

The calculation of primary and ancillary resource energy requirements has somewhat more meaning for oil shale than for the liquid fuels from coal technologies, since without the investment of a certain amount of ancillary energy from another resource, no useful products could be produced from oil shale. Coal is already a useful form of energy, and energy is invested only to convert it to another form. Table 4-4 shows the primary and ancillary resource energy requirements for converting oil shale into  $10^{12}$  Btu of synthetic crude oil.

Table 4-4

OIL SHALE-TO-SYNCRUDE ENERGY REQUIREMENTS

|                           | <u><math>10^{12}</math> Btu</u> | <u><math>10^{15}</math> J</u> |
|---------------------------|---------------------------------|-------------------------------|
| Syncrude energy           | 1.00                            | 1.06                          |
| Primary resource energy   | 1.48                            | 1.56                          |
| Ancillary resource energy | 0.07                            | 0.07                          |

2. Resource Consumption

We have defined resource in a broad way to include not only the primary resources coal and oil shale but also the quantities of water, land, labor and steel necessary to build and operate synthetic fuels plants. In addition we consider briefly the consumption of catalysts, chemicals, and other such materials. The reason for defining resources in this way is to be able to examine a broad range of social and economic impacts from synthetic fuels development as well as impacts on the natural environment. We therefore use the concept of societal/ industrial resources as well as natural resources. Strictly speaking, capital should also be included as a resource, but due to the somewhat

greater complexity of analyzing capital and operating costs; we defer the discussion of capital to Section 4.

a. Coal and Oil Shale

The consumption of primary resources in a given synthetic fuel conversion process depends on both the particular process design and the energy content of the resource. We will maintain consistency with our previous discussion by assuming here and in subsequent sections that coal is converted to syncrude via the H-Coal process; coal is converted to methanol via Lurgi gasification followed by intermediate pressure methanol synthesis; and oil shale is converted to syncrude via TOSCO II retorting followed by coking and hydrotreating.

The quantity of oil shale consumed is determined by its kerogen content. Colony Development Operation has designed its first commercial plant to operate on 35 gal/ton (0.15 m<sup>3</sup>/1000 kg) shale.<sup>12</sup> Other processes have been designed to operate on shale with oil content down to 27 gal/ton (0.11 m<sup>3</sup>/1000 kg) and we include this for comparison. The coal requirement is the amount of western subbituminous coal which must be burned to provide electric power for the shale plant.

The two U.S. coal types which we consider for liquefaction are western subbituminous (8000-9000 Btu/lb ( $1.9 \times 10^7$ - $2.1 \times 10^7$  J/kg) and eastern bituminous (11,000-12,000 Btu lb or  $2.6 \times 10^7$ - $2.8 \times 10^7$  J/kg). The amount of coal consumed is calculated on the basis of both the primary resource required and the amount of coal necessary to provide plant fuel and electricity. The considerably lower requirement for eastern compared to western coal is due not only to the higher heating value of eastern coal but also to the significantly larger amount of byproduct gases recovered during eastern coal liquefaction which can be used in place of coal as plant fuel.<sup>8</sup>

In methanol produced from coal, we consider in addition to bituminous and subbituminous coal, North Dakota lignite (about 6500 Btu lb or  $1.5 \times 10^7$  J/kg), which is an excellent feedstock for coal gasification, and would thus be suitable for methanol production as well. The production of methanol from bituminous coal requires technology other than the Lurgi gasifier, which has not operated well with U.S. eastern coals. We assume that either a modified Lurgi gasifier or another type of gasifier such as the Koppers-Totzek will be used with bituminous coal.

The coal and oil shale requirements for the three technologies under consideration are shown in Table 4-5. These annual requirements are based on daily resource inputs, assuming the plant is operating 90 percent of the time over a period of one year.

b. Water

The water requirement for synthetic fuels production arises mainly from the need for cooling water to dispose of waste heat, and the chemical need for hydrogen in the conversion process. The chemical hydrogen requirement is more or less fixed for each process, while the cooling requirement is variable depending on the degree to which wet cooling versus dry cooling is used in the plant, and the level to which heat given off during each process step can be recovered for useful purposes. Other uses of water within the plant may be quenching of gaseous products to remove oil and particulates, dust suppression, solid waste disposal, and the generation of steam to drive turbines or gas compressors.

In the conversion of coal to methanol, about 3300 acre-ft of water per year (as steam) is consumed in chemical reactions (gasification, shift conversion and methane reforming).<sup>6</sup> For the H-Coal liquefaction process, the chemical consumption of water is about 3500 acre-ft

Table 4-5

ANNUAL COAL AND OIL SHALE REQUIREMENTS FOR  
100,000-B/D SYNTHETIC FUELS PLANTS

|                                           | Oil Shale<br>(million tons) | Oil Shale<br>(10 <sup>9</sup> kg) | Coal<br>(million tons) | Coal<br>(10 <sup>9</sup> kg) |
|-------------------------------------------|-----------------------------|-----------------------------------|------------------------|------------------------------|
| Syncrude from oil shale                   |                             |                                   |                        |                              |
| 35 gal/ton (0.15 m <sup>3</sup> /1000 kg) | 43                          | 39                                | 0.8                    | 0.7                          |
| 27 gal/ton (0.11 m <sup>3</sup> /1000 kg) | 55                          | 50                                | 1.0                    | 0.9                          |
| Syncrude from coal                        |                             |                                   |                        |                              |
| Bituminous                                | --                          | --                                | 13                     | 12                           |
| Subbituminous                             | --                          | --                                | 18                     | 16                           |
| Methanol from coal                        |                             |                                   |                        |                              |
| Bituminous                                | --                          | --                                | 10                     | 9                            |
| Subbituminous                             | --                          | --                                | 13                     | 12                           |
| Lignite                                   | --                          | --                                | 18                     | 16                           |

per year ( $4.2 \times 10^6 \text{ m}^3/\text{Y}$ ) using either western or eastern coal.<sup>8</sup> This water is utilized as steam in the partial oxidation plant and steam reformer to convert solid and gaseous byproducts, respectively, into hydrogen for the coal hydrogenation process. The chemical consumption of water in oil shale processing is in the steam reforming furnaces, where hydrogen is produced for use in hydrotreating raw shale oil products. This use of water amounts to 1500 acre-ft per year ( $1.8 \times 10^6 \text{ m}^3/\text{Y}$ ).<sup>11</sup>

Other uses for water in oil shale mining, retorting and upgrading have been fairly well established and are shown in Table 4-6 below.

Table 4-6

ANNUAL WATER REQUIREMENTS FOR A 100,000-B/D OIL SHALE  
MINING, RETORTING, AND UPGRADING OPERATION

| <u>Process</u>       | <u>Water<br/>(acre-ft)</u> | <u>Water<br/>(<math>10^6 \text{ m}^3</math>)</u> |
|----------------------|----------------------------|--------------------------------------------------|
| Mining and crushing  | 900                        | 1.1                                              |
| Retorting            | 1300                       | 1.6                                              |
| Upgrading            | 3600                       | 4.3                                              |
| Spent shale disposal | 7300                       | 8.8                                              |
| Power generation     | 1800                       | 2.2                                              |
| Revegetation         | <u>700</u>                 | <u>0.8</u>                                       |
| <b>Total</b>         | <b>15,600</b>              | <b>18.7</b>                                      |

Source: Reference 11.

Of the above total, about 3800 acre-ft per year ( $4.6 \times 10^6 \text{ m}^3/\text{Y}$ ) are consumed as makeup water to the evaporative cooling towers. This quantity could be reduced significantly if more costly dry cooling were utilized. There are relatively few additional areas where

water consumption could be reduced. Essentially all process waste water will be reused within the plant.

Information on nonchemical water requirements for producing methanol from coal is somewhat sketchy. Depending on the extent to which air cooling is used, makeup water for cooling is in the range of 12,000-24,000 acre-ft per year ( $14 \times 10^6$ - $28 \times 10^6$  m<sup>3</sup>/Y). Much of the water requirement for steam generation and cooling can be made up by treating and recycling process waste water. We estimate the total water requirement for a 100,000-B/D (16,000 m<sup>3</sup>/D) plant to be 10,000-20,000 acre-ft per year ( $12 \times 10^6$ - $24 \times 10^6$  m<sup>3</sup>/Y).

Coal liquefaction via the H-Coal process consumes 22,000 acre-ft of water per year ( $26 \times 10^6$  m<sup>3</sup>/Y) in evaporative cooling losses.<sup>8</sup> The total requirement is 26,000-29,000 acre-ft per year ( $31 \times 10^6$ - $35 \times 10^6$  m<sup>3</sup>/Y) with no waste water recycling. To the extent that dry cooling and internal cleanup and recycling are used, this figure could be reduced by about half.

c. Land

Land use for synthetic fuels production includes permanent uses such as the plant site itself, roads, pipeline and utilities corridors, and water storage areas. Temporary uses include areas disturbed by mining and solid waste disposal, assuming the disturbed land can be rehabilitated for other uses. To the extent that the land is disturbed so that restoration or rehabilitation is not possible, these uses of the land become permanent.

