies. Instead, they may be developed by private groups, such as a consortium of energy companies.

SAN JUAN RIVER BASIN

There exist two major sources of water in the San Juan River Basin in New Mexico which could supply the amounts of water required by coal conversion plants. These are the San Juan River and groundwater. It must be realized, however, that there will be strong competition for the water from a variety of sources, among whom a very important one is the rapidly developing uranium mining and processing industry. New Mexico is one of the centers of the uranium minimg and milling industry, and this industry's development will closely follow the general development of nuclear power activities in the United States and the world.

One of the most important effects of both uranium and coal mining will be the consequences of dewatering on the surrounding areas, and on the water supply picture in general. Mine dewatering will produce a large amount of water of varying qualities available for immediate consumption. This has the effect of mining the aquifer of its water, and could potentially have very serious and far-reaching long-term consequences. For this reason, the mine dewatering will necessarily be closely monitored by the New Mexico State Engineer, who is concerned primarily with quantities of water, and the New Mexico Department of Environmental Improvement, which is concerned mainly with the pollutional aspects. Until now, no policy has been established in New Mexico with respect to this problem. It is possible that this will change in the near future.

The San Juan River is the other major possibility for a large supply of water. A tributary of the Colorado River, it is the only major river flowing through the Northwest Quadrant of New Mexico. The only significant reservoir on the San Juan River is Navajo

Reservoir which has approximately 100,000 AF/year allotted for industrial purposes, most or all of which will be energy-related. This river is subject to the Colorado River Compact and the Upper Colorado River Basin Compact. Because it is essentially the entire Colorado River drainage of New Mexico, it is the San Juan River and drainage from which New Mexico receives its allotment of Colorado River water.

The low level and medium level of demand scenarios, calling for 40,000 AF/year, 100,000 AF/year, would probably come from the Navajo Reservoir on the San Juan River, with groundwater sources as a supplement.

The high demand scenario of 140,000 AF/year could also be supplied primarily from the Navajo Reservoir, it would require an arrangement with local Indian tribes in which part of their water allocations would be used for industrial purposes. There would be severe complications in supplying the high demand scenario, due to institutional problems of water transfer. It is not known at this time to what extent groundwater can serve as a source for the water demand.

6.4 Conclusions on Water Supply Availability

Based on the data presented earlier in this section, several conclusions can be drawn concerning the role of water availability in future energy developments in the west. It is apparent from future use projections that in most regions, actual water use other than for energy will be considerably less than the total available surface water supply. Of the remaining water, however, significant quantities may already be legally committed to other uses, or may be required for instream flow uses. In many cases therefore water to meet energy requirements will have to be acquired through the purchase of existing rights; diverted from major interstat rivers and piped to the point of intended use; developed from groundwater reserves; or a combination of these.

The results of this investigation indicate that synthetic fuel plant water requirements will most easily be accomplished for those plant sites located along the main stems of the major rivers and in areas where the level of competing use is projected to be small relative to overall water availability. Sub-regions in this category include the following:

1. Yellowstone River Mainstem
2. Missouri River Mainstem
3. North Platte River
4. Upper Green River
5. Upper Colorado Mainstem

Although overall water availability is generally favorable within these regions, individual plant sites may be located considerable distances away from the water sources and require major water delivery developments to transport the water to the required places.

On the other hand, in several areas the expected level of future water needs for energy development will be very difficult to meet from the available sources within the region without major disruptions to the present water use structure. Some of the most readily developable coal reserves in the Powder River and Fort Union coal formations of northeast Wyoming and the Western Dakotas are located in regions with these characteristics. These sub-regions include the following:

1. Tongue-Rosebud
2. Powder River
3. Belle Fourche-Cheyenne
4. Heart-Cannonball

In these regions the energy water requirements probably can best be met by trans-basin diversions from more adequate supplies outside the regions.

7. REFERENCES AND DATA SOURCES

Harza Engineering Company, 1976, "Analysis of Energy Projections and Implications for Resource Requirements".

Missouri River Basin Commission,1976, "Yellowstone Basin and Adjacent Coal Area Level B Study - Depletion Report".

Montana Department of Natural Resources and Conservation, 1975a, "Water Use in Montana",Inventory Series Report No. 13.

_________,1975b, "Yellowstone River Basin - Water Resources Situation Report".

_________,1976, "The Framework Report, A Comprehensive Water and Related Land Resources Plan for the State of Montana".

_________,1977, "The Future of the Yellowstone River?"

North Dakota State Water Commission, 1968, "North Dakota Interim State Water Resources Development Plan", Information Series No.8.

Northern Great Plains Resources Program, 1974, "Water Work Group Report".

__________,1974, "Water Quality Subgroup Report".

Upper Colorado Region State-Federal Interagency Group, 1971, "Upper Colorado Region Comprehensive Framework Study , Appendix X, Irrigation and Drainage".

U.S. Bureau of Reclamation, 1974, "Alternative Sources of Water in Prototype Oil Shale Development - Colorado and Utah".

U.S. Department of Commerce, National Oceanic and Atmospheric Administration, 1974, "Climatic Atlas of the United States".

U.S. Department of Health, Education and Welfare, Public Health Service, 1962, "Standards for Public Drinking Water Supplies".

U.S. Department of Interior, 1971a, "Index of Surface-Water Records to September 30,1970 - Missouri River Basin", Geologic Survey Circular 656.

___________, 1971b, "Index of Surface-Water Records to September 30, 1970 - Colorado River Basin, "Geologic Survey Circular 659.

___________,1973,"Final Environmental Impact Statement for the Prototype Oil Shale Leasing Program, Vol. I", U.S. Gov't Printing Office, Washington, D.C.

___________, 1974a, "Summary Appraisals of the Nation's Groundwater Resources - Upper Colorado Region", Geological Survey Professional Paper 813-C, U.S. Gov't Printing Office, Washington, D.C.

________, 1974b, "Report on Water for Energy in the Upper Colorado River Basin", U.S. Gov't Printing Office, Washington, D.C.

________, 1975a, "Westwide Study Report on Critical Water Problems Facing the Eleven Western States", U.S. Gov't Printing Office, Washington, D.C.

U.S. Geological Survey, 1964, "Generalized Map Showing Annual Runoff and Productive Aquifers in the Conterminous United States", Hydrologic Atlas HA - 194.

________, 1965,"Preliminary Map of the Conterminous United States Showing Depth to and Quality of Shallowest Ground Water Containing More than 1000 ppm Dissolved Solids", Hydrologic Atlas HA-199.

________, 1975a, "The Role of Groundwater in Resource Planning in the Western United States", Open File Report 74-125.

________, 1975b, "Water Resources Data for Colorado", U.S. Gov't Printing Office, Washington, D.C.

________, 1975c, "Water Resources Data for New Mexico", U.S. Gov't Printing Office, Washington, D.C.

________, 1975d, "Water REsources Data for Montana", U.S. Gov't Printing Office, Washington, D.C.

________, 1975e, "Water Resources Data for Utah", U.S. Gov't Printing Office, Washington, D.C.

________, 1975f, "Water REsources Data for Wyoming", U.S. Gov't Printing Officw, Washington, D.C.

________, 1977, "STORET Data Retrieval System Printout".

Water Purification Associates, 19676, "An Assessment of Minimum Water Requirements for Steam-Electric Power Generation and Synthetic Fuel Plants in the Western United States, 1976.

Wyoming State Engineer's Office , 1971, "Compacts, Treaties and Court Decrees".

Wyoming State Engineer's Office and Wyoming State Water Planning Program, 1973, "Wyoming Framework Water Plan".

APPENDIX A

SUMMARY OF STATE WATER CODES

A.1 Upper Missouri River Basin States

Wyoming

The Appropriation System is used in Wyoming exclusively for water administration. The Wyoming State Engineer is the person responsible for handling this procedure, and for ensuring that all water is used in accordance with set priorities and conditions.

Generally, the procedure for obtaining a water right is as follows: the prospective user files an application for a permit with specific maps and plans with the State Engineer; the priority date being established when the State Engineer accepts the application At the time that the permit is granted by the State Engineer, dates are set for the construction and completion of the facility and the commencement of water diversion. Usually, project construction must be completed within five years of the date of project approval, with the possibility of extension of the completion deadline by the State Engineer for good cause. When the water specified in the approved permit application is put to beneficial use, and the required notices are filed, the State Board of Control will issue a certificate of appropriation which is the final step in the granting of a decreed water right. In some instances, a water right is recognized in Wyoming as being attached to the land. Transfers may take place with the approval of the Board of Control.

There is a rank ordering of the beneficial uses in Wyoming, indicating which categories of use are preferred over others. Agriculture, the use consuming the greatest amount of water, is relatively low on the list, as domestic, municipal, stream power plants, transportation, and industrial uses of water are preferred to it. The meaning of preference in beneficial uses is simply that transfers from a use lower on the list to a use higher on the list are more easily handled and encouraged than other types of transfers, and in some cases, preferred uses may condemn the rights put to inferior use. In fact, almost any use to which water is put that benefits somebody in the slightest way is considered a benficial one. An important exception to this is instream flow which at present is not considered a beneficial use.

Because most of the water is presently in agricultural use, and agricultural uses are so low on the list of preferred uses, most of the water transfers would probably come from agricultural-industrial transfers if no new water supplies are developed. Agricultural water is, in some cases, tried to the land upon which it is used. It may therefore be necessary to purchase the land in order to acquire the water.

Because of the time requirement for the perfection of completion of decrees, there are relatively few permits for the construction of diversion facilities which are still outstanding, i.e., being completed. Thus, a dynamic, rapidly changing situation exists currently in the Wyoming water resources picture with respect to the availability of presently undeveloped and undecreed water.

Montana

Montana has, since 1973, a permit system for the orderly management of its water rights. Before 1973, even through Montana followed the appropriation doctrine, there existed no centralized water management and administration authority in Montana. Water rights were only erratically, if at all, recorded at local county courthouses, and there was no legal requirement to have them recorded.

The procedure used in establishing a water right is set in the Montana Water Use Act Regulations of 1973 and is described here. After application to the Montana Department of Natural Resources and Conservation, a permit is issued following ascertainment that the Water Use Act Regulations are met. After the water is put to beneficial use, and the Department has inspected in order to determine completion of appropriation, a certificate of water right is issued. It should be noted that certificates are issued only in areas where the existing rights have already been established and recorded. This is significant, because until 1973, no water rights had received this treatment, and the process is still unfinished, as the Department of Natural Resources and Conservation is in the process of recording all existing water rights and filings.

In an attempt to gain time for the State agencies to complete their planning programs, the 1974 Montana Legislature enacted a 3-year moratorium on Yellowstone River Basin diversions greater than 20 cfs (14,000 AF/Year). Developments in the near future are anticipated as the moratorium terminates on July 31, 1978 after a six month extension.

Of general interest to those involved in water supply will be the final outcome of the Intake vs. Yellowstone River Compact Commission court case. Essentially, the Intake Water Company is a firm seeking to perfect a large water right near Intake, Montana for purposes including the marketing of water, possibly to out-of-state customers. The Yellowstone River Compact Commission is seeking to deny this permit, and the Intake Water Company is in the process of appealing through the courts. It is anticipated that the outcome will have significant effects of future interstate water marketing efforts.

Generally, water must be diverted for beneficial use, which, in Montana, has a broad difinition. The use of water for slurry pipelines exporting coal from Montana, however, is not a beneficial use, by act of the Montana Legislature. Instream water use, on the other hand, is recognized as a beneficial use in Montana. Transfers of water with respect to use, location, and ownership are permitted if Department of Natural Resources and Conservation approval is obtained. Groundwater is, in general, handled in much the same manner as surface water.

North Dakota

The water administration system of North Dakota incorporates aspects of both the appropriation doctrine and the riparian code. Originally riparian rights were the water law of the State; in 1955 the State Legislature enacted the irrigation code which is the basis of the current appropriation doctrine. It recognizes the riparian rights which were established before 1955, e.g., rights belonging to those who owned land adjacent to the water body, and in keeping with the "reasonable use" requirement.

To appropriate water, an application for appropriation is made to the State Engineer. If water is available and the approval is not "contrary to the public interest," the permit is approved, and a completion time is set. The final license is issued after inspection by the State Engineer for the amount of water actually applied to beneficial use. The actual beneficial use is the basis and measure of the water right. Transfers can take place with the approval of the State Engineer.

A.2 Upper Colorado River Basin States

Colorado

Colorado has a unique form of the appropriation system in which the judiciary is incorporated in the administration and establishment of water rights. The Colorado State Engineer is responsible for the enforcement of the decisions made in the Water Court system.

When a water right is to be established, the plans for the diversion and beneficial use are presented to the water court. After determination is made that other parties will not be damaged, a "conditional decree" is granted for a diversion of a specific amount and location. A requirement for the continuation of the conditional decree is "due diligence" - i.e., some progress towards constructing the facility and putting the water to beneficial use. With the completion of construction, the decree is "perfected," or made final, in a court adjudication, and the seniority date of the decree is that date when the conditional decree was granted. This permits long-term projects to be undertaken with the firm assurance of a priority date and water supply. This system also permits speculation to take place with conditional permits, which tends to inflate drastically the price of undeveloped water.

