WATER DEMANDS FOR EXPANDING ENERGY DEVELOPMENT

GEOLOGICAL SURVEY CIRCULAR 703

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By George H. Davis and Leonard A. Wood

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1974

United States Department of the Interior
ROGERS C. B. MORTON, *Secretary*

Geological Survey
V. E. McKelvey, *Director*

First printing 1974
Second printing 1974

Free on application to the U.S. Geological Survey, National Center, Reston, Va. 22092

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Length

1 inch=25.4 millimeters (mm)
1 mile=1.60934 kilometer (km)

Area

1 acre=0.4047 hectares (ha)

Volume

1 gallon=0.0037845 cubic meters (m^3)
1 barrel (42 gal)=0.15899 cubic meters (m^3)
1 acre-foot=1,233 cubic meters (m^3)
1 cubic foot=0.0283 cubic meters (m^3)

Mass

1 ton (2,000 lbs)=0.907185 metric tons (t)

Flow

1 gallon per minute=0.0037854 cubic meters per minute (m^3/min)

Temperature

°C=5/9 (°F-32)

Pressure

1 pound per square inch=0.0703 kilograms per square centimeter (kg/cm^2)

Energy

1 British thermal unit (Btu)=0.252 kilogram calories
1 British thermal unit (Btu)=0.000293 kilowatt hours (kwhr)

Energy – Volume

1 British thermal unit per cubic foot (gas)=0.01035 kilowatt hours per cubic meter (kwhr/m^3)
1 British thermal unit per cubic foot (gas)=8.9046 kilogram calories per cubic meter (kcal/m^3)
1 gallon (water) per kilowatt hour=0.0283 cubic meters per kilowatt hour (m^3/kwhr)
1 gallon (water) per million British thermal units=0.01292 liters per kilowatt hour (l/kwhr)

Water Demands for Expanding Energy Development

By George H. Davis *and* Leonard A. Wood

ABSTRACT

Water is used in producing energy for mining and reclamation of mined lands, onsite processing, transportation, refining, and conversion of fuels to other forms of energy. In the East, South, Midwest, and along the seacoasts, most water problems are related to pollution rather than to water supply. West of about the 100th meridian, however, runoff is generally less than potential diversions, and energy industries must compete with other water users. Water demands for extraction of coal, oil shale, uranium, and oil and gas are modest, although large quantities of water are used in secondary recovery operations for oil. The only significant use of water for energy transportation, aside from in-stream navigation use, is for slurry lines. Substantial quantities of water are required in the retorting and the disposal of spent oil shale. The conversion of coal to synthetic gas or oil or to electric power and the generation of electric power with nuclear energy require large quantities of water, mostly for cooling.

Withdrawals for cooling of thermal-electric plants is by far the largest category of water use in energy industry, totaling about 170 billion gallons (644 million m^3) per day in 1970.

Water availability will dictate the location and design of energy-conversion facilities, especially in water deficient areas of the West.

WATER DEMANDS FOR EXPANDING ENERGY DEVELOPMENT

Much concern has been expressed recently as to whether water supplies will be sufficient to support accelerated energy development foreseen in Operation Independence. Taking the Nation as a whole, sufficient water is available for energy growth, but locally, as in arid parts of the Colorado River Basin, limited water supplies will dictate economies in water use and affect plant siting. As Young and Thompson (1973) point out with respect to electric-power generation, the term "water requirements" is misleading because demand for water for cooling is sensitive to price of water and thus is quite flexible rather than inflexible or fixed as implied by the word "requirement." Much the same is true of other energy-conversion systems.

Water is used in many aspects of energy production including mining and reclamation of mined lands, onsite processing, transportation, refining, and conversion to other forms of energy. In the East, South, Midwest, and along the seacoasts, water supplies are generally adequate for energy industries; most water problems in those regions are related to pollution rather than to supply. West of about the 100th meridian, however, runoff is generally less than potential diversions, and energy industries must compete with other users for the limited available water supplies. Water is especially short in areas having less than 10 inches (254 mm) mean annual rainfall, generally not enough for establishing vegetation without irrigation.

EXTRACTION

The principal categories of extraction comprise coal mining, oil and gas production, uranium mining, and oil-shale mining.