The permanent land requirement for a 100,000 B/D (16,000 m<sup>3</sup>/D) oil shale mining, retorting, and upgrading operation is about 600 acres ( $2.4 \times 10^6$  m<sup>2</sup>).<sup>12</sup> In addition, about 150 acres per year ( $6.1 \times 10^5$  m<sup>2</sup>/Y) are disturbed by the disposal of spent shale in deep canyons,

assuming the disposal pile is 250-ft (76 m) high.<sup>11</sup> Revegetation of spent shale has not been convincingly demonstrated at this time, and it remains to be seen whether canyons which have been filled with spent shale can be reclaimed for other uses.

By analogy with synthetic natural gas plants, a coal-to-methanol conversion facility will occupy about 1000 acres ( $4 \times 10^6 \text{ m}^2$ ).<sup>17</sup> Solid waste in the form of ash will be returned to mined-out areas for burial. A coal liquefaction plant and associated facilities will occupy about 1000 acres ( $4 \times 10^6 \text{ m}^2$ ).

The land disturbed by surface coal mining depends strongly on the area of the country in which the coal is mined and is a function of the coal seam thickness and the method used for mining, i.e., contour stripping versus area stripping. Table 4-7 shows the average amount of land disturbed by area strip mining in several western states.<sup>18</sup>

Table 4-7

AVERAGE LAND AREA DISTURBED PER MILLION  
TONS OF COAL RECOVERED

| <u>State</u> | <u>Land Area<br/>(acres)</u> | <u>Land Area<br/>(<math>10^3 \text{ m}^2</math>)</u> |
|--------------|------------------------------|------------------------------------------------------|
| Arizona      | 78                           | 320                                                  |
| North Dakota | 65                           | 260                                                  |
| New Mexico   | 62                           | 250                                                  |
| Montana      | 47                           | 190                                                  |
| Wyoming      | 25                           | 100                                                  |

Source: Reference 18.

Combining this information with data from Table 4-5, we find that the land disturbed annually to supply coal to a 100,000-B/D (16,000 m<sup>3</sup>/D) methanol plant ranges from 325 acres (1.3 × 10<sup>6</sup> m<sup>2</sup>) for Wyoming subbituminous coal to 1170 acres (4.7 × 10<sup>6</sup> m<sup>2</sup>) for North Dakota lignite. For liquefaction of subbituminous coal at the 100,000-B/D (16,000 m<sup>3</sup>) level, the land disturbed ranges from 450 to 1400 acres per year (1.8 × 10<sup>6</sup> - 5.7 × 10<sup>6</sup> m<sup>2</sup>/Y).

In the Midwest, coal seams are much thinner than in the West; consequently, more land must be disturbed per unit of coal recovered. The average land area disturbed in the Midwest per million tons of coal recovered is 144 acres (5.8 × 10<sup>5</sup> m<sup>2</sup>).<sup>19</sup> Thus, 1440 acres (5.8 × 10<sup>6</sup> m<sup>2</sup>) must be disturbed annually to supply a 100,000-B/D (16,000 m<sup>3</sup>/D) methanol plant and 1870 acres (7.6 × 10<sup>6</sup> m<sup>2</sup>) must be disturbed to supply a 100,000-B/D (16,000 m<sup>3</sup>/D) coal liquefaction plant.

In Appalachia, most surface coal mining is done by contour stripping, in which land is disturbed not only in the area of overburden removal but also by covering the downslope region with a spoil bank and to a lesser extent by drainage ditches and induced landslides. The average land area disturbed in Appalachia per million tons of coal recovered is 415 acres (1.7 × 10<sup>6</sup> m<sup>2</sup>) for the contour stripping method.<sup>19</sup> This means that 4150 acres (1.7 × 10<sup>7</sup> m<sup>2</sup>) must be disturbed annually to supply a methanol plant and 5400 acres (2.2 × 10<sup>7</sup> m<sup>2</sup>) must be disturbed to supply a coal liquefaction plant.

The reclamation potential for surface mining in the major coal-bearing regions of the United States is discussed in detail in Chapters 13 and 15. Generally speaking, it is possible in almost all areas for some form of reclamation to take place and is in fact now required by law in many states. Therefore, we may consider land disturbed



by surface mining to supply synthetic fuels plants a temporary land use.\*

Land disturbance from eastern underground coal mining is mostly in the form of surface subsidence. The degree to which subsidence occurs will depend on the mine depth, the strength of the rock formation above the mine, and the type of mining which is employed. For example, long-wall mining results in greater subsidence than room-and-pillar mining. The effect of subsidence is more or less permanent but does not necessarily remove the land from other uses. Using an average figure of 0.1 acres ( $400 \text{ m}^2$ ) of subsidence per 500 tons ( $4.5 \times 10^5 \text{ kg}$ ) of coal mined,<sup>20</sup> we find that 2000 acres ( $8.1 \times 10^6 \text{ m}^2$ ) could be disturbed annually to supply a methanol plant, and 2600 ( $1.1 \times 10^7 \text{ m}^2$ ) acres could be disturbed to supply a coal liquefaction plant.

d. Labor

To assess impacts due to the buildup of population in rural areas where much of the synthetic fuels development is expected to occur, it is necessary to know the manpower requirements for construction and operation of the plants. The influx of personnel required for plant construction will represent a temporary population buildup lasting three to four years, while the plant operation and maintenance personnel will represent a stable long-term population increase in the area. However, in oil shale development, where synthetic fuels plants and mines are concentrated in a small area and there is a gradual buildup of large productive capacity, the population increase due to the

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\*The reclamation potential of many arid regions of the West has not been established, and surface mining in some areas may result in permanent land disturbance.

construction labor force will be spread out over a longer time period-- perhaps 10 to 15 years.

Colony Development Operation has estimated that 40 months will be required for construction of its 50,000-B/D (8000 m<sup>3</sup>/D) oil shale complex, and that the construction force will rise from several hundred at the beginning of construction to a peak of 1200 halfway through the project.<sup>13</sup> Assuming a model for the buildup and fall-off of construction personnel as shown in Figure 4-10, we calculate about

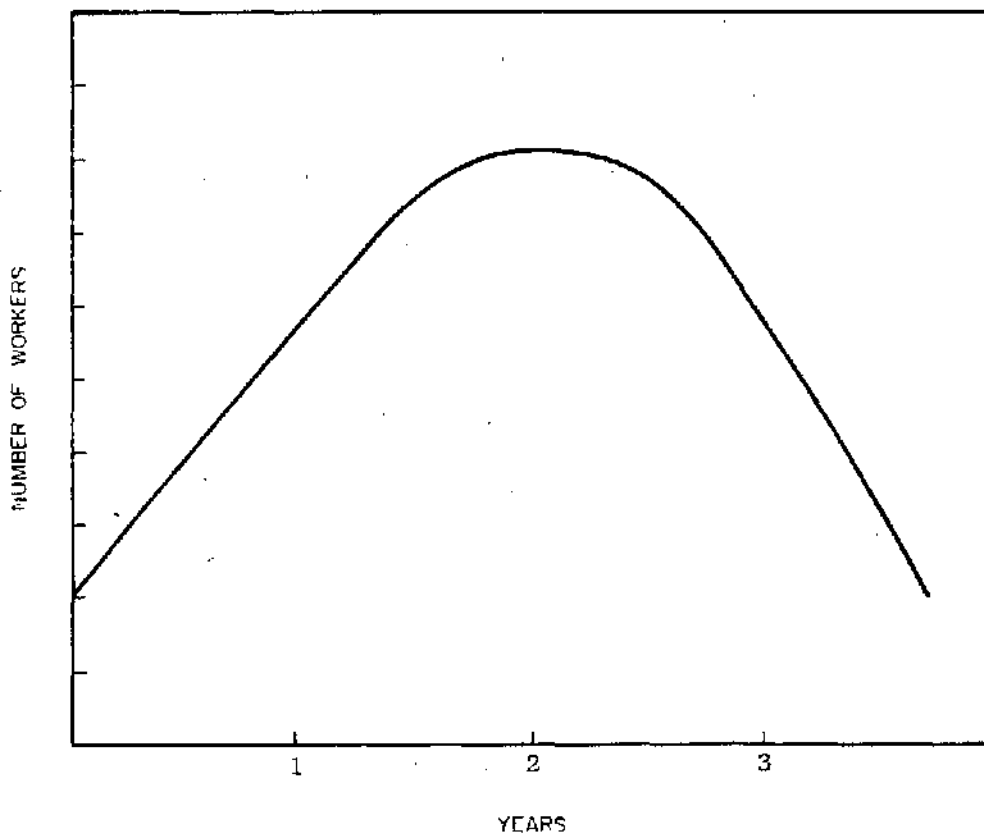


FIGURE 4-10. TYPICAL CONSTRUCTION LABOR PROFILE FOR LARGE PROPOSED FUEL CONVERSION PROJECTS

a 3000 man-year construction requirement. For a 100,000-B/D (16,000 m<sup>3</sup>/D) complex we estimate a 5000-6000 man-year requirement, with a peak construction force of about 2000. Colony estimates that operation,

maintenance, and administrative personnel will total 900-1000 for its 50,000-B/D (8000 m<sup>3</sup>/D) complex. A mining, retorting, and upgrading operation twice this size might be expected to employ 1500-1800 people.