Transfers in ownership, location, and point of use are made through the courts; with the primary factor under consideration being that other user, both senior and junior, are not adversely affected.

Actual beneficial use is the basis, measure, and limit of the water right.

Groundwater tributary to a surface stream is administered in the same manner as surface water. The State Engineer exercises control of groundwater that is non-tributary to surface waters, i.e., deep aquifer systems, to a much greater extent.

New Mexico

The State Engineer of New Mexico plays a dominant role in the administration of the water of the State. The Appropriation doctrine is followed in New Mexico, with actual beneficial use as the basis, measure, and limit of the right to divert and use water. Generally, the State Engineer handles the entire procedure of water rights administration and establishment, from permit application to final adjudication of the water right, including hearings and protests from existing water users. The decisions of the State Engineer may be appealed to the appropriate district court; in fact, this is rarely done. Transfers are handled by the State Engineer in essentially the same manner as described above for the establishment of new water rights.

Utah

Utah uses a permit system of water rights following the APpropriation docutrine. A permit date is granted at the time when the application is first received in the State Engineer's Office. The application is approved after notice publication, opportunity for protest, and a hearing of all interested parties in the State

Engineer's Office. All of the State Engineer's decisions can be reviewed by the District Court, which is also responsible for adjudicating all rights in each drainage basin. Because applications have a value determined by their date, they are marketable; this is encouraged because of the possibility of change of point of diversion, point of use, and type of use. Additionally, there are a large number of permits applications which have been filed, but not approved, implying a very active market in water speculation.

APPENDIX 15

COST OF SUPPLYING WATER TO CHOSEN SITES

INTRODUCTION

The degree to which dry cooling is used in a coal conversion plant is mainly an economic one and depends primarily on the cost of water[1]. The cost of water is equal to the cost of transporting water to the site as well as the cost of water treatment and disposal of any blown down streams. In most of the Appalachian and Illinois coal bearing regions the legal doctrine governing the use of water is the Riparian Doctrine which defines surface water rights as ownership of land next to or traversing the natural stream. The cost of transporting water in these regions is very low because of the close proximity of the coal conversion plant to the water source. In the Western coal bearing regions the Appropriation Doctrine usually applies. The first appropriation of the water conveys priority independently of the location of the land with respect to the water so that the source water may not be in close proximity to the conversion plant. Furthermore, chronic water shortages exist in many of the river basins. Large reservoirs may have to be built on the main stems of the principal rivers and water transported over large distances to the water-short regions. In this appendix the costs of transporting water by pipeline to all of the coal conversion sites in the Western states are estimated for a number of different water supply options.

SUPPLY WATER COSTS

The cost of transporting water by pipeline over long distances is dependent on the costs associated with the construction of the pipeline itself and the costs associated with pumping water through the pipeline. There have been quite a number of excellent studies defining the economics for water conveyance systems including those of Singh[2] and Tyteca[3]. For convenience we have used Singh's classification of the cost elements of the conveyance system. However, we have derived a simple, yet accurate model to illustrate the important features of the economics.

The three principal costs of transporting water are the pipeline construction cost, the cost of pumping water through the pipeline, and the cost of the pumping stations. We have neglected the pipeline and pumping station operation, maintenance and repair costs and the easement cost, but have included insurance and tax costs in the annual cost.

Pipeline Construction Costs

The pipeline construction costs include the cost of the pipe material, labor for installation, excavating, backfill, contingencies and valves and other appurtenances integral to the pipeline. Allowance was also made for landscaping and environmental enhancement. Extra costs for going under or over roads, railroads, rivers or bridges are not included. The pipeline construction costs are approximated by

$$C_c = k_c \, D \, L \tag{1}$$

where

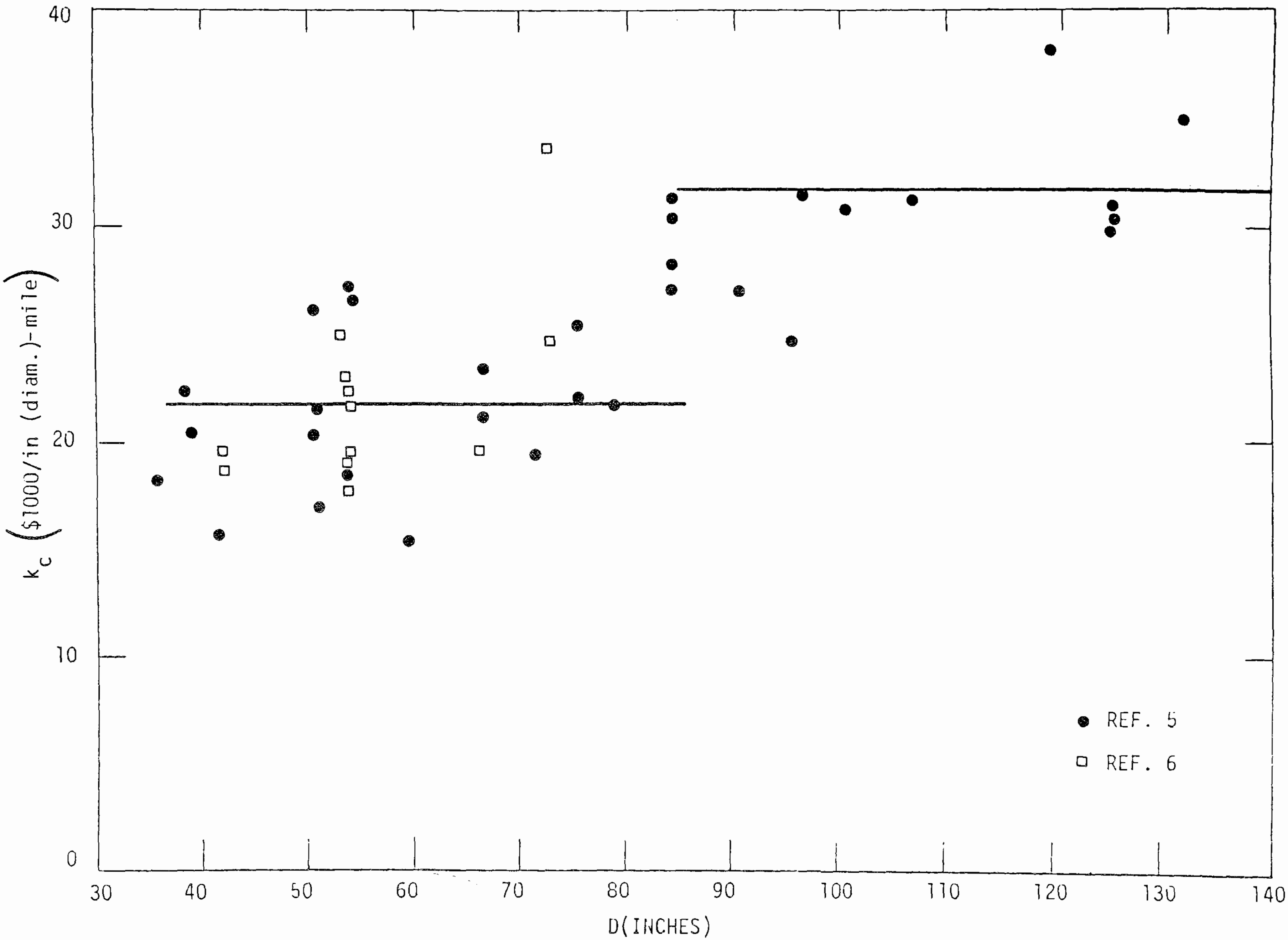
k_c = pipeline construction costs, in \$/in(diameter)-mile

D = inside pipe diameter, in inches

L = length of pipe, in miles.

We have obtained data from three sources. Stone and Webster has estimated costs for a 12 inch diameter pipeline in the Wyodak, Wyoming area[4]. The line was designed for a water flow of 2,200 gpm (3.2×10^6 gpd) and runs for about 3.8 miles. The total cost was estimated to be approximately $\$10^6$ and represents about \$22,000/inch(diam)-mile. Pipelines of this nature cost in the range of \$20,000 - \$30,000/inch(diam)-mile.

Data for a 1972 Bureau of Reclamation study[5] on buried aqueducts and data from the North Central Power study are presented in Figure A15-1 where the installed cost in terms of \$/inch(diam)-mile is shown as a function of



$k_c \left(\$1000/\text{in (diam.)-mile} \right)$
0
10
20
30
40
D(INCHES)
30
40
50
60
70
80
90
100
110
120
130
140
REF. 5
REF. 6

aqueduct diameter. These costs include the interest charges during construction and the cost of the pumping stations. The costs from Ref. 6 are based on 1975 costs. The data seem to group according to pipe diameter. For pipe diameters less than 84 inches, k_c is approximately \$21,000/ inch(diam)-mile; while for pipe diameters larger than 84 inches, k_c is about \$32,000/inch(diam)-mile. For the present study we have assumed an installed cost of k_c = \$25,000/ inch(diam)-mile.

Another interpretation of the data presented in Figure A15-1 is that k_c is a function of D. For example, if $k_c \sim D^a$, then $C_c = ALD^{1+a}$. The data in Figure A15-1 give A = 7600 and a = 0.30. Singh[2] uses values of A = 2160 and a = 0.20. However, as we discussed above, for the present study we used Eq.(1) with k_c = \$25,000/inch(diam)-mile.

Annual Pipeline Construction Cost

We have taken a fixed annual charge rate to be applied to the pipeline construction costs. This rate includes the interest rate on capital and the insurance and tax rates. The annual pipeline construction cost is

$$P_c = y_c k_c DL \qquad (2)$$

where

y_c = annual charge rate on pipeline construction costs

Annual Pumping Cost

We have sized the pipelines and pumping plants to deliver a constant daily water demand $Q = 1.5Q_m$, where Q_m are the maximum daily plant water requirements (expressed in terms of million gal/stream day), over a period of X days corresponding to a plant load factor of N. For the examples given in this section, N = 0.91 corresponding to 333.3 days or 8000 hrs. The annual pumping cost is given by

$$P_p = 1.15\text{x}10^3 \; \frac{k_p Q H_T N}{E} \qquad (3)$$

where

k_p = cost of energy, in \$/kw-hr

$H_T = 984.8 \frac{fLV^2}{D} + H$

N = plant load factor (4)

f = Mannings coefficient of roughness

Q = flow rate, in mgd

V = flow velocity in pipe, in ft/sec

H = static head, in feet of water

E = pump efficiency

The flow rate is rela :d to the flow velocity by

$$Q = 3.54 \times 10^{-3} D^2 V \tag{5}$$

Pumping Station Cost

We have used a simplified form of the cost function of Singh for the pumping station cost. Singh[2] assumed that a single pumping station will increase the pipeline pressure to no more than 300 feet of water. The cost of a single pumping station is \$[17,000 + 135W] when W is the total installed horsepower when the head is 300 feet. If the total head, H_T, exceeds this limit, more pumping stations are required. For convenience the total capital cost of the pumping station is taken to be

$$C_{ps} = [17,000 + 135W] \frac{H_T}{300} \tag{6}$$

where

$$W = 68.3\ Q/E^*, \text{ in hp} \tag{7}$$

*The standby factor in Ref. 2 has been taken as 1.30 and the storage capacity has been taken as 0.

Annual Pumping Station Cost

We have taken a fixed charge rate to be applied to the cost of the pumping station. It includes the interest rate on the capital cost, and the insurance and tax rates,

$$P_{ps} = y_p \left(56.7 + 30.8 \frac{Q}{E}\right) H_T \tag{8}$$

where

y_p = annual charge rate on pumping station costs

Pipeline Operation, Maintenance and Repair Cost

Based upon the cost functions defined in Ref. 1, the pipeline operation maintenance and repair cost is not more than 5 percent of the annual pipeline construction cost if the amortized rate is greater than 6 percent and the pipeline diameter is greater than 24 inches. These costs have been neglected in the present study.

Easement Cost

Based upon the cost functions defined in Ref. 1, the easement costs do not exceed more than 2 percent of the pipeline construction costs for pipe diameters greater than 24 inches. Those costs have been neglected in the present study.

Pumping Stations Operations: Maintenance and Repair Cost

Based upon the cost functions defined in Ref. 1, these costs do not exceed 6 percent of the annual pumping station costs. These costs have been neglected in the present study.

Total Annual Cost

The total annual cost of transporting water by pipeline is given by

$$P = P_c + P_p + P_{ps} \tag{9}$$

$$= y_c k_c DL + 1.15 \times 10^3 \; \frac{k_p Q H_T N}{E}$$

$$+ y_p (56.7 + 30.8 \frac{Q}{E}) H_T$$

Cost Optimization

The factors that directly influence the annual pipeline costs are the length, diameter, flow rate and the static head, or slope of the pipeline. Other factors such as the annual charge rates, or friction coefficient, and the pump efficiency are parameters that are fixed once the materials of construction, pumps, money market, etc. are known. The length of the pipeline and static head are considered known. Thus the total annual cost can be considered to be a function of the flow rate and pipe diameter. Furthermore, the flow rate is defined for a particular plant.