Coal-mining water demands are modest, and include water for dust control, fire protection, and coal washing. These needs are nominal and quality is not a limiting factor in any of them. In areas where natural precipitation is less than 10 inches (254 mm), an additional water demand exists for establishing vegetation on disturbed areas following surface mining. The amount of water needed is related to natural precipitation and area disturbed and thus is highly variable. In most arid areas, application of 0.5–0.75 acre-ft/acre (152–229 mm) should be sufficient to establish seedlings that would survive without further water application (National

Academy of Sciences-National Academy of Engineering, 1973). This water must be of reasonably good quality to encourage plant growth (preferably less than 2,000 mg/l dissolved-solids concentration). Even now, water demands for revegetation pose serious problems, particularly in the Four Corners area of Arizona, New Mexico, Utah, and Colorado.

Oil and gas extraction generally involves only nominal water demands for drilling, some 37,000 acre-ft (45.6 million m^3) of freshwater annually nationwide. However, where water flooding is employed as a secondary recovery technique, somewhat larger quantities of water are needed to drive oil toward recovery wells. Where saltwater is available for this use (that is, formation waters produced with oil), it is generally preferable to freshwater, but in some fields freshwater is used for water flooding. Magnitude of use is highly variable and depends upon formation characteristics, but generally is modest compared to other energy-industry demands. Buttermore (1966, p. 6–8) calculated that the total demand for secondary recovery nationwide in 1962 was about 560,000 acre-ft (690 million m^3) of which 157,000 acre-ft (194 million m^3) was freshwater. The remainder was saline water, most of which was produced with oil.

Uranium mining involves water demands for dust control, ore beneficiation, and revegetation similar to coal mining, but tonnage handled is much less than for coal; thus, the total water requirements are lower. As in coal mining, quality of the water generally is not critical for these uses. Where surface mining is practiced, water requirements for revegetation are comparable to those of coal mining.

The U.S. Atomic Energy Commission (1972, table S-3A) estimates that the area disturbed in surface mining of uranium, normalized for annual requirements of a typical 1,000 mw (megawatts, electric output) light-water reactor generating station, would be 17 acres (6.9 hectares). The water requirement for revegetation at that rate would be trivial even for great increases in nuclear generation. For a rough comparison, it is estimated that mining for comparable energy production by a typical coal-fired electric plant would result in about 10 times more land disturbance.

Oil-shale mining is expected to become a major industry in several parts of Colorado, Utah, and Wyoming underlain by the Green River Formation. Shale will be extracted by surface mining, underground mining, and perhaps as an adjunct to in situ underground retorting. Retorting of shale mined by surface or underground conventional methods will be done on or near the mining site, and large volumes of loosely compacted waste will be produced in the retorting process. Water demands for mining, processing, waste disposal, and land reclamation are intimately related. One of the largest demands is for compaction and revegetation of retort-plant waste which comprises some 40 percent of the total water use. The Department of the Interior's Final Environmental Impact Statement for the Prototype Oil Shale Leasing Program (U.S. Department of the Interior, 1973) estimates consumptive water demand of from 121,000 to 189,000 acre-ft (149 million to 233 million m^3) per year at a production rate of 1 million barrels (158,899 m^3) per day of shale oil, or from 2.5 to 4 volumes of water consumed per volume of oil produced.

TRANSPORT

The only significant use of water in energy transport, aside from in-stream navigation use, is for slurry lines. Slurry lines have been used for many years in the eastern coal districts, but one of the more recent installations is the slurry line extending from the Black Mesa coal mine in northeastern Arizona to the Mojave Power Plant on the Colorado River at the southern tip of Nevada 273 miles (440 km) away. A slurry line was adopted because the terrain made it economically attractive vis-a-vis rail transportation, the only other reasonable mode of conveyance. Another plant, the Navajo Power Plant (under construction) near Lake Powell is to be supplied from the same mine by a railroad built for that purpose. Water for the Mojave slurry lines is supplied by wells pumping some 3,200 acre-ft (3.9 million m^3) per year from a thick extensive sandstone aquifer that underlies Black Mesa. In this area, recharge from precipitation is negligibly small, and the pumped water is mainly withdrawn from storage. The power plant, rated at 1,500 mw, consumes about 23,000 acre-ft (28 million m^3) per year for cooling and other plant uses; thus, the water use for transport is only about one-sixth that of the plant consumption. At the plant the slurry water is separated from the coal and treated, and part is used in the plant water supply.