Labor requirements for a coal-to-methanol plant can be estimated by comparison with El Paso Natural Gas Company's 288 million SCF per day ( $8.2 \times 10^6$  m<sup>3</sup>/D) SNG plant.<sup>17</sup> Construction time will be about three years with a peak construction force of 3500. Assuming that the labor force at the beginning and end of the project is about one-fourth the peak force, we estimate that 7500 man-years are required to build a 100,000-B/D (16,000 m<sup>3</sup>/D) methanol plant. Operating personnel requirements will total about 900.

Labor requirements for coal liquefaction plant construction are difficult to estimate. Estimates range from about 5000<sup>18</sup> to about 12,000 man-years of effort<sup>21</sup> over a period of three to four years. On the basis of the total plant investment cost, we estimate the level of construction effort to be 7000-8000 man-years, with a peak labor force of 2000-3000. The number of workers and supervisors involved in operating the plant will be about 1400.

Construction of a 5 million ton per year ( $4.5 \times 10^9$  kg/Y) surface coal mine in the western United States requires a 250 man-year effort over a period of two years with a peak labor force of about 150. Operating personnel required to run such a mine number about 100.<sup>22</sup>

e. Steel

The principal material requirement in the construction of synthetic fuels plants will be steel. This will be in the form of equipment and machinery, piping, girders for building construction, etc. A rough estimate of the total steel requirement for a synthetic fuels plant can be made through a breakdown of plant investment costs (shown

in Section C-4) using some average cost for fabricated steel. We have used the figure \$1 per pound (\$2.20/kg) for fabricated carbon steel and \$2.50 per pound (\$5.50/kg) for fabricated stainless or alloy steel. We have also assumed that approximately one-quarter of the fabricated steel is stainless. Construction steel is assumed to be carbon steel. With these rough estimating methods, we obtain a figure of about 100,000 tons ( $9.1 \times 10^7$  kg) of steel as the requirement for a coal-to-methanol coal liquefaction, or oil shale plant of 100,000-B/D (16,000 m<sup>3</sup>/D) capacity.

The Oil Shale Task Force Report and Synthetic Fuels from Coal Task Force Report of Project Independence Blueprint estimate that about 130,000 tons ( $1.2 \times 10^8$  kg) of steel will be used in a 100,000-B/D (16,000 m<sup>3</sup>/D) oil shale mining, retorting, and upgrading plant or coal liquefaction plant.<sup>23,24</sup> By way of comparison, the MIT Energy Laboratory has estimated that 170,000 tons ( $1.5 \times 10^8$  kg) of steel are required for construction of a 200,000-B/D (32,000 m<sup>3</sup>/D) petroleum refinery.<sup>25</sup>

f. Other

The second most critical material will probably be copper, primarily in the form of electrical wiring, instrumentation, windings for electric motors, etc. Based on the percentage of plant facilities investment spent for major equipment and for electrical supplies and materials and using the figures 3.7 tons ( $3.4 \times 10^3$  kg) of copper per million dollars of output and 23 tons ( $2.1 \times 10^4$  kg) of copper per million dollars of output<sup>26</sup> for the Industrial Equipment and Machinery sector and Electrical Equipment and Supplies sector of the economy, respectively, we estimate that about 1500 tons ( $1.4 \times 10^6$  kg) of copper will be utilized in a 100,000-B/D (16,000 m<sup>3</sup>/D) synthetic fuels plant. The Synthetic Fuels from Coal Task Force Report of Project Independence

Blueprint estimates that about 1200 tons ( $1.1 \times 10^6$  kg) of copper are required for a 100,000-B/D (16,000 m<sup>3</sup>/D) Fischer-Tropsch synthesis type gasoline-from-coal plant.<sup>24</sup>

In addition to the metals requirements, there will be other materials requirements such as concrete (several hundred thousand cubic yards or several hundred thousand m<sup>3</sup> for foundations, parking areas, etc.), insulation and paint.

Major equipment components will probably be fabricated elsewhere and shipped to the construction site, although the largest items, such as pressure vessels, may be fabricated on site due to the difficulty in shipping such large objects. Numerous smaller pieces of equipment such as pumps, motors, valves and conveyor belts will be needed as well. Most of these items are not unique to synthetic fuels plants but, due to the possible remote location of some of the plants, there may be difficulties and delays in supplying equipment and materials. Delays in equipment deliveries can contribute to increased costs due to the necessity of keeping construction personnel on-site for longer periods of time.

Once the plant has been constructed, the materials requirements for operation and maintenance are much smaller. Other than coal or oil shale, water and fuel, the main requirements are for the chemicals and catalysts consumed in various chemical processes and in water cleanup and air pollution control equipment. A large supply of spare parts, lubricants, tools, and other maintenance equipment will be needed. Again, the supply of these materials presents no special problems other than those imposed by the remote location of some of the plants.

The catalysts and chemicals requirement will vary with the types of chemical processes employed in the production of each

synthetic fuel. In coal liquefaction, about 5500 tons ( $5.5 \times 10^6$  kg) of cobalt-molybdenum catalyst are consumed annually in the coal hydrogenation process,<sup>7</sup> as well as 230 tons ( $2.1 \times 10^5$  kg) of nickel oxide catalyst in the steam reforming plant.

In the coal-to-methanol conversion process, 875 tons ( $7.9 \times 10^5$  kg) of copper-chromium-zinc catalyst for methanol synthetic must be replaced every 1-2 years. Other catalysts such as the nickel oxide catalyst for methane reforming and copper-zinc or iron-chromium catalysts for CO shift must be replenished every 2-5 years.

Colony Development Operation has set forth requirements for the processing and treating steps in the production of oil from oil shale. These are listed in detail in Table 4-8. The replacement time written after each quantity of catalyst is roughly the lifetime of the catalyst.

Some additional chemicals that may be required in synthetic fuels plants for water treating and cleanup, fuel gas cleanup, stack gas scrubbing, etc. include lime (CaO), alum, salt, methanol, isopropyl ether, sulfuric acid, and sodium hydroxide.

### 3. Byproducts and Residuals

In addition to the production of end products--syncrude and methanol--for which synthetic fuel plants are designed, there will be byproducts and residual materials generated which will be sold or disposed of. Usable byproducts which can be sold on the open market bring in additional revenue to the plant and help defray the production costs of synthetic fuels. Solid, liquid, or gaseous waste materials generated during synthetic fuels production must be considered environmental contaminants. The manner in which these wastes are disposed governs the degree of environmental acceptability of the plant. At present,

Table 4-8

CATALYST AND CHEMICAL REQUIREMENTS FOR A  
100,000-B/D OIL SHALE RETORTING AND UPGRADING PLANT

Naphtha and gas oil hydrotreaters

670 tons ( $6.1 \times 10^5$  kg)/2 yr (max) hydrodenitrogenation  
catalyst

Steam reformer

270 tons ( $2.4 \times 10^5$  kg)/4 yr cobalt-molybdenum hydro-  
desulfurization catalyst

5 tons ( $4.5 \times 10^3$  kg)/day caustic soda (NaOH)

30 tons ( $2.7 \times 10^4$  kg)/2 yr zinc oxide sulfur guard

100 tons ( $9.1 \times 10^4$  kg)/5 yr iron-chromium CO shift catalyst

100 tons ( $9.1 \times 10^4$  kg)/3 yr copper-zinc CO shift catalyst

Sulfur conversion

300 tons ( $2.7 \times 10^5$  kg)/2 yr bauxite claus plant catalyst

200 tons ( $1.8 \times 10^4$  kg)/5 yr cobalt and nickel molybdate  
tail gas hydrotreater catalyst

Fuel gas treating

17.5 tons ( $1.6 \times 10^4$  kg)/2 wk diatomaceous earth filter

17.5 tons ( $1.6 \times 10^4$  kg)/2 wk activated carbon sulfur trap

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Source: Reference 12.

there are no federal standards that govern emissions from synthetic fuels plants, although there are standards which govern individual processes which may occur in the plant, such as combustion of fuel in steam boilers. New Mexico has promulgated emission standards for coal gasification plants, and undoubtedly other states as well as the federal government will direct increasing attention towards synthetic fuels plants as the industry develops.

a. Salable Byproducts

A variety of byproducts is produced from the conversion of coal to methanol. These generally are produced during purification processes in which impurities are removed from the synthesis gas or methanol product. Tar, oil, and naphtha are removed during quenching of the synthesis gas exiting the gasifier. The quench water dissolves ammonia and phenols which are recovered in the water treatment plant. Sulfur is a product of the sulfur recovery plant which treats the acid gas stream which results from synthesis gas purification. Finally, a small quantity of higher alcohols (ethanol, propanol, butanol, etc.) are formed during methanol synthesis, and these are separated from the final product by distillation.