It is clear from Eq. (9) that the total annual cost has a minimum. The capital cost of the pipeline varies directly as D, while the pumping and pumping station costs are proportional to $1/D^5$ for a fixed flow rate Q. The latter two costs are also proportional to the slope of the pipeline H/L. Figures A15-2 and A15-3 show the total annual cost (expressed in terms of \$/1000 gal-mile) as a function of pipe diameter for a particular set of conditions For the particular example shown in Figure A15-2, the diameter of the pipeline that gives the minimum cost is $D = D_m = 20.3$ inches with a flow velocity of $V = V_m = 6.7$ ft/sec. The total annual cost increases more rapidly for diameters smaller than D_m than for diameters larger than D_m. The friction pumping costs dominate the total costs for the former case while the pipeline construction costs dominate for the latter case. For the particular example the costs of pumping against the static head are very small. The effect of changing Q on the total annual cost is shown in Figure A15-3.

The minimum or optimum cost is found by setting the derivative of Eq. (9) with respect to D (keeping Q constant) equal to zero. The pipe diameter and velocity for which the total cost is a minimum are

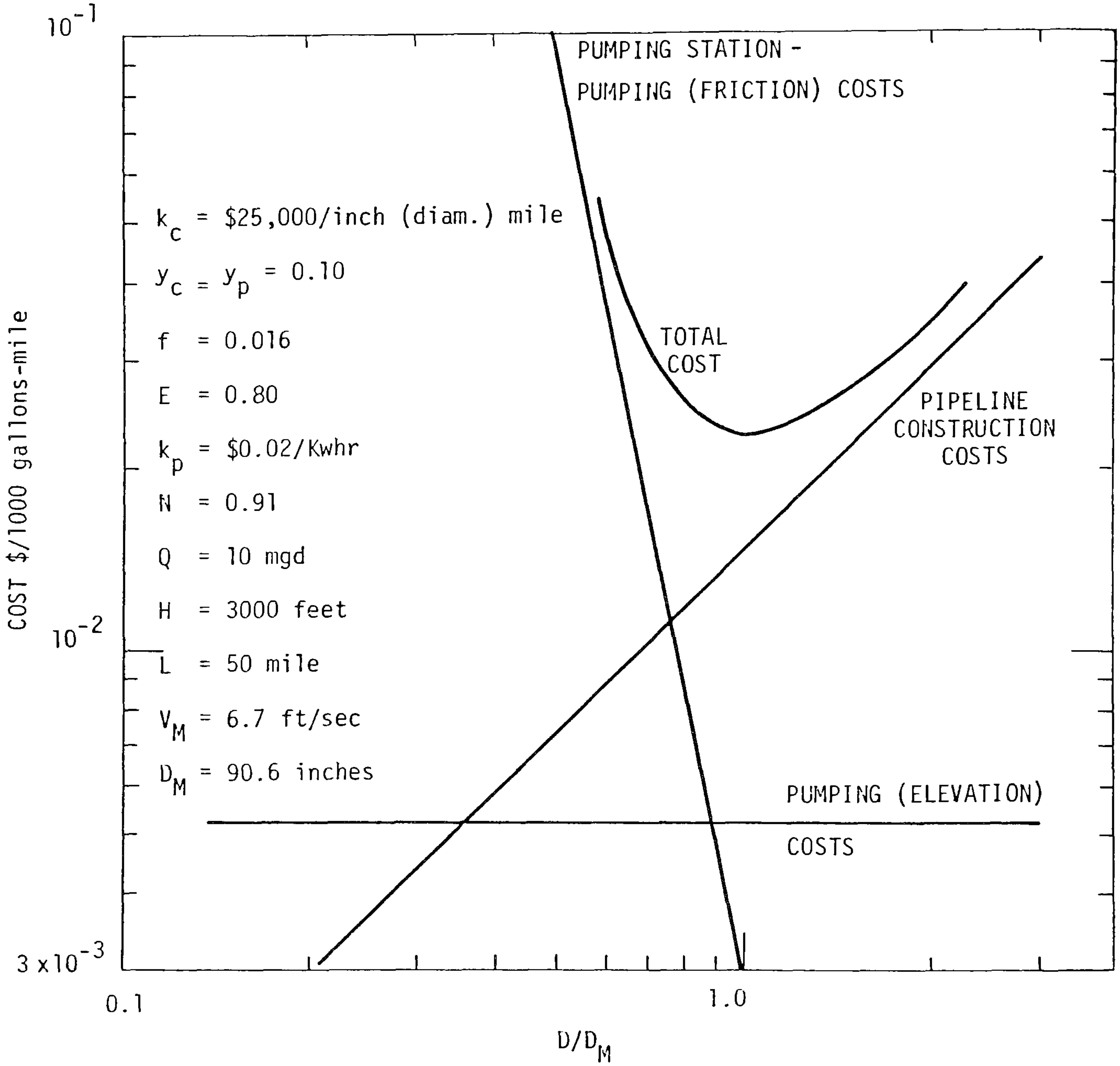


Figure A15-2 Total annual costs for transporting water as a function of pipe diameter.

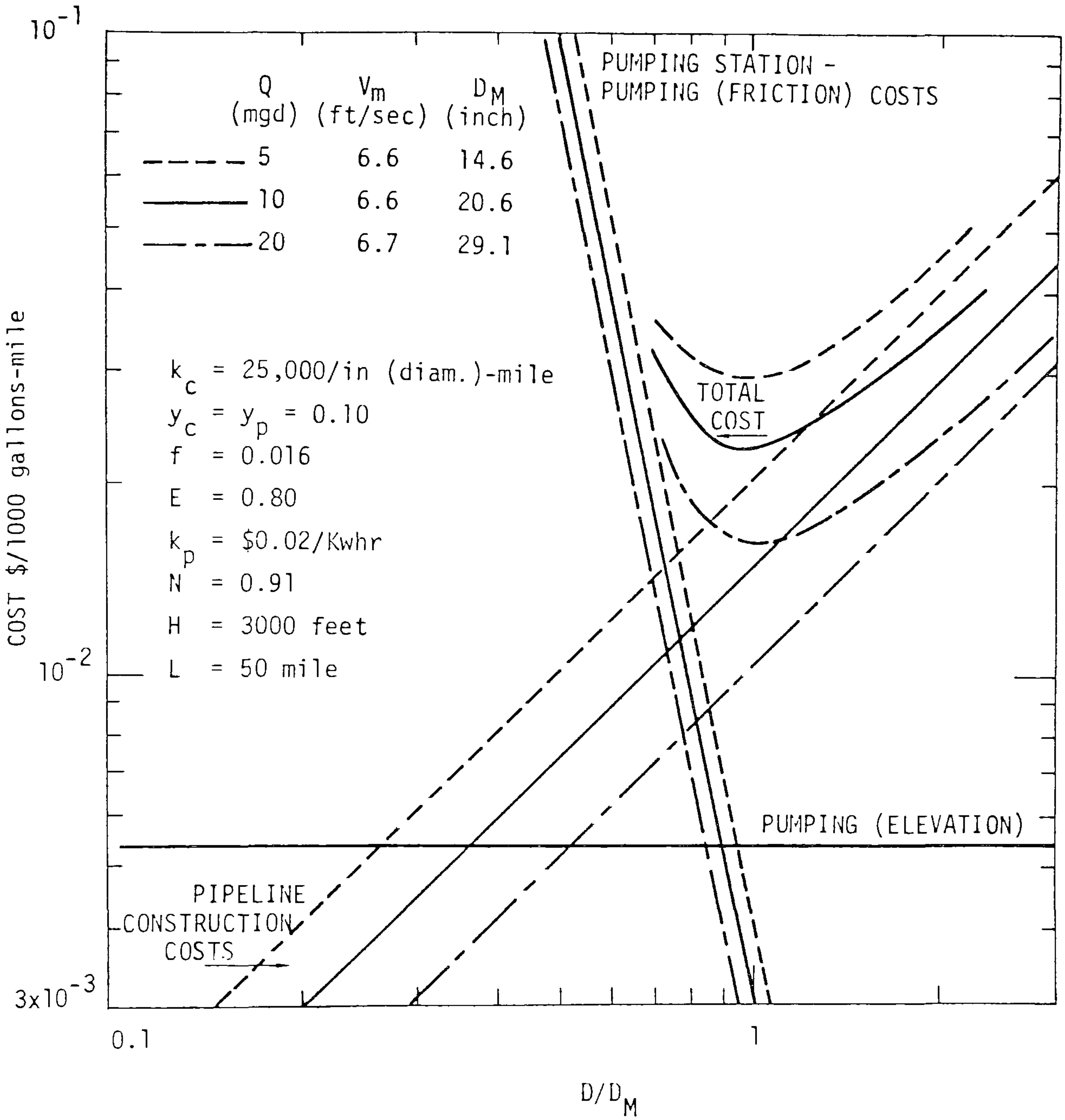


Figure A15-3 Effect of flow rate on the total annual costs of transporting water.

$$D_m = 87.6 \sqrt{Q} \Big/ \left(\frac{Ey_c k_c}{k_p NfG} \right)^{1/6} \tag{10}$$

$$V_m = 0.0368 \left(\frac{Ey_c k_c}{k_p NfG} \right)^{1/3} \tag{11}$$

where

$$G = 1 + \frac{0.0268}{N} \frac{y_p}{k_p} \left(1 + 1.84 \frac{E}{Q}\right) \tag{12}$$

The minimum costs are given by

$$P_c = y_c k_c D_m L \tag{13}$$

$$P_p + P_{ps} = \frac{P_c}{5} \left[1 + 5.75\text{x}10^3 \frac{H}{L} \frac{Q}{D_m} \frac{k_p NG}{Ey_c k_c} \right] \tag{14}$$

It is interesting to note that if the static head is zero (or if the second term in Eq. (14) is small), the minimum cost occurs when the costs of pumping and pumping stations is 1/5 of the annual pipeline construction cost, or 1/6 of the total annual cost. This was found by Singh[2] on the basis of a more detailed cost analysis. Furthermore, for the cases that we are going to consider, the function G is relatively insensitive to Q, so that the flow velocity in the pipeline corresponding to the minimum annual cost is also insensitive to Q (Figure A15-3).

Table A15-1 lists the values of the cost parameters used in the present study.

TABLE A15-1 COST PARAMETERS USED IN THE PRESENT STUDY

k_c = \$25,000/inch(diam)-mile

k_p = \$0.02/kwhr

$y_c = y_p = 0.10$

$f = 0.016$

$E = 0.80$

$N = 0.91$

With these values Eqs. (10)-(14) become

$$D_m = 6.50 \sqrt{Q} \tag{15}$$

$$V_m = 6.68 \text{ ft/sec} \tag{16}$$

$$G = 1.15 \tag{17}$$

$$\bar{P}_c = P_c/QL = \frac{0.048}{\sqrt{Q}} \tag{18}$$

$$\bar{P}_p + \bar{P}_{ps} = P_p + P_{ps}/QL = \frac{0.0096}{\sqrt{Q}} \left[1 + 0.0093\sqrt{Q}\,\frac{H}{L}\right] \tag{19}$$

$$\bar{P} = \frac{0.0576}{\sqrt{Q}} + 8.93 \times 10^{-5}\,\frac{H}{L} \tag{20}$$

where $\bar{P}$ is the minimum cost expressed in \$/1000 gal-mile. The first term of Eq. (20) is the annual cost of pipeline construction, pumping stations and pumping against friction while the second term is the annual cost of pumping against a static head. Figures A15-4 and A15-5 show the cost of transporting water. The capital and pumping (friction) costs does not include the cost of pumping against a static head. The static head pumping costs are given in the lower part of the figures and should be added to the capital and pumping (friction) costs to arrive at a total annual cost. In general, the static head pumping costs can be neglected with respect to the other costs.