REFINING

Most energy fuels require some degree of refining before ultimate use. Some or parts of these processes are carried out at or near the site of extraction, that is, gas scrubbing, coal washing, oil-shale retorting, and uranium-ore concentration. In other instances, the raw material may be transported to industrial centers for all or part of the refining process as is the case with crude oil, solvent refining of coal, and uranium enrichment and reactor-fuel fabrication.

The energy fuels that involve a refining process distinct from both extraction and subsequent conversion or consumption are nuclear fuels and oil (including shale oil and synthetic oil from coal), and are described in the following section.

Water demands in the nuclear fuel cycle have been calculated by the Atomic Energy Commission (1972) on the basis of annual requirements of a typical 1,000-mw light-water reactor steam-electric plant operating 80 percent of the time. Of a total consumption of 163 million gallons (617 thousand m^3), 65 million gallons (246 thousand m^3), or about 40 percent, is assigned to the uranium-ore milling stage, almost entirely as evaporation from tailings ponds. The remaining consumption of water occurs mainly in evaporative cooling in the uranium enrichment plant, which is normalized to 90 million gallons (341 thousand m^3) annually for a 1,000-mw plant. The remaining 8 million gallons (30 thousand m^3) is assigned in about equal proportions to the production of uranium hexafluoride and reprocessing of used fuel elements. Not included in the above water consumption calculations is water consumed at power plants supplying electricity for the enrichment process. This annual power requirement is estimated at 310,000 mwhr (megawatt hours) that, if produced in a fossil-fuel plant, would indicate an evaporative requirement of roughly 160 million gallons (604 thousand m^3). To keep this demand in proper perspective, it should be remembered that the electrical power produced by the model 1,000-mw nuclear station annually (at 80 percent load factor) amounts to about 22 times the energy consumed to produce an annual fuel requirement for a 1,000-mw station (U.S. Atomic Energy Commission, 1972, p. D5).

Water demand for petroleum refining is highly variable, depending upon such factors as process employed, refinery design, and cost and availability of water. A sampling of refineries producing 30 percent of the petroleum products in the United States in 1955 (Otts, 1963, p. 299), indicated an average withdrawal demand of 468 gallons (1.76 m^3) of water per barrel (42 gallons or 0.159 m^3) of crude-oil input. Some 90 percent of this water was used in cooling processes at various stages of refining. A more meaningful measure of water demand, however, is the consumptive use, which averaged 39 gallons (0.14 m^3) of water per barrel of crude-oil input, or roughly 1 volume of water consumed per 1 volume of crude. Of this consumption, 71 percent was accounted for in evaporative cooling, 26 percent as boiler feed water, and the remaining 3 percent for sanitary and other in-plant uses.

CONVERSION

Conversion embraces the concept of changing an energy raw material into a more usable form of energy. Examples include burning of coal, gas, or oil to produce electricity, or converting energy of nuclear fission to electricity. Other examples include changing coal or oil into gas, a cleaner, more convenient fuel for space heating, or even changing coal into a form of oil for further refining. Much of the present emphasis on conversion seeks to use fuels abundant in the United States, such as coal and oil shale, to meet the present energy crisis without sacrificing air quality objectives. Generally, this involves processing near the site of extraction to produce a nonpolluting fuel which can be transported to a distant market. Alternatively, the coal can be used near the mine to produce electricity for transport to market.

The processes of particular interest in the present energy shortage are coal gasification, coal liquefaction, oil-shale retorting, use of geothermal energy for electric generation, and increased use of coal-burning plants and nuclear reactors for power generation. In each mode considerable flexibility is possible in plant design, process employed, and location of processing facilities with respect to site of extraction, source and use of water, and location of market. It is impractical, if not impossible, to assign rigid values of water use per unit of energy produced to all processes because of economic trade-offs, but ranges of water demand are useful for planning purposes. Moreover, in electric-power generation the need for high fuel efficiency generally dictates water demand within close limits; accordingly, water demand for electric generation can be estimated reasonably well.

STEAM-ELECTRIC GENERATION

The most efficient method of meeting large steady electric demand (base load) is by use of a steam turbine to drive a generator (fig. 1). The steam may be produced from geothermal wells, by burning coal, oil, or gas, or by heat given off by nuclear fission. The power output of a steam turbine is greatly increased by reducing the pressure on the outlet side of the turbine. This is done by use of a condenser, which lowers the temperature of the exhaust steam, causing condensation and thus significantly reducing the pressure. The cooling capacity needed for the condensation phase accounts for the greatest consumption of water in the entire energy-production process.