The quantities of different byproducts generated by a 100,000-B/D (16,000 m<sup>3</sup>/D) methanol plant utilizing western coal are listed in Table 4-9.

Table 4-9

BYPRODUCTS FROM A 100,000-B/D  
COAL-TO-METHANOL PLANT  
(Western Coal)

|                       |                                      |
|-----------------------|--------------------------------------|
| Tar, oil, and naphtha | 15,200 B/D (2400 m <sup>3</sup> /D)  |
| Phenols               | 840 B/D (130 m <sup>3</sup> /D)      |
| Higher alcohols       | 405 B/D (64 m <sup>3</sup> /D)       |
| Ammonia               | 450 T/D (4.1 × 10 <sup>5</sup> kg/D) |
| Sulfur                | 170 T/D (1.5 × 10 <sup>5</sup> kg/D) |

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Source: Reference 6.



All of these products have commercial value and could be sold if a market could be found for them. Otherwise they would have to be stored or disposed along with the solid wastes.

The H-Coal liquefaction process is designed to maximize syncrude production and to minimize the production of byproducts.<sup>8</sup> The large quantities of high-Btu gases generated are utilized as plant fuel or as feed to the steam reformer. The heavy bottoms product, which is separated from the syncrude, is fed to the partial oxidation plant for hydrogen production. The only usable byproducts generated from this process are 320 to 420 tons per day ( $2.9 \times 10^5$ - $3.8 \times 10^5$  kg/D) of ammonia and 200 to 1300 tons per day ( $1.8 \times 10^5$ - $1.2 \times 10^6$  kg/D) of sulfur.<sup>8</sup> A small amount of char is also produced, but it is not of commercial value and will be disposed of with the ash.

As in the case of coal liquefaction, oil shale processing will result in a minimum of byproducts. All gases and C<sub>4</sub> liquids (butane and butene) produced from retorting will be consumed on-site as plant fuel. The main byproduct will be 1600 tons per day ( $1.5 \times 10^6$  kg/D) of coke, derived from the heavy residual shale oil fraction.<sup>12</sup> This product may or may not be of commercial value. Other byproducts are 400 tons per day ( $3.6 \times 10^5$  kg/D) of elemental sulfur and 300 tons per day ( $2.7 \times 10^5$  kg/D) of ammonia.

b. Solid Waste

The main solid waste resulting from coal liquefaction and methanol production is the ash that remains after the organic portion of the coal is converted to liquid and gaseous products. The amount of ash produced depends on the original ash content of the coal. Typically, 3000 to 4000 tons ( $2.7 \times 10^6$ - $3.6 \times 10^6$  kg) of ash and char (mostly ash) will be generated per day by a 100,000-B/D ( $16,000 \text{ m}^3/\text{D}$ )

coal liquefaction or coal-to-methanol plant. If the plant is located near the mine, then this waste material can be disposed of in the mine-- either buried in a mined-out area in the case of an underground mine, or added to the spoil piles and buried under topsoil during reclamation operations for a surface mine. If it is not feasible to return the ash to the mine, it must be stored in waste piles or used as landfill.

The major solid waste from oil shale retorting and upgrading is, of course, the spent shale which results from retorting the oil shale, amounting to 100,000 to 150,000 tons per day ( $9.1 \times 10^7 - 1.4 \times 10^8$  kg/D). The enormity of this disposal problem is reflected in the plan proposed to deal with it--filling in a 250-ft (76 m) deep canyon. The land area required for such an operation was discussed earlier in Section 2c.

It may be possible to dispose of some of the spent shale in areas of the mine where recovery operations have been completed. There is general reluctance in the industry to do this, however, since lower grade deposits that might be economically recoverable at a later date would be made inaccessible. In any case, not all the spent shale could be disposed of in this way since the total shale volume expands 10 to 30 percent in crushing and retorting.<sup>11</sup>

Other minor solid wastes generated by synthetic fuel plants include coal and shale dust, spent catalysts, and char and coke if these cannot be sold commercially. In general, these wastes will be disposed of along with the spent shale and ash.

The potential for recovering valuable minerals or metals from spent shale or coal ash has yet to be assessed. At present there are no plans to process spent shale. Of the major constituents of spent shale, the only ones of value are magnesium, aluminum, and iron oxides. Valuable trace metals such as gold, silver and platinum are

present in quantities less than 0.1 part per million. There is about 1 part per million of uranium. The spent shale itself may have potential uses as filler in concrete and building blocks, or as road substrate. However, only a tiny fraction of the total spent shale generated by a mature industry could be used in this way.

Coal ash also contains aluminum, magnesium and iron oxides, and perhaps trace quantities of valuable metals. The possibility has been raised of recovering uranium from North Dakota lignite ash. In general the uranium content of western coal ash is from 1 to 10 parts per million.

c. Effluents to Water

In principle, the effluents to water from synthetic fuels plants can be reduced effectively to zero. This can be done by treating and recycling all boiler and cooling tower blowdown water, process waste water, etc., and discharging to on-site evaporation ponds any remaining water that is too highly contaminated to be recycled. All discharges to streams and rivers can thus be eliminated. Furthermore, the raw water requirement for plant operation can be considerably reduced. This is particularly important in arid western regions where water supplies are limited.

Colony Development Operation has designed its first commercial 50,000-B/D oil shale retorting and upgrading plant so that no waste streams from the plant are discharged to natural sources.<sup>12</sup> Most of the process water waste streams are treated and used for cooling or processed shale moisturizing. This results in considerable water consumption savings. The overall water use and treatment plan for the Colony plant is shown in Figure 4-11. Although not all the steps in this scheme are directly applicable to other synthetic fuels processes,

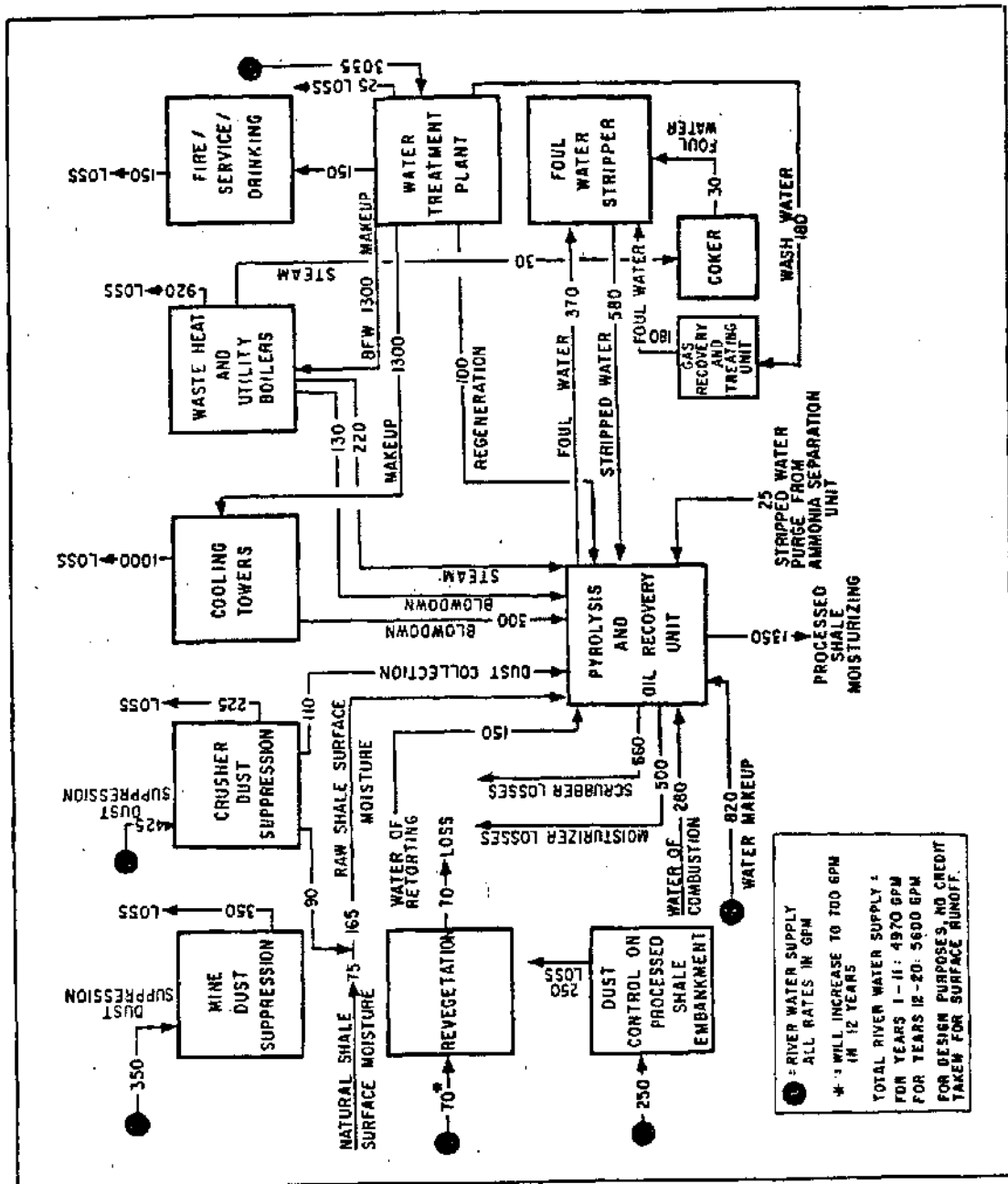


FIGURE 4-11. RIVER WATER UTILIZATION (from Reference 11) (50,000-BPD TOSCO II OIL SHALE PLANT)

it does serve to illustrate the kinds of steps which may be taken to reduce aqueous emissions to zero.