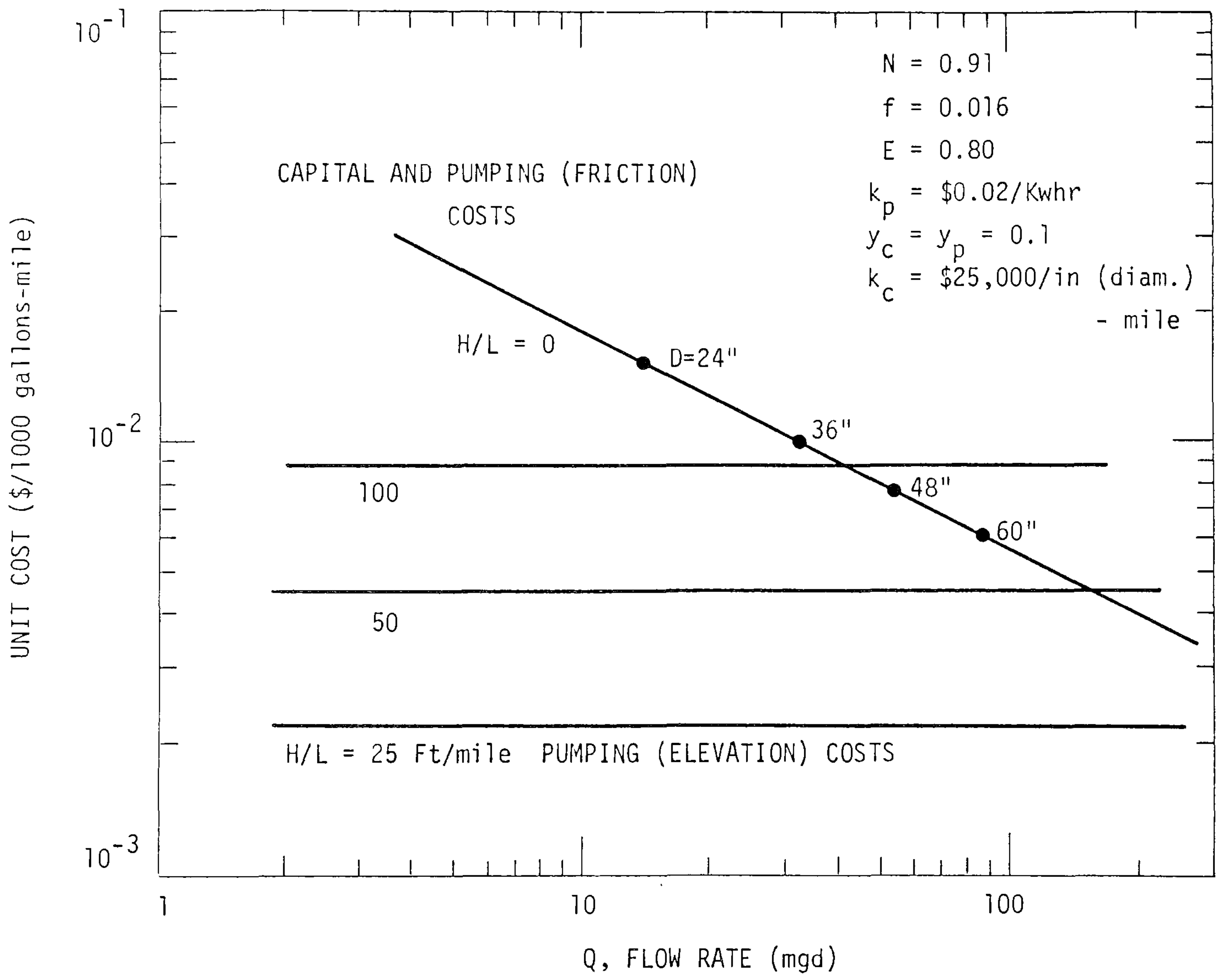


Figure A15-4 Unit cost of water supply.

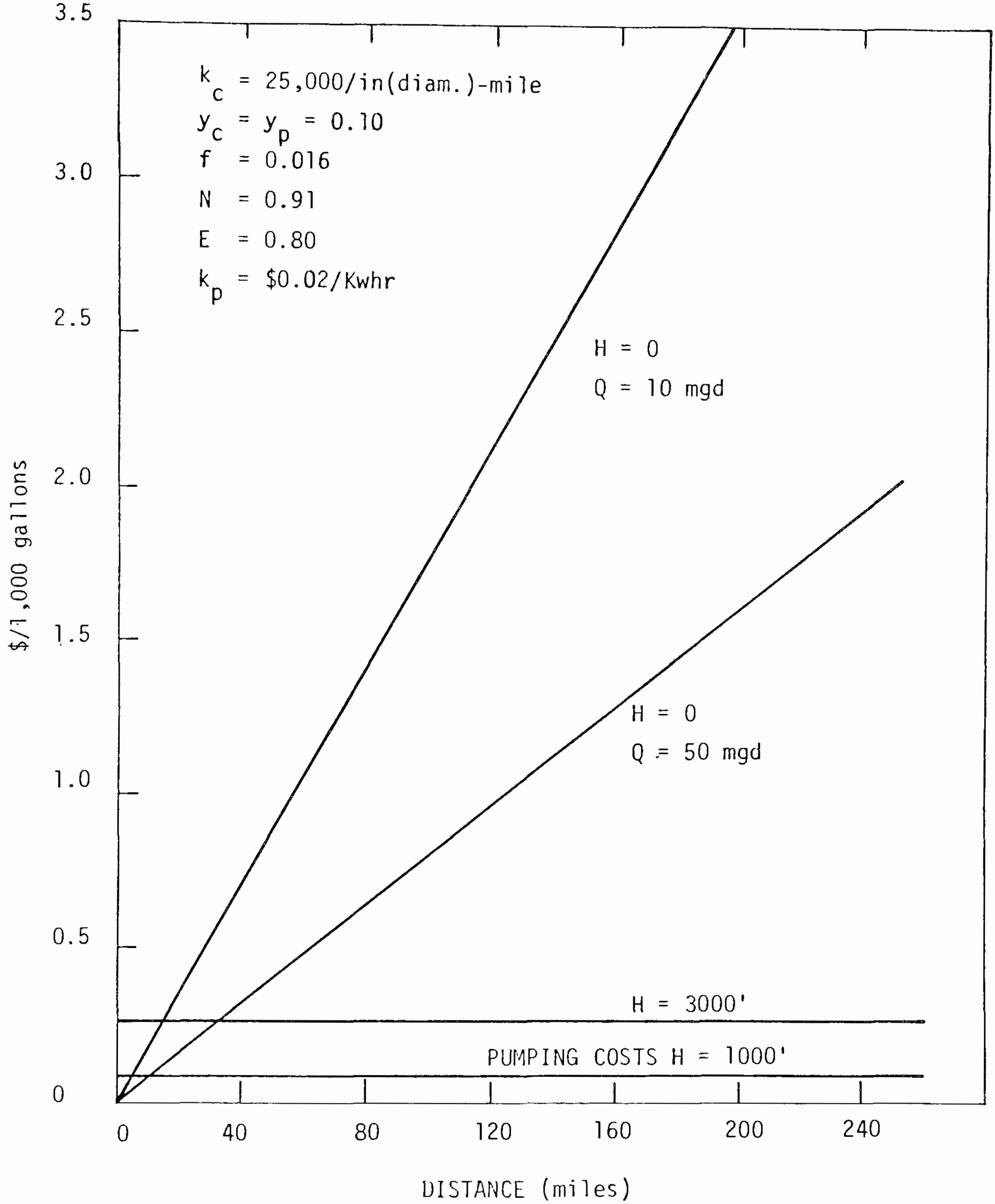


Figure A15-5 Water supply costs.

Sensitivity Analysis

The effects of variable interest rates, pipeline installation costs and power costs on the unit cost of water are shown in Figures A15-6, A15-7 and A15-8 respectively. The interest rates were varied from 6% to 14% per year, pipeline installation costs were varied from \$20,000/inch(diam)-mile to \$40,000/inch(diam)-mile, and the power costs were varied from \$0.01/kw-hr to \$0.04/kw-hr. Eqs. (10) and (12) were used to compute the pipeline diameter and Eqs. (13) and (14), rewritten in terms of \$/1000 gal-mile, were used to compute the minimum cost. However, the last term in Eq. (12) was neglected in the calculation.

Furthermore, if we neglect the second term in Eq. (12) so G = 1, then the effect of varying the above parameters can be conveniently shown, as follows

$$D_m \sim \sqrt{Q} \Big/ \left(\frac{y_c k_c}{k_p} \right)^{1/6}$$

$$\bar{P} \sim k_c^{\,5/6}\, y_c^{\,5/6}\, k_p^{\,1/6} \Big/ \sqrt{Q} \qquad H/L = 0$$

The cost of pumping against a static head is given by k_p H/L.

Increasing the interest rate from 10% per year to 12% per year and from 10% per year to 14% per year increases the total cost 16% and 32% respectively. If the pipeline installation cost is increased from \$25,000/inch(diam)-mile to \$30,000/inch(diam)-mile and then to \$40,000/inch(diam)-mile, the total cost is increased by 16% and 48% respectively. Similarly, if the power cost is increased from \$.02/kw-hr to \$0.04/kw-hr, the total cost is increased by 11%.

Comparison with Other Analysis

The results of the present study were compared to those of Singh[2]. The major difference between the two analyses is that the effective values of k_c are very different. For examples, in the present analysis k_c = \$25,000/inch(diam) mile and was taken to be constant. In the analysis of Singh, k_c varied with the diameter of the pipe, i.e., $k_c = 2160\ D^{0.2}$. For D = 24, k_c = 3900 and for D = 60, k_c = 4900. These values of k_c will lead to a factor of about 4-5 lower in the optimized total annual cost as compared to our analysis.