Various systems are used for condenser cooling— once-through circulation, cooling ponds, sprayers, wet cooling towers, dry cooling towers, and combinations of the preceding systems. Once-through cooling commonly

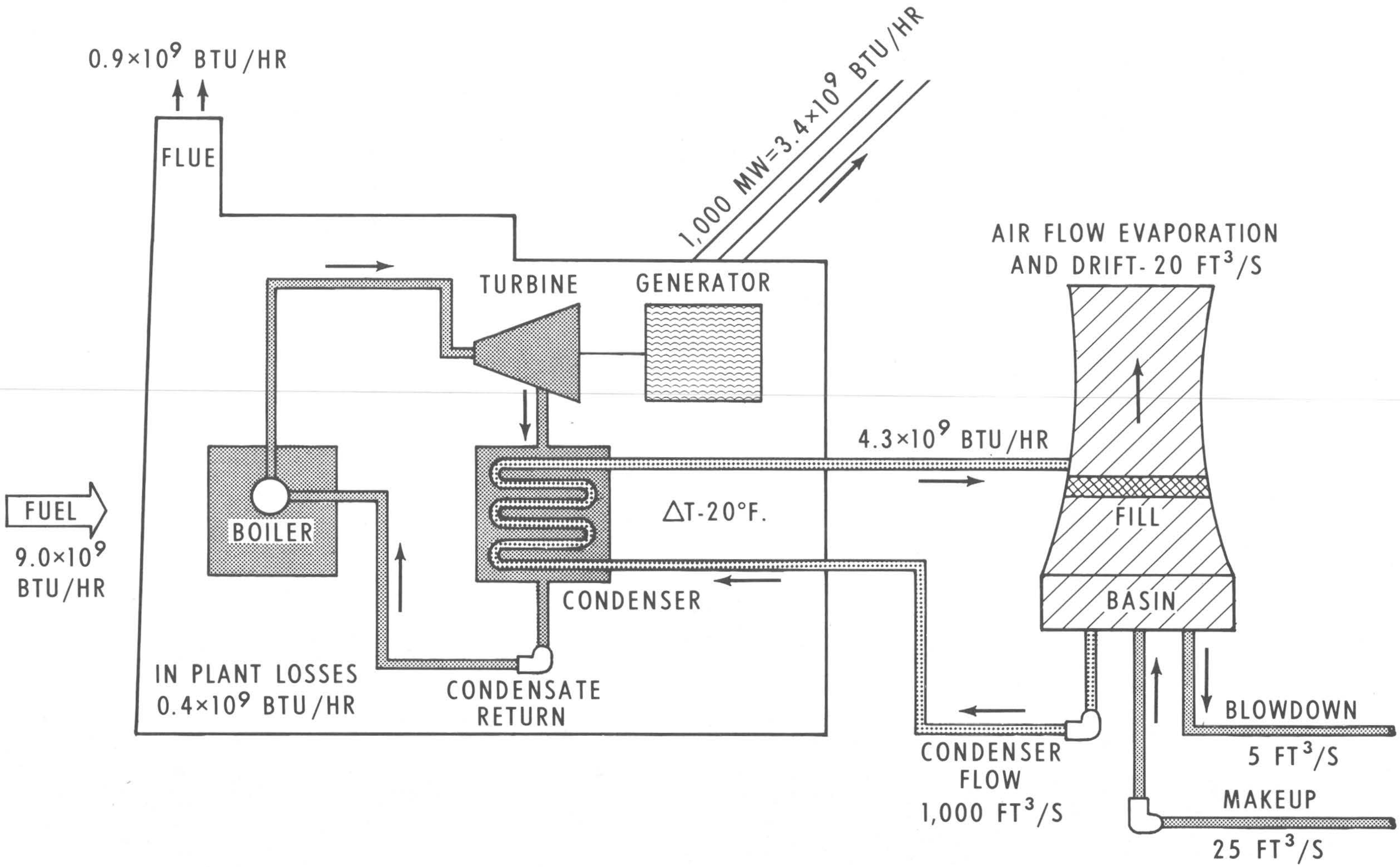

Figure 1.—Heat balance diagram of typical 1,000-mw fossil-fueled thermal-electric plant.

is used where the plant is near an abundant source of water, such as the sea, a large lake, or a large river. As the name suggests, water from an infinite (for practical purposes) source is circulated through the condenser and carries the waste heat away to a point of discharge elsewhere on the water body. The heat is dissipated through increased evaporation from the slightly warmer water body and by conduction to the atmosphere.