El Paso Natural Gas Company has also developed a waste water treatment and recycling plan for its Burnham, New Mexico, coal gasification project.<sup>17</sup> In this scheme, most of the treated waste water is used to replace water lost in cooling tower evaporation--the single largest consumptive use of water in the plant.

The sources and ultimate disposition of aqueous contaminants are different for each synthetic fuel process. In the conversion of coal to methanol, most of the contaminants originate in the coal gasification process. In addition to the tar, oil, naphtha, and phenols formed from volatile matter in the coal, the nitrogen and sulfur compounds are converted to ammonia, hydrogen cyanide (HCN), hydrogen sulfide, carbon disulfide (CS<sub>2</sub>) and carbonyl sulfide (COS) in the gasifier.<sup>27</sup> Subsequent to gasification, during the synthetic gas quenching step, the tar, oils, and naphtha are condensed, decanted, and recovered as byproducts. The remaining quench water (called gas liquor) contains dissolved phenols and ammonia, which are recovered by the (proprietary) Phenosolvan process. The remaining water containing small amounts of all the above contaminants is sent to the water bio-treating plant and recycled for use as cooling water and boiler feedwater.

The sulfur compounds and hydrogen cyanide remaining in the synthesis gas are removed by the Rectisol process (cold methanol scrubbing) and sent to a Stretford sulfur recovery unit where the HCN, CS<sub>2</sub>, and COS are converted to sodium thiocyanate (NaSCN) and sodium thiosulfate (NaS<sub>2</sub>O<sub>3</sub>). The contaminated Stretford solution is periodically replaced with fresh solution and sent to water bio-treating.<sup>27</sup>

In coal liquefaction, aqueous contaminants are produced during coal drying and coal hydrogenation in which the oxygen, nitrogen

and sulfur in the coal are converted to water, ammonia, and hydrogen sulfide, respectively. The contaminated water is sent to the ammonia stripper unit where aqueous ammonia is recovered as a byproduct and a concentrated H<sub>2</sub>S stream is generated and sent to the Claus sulfur recovery plant. The remaining water can be sent to a bio-treating unit along with the waste water from coal drying, cooling tower and boiler blowdown and other process waste water.<sup>28</sup>

The levels of contaminants expected in the effluent water from a biological treatment pond in which waste water from coal liquefaction is treated is shown in Table 4-10. A 100,000-B/D coal liquefaction plant produces about 5 million gallons of waste water per day; this weighs about 21,000 tons ( $1.9 \times 10^7$  kg). Therefore, the concentrations shown in Table 4-10 multiplied by the above figure give the amounts of these contaminants discharged daily if the waste water is not recycled or sent to on-site evaporation ponds.

Table 4-10

COAL LIQUEFACTION PLANT BIOLOGICAL  
TREATING POND WATER EFFLUENT

| Constituent                    | Concentration<br>(wt ppm) |
|--------------------------------|---------------------------|
| Sulfide                        | < 0.005                   |
| Ammonia                        | 0.11                      |
| Oil                            | 0.68                      |
| Biological oxygen demand (BOD) | 10.5                      |
| Suspended solids               | 12.9                      |
| Phenol                         | 0.38                      |
| Chemical oxygen demand (COD)   | 45                        |
| Phosphate                      | 0.11                      |
| Chromate                       | 7.1                       |
| Zinc                           | 3.5                       |

Source: Reference 28.

During the retorting and upgrading of oil shale, waste water is generated as excess moisture from the retorting process and the gas recovery unit, as process water and condensed moisture from the coking unit and boiler and cooling tower blowdown, as well as fuel gas and stack gas scrubbing water. Waste water containing  $H_2S$  and ammonia is recovered in the foul water stripper and recycled. Most of the treated waste water is disposed of by using it to moisturize the spent shale generated during retorting. This use amounts to about 4 million gallons per day ( $1.5 \times 10^4 \text{ m}^3/\text{D}$ )<sup>12</sup> which weighs about 17 tons.

The water used to moisturize the spent shale will consist of any mine drainage water and spent shale runoff water that has been collected in addition to process waste water. The approximate concentrations of contaminants expected in this water are listed in Table 4-11. A potential source of water pollution is leaching or runoff from the spent shale disposal pile into local aquifers. Except in catastrophic failure of the pile or flash flooding, catchment dams will probably be sufficient to retain any runoff water. The potential for water contamination due to leaching depends on several factors, such as the degree of compaction of the spent shale, and has yet to be fully assessed.

In addition to direct plant discharges, there are possible indirect water contamination problems. For example, the withdrawal of low salinity water from the Upper Colorado River Basin for use in oil shale processing will result in an increase in salinity in the Lower Colorado, due to a decreased dilution effect. The salinity increase resulting from a 1-million B/D oil shale industry would be about 10 parts per million (out of a present level of 860 ppm) at Imperial Dam.<sup>12</sup> Even though this increase is small, the fact that the United States is planning to build a desalination plant on the lower Colorado River to meet its treaty obligations with Mexico indicates that some

additional costs will be incurred (and paid for by the taxpayers) due to this additional--indirectly caused--salinity increase.

Table 4-11

COMPOSITION OF WASTE WATER USED IN  
SPENT SHALE MOISTURIZING

| <u>Constituent</u> | <u>Concentration<br/>(wt ppm)</u> |
|--------------------|-----------------------------------|
| Sulfates           | 510                               |
| Thiosulfates       | 60                                |
| Carbonates         | 520                               |
| Phosphates         | 15                                |
| Chlorides          | 330                               |
| Cyanides           | 50                                |
| Hydroxides         | 30                                |
| Phenol             | 60                                |
| Ammonia            | 30                                |
| Amines             | 1900                              |
| Organic acids      | 1000                              |
| Chelates           | 3                                 |
| Chromates          | 130                               |
| Arsenic            | 0.03                              |

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Source: Reference 12.

d. Effluents to the Air

Sufficient information on plant design and emission sources has been set forth in the literature so that quantitative estimates can be made of the emissions of air pollutants. Generally speaking, there are two major sources for the emission of contaminants to the air from synthetic fuels production--the combustion of fuels to provide



heat, steam and electricity to drive the various plant processes and the emission of sulfur-containing waste gas (tail gas) from sulfur recovery operations. In almost all cases, some sort of emission controls, direct or indirect, have been incorporated into the plant designs. Although there are presently no federal performance standards for synthetic fuels plants, it is generally assumed that combustion of fuel in boilers, for example, will be required to meet federal standards. It is likely that standards for such plants will be promulgated as the industry develops.

Since a more detailed discussion of air pollutant emissions and controls will be given in Chapter 16, only a summary of the relevant emission data is given here. Table 4-12 shows the quantities of SO<sub>2</sub>, particulates, NO<sub>x</sub> and hydrocarbon emissions that may be expected to result from the liquefaction of Montana-Wyoming coal and eastern coal via the H-Coal process,<sup>8</sup> the conversion of Navajo coal to methanol<sup>6</sup> and the retorting and upgrading of 35 gal/ton oil shale to syncrude,<sup>12</sup> all at the 100,000-B/D level. The emission levels shown in Table 4-12 are those resulting from application of the "best available" emission controls appropriate to each technology. The types of controls applied are discussed in detail in Chapter 16.