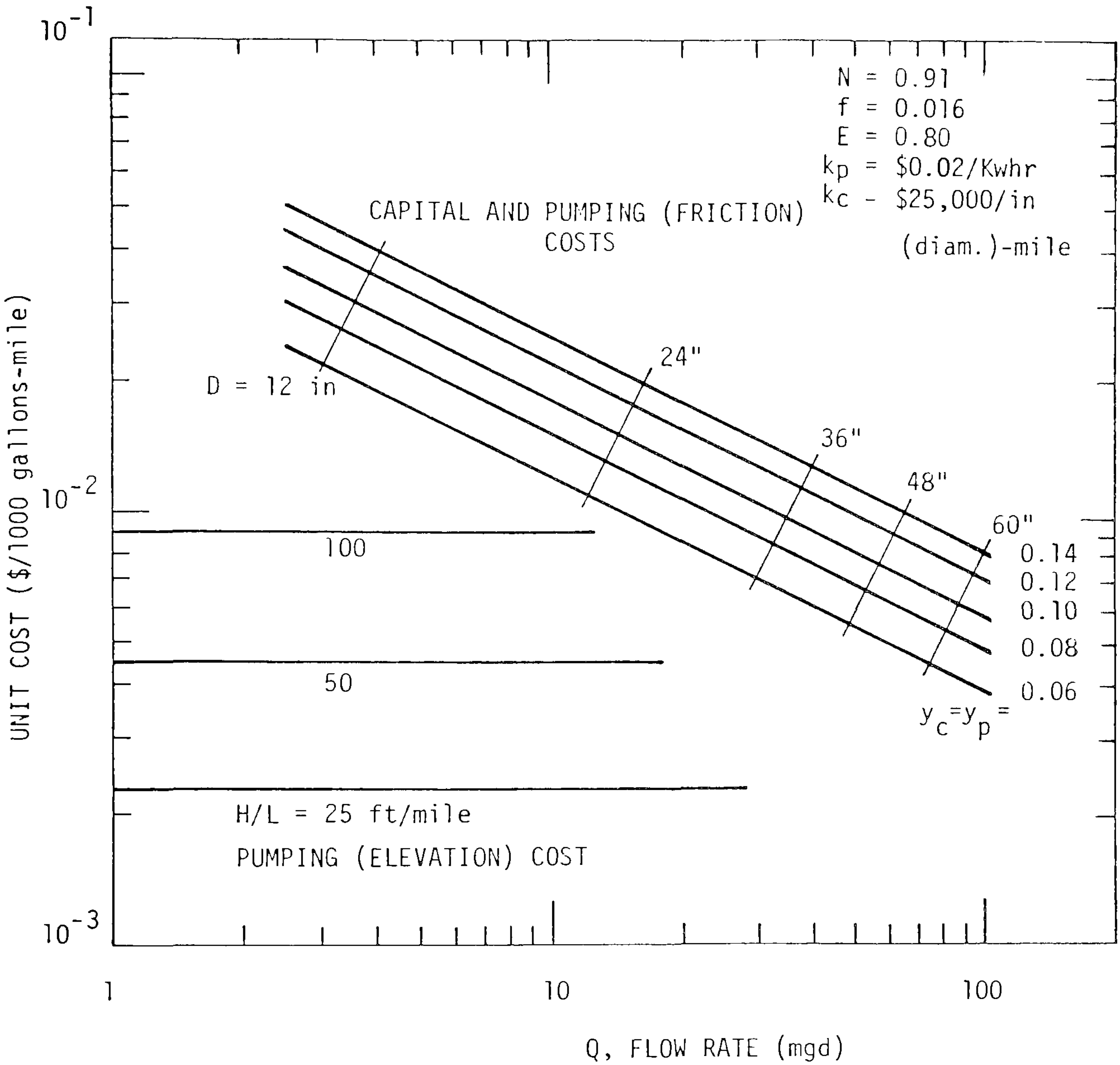


Figure A15-6 Effect of interest rate on unit cost of water supply

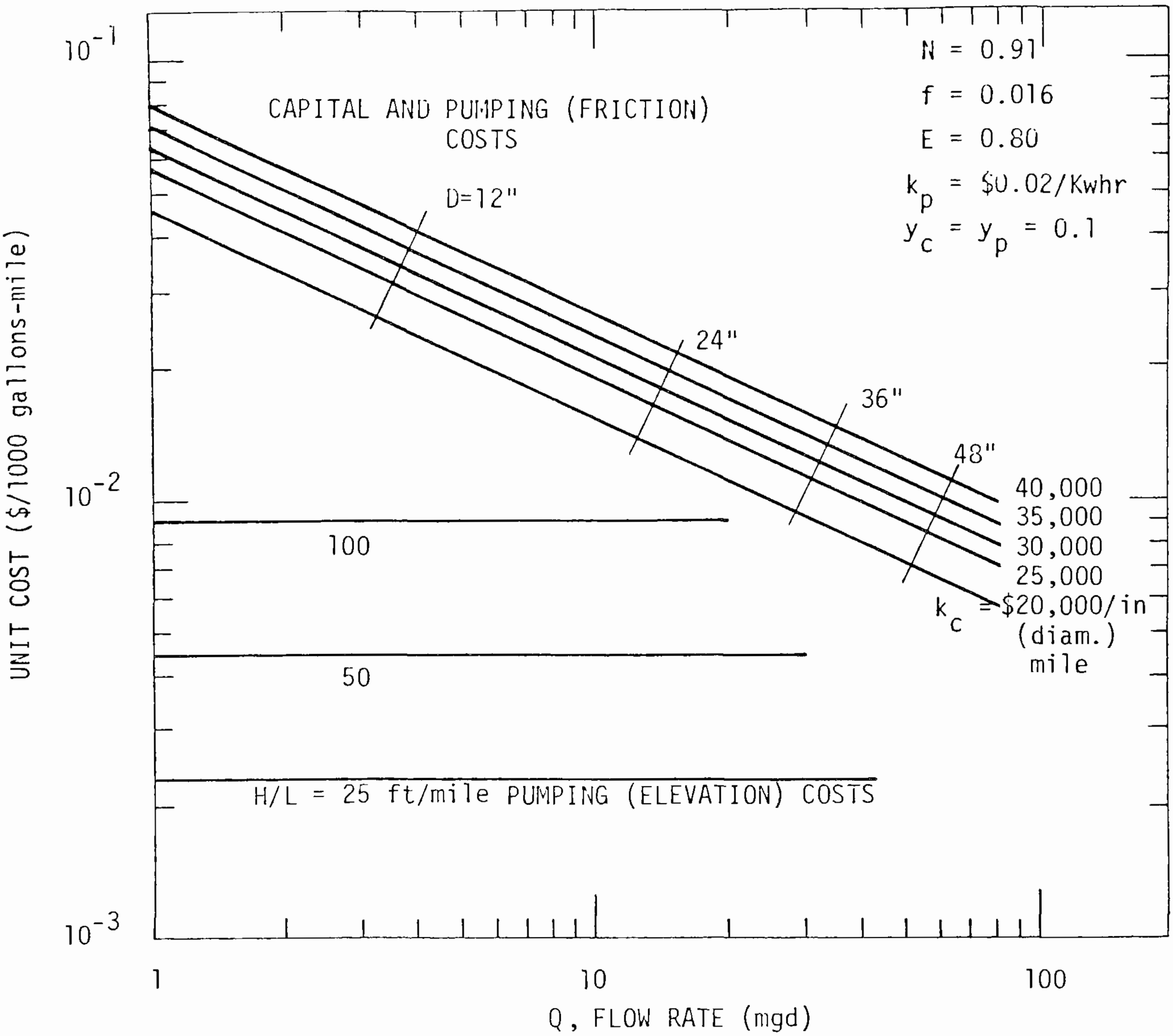


Figure A15-7 Effect of pipeline construction cost on the unit cost of water supply.

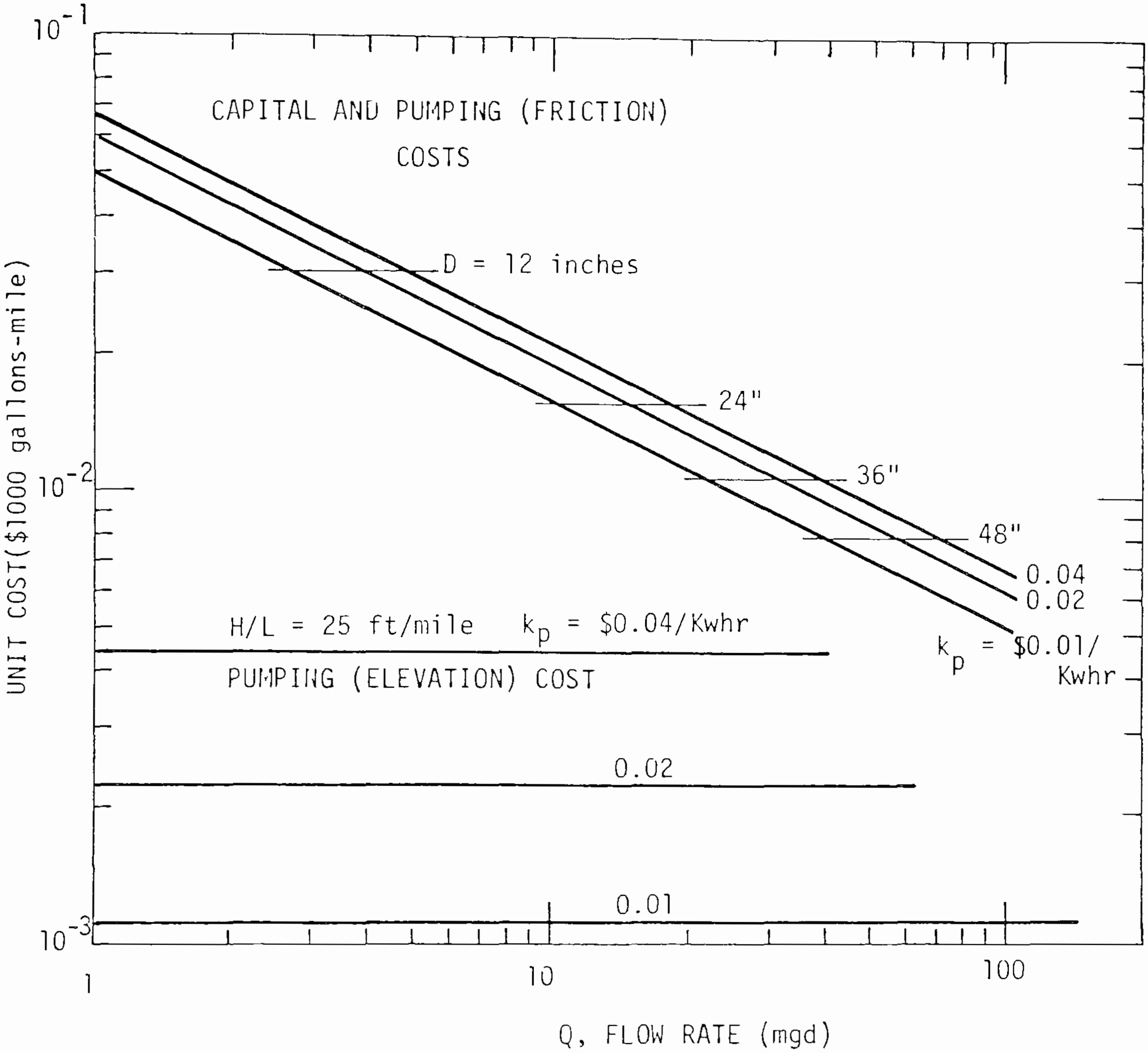


Figure A15-8 Effect of power cost on the unit cost of water supply.

The results were also compared to the design and cost estimates of the Montana-Wyoming aqueduct study of the Bureau of Reclamation. The cases that were selected for comparison had a constant flow capacity through the pipeline, i.e., there are no flow diversions and the pipeline diameter is constant. The following quantities were used in their study: $y_c = 0.0426$, $N = 0.9$ and $k_p = \$0.004$/kw-hr. The results are compared in Table A15-2. On the lefthand side of the table are the values used in Ref. 5; on the righthand side are derived values calculated from the basic data. The water costs do not include basic charges to purchase water. For example, k_c is derived from the investment cost and the length and diameter of the pipeline. The static head is calculated from the difference between the total dynamic head and the friction head. The values of D_m and V_m are calculated from Eqs. (10 and (11) and the optimized costs are obtained from Eqs. (13) and (14). The nominal pipe diameter is always greater than the calculated value of D_m to minimize pumping costs (Figure A15-2). The optimized total costs are consistently lower, but fairly close to the water costs as estimated by the Bureau of Reclamation. The last column is the product of the optimized total water cost in ¢/1000 gals-mile and $\sqrt{Q}$ and should be equal to 2.2 for $k_c = 25{,}000$. The differences are due primarily to the different values of k_c, with some differences attributable to the costs of pumping against a static head.

In summary, the simplified model that we have proposed qualitatively predicts the behavior of the design parameters and quantitatively predicts the annual cost of transporting water by pipeline. It appears that the estimated cost of installing pipelines in the West ranges from \$20,000 - \$30,000/ inch(diam)-mile.

SITE STUDIES

The site studies on water transport and water availability are broad in geographical scope, encompassing eight sites each in Montana and North Dakota, nine sites in Wyoming, and three sites in New Mexico. The water conveyance systems were sized and layed out to serve a single plant or a complex of

TABLE A15-2. ANALYSIS OF BUREAU OF RECLAMATION AQUEDUCT DATA[5]

Origin-Terminal	Capacity (mgd)	Annual Water Delivery (10^9 gals/hr)	L (mile)	D (inch)	H_T (ft)	Investment Cost ($\$10^6$)	Total Water Cost ($/1000 gals)	Total Water Cost (¢/1000 gals-mile)	k_c $/in (diam)-mile	V (ft/sec)	H (ft)	D_m (inch)	V_m (ft/sec)	Optimum Water Cost ($/1000 gal)	Optimum Water Cost (¢/1000 ga-mi)	Optimum Water Cost x $\sqrt{Q}$
Moorehead Reservoir-Gillette	48.4	16.9	52	51	1383	53.5	0.17	.33	20,200	5.26	938	41.6	8.23	0.15	0.28	1.9
Moorehead Reservoir-Gillette	96.8	33.8	52	66	1393	81.1	0.13	.25	23,600	6.28	903	56.1	8.67	0.12	0.23	2.3
Boysen Reservoir-Gillette	129.1	45.2	182	78	1817	309.7	0.34	.19	21,800	5.99	498	65.7	8.44	0.30	0.16	1.8
Yellowst. Reservoir-Colstrap	83.9	29.4	32	66	1020	45.0	0.088	.28	21,300	5.44	794	53.2	8.38	0.076	0.24	2.2
Miles City-Gillette Aq.-Reservation Cr.	167.9	58.7	34	84	365	75.5	0.063	.19	26,400	6.72	77	72.6	9.00	0.058	0.17	2.2
Miles City-Gillette Aq.-Decker	167.9	58.7	90	84	1418	211.9	0.18	.20	28,000	6.72	656	71.8	9.19	0.17	0.19	2.5

plants. The plants were sited from a minimum of one mile from the water source (Decker mine from Upper State Line Reservoir) to a maximum of 290 miles (East Moorhead mine from Boysen Reservoir). It has been assumed that water will be delivered in harmony with existing water laws and water rights.

Water Supply and Requirements

The area encompassing the chosen mine locations was subdivided into the following river basins (cf Appendix 14):

Powder River Basin
Tongue-Rosebud River Basins
Heart-Cannonball River Basins
Belle Fourche-Cheyenne River Basins
Green River Basin
North Platte River Basin
Yellowstone-Missouri River Basins
San Juan River Basin.

Table A15-3 lists all of the mine locations with respect to the seven river basins.

The most important water sources for each of the river basins were selected based on present and potential reliable water supplies. Potential developments of water supplies for coal-related industrial and agricultural uses in the Western coal bearing regions have been studied extensively (Appendix 14 and Refs. 6 to 11). Present and potential water supplies which could be developed for industrial use, on an annual firm basis, are shown in Table A15-4.

The water requirements for each plant-site combination is presented in Table A15-5 expressed in acre-ft/yr and mgd. At some sites more than one coal conversion process was considered. The water requirements vary from 2878 acre-ft/yr (2.6 mgd) to 11,082 acre-ft/yr (9.9 mgd) with an overall average of 4872 acre-ft/yr (4.4 mgd).

TABLE A15-3 MINE LOCATIONS WITH RESPECT TO RIVER BASINS

Powder River Basin	Tongue-Rosebud River Basins	Heart - Cannonball River Basins	Belle Fourche - Cheyenne River Basins	Green River Basin	North Platte River Basins	Yellowstone - Missouri River Basins	San Juan River Basin
Lake-de-Smet	Decker Creek	Slope	Gillette	Jim Bridger	Hanna	Beulah	Gallup
Spotted Horse	Otter Creek	Dickinson	Antelope Creek	Kemmerer		Knife R.	Wesco
East Moorhead	Foster Creek	Bentley	Belle Ayr	Rainbow #8		Williston	El Paso
	Pumpkin	Scranton				Underwood	
	Colstrip					U.S.Steel	
						Coalridge	

TABLE A15-4 WATER SOURCES AND SUPPLIES FOR SITE STUDIES ON AN ANNUAL FIRM BASIS IN ACRE-FEET PER YEAR

<u>Powder River Basin</u>	
Lake-de-Smet	35,000
Moorhead Reservoir	50,000
Lower Clear Creek Reservoir	50,000
Bighorn River	230,000
Hole-in-the-Wall	20,000
Crazy Woman Creek Reservoir	67,000
Beaver Creek Reservoir	20,000
Boysen Reservoir	230,000
Agricultural transfer	15,000
<u>Tongue-Rosebud River Basins</u>	
Lower State Line Reservoir	88,000
Upper State Line Reservoir	86,000
Rockwood Reservoir	45,000
Prairie Dog Reservoir	38,000
Yellowstone River	100,000
Bighorn River	100,000
Boysen Reservoir	100,000
Agricultural transfer	15,000
<u>Heart-Cannonball River Basins</u>	
Mott Reservoir	22,000
Cannonball Reservoir	22,000
Thunderhawk Reservoir	22,000
Broncho Reservoir	22,000
Missouri River	120,000
Yellowstone River	120,000
Fort Peck Reservoir	120,000
Lake Sakakawea	120,000

Continued.