Where no large water body is available, a natural or artificial pond may be used for storage and as a heat sink. In this mode, heat is dissipated mainly through surface evaporation from the warmed pond. Where the cooling capacity of the pond is inadequate, sprayers may be used to increase evaporation. Sprayers may also be used together with canals in once-through systems to reduce the impact of heated discharge on fish and other aquatic biota.

Where water is in short supply or discharge of heated water is unacceptable, and ponds are not practicable, cooling towers generally are employed. In wet cooling towers some of the warm water evaporates through contact with an air draft, either naturally induced or driven by fans, thus cooling the remaining water. Dry cooling towers dissipate heat directly to an air draft in a fashion similar to an automobile radiator. Although dry cooling towers are effective in reducing water consumption, their capital cost greatly exceeds that of wet cooling processes, and their use results in a loss of thermal efficiency as well. They find their greatest use in cold climates and to date have seen little use in the United States in steam-electric power generation.

Various combinations of these cooling techniques are applied to achieve maximum economy in combination with acceptable environmental effects. The cooling system is quite independent of the type of fuel; rather, it depends mainly on local factors such as availability of water, terrain features, and potential environmental impacts.

The cooling demand, regardless of how the waste heat is dissipated, is governed by the thermal efficiency of the plant, which is expressed as electrical output as a percentage of energy input. Maximum thermal efficiency is achieved by use of very high steam temperatures and inlet pressures. In the newer modern fossil-fueled plants, for example, thermal efficiency of 40 percent is achieved with inlet temperatures as high as 1,000°F (538°C) and pressures of 3,500 psi (246 kg per cm^2).

The evaporative demand of a fossil-fueled steam-electric generator may be expressed as (Cootner and Löf, 1965, p. 74):

$$\text{Gallons evaporated/kwhr} = 0.39\ (aH - 1),$$

where H is overall thermal efficiency, and a is boiler-furnace efficiency (usually about 0.9). The boiler-furnace efficiency, normally about 90 percent, represents the fuel energy that is not lost in flue gases. The heat energy lost in flue gases is about 10 percent. An additional 5 percent of the input is dissipated to the atmosphere through in-plant losses and uses. Thus about 85 percent of the input energy is used in driving the turbines or is disposed of as thermal waste in the form of warmed water.

Present nuclear plants are less efficient than fossil-fueled plants because of safety restrictions on maximum steam temperatures, and nuclear plants dissipate waste heat almost entirely to cooling water because no flue gases are emitted. A typical nuclear plant of 31-percent thermal efficiency releases about 50 percent more heat to cooling water than a fossil-fueled plant of comparable power output.

With respect to consumption of water, geothermal plants are the least efficient form of steam-electric generation. Because of inherent low temperature and pressure of natural steam used, the geothermal plants at the Geysers Field, Calif., for example, have an overall thermal efficiency of only about 14 percent, the remaining energy being dissipated by evaporative cooling with comparably greater water consumption. The source of cooling water is the condensed geothermal steam, about 80 percent being consumed in the cooling process. The remaining 20 percent, which is of poor quality, is injected into the producing formation (Finney, 1972).

The rapid growth of electric consumption in the United States in recent decades is reflected in increased water withdrawals for thermal-electric power. Surveys of water use compiled at 5-year intervals by the U.S. Geological Survey (fig. 2) show that by 1965 withdrawals by thermal-electric plants exceeded irrigation withdrawals, to become the leading class of withdrawal use in the Nation. This reflects not only the rapid growth of electric demand but also the fact that most plants employed once-through systems for condenser cooling. Concern over thermal pollution of water bodies, however, has resulted in a trend to greater use of closed evaporative systems employing cooling towers, ponds, or sprayers. Thus the rapid growth of thermal-electric withdrawal should level off considerably in coming decades. This effect, coupled with the influence of improvements in thermal efficiency, can be observed in figure 3. Nonetheless, consumptive use by thermal-electric generation will continue to grow and will increase relative to withdrawals. This seeming paradox is due to the fact that closed cooling systems have a greater evaporation loss relative to once-through systems as well as additional water consumption not applicable to once-through systems. The principal water economies of once-through systems are attributable to a greater proportion of conductive heat