All the emissions and NO<sub>x</sub> shown in Table 4-12 result from the combustion of gaseous, liquid, or solid fuels to power the various plant processes. The total includes the combustion of fuel necessary to provide purchased electricity when it has been incorporated into the plant design. All particulate emissions are from fuel combustion or coal drying, except for oil shale processing where one-fourth of the particulate emissions are in the form of fugitive dust.<sup>12</sup> We have assumed a level of control of 99.5 percent using electrostatic precipitators or Venturi scrubbers for reducing stack gas emissions from

Table 4-12

EMISSIONS OF AIR POLLUTANTS FROM  
SYNTHETIC FUELS PRODUCTION  
(Tons per 100,000 Barrels of Product)

|                                              | <u>SO<sub>2</sub></u> | <u>Particulates</u> | <u>NO<sub>x</sub></u> | <u>Hydrocarbons</u> |
|----------------------------------------------|-----------------------|---------------------|-----------------------|---------------------|
| Coal liquefaction (H-Coal)                   |                       |                     |                       |                     |
| Montana/Wyoming coal                         | 11                    | 7.1                 | 96                    | 1.6                 |
| Illinois No. 6 coal                          | 16                    | 2.7                 | 28                    | 0.4                 |
| Coal-to-methanol (Lurgi)                     |                       |                     |                       |                     |
| Navajo coal                                  | 15                    | 2.0                 | 25                    | 0.4                 |
| Oil shale retorting and upgrading (TOSCO II) |                       |                     |                       |                     |
| 35 gal/ton shale                             | 40                    | 10                  | 72                    | 7.6                 |

coal combustion. Fugitive dust control is assumed to be 98-99.8 percent effective (see Chapter 16).

The SO<sub>2</sub> emissions shown in Table 4-12 result from both fuel combustion and sulfur recovery plant tail gas. We have assumed a level of control for stack gas emissions from burning high sulfur fuels of 90 percent, while for tail gas emissions a control level resulting in SO<sub>2</sub> emissions of 250 ppm by volume (equivalent to about 95 percent SO<sub>2</sub> removal) has been assumed. The relative proportions of SO<sub>2</sub> emissions from fuel combustion and tail gas are as follows: eastern coal liquefaction, 59 percent from combustion, 41 percent from tail gas; western coal liquefaction, 86 percent from combustion, 14 percent from tail gas; methanol from Navajo coal, 94 percent from combustion, 6 percent from tail gas; syncrude from oil shale, 96 percent from combustion, 4 percent from tail gas.

e. Trace Elements

The question of the fate of toxic trace elements in coal and oil shale conversion processes has received considerable attention due to the potential for highly toxic metals such as mercury, lead, beryllium, arsenic, cadmium, selenium, and fluorine to enter the air, water, or soil and ultimately to create a health hazard. At present, few pathways of trace elements through energy conversion activities have been identified. It is known, for example, that volatile elements, including those listed above, will be discharged to the air during combustion. Other nonvolatile elements will end up primarily in the ash. However, the fate of these elements during coal gasification and liquefaction and oil shale retorting is not as clearly defined.

The quantities of toxic trace elements which are found in oil shale and coal are shown in Tables 4-13 and 4-14, respectively. The oil shale determinations were made on 35-gallons per ton (0.15 m<sup>3</sup>/1000 kg) Green River oil shale. The coal analyses were based on a variety of coals found in both the eastern and western United States. Typically, as seen from Table 4-14, eastern coals have a somewhat higher trace element content than western coals.

During the coal gasification step of methanol production, volatile elements in the coal are vaporized and may exit the gasifier along with the raw synthesis gas. During gas quenching these elements are condensed and separated out along with the tar, oil, and naphtha or as part of the gas liquor stream. It is unlikely that any significant fraction of the trace elements in the coal make their way to the final methanol product.

In tests made on the Bureau of Mines Synthane gasifier,<sup>29</sup> it was determined that 20 trace elements were present in the raw gas quench water in the range of 2 parts per billion to 4 parts per million.

The concentration of selenium was 360 parts per billion and that of arsenic was 30 parts per billion. Byproduct tar was found to contain 3 parts per billion of mercury and 0.7 parts per million of arsenic. Only 0.01 parts per billion of mercury could be detected in the cleaned synthesis gas, and none could be detected in the final product (methane).

Table 4-13

CONCENTRATION OF TOXIC TRACE  
ELEMENTS IN OIL SHALE

| <u>Element</u> | <u>Concentration in<br/>Oil Shale<br/>(wt ppm)</u> |
|----------------|----------------------------------------------------|
| Arsenic        | 7.2                                                |
| Beryllium      | 35                                                 |
| Cadmium        | 0.14                                               |
| Fluorine       | 1700                                               |
| Lead           | 10                                                 |
| Mercury        | < 0.1                                              |
| Selenium       | 0.08                                               |

Source: Reference 12.

During coal liquefaction, coal is exposed to considerably different conditions than in gasification, the primary differences being the presence of a solvent (and perhaps a catalyst) and hydrogen at high pressures. These conditions strongly affect the fate of trace elements. A large portion of the trace metals will remain with the ash and unreacted solids that are separated from the liquid product. Gasification of this solid material to produce hydrogen will produce trace elements in waste streams in a fashion similar to coal gasification.

Table 4-14

MEAN TRACE ELEMENT CONCENTRATIONS (ppm, Moisture Free) OF VARIOUS COALS

| Element   | S  | Western Region                                        |                           |                            |                     |      | Eastern Region |                           |                                  |                                         |
|-----------|----|-------------------------------------------------------|---------------------------|----------------------------|---------------------|------|----------------|---------------------------|----------------------------------|-----------------------------------------|
|           |    | Colorado,<br>Valmount<br>Power<br>Station,<br>Boulder | Montana<br>and<br>Dakotas | Wyoming<br>Powder<br>River | Montana<br>Colstrip | Utah | Illinois       | Penn.-<br>Ohio-<br>W. Va. | Tenn.<br>Allen<br>Power<br>Plant | Maryland<br>Chalk Pt.<br>Power<br>Plant |
| Beryllium | Be |                                                       | 0.12-3.9                  | 0.25*                      | Trace               | 1.0  | 1.9            | 2.0-3.1                   | 0.3                              |                                         |
| Fluorine  | F  |                                                       | 65                        | 56.5                       | 31.6                | 66   | 42-134         | 50-120                    |                                  |                                         |
| Arsenic   | As |                                                       |                           | 2.1                        | Trace               | 0.5  | 14             | 3-59                      | 5                                | 25                                      |
| Selenium  | Se | 1.9                                                   |                           | 1.1                        | 0.016               | 1.2  | 2.2            |                           |                                  | 5.1                                     |
| Cadmium   | Cd |                                                       |                           | 0.11 <sup>†</sup>          | 0.23                | ≤0.2 | ≤0.2-22        | (0.39)                    | 0.46                             |                                         |
| Mercury   | Hg | 0.07                                                  | 0.07                      | 0.12                       | 0.15                | 0.04 | 0.24           | 0.12-0.21                 | 0.12                             |                                         |
| Lead      | Pb | ≤5                                                    | 7                         | 5.3 <sup>‡</sup>           | 4.8                 | 5    | 49             | 4-14                      | 4.9                              | 9.6                                     |
| Bromine   | Br |                                                       |                           |                            | 21.0                | 23   | 15             |                           | 4.3                              | 41                                      |
| Zinc      | Zn | 7.3                                                   |                           | 6.6                        |                     | 10   | 342            | (24.8)                    |                                  | 80                                      |
| Copper    | Cu | 9.6                                                   | 15                        | 13.7                       | ≤100                | 10   | 15             | 14-17                     |                                  |                                         |
| Nickel    | Ni |                                                       | 7                         | 4.0                        |                     | 4    | 23             | 9.7-20                    |                                  | 25                                      |
| Chromium  | Cr |                                                       | 7                         | 7.7                        | 2.9                 | 7    | 17             | 11-15                     |                                  | 28                                      |
| Vanadium  | V  |                                                       | 16                        | 20.9                       | 2.5                 | 10   | 34             | 19-25                     |                                  | 40                                      |
| Barium    | Ba |                                                       |                           | 206.3                      |                     |      |                |                           |                                  | 150                                     |
| Strontium | Sr | 120                                                   |                           | 92.6                       |                     |      |                |                           |                                  | 86                                      |

\*44 percent of the coal samples contained less than 0.15 ppm beryllium.

†70 percent of the coal samples contained less than 0.1 ppm cadmium.

‡8 percent of the coal samples contained less than 1.5 ppm lead.

Source: Reference 31.

Trace elements such as arsenic and selenium, which can react with hydrogen, may enter the gas phase during liquefaction.<sup>30</sup> Those that are not removed during cooling and scrubbing of the gas will enter the atmosphere if byproduct gases are combusted to provide plant steam and heat.

Finally, some trace elements, especially those which are bound to organic molecules in the coal, will be carried through into the synthetic crude oil product.

During oil shale retorting, trace elements are carried over into the raw shale oil product. Twenty-nine trace elements have been detected in raw shale oil,<sup>12</sup> including all of those listed in Table 4-13. Undoubtedly, a large fraction of the trace elements will remain with the spent shale. Further processing and upgrading of the raw shale oil may result in the introduction of some elements into waste streams. The ultimate disposition of all solid and liquid waste streams will be in the spent shale pile. Therefore, the major potential source of environmental contamination will be from leaching from this pile or failure of a catchment dam.

Although it is certain that some of the trace constituents in the raw shale oil will remain in the syncrude product, there has been no quantitative measurement of their concentrations. In general, few quantitative assessments of the presence of trace elements in synthetic fuel products or waste streams have been made. Much more research must be carried out in this area before any realistic evaluation of potential health hazards from trace element emissions from synthetic fuel plants can be undertaken.