Table A15-4 (concluded)

Belle Fourche-Cheyenne River Basins	
Beaver Creek	20,000
Boysen Reservoir	50,000
Bighorn River	50,000
Yellowstone River	50,000
Agricultural transfer	15,000
Ground water	25,000
Green River Basin	
Green River	750,000
Fontanelle Reservoir	750,000
Flaming Gorge Reservoir	750,000
Yellowstone-Missouri River Basins	
Yellowstone River	220,000
Missouri River	220,000
Lake Sakakawea	220,000
Fort Peck Reservoir	220,000
Bighorn Lake	220,000
San Juan River Basin	
San Juan River	100,000
Navajo Reservoir	100,000
Ground water	

TABLE A15-5 WATER REQUIREMENTS FOR PLANT SITE COMBINATIONS IN ACRE-FT/YEAR AND (mgd)

Mine	HyGas	Synthane	Lurgi	Bigas	SRC	Synthoil
Wyoming						
Gillette (Wyodak)	4060(3.6)				2587(2.4)	
Lake-de-Smet-Banner-Healy						6020(5.4)
Antelope Creek Mine	3920(3.5)	3260(2.9)			2729(2.4)	
Spotted Horse Strip-Felix Bed		3310(3.0)				
Jim Bridger Mine			4869(4.3)			3677(3.3)
Belle Ayr Mine	4340(3.9)					
Hanna Coal Fld(Rosebud #4,5)	5689(5.1)		5634(5.0)			
Kemmerer			5634(5.0)	2878(2.6)		
Rainbow #8 Mine					4838(4.3)	
North Dakota						
Slope (Harmon)				2878(2.6)		
Knife River			3481(3.1)			
Dickenson					2926(2.6)	
Williston			7889(7.0)			
Center				5516(4.9)		
Bently					3055(2.7)	
Underwood					5561(5.0)	
Scranton				3156(2.8)		
Montana						
Decker (Dietz)	5620(5.0)		7170(6.4)			
Otter Creek (Knobloch)					3845(3.4)	
East Moorhead Coal Field	4050(3.6)					
Foster Creek			4050(3.6)			
Pumpkin Creek					3071(2.7)	
Coalridge					3487(3.1)	
U.S. Steel, Chupp Mine				5970(5.3)		
Colstrip	4220(3.8)	5390(4.8)			3391(3.0)	
New Mexico						
El Paso	4646(4.1)		5865(5.2)			
Wesco			5831(5.2)			
Gallup	4101(3.7)		5265(4.1)			4070(3.6)

Pipeline Routes

The route studies of water conveyance facilities consisted generally of layouts on one-degree U.S. Geological Survey quadrangle maps of 1:250,000 scale. The routes chosen generally followed existing roads, railways, rivers and streams. Where this was not possible, routes were chosen to follow the least difficult terrain. The difference in elevation, or static head, was taken to be the difference in elevation between the ground surface at the mine location and the water surface at the source, as obtained from the U.S. Geological Survey maps. Where water surface elevation was unknown, nearby ground elevation was used.

Gillette, Wyoming Site Study

As an example, we have considered the cost of transporting water to Gillette, Wyoming, from sources within the basin and outside of the basin. Two plants have been sited at Gillette; one utilizes the Hygas process for coal gasification and has a total water requirement of 3.6 million gallons per stream day; while the other is an SRC plant for coal liquefaction which has a water requirement of 3.2 million gallons per stream day. The pipelines have been sized to deliver 50 percent more water than the daily requirement. Table A15-6 lists the unit costs of transporting water for each process (Eqs. (15) to (20)). Water sources for the Gillette mine were selected (Table A15 - 4) and the water conveyance routes layed out. Figure A15-9 shows the location of the Gillette mine[6] and each pipeline route, together with the milage and total annual cost (in $/1000 gals). The water requirements correspond to those of the Hygas process. Table A15-7 shows the distance and static head for each source of water, while Table A15-8 shows a breakdown of the water costs. If individual pipelines provide water to each plant, then the cost of water will range from $1.20 to $6.17 per 1000 gals. If a single pipeline would provide water for both plants, then the range of water costs would be reduced to $0.95 to $3.86 per 1000 gals; the diameter of the pipeline would be 19 inches.

Figures A15-10 through A15-13 show four other river basins and the location of one mine under study in each of the basins. Alternate water sources, together with the pipeline routes, are also shown.

TABLE A15-6 UNIT COSTS OF TRANSPORTING WATER TO GILLETTE, WYOMING

Process Type	Daily Water Requirement (mgd)	Pipeline Flow Rate (mgd)	D_m (inches)	Capital Cost-$/1000 gals-mile	Pumping (Friction) Cost/$1000 gals-mile	Pumping (Head) Cost/$1000 gals-ft
Hygas	3.6	5.4	15	0.0207	0.00414	0.000089
SRC	2.3	3.5	12	0.0257	0.00514	0.000089

TABLE A15-7 ROUTE DATA FOR GILLETTE, WYOMING

Water Source	Distance (miles)	Static Head (feet)
Lake-de-Smet	72	0
Lower Clear Creek Reservoir	62	1000
Crazy Woman Creek Reservoir	45	940
Moorhead Reservoir	60	1240
Bighorn River at Hardin	180	1840
Boysen Reservoir	200	-253
Miles City on Yellowstone River	170	2340
Beaver Creek Reservoir	84	900
Hole-in-the-Wall Reservoir	100	0

TABLE A15-8 COST OF TRANSPORTING WATER TO GILLETTE, WYOMING

Entries on the Table apply to two processes, thus { Hygas / SRC }

Location	Water Source	Capital Cost $/1000 gal	Pumping v. Friction $/1000 gal	Pumping v. Head $/1000 gal	Total Cost $/1000 gal	Total Cost $/acre-ft
Gillette	Lake-de-	1.49	0.30	0	1.79	583
	Smet	1.85	0.37	0	2.22	724
	Lower Clear	1.28	0.26	0.09	1.63	530
	Cr. Res.	1.59	0.32	0.09	2.00	652
	Crazy Woman	0.93	0.19	0.08	1.20	390
	Reservoir	1.16	0.23	0.08	1.47	479
	Moorhead	1.24	0.25	0.11	1.60	520
	Reservoir	1.54	0.31	0.11	1.96	639
	Hardin on	3.73	0.75	0.16	4.64	1508
	Bighorn R.	4.63	0.93	0.16	5.72	1868
	Boysen Res.	4.14	0.83	0	4.97	1619
		5.14	1.03	0	6.17	2011
	Miles City	3.52	0.70	0.20	4.42	1441
	on Yellowst.	4.37	0.87	0.20	5.44	1773
	Beaver Creek	1.74	0.35	0.08	2.17	705
	Reservoir	2.16	0.43	0.08	2.67	870
	Hole-in-the	2.07	0.41	0	2.48	810
	Wall Res.	2.57	0.51	0	3.08	1004

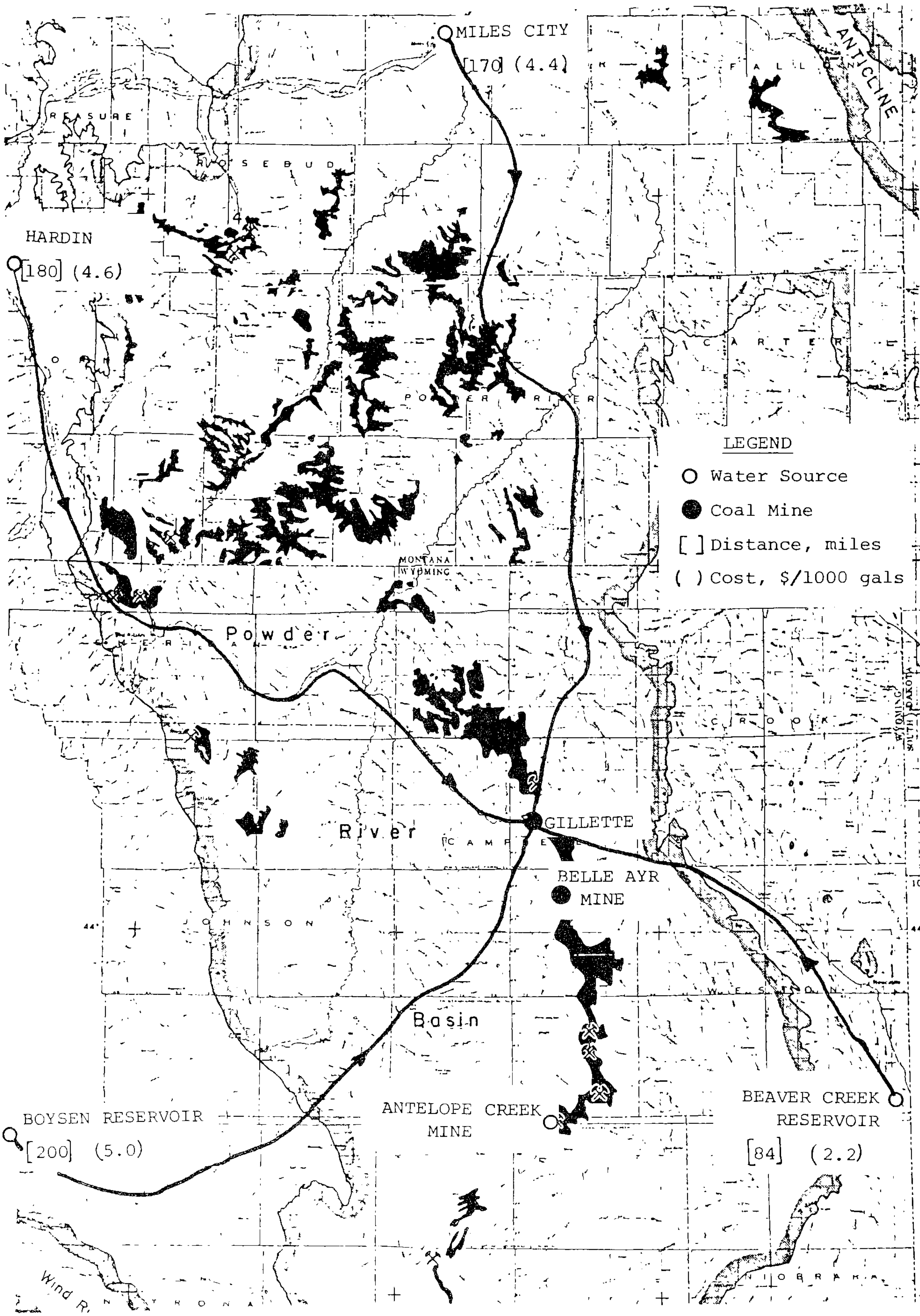


Figure A15-9 Pipeline conveyance routes in the Belle Fourche-Cheyenne River Basins from various water sources to Gillette, Wyoming.