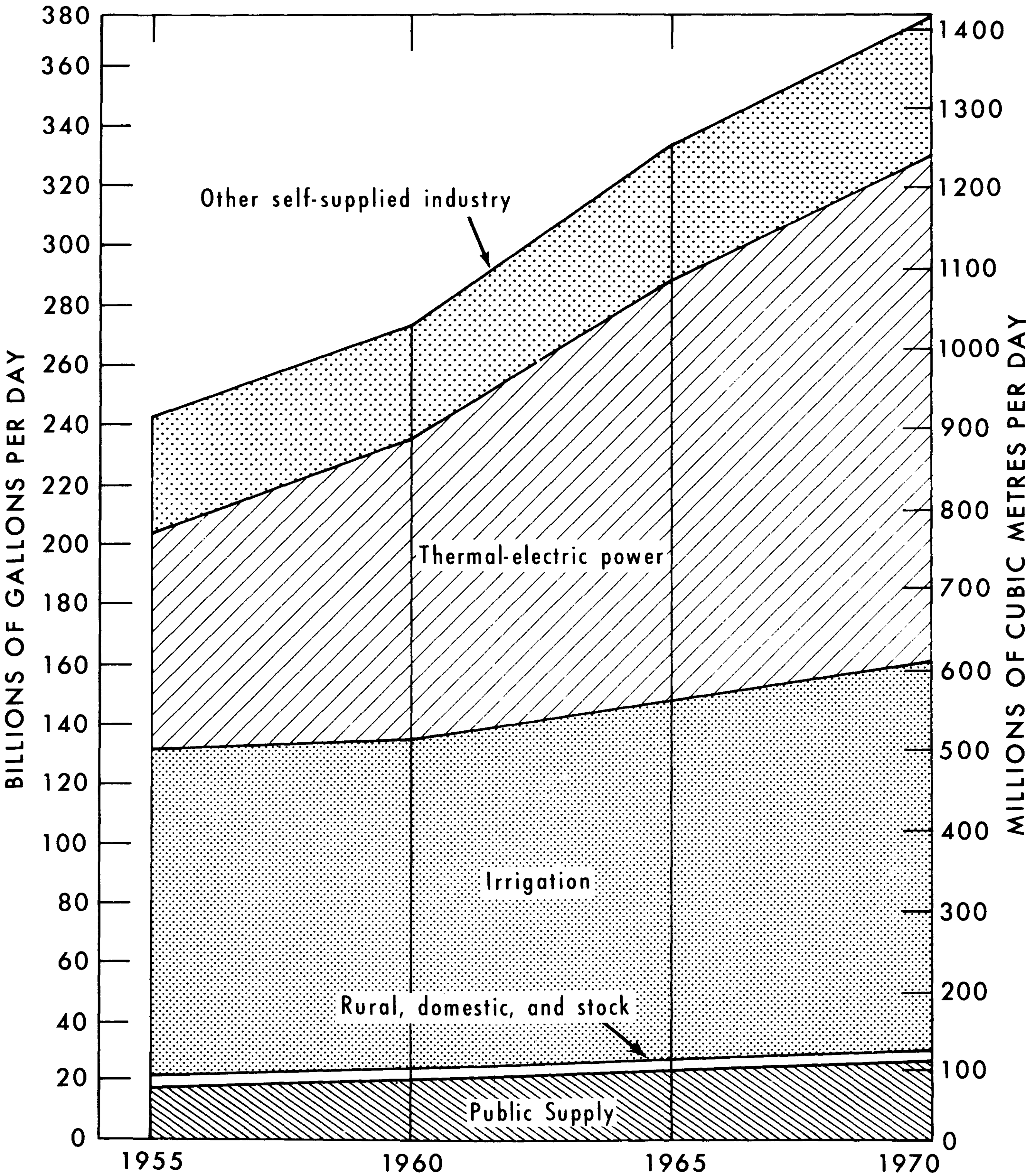

Figure 2.—Withdrawal of water for major uses.