#### 4. Costs and Dollar Flows

##### a. Investment and Operating Costs

The Arab oil embargo of late 1973 and the subsequent increases in world oil prices brought about a renewed interest in the possibility of using synthetic crude oil from coal and oil shale to augment declining domestic oil reserves. One of the greatest areas of concern has been the question of whether synthetic liquid fuels can be economically competitive with conventional fuels even at high prevailing world prices.

During 1974, a number of studies were carried out in which new cost estimates were made, or previous estimates revised, to determine the costs at which synthetic fuels could be produced from coal and oil shale, and the prices at which they would have to be sold to achieve a reasonable return on investment. Table 4-15 summarizes some of the estimates of costs and prices made during this period. All dollar figures are in 1973 dollars.

Unfortunately, these estimates were made during a period of rapid inflation, and few knowledgeable sources would consider the figures shown in Table 4-15 to be representative of current costs. The figures do, however, provide a relative basis of comparison for the costs of synthetic fuels.

From mid-1973 to late 1975 chemical plant construction and operating costs have increased by nearly 30 percent. Thus, the synthetic fuel prices shown in Table 4-15 would be at least 30 percent higher if estimated using current cost figures. However, even if inflation is properly accounted for in making cost estimates, there is another reason why the resulting figures are likely to be low. As new technologies move from the R&D stage through the pilot plant and demonstration plant level and approach commercialization, the bases for making

Table 4-15

## COST ESTIMATES FOR SYNTHETIC LIQUID FUELS (1973 COSTS)

| Type of Plant                                                                                                    | Size<br>(B/D) | Capital<br>Cost<br>(\$10 <sup>6</sup> ) | Operating<br>Cost<br>(\$10 <sup>6</sup> /yr) | Byproduct Credits<br>(\$10 <sup>6</sup> /yr)                                     | Cost of<br>Coal<br>(\$/ton) | Rate of<br>Return<br>(% DCF) | Price of<br>Product<br>(\$/B)                                            |  |  |
|------------------------------------------------------------------------------------------------------------------|---------------|-----------------------------------------|----------------------------------------------|----------------------------------------------------------------------------------|-----------------------------|------------------------------|--------------------------------------------------------------------------|--|--|
| H-Coal <sup>a</sup><br>(Navajo coal)                                                                             | 100,000       | 1014                                    | 160                                          | 113                                                                              | 3                           | 10                           | 8.00                                                                     |  |  |
|                                                                                                                  |               |                                         |                                              | (Sulfur, 1.8;<br>ammonia, 9.5;<br>fuel gas, 102)                                 | 5                           | 15                           | 10.70                                                                    |  |  |
|                                                                                                                  |               |                                         | 199                                          |                                                                                  |                             | 10                           | 8.70                                                                     |  |  |
|                                                                                                                  |               |                                         |                                              |                                                                                  |                             | 15                           | 11.40                                                                    |  |  |
| H-Coal <sup>b</sup><br>(Powder<br>River coal)                                                                    | 100,000       | 668                                     | 133                                          | 12                                                                               | 3                           | 10                           | 7.80                                                                     |  |  |
|                                                                                                                  |               |                                         |                                              |                                                                                  |                             | 15                           | 9.80                                                                     |  |  |
|                                                                                                                  |               |                                         |                                              | (Sulfur, 1.5;<br>ammonia, 10.5)                                                  |                             |                              |                                                                          |  |  |
| H-Coal <sup>b</sup><br>(Illinois<br>coal)                                                                        | 100,000       | 685                                     | 188                                          | 20.3                                                                             | 9                           | 10                           | 9.80                                                                     |  |  |
|                                                                                                                  |               |                                         |                                              |                                                                                  |                             | 15                           | 11.40                                                                    |  |  |
|                                                                                                                  |               |                                         |                                              | (Sulfur, 7.6;<br>ammonia, 13.7)                                                  |                             |                              |                                                                          |  |  |
| H-Coal <sup>c</sup><br>(Bituminous<br>coal)                                                                      | 30,000        | 260                                     | 61                                           | 33                                                                               | 8                           | 10                           | 8.08                                                                     |  |  |
|                                                                                                                  |               |                                         |                                              |                                                                                  |                             | 15                           | 10.70                                                                    |  |  |
|                                                                                                                  |               |                                         |                                              | (Fuel gas)                                                                       |                             |                              |                                                                          |  |  |
| Methanol <sup>a</sup><br>(Navajo coal;<br>Lurgi gasi-<br>fier)                                                   | 81,200        | 475                                     | 63                                           | 28                                                                               | 3                           | 10                           | 5.10                                                                     |  |  |
|                                                                                                                  |               |                                         |                                              | (Tar, tar oil,<br>naphtha, phenol<br>ammonia, and<br>sulfur, 18;<br>methane, 10) | 5                           | 15                           | 6.70                                                                     |  |  |
|                                                                                                                  |               |                                         | 79                                           |                                                                                  |                             | 10                           | 5.70                                                                     |  |  |
|                                                                                                                  |               |                                         |                                              |                                                                                  |                             | 15                           | 7.30                                                                     |  |  |
| Methanol <sup>d</sup><br>(Navajo coal;<br>Lurgi gasi-<br>fier)                                                   | 81,200        | 517                                     | 82                                           | 36                                                                               | 3                           | 15                           | 4.10                                                                     |  |  |
|                                                                                                                  |               |                                         |                                              |                                                                                  |                             |                              | (Tar oil, naphtha,<br>phenol, ammonia,<br>sulfur and higher<br>alcohols) |  |  |
| Methanol <sup>e</sup><br>(Illinois<br>coal;<br>Koppers-<br>Totzek<br>gasifier)                                   | 35,800        | 353                                     | 50                                           | 1                                                                                | 7.30                        | 12                           | 9.80                                                                     |  |  |
|                                                                                                                  |               |                                         |                                              |                                                                                  |                             |                              | (Sulfur)                                                                 |  |  |
| Oil shale <sup>3</sup><br>mining, re-<br>torting &<br>upgrading<br>(TOSCO II<br>retort, 35-<br>gal/ton<br>shale) | 100,000       | 643                                     | 70                                           | 5                                                                                | --                          | 10                           | 4.70                                                                     |  |  |
|                                                                                                                  |               |                                         |                                              |                                                                                  |                             |                              | (Coke, sulfur and<br>ammonia)                                            |  |  |
|                                                                                                                  |               |                                         |                                              |                                                                                  |                             | 15                           | 6.00                                                                     |  |  |

(continued)



Table 4-15 (concluded)

| Type of Plant                                                                                                             | Size<br>(B/D) | Capital<br>Cost<br>(\$10 <sup>6</sup> ) | Operating<br>Cost<br>(\$10 <sup>6</sup> /yr) | Byproduct Credits<br>(\$10 <sup>6</sup> /yr) | Cost of<br>Coal<br>(\$/ton) | Rate of<br>Return<br>(% DCF) | Price of<br>Product<br>(\$/B) |
|---------------------------------------------------------------------------------------------------------------------------|---------------|-----------------------------------------|----------------------------------------------|----------------------------------------------|-----------------------------|------------------------------|-------------------------------|
| Oil shale, <sup>f</sup><br>mining, re-<br>torting &<br>upgrading<br>(gas com-<br>bustion<br>retort, 30-<br>gal/ton shale) | 100,000       | 522                                     | 82                                           | 8.6<br>(Coke, sulfur and<br>ammonia)         | --                          | 12<br>15<br>20               | 5.20<br>6.10<br>7.90          |
| Oil shale, <sup>g</sup><br>mining, re-<br>torting &<br>upgrading<br>(gas com-<br>bustion<br>retort, 30-<br>gal/ton shale) | 54,500        | 421                                     | 82                                           | 7<br>(Coke, sulfur and<br>ammonia)           | --                          | 12                           | 8.70                          |

a. From Reference 1.

b. From Reference 8.

c. From Reference 25. Capital recovery factors of 20 and 30 percent were used to calculate prices in the table instead of 15 percent used in this reference.

d. From Reference 6. Methanol price based on utility financing, assuming a 75/25 debt-to-equity ratio and a 9 percent cost of capital.

e. From Reference 2.

f. From Reference 32.

g. From Reference 33.

accurate cost estimates become more concrete. Cost estimates made early in the developmental stage of a technology are simply not able to anticipate the cost factors that are realized at later stages of development.

Oil shale retorting and upgrading is currently closer to commercial development than any of the other synthetic liquid fuels considered in this paper, and recent cost estimates have tended to confirm the above discussion. When Colony Development Operation announced suspension of its plans to develop the first commercial oil shale facility (October 1974), the capital cost estimates for a 50,000-B/D plant had increased 45 percent (from \$435 million to \$630 million) in six months. This sort of cost inflation, due to actual increases in components of construction costs plus more realistic estimates of total costs, will undoubtedly continue to characterize the synthetic fuels economic picture.