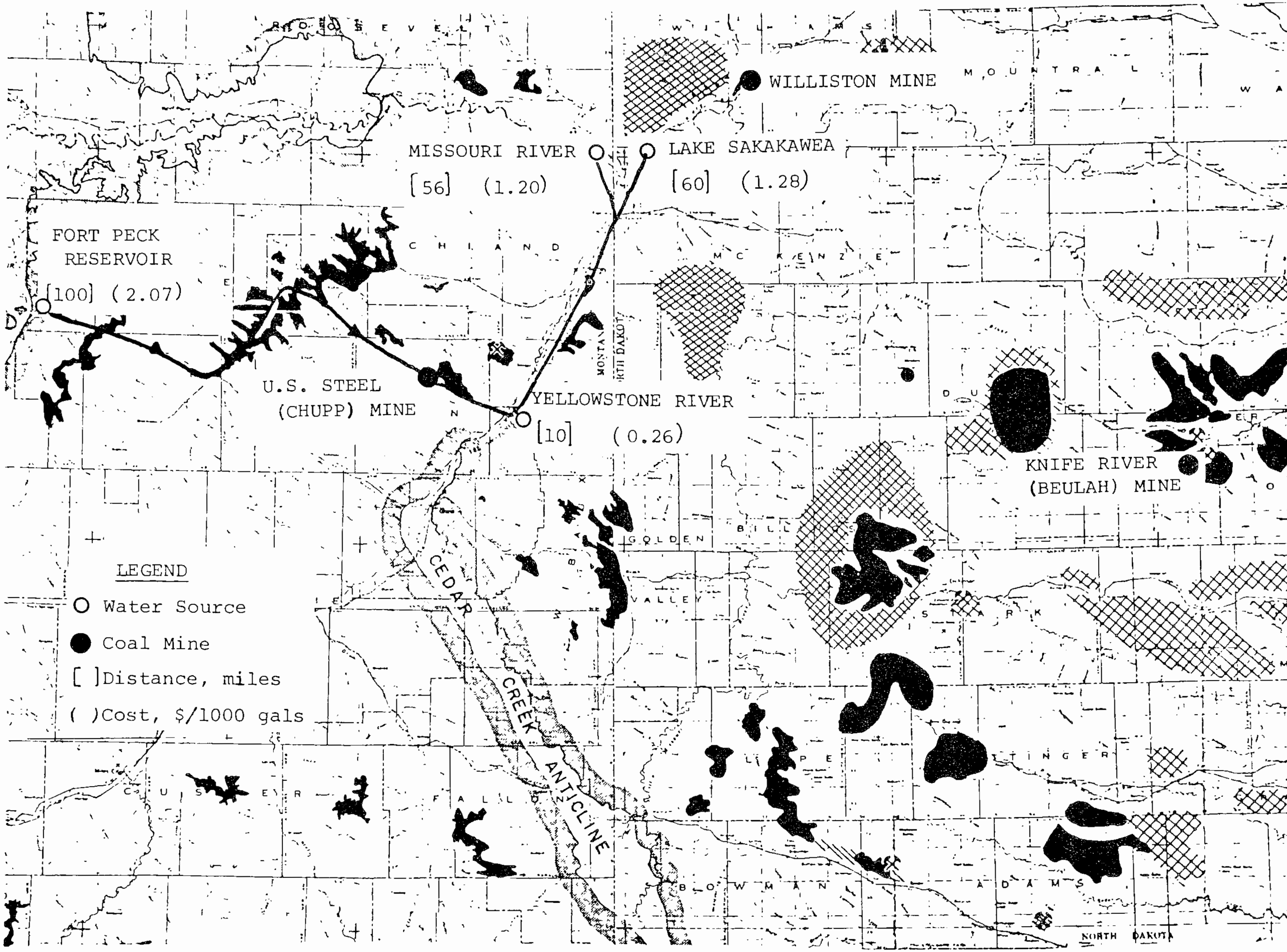


Figure A15-10 Pipeline conveyance routes in the Yellowstone-Missouri Mainstem River Basin from various water sources to U.S. Steel (Chupp) Mine, Montana.

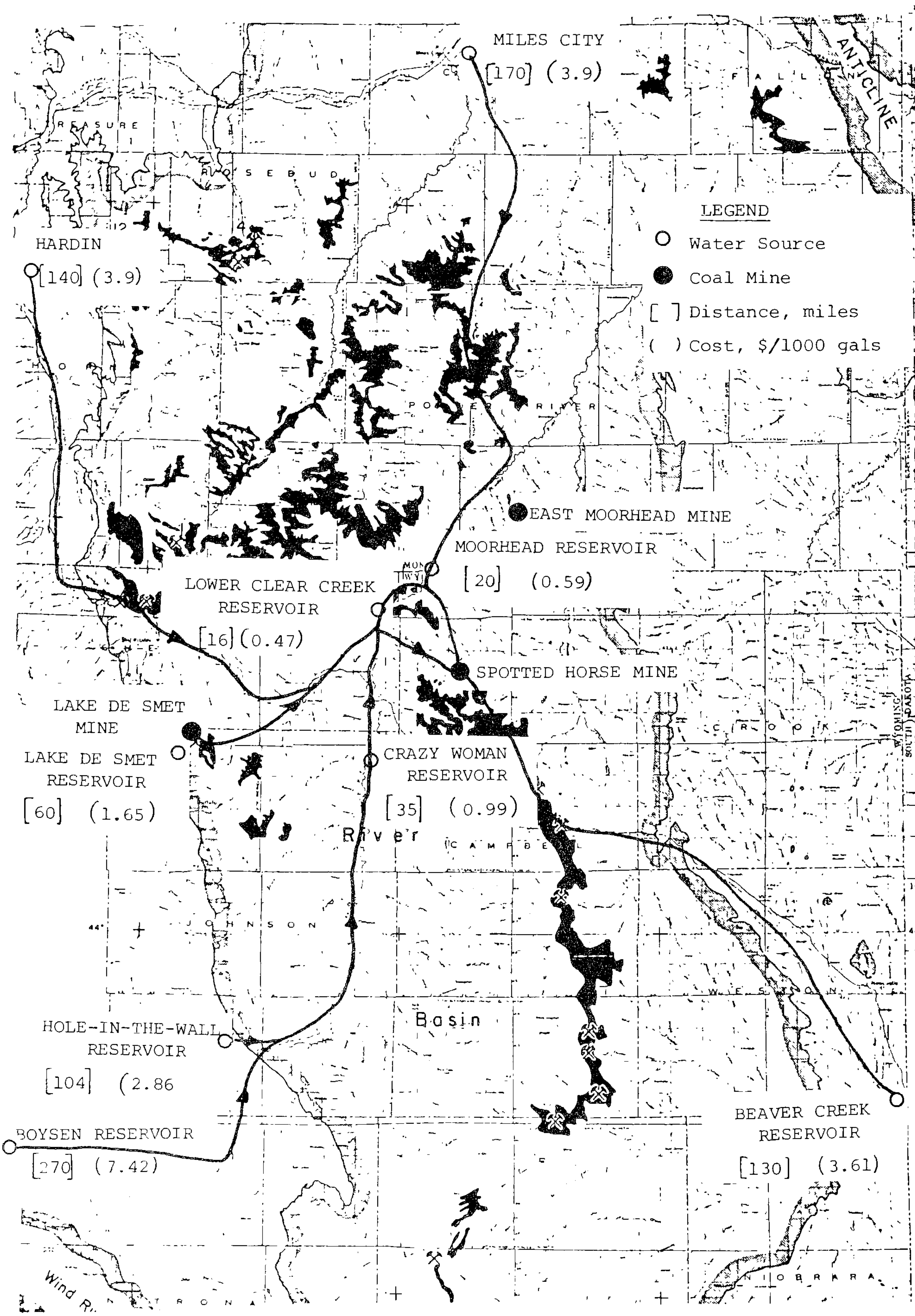


Figure A15-11 Pipeline conveyance routes in the Powder River Basin from various water sources to Spotted Horse Mine, Wyoming

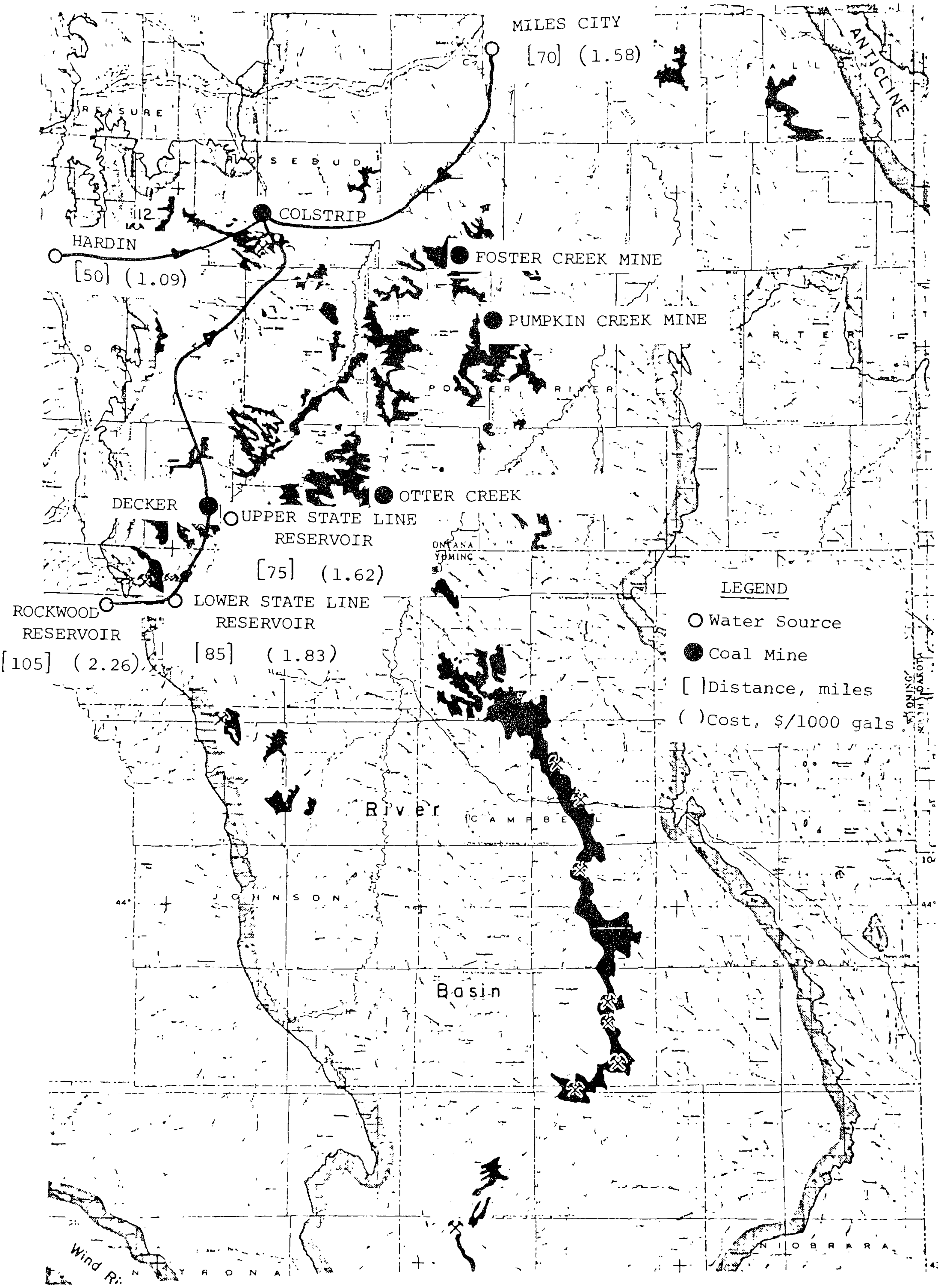


Figure A15-12 Pipeline conveyance routes in the Tongue-Rosebud River Basin from various water sources to Colstrip, Montana

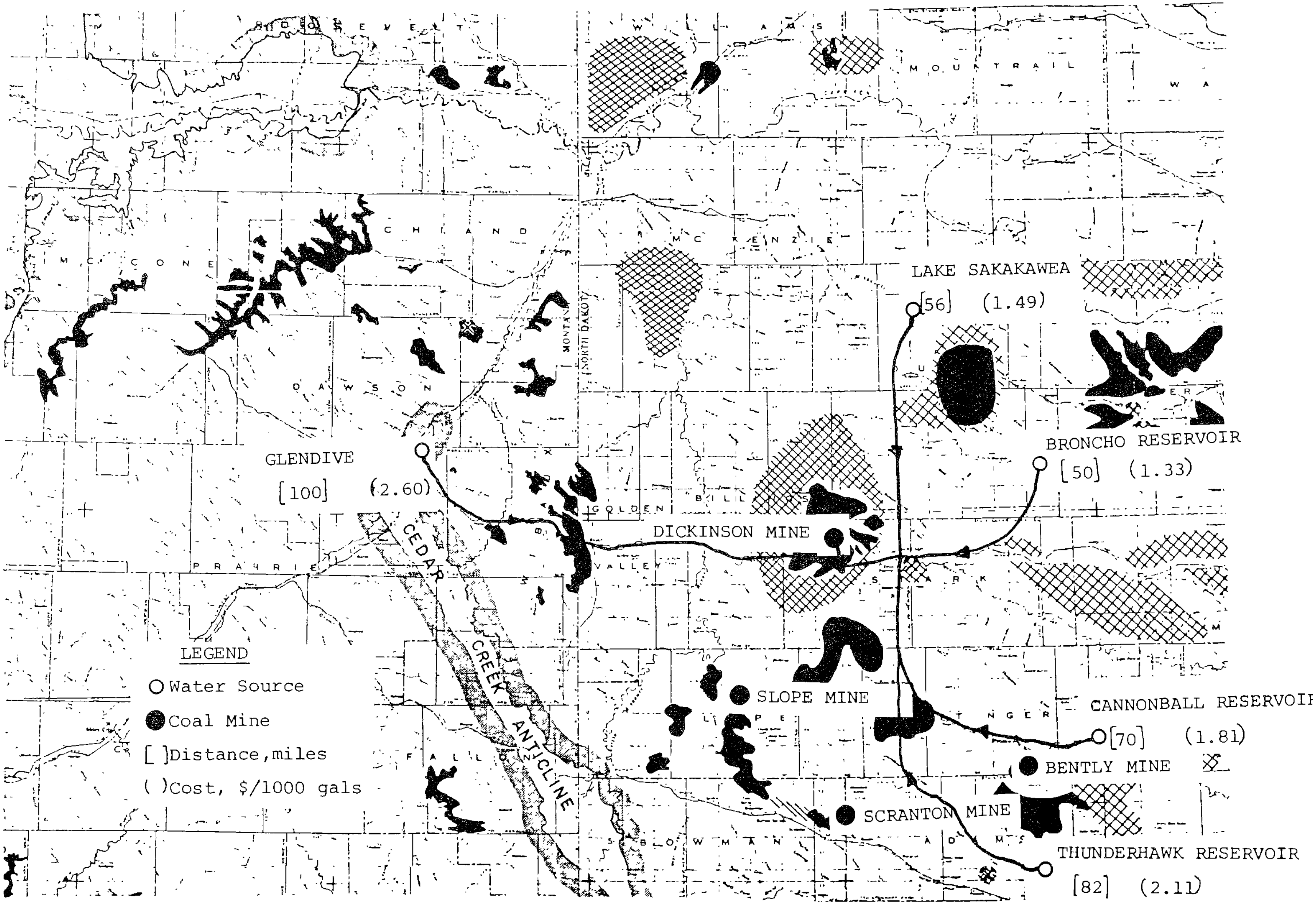


Figure A15-13 Pipeline conveyance routes in the Heart and Cannonball River Basins from various water sources to Dickinson Mine, North Dakota

Individual Plant Site Studies

We have considered the case of a single pipeline supplying water to a single plant. We have assumed that the water supply comes from the nearest reliable water source of sufficient size. Transbasin diversions are presumed possible. Potential reservoirs have been included as reliable water sources. In some instances agricultural water was used, but only in those river basins where it was considered feasible. However, change-of-use permits might be difficult to acquire.