#### b. Dollar Flows for Plant Construction and Operation

To understand the disposition of money spent for the construction and operation of synthetic fuel plants it is not necessary to display the total cost of construction or plant operation but only the relative sizes of the components of the total costs. Figures 4-12 and 4-13 show breakdowns of the capital cost and operating expenses for a 100,000-B/D H-Coal plant. These breakdowns were derived from actual costs presented in Reference 8 and the capital cost estimating techniques discussed in Reference 34. The relative costs of construction shown in Reference 34 were updated from 1969 to 1973 using components of plant cost indices published in Chemical Engineering.

Figure 4-12 shows that equipment and materials constitute the largest source of capital expenditure, contributing nearly 50 percent of the plant construction cost. The next largest single item is

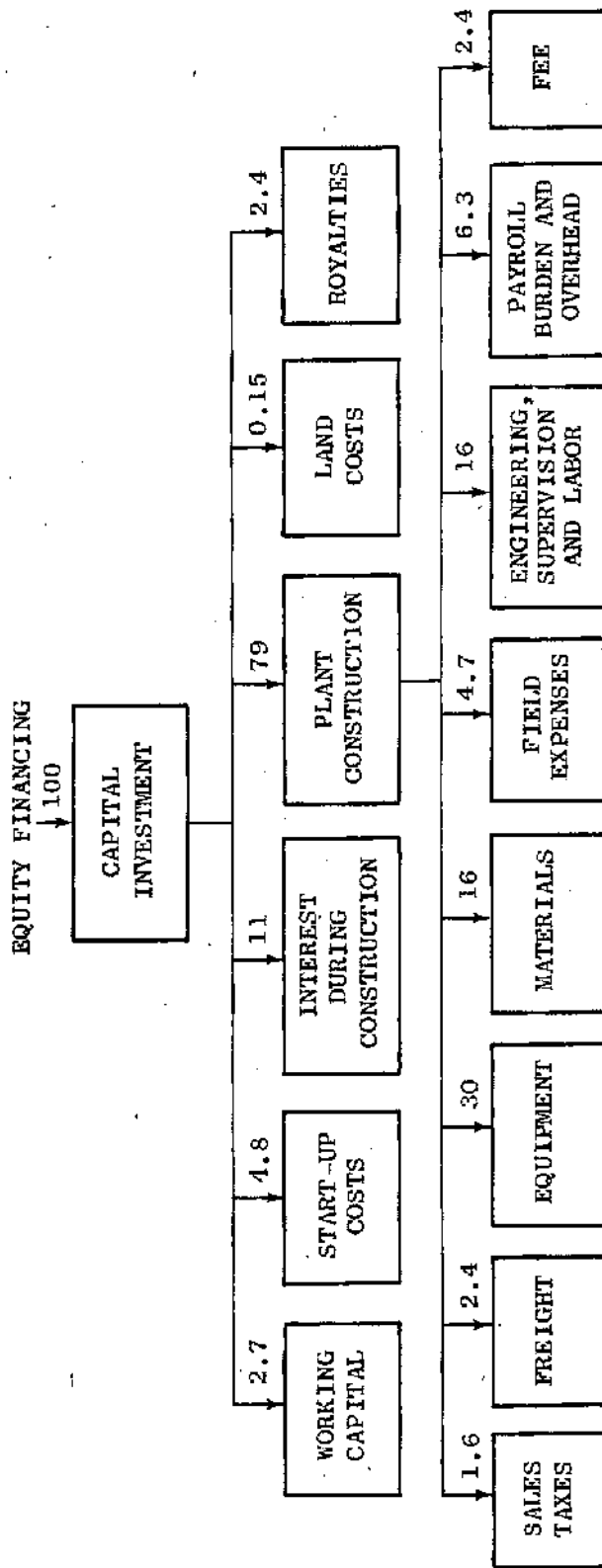


FIGURE 4-12. CAPITAL INVESTMENT DOLLAR FLOWS FOR H-COAL LIQUEFACTION PLANT

labor (including engineering and supervision) which contributes over 20 percent of the cost if payroll burden (fringe benefits) is counted.

In the operation of a coal liquefaction plant, the single largest expense item is the coal. The operation is not particularly labor intensive. On the other hand, the coal mining operation is considerably more labor intensive, with salaries and associated benefits consuming 30 percent of the mine revenue.

As shown in Figure 4-13, capital recovery and profit--the sum of depreciation, net income, and income taxes--contribute an overwhelming amount to the price of syncrude--nearly two-thirds if the operation of both mine and liquefaction plant are counted. These figures are proportional to the capital cost of the plant and mine so that in the long run it is mainly the initial capital investment in synthetic fuel facilities that will determine the viability of the industry. This is true, of course, not only because of the effect of capital costs on product prices, but also because of the difficulty in marshalling sufficient capital for the development of the industry.

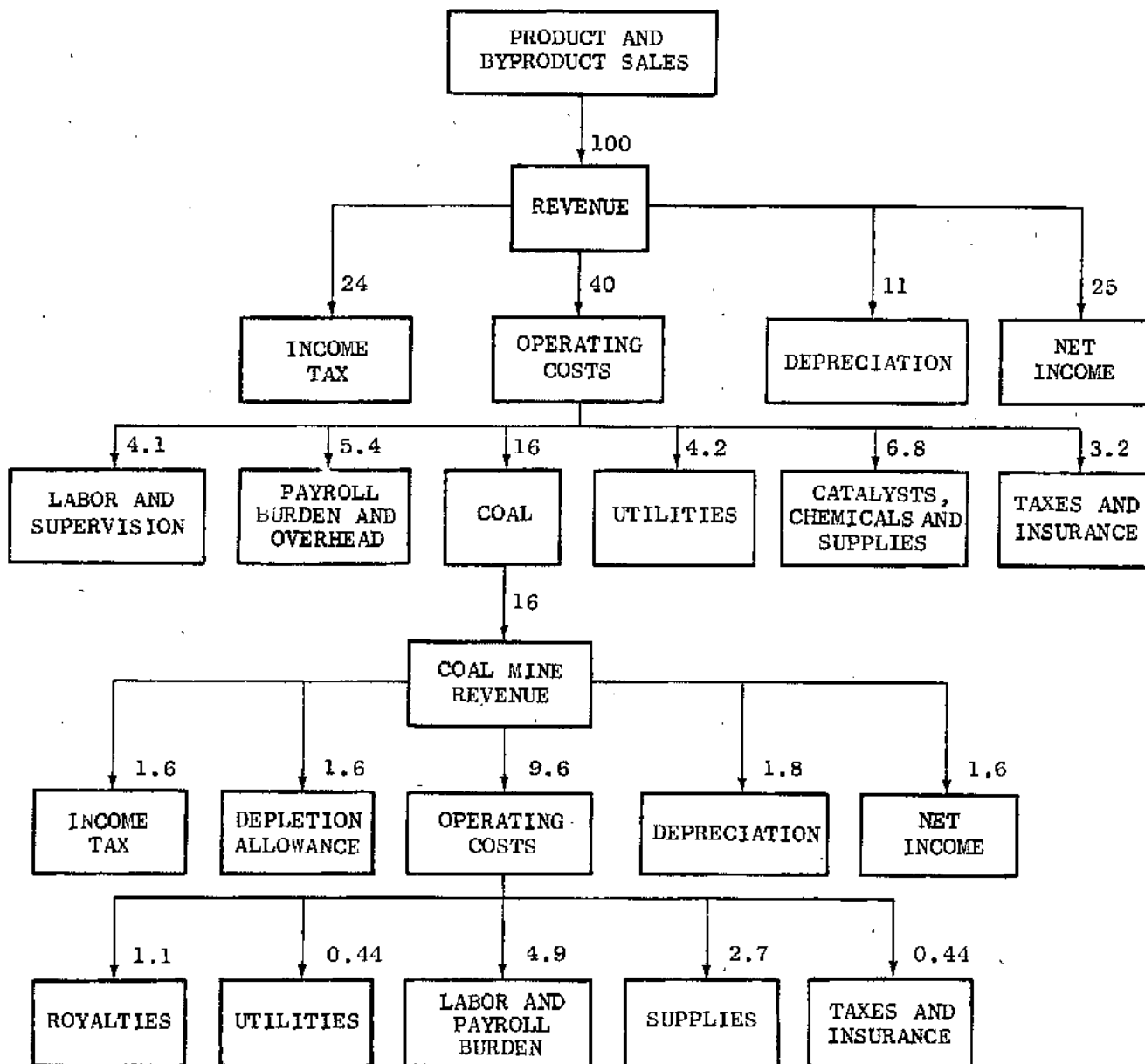


FIGURE 4-13. OPERATING DOLLAR FLOWS FOR WESTERN COAL LIQUEFACTION VIA THE H-COAL PROCESS (BASED ON 15% DCF RETURN ON INVESTMENT AND COST OF COAL AT \$3.00/TON)

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