Table A15-9 lists the mine location, water source and total cost of water conveyance for the twenty-nine plant locations. The minimum distances for transporting water was 1 mile (Decker to North State Line Reservoir) and the maximum distance was 96 miles (Gallup, N.M. to San Juan River). The cost varied from $0.023/1000 gals to $2.54/1000 gals.

Large Scale Water Conveyance

If a large scale coal industry is to be developed in the West, large quantities of water will be required. In the individual plant site studies discussed above, a single standard size plant will have water requirements that vary from 2.4 mgd to 7.0 mgd; the overall average is 4.0 mgd. It is clear from our previous discussions that a single pipeline will supply, say, 10 standard size plants, at a lower cost then 10 single pipelines, each supplying a single standard size plant.

We have sized and estimated costs of uniform diameter pipelines having a constant capacity throughout its length. The water requirements that were selected are: 50 mgd (56,000 acre-ft/yr), 100 mgd (112,000 acre-ft/yr), 150 mgd (168,000 acre-ft/yr) and 300 mgd (336,000 acre-ft/yr). This corresponds to the water requirements for 13 standard size plants to 75 plants, based on an average of 4.0 mgd per standard size plant. The pipe diameters are respectively: 46, 65, 80 and 113 inches.

The plants were grouped together such that the maximum distance between two adjacent mines supplied by the same pipe line was 60 miles. The pipeline provided water from a reliable water supply to a town located approximately central to the group of mines. One pipeline which linked seven mines situated approximately in a straight line was also evaluated. Table A15-10 shows the total cost for a number of mine groupings. We see that the total cost of

TABLE A15-9 LOCAL SUPPLY TO INDIVIDUAL PLANTS

Location	Water Source	Distance (miles)	Static Head (feet)	Total Cost $/1000 gals	Total Cost $/acre-ft
Beulah	Lake Sakakawea	16	50	0.43	140
Williston	Lake Sakakawea	8	250	0.16	53
Center	Missouri River	16	300	0.37	120
Underwood	Lake Sakakawea	8	150	0.13	43
U.S. Steel	Yellowstone River	10	600	0.26	83
Coalridge	Medicine Lake	16	400	0.40	130
Gillette	Crazy Woman Creek	45	940	1.20	390
				1.26	411
Antelope Creek	Beaver Creek Reservoir	72	1000	1.90	620
				2.08	678
				2.03	661
Lake-de-Smet	Lake-de-Smet	5	200	0.12	39
Spotted Horse	Clear Creek Reservoir	16	400	0.47	154
E.Moorhead	Moorhead Reservoir	22	700	0.61	198
Decker Cr.	North State Line Reservoir	1	50	0.03	8
				0.02	7
Otter Cr.	Moorhead Reservoir	20	200	0.48	156
Foster Cr.	Tongue River	16	350	0.43	139
Pumpkin Cr.	Tongue River	24	600	0.60	197
Colstrip	Yellowstone River	28	700	0.74	241
				0.66	216
				0.67	220
Belle Ayr	Crazy Woman Reservoir	54	850	1.37	446
Slope	Mott Reservoir	44	350	1.32	431
Dickinson	Mott Reservoir	50	100	1.29	420
Bentley	Mott Reservoir	10	150	0.26	86
Scranton	Thunderhawk Reservoir	42	550	0.91	295
Hanna	Seminoe Reservoir	20	100	0.43	140

Continued

TABLE A15-9 (concluded)

Location	Water Source	Distance (miles)	Static Head (feet)	Total Cost $/1000 gals	Total Cost $/acre-ft
Kemmerer	Fontanelle Reservoir	70	900	1.53	505
				2.13	695
Jim Bridger	Flaming Gorge Reservoir	18	400	0.50	164
				0.44	144
Rainbow #8	Flaming Gorge Res.	18	500	0.37	121
Gallup	San Juan River	96	1800	2.52	823
				2.54	827
				2.25	732
Wesco	San Juan River	30	400	0.66	213
El Paso	San Juan River	50	800	1.23	401
				1.10	358

TABLE A15-10 LARGE SCALE WATER CONVEYANCE COSTS

Location	Group of Mines	Water Source	Distance (miles)	Static Head (feet)	Flow (mgd)	Total Cost $/1000 gals	Total Cost $/acre-ft
Midpoint between Wesco and El Paso	Wesco, El Paso	Navajo Reservoir via San Juan River	38	500	50	0.35	115
					100	0.26	86
					150	0.22	73
					300	0.17	56
Highlight	Gillette, Belle Ayr, Antelope Creek	Boysen Reservoir	150	0	50	1.22	398
					100	0.86	281
					150	0.71	230
					300	0.50	163
Rock Springs	Jim Bridger, Rainbow #8	Green River	14	400	50	0.15	49
					100	0.12	38
					150	0.10	33
					300	0.08	27
Gillette	Foster, Pumpkin, Moorhead, Spotted Horse, Gillette, Belle Ayr, Antelope Creek	Boysen Reservoir	180	-253	50	1.47	478
					100	1.04	338
					150	0.85	276
					300	0.60	195
		Yellowstone at Miles City	165	2300	50	1.55	505
					100	1.16	376
					150	0.98	319
					300	0.75	246
		Bighorn River at Hardin	180	1840	50	1.63	531
					100	1.20	391
					150	1.01	329
					300	0.76	249
Stanton	Center, Underwood, Knife River	Lake Sakakawea	14	100	50	0.12	40
					100	0.09	29
					150	0.07	24
					300	0.06	18

AB Concluded)

Location	Group of Mines	Water Source	Distance (miles)	Static Head (feet)	Flow (mgd)	Total Cost $/1000 gals	Total Cost $/acre-ft
Stanton	Center, Underwood, Knife River	Missouri River	1	0	50	0.008	3
					100	0.006	2
					150	0.005	2
					300	0.003	1
DeSart	Slope, Scranton, Bentley, Dickinson	Lake Sakakawea	86	900	50	0.78	254
					100	0.58	188
					150	0.48	158
					300	0.37	119
		Lake Oahe	120	1100	50	1.08	351
					100	0.79	257
					150	0.66	216
					300	0.50	162
		Yellowstone River at Glendive	122	700	50	1.06	344
					100	0.77	326
					150	0.64	207
					300	0.47	152
Loesch	Foster Creek, Pumpkin Creek	Yellowstone River at Miles City	60	850	50	0.56	184
					100	0.42	137
					150	0.36	117
					300	0.28	90
Quietus	Decker, Otter Creek, Moorhead, Spotted Horse	Yellowstone River at Miles City	108	1900	50	1.05	342
					100	0.79	258
					150	0.68	221
					300	0.53	172
		Bighorn River at Hardin	102	1400	50	0.96	311
					100	0.71	232
					150	0.60	197
					300	0.46	151

transporting water does not exceed \$1.63/1000 gals for the cases that we have considered.

REFERENCES

1. Gold, et al "Water Requirements for Steam-Electric Pour Generation and Synthetic Fuel Plants in the Western United States", EPA-600/7-77-037, U.S. Environmental Protection Agency, Washington, D. C., February 1977.

2. Singh, K.P., "Economic Design of Central Water Supply Systems for Medium Sized Towns," Water Resources Bulletin, 7, 79-92, February 1971.

3. Tyteca, D., "Cost Functions for Wastewater Conveyance Systems," Journal WPCF, 48, 2120-2130, September 1976.

4. Comley, W.D., Private communication, Stone and Webster Engineering Corporation, Boston, Massachusetts, September 3, 1975.

5. Bureau of Reclamation, "Appraisal Report on Montana-Wyoming Aqueducts," U.S. Department of the Interior, Washington, D. C., April 1972.

6. "North Central Pour Study-Report of Phase 1, Vol 2," U.S. Bureau of Reclamation, Billings, Montana, October 1971.

7. "Northern Great Plains Resources Program-Report of the Work Group on Water," December 1974.

8. "Powder River Storage Development," prepared by Harza Engineering Corporation for the State of Wyoming, State Engineer's office, Wyoming Water Planning Program, August 1974.

9. "The West River Study-An Analysis of Alternatives for Developing and Managing the West River Area's Water and Related Land Resources," SWC Project No. 1543, Information Series No. 30, North Dakota State Water Commission, Bismarck, North Dakota, January 1975.

10. "The Wyoming Framework Water Plan," State Engineer's Office, Wyoming Water Planning Program, May 1973.

11. U.S. Geological Survey, "Mineral and Water Resources of New Mexico," U.S. Senate Committee in Interior and Insular Affairs, U.S. Govern. Print. Office, Washington, D. C. 1965.

TECHNICAL REPORT DATA
(Please read Instructions on the reverse before completing)

1. REPORT NO. EPA-600/7-78-197b	2.	3. RECIPIENT'S ACCESSION NO.
4. TITLE AND SUBTITLE Water-related Environmental Effects in Fuel Conversion: Volume II. Appendices		5. REPORT DATE October 1978 6. PERFORMING ORGANIZATION CODE
7. AUTHOR(S) Harris Gold and David J. Goldstein		8. PERFORMING ORGANIZATION REPORT NO.
9. PERFORMING ORGANIZATION NAME AND ADDRESS Water Purification Associates 238 Main Street Cambridge, Massachusetts 02142		10. PROGRAM ELEMENT NO. EHE623A 11. CONTRACT/GRANT NO. 68-03-2207
12. SPONSORING AGENCY NAME AND ADDRESS EPA, Office of Research and Development Industrial Environmental Research Laboratory Research Triangle Park, NC 27711		13. TYPE OF REPORT AND PERIOD COVERED Final; 10/76 - 9/78 14. SPONSORING AGENCY CODE EPA/600/13

15. SUPPLEMENTARY NOTES IERL-RTP project officer is Chester A. Vogel, Mail Drop 61, 919/541-2134.

16. ABSTRACT The report gives results of an examination of water-related effects that can be expected from siting conversion plants in the major U.S. coal and oil shale bearing regions. Ninety plant-site combinations were studied: 48 in the Central and Eastern U.S. and 42 in the Western. Synthetic fuel technologies examined include: coal gasification to convert coal to pipeline gas; coal liquefaction to convert coal to low sulfur fuel oil; coal refining to produce a de-ashed, low-sulfur solvent refined (clean) coal; and oil shale retorting to produce synthetic crude. Results presented include the range of water requirements, conditions for narrowing the range and optimizing the use of water, ranges of residual solid wastes, and cost and energy requirements for waste-water treatment. A comparison of water requirements with those of two recently published studies shows widely varying estimates and emphasizes the need for both site- and design-specific calculations. A review of various combinations of cooling requirements indicates a factor of 4 difference in water consumption across all processes studied. Where water costs < 25¢/1000 gal., a high degree of wet cooling appears best. If >$1.50/1000 gal, a minimum of wet cooling should be considered. Between these, a more balanced mix needs to be reviewed. All water requirements of this study are based on complete water re-use; i.e., no direct water discharge to streams or rivers.

17. KEY WORDS AND DOCUMENT ANALYSIS

a. DESCRIPTORS		b. IDENTIFIERS/OPEN ENDED TERMS	c. COSATI Field/Group
Pollution	Crude Oil	Pollution Control	13B
Water Consumption	Water Cooling	Stationary Sources	13A
Coal Gasification	Waste Water	Fuel Conversion	13H
Coal	Wastes	Synthetic Fuels	21D
Shale Oil	Water Treatment	Coal Refining	
Liquefaction	Waste Treatment	Solvent Refined Coal	07D
Fuel Oil		Solid Waste	

18. DISTRIBUTION STATEMENT Unlimited	19. SECURITY CLASS *(This Report)* Unclassified	21. NO. OF PAGES 666
	20. SECURITY CLASS *(This page)* Unclassified	22. PRICE

EPA Form 2220-1 (9-73)