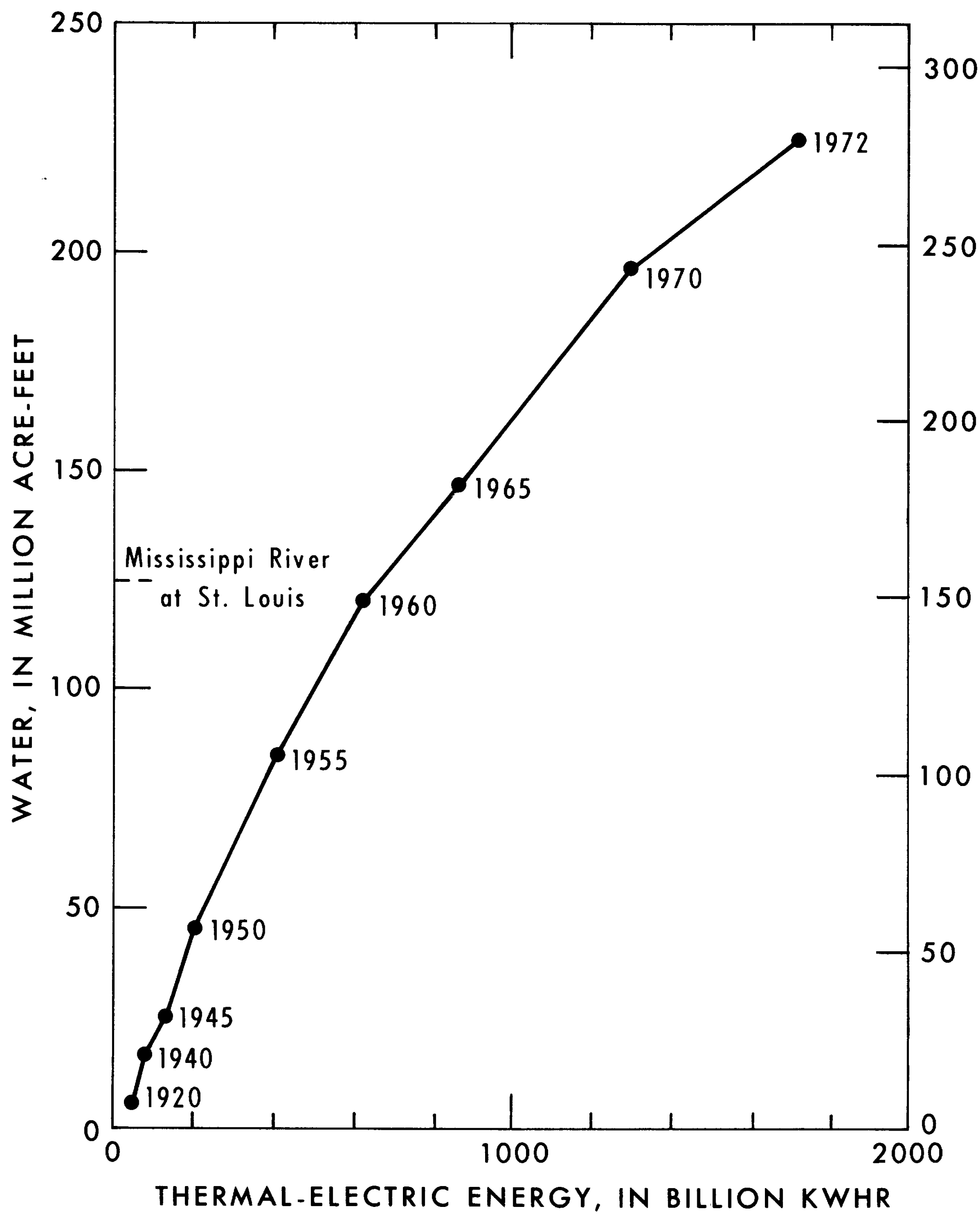

Figure 3.—Annual withdrawals of water for thermal-electric power generation in the United States, 1920–72.

loss vis-a-vis evaporative loss from natural water bodies than from high temperature ponds or cooling towers. Cooling towers, moreover, waste a small proportion of their water supply as drift (small droplets of water escaping the tower without contributing to the evaporation process) and, in most cases, have additional consumption chargeable to "blowdown," disposal of poor-quality waste water that cannot be returned to the natural system. A thorough examination of the question of unit consumption of water in power-plant cooling is not warranted here, but expert opinion ranges from Cootner and Löf's (1965, p. 58) observation that water loss from a receiving stream in once-through cooling is nearly the same as in a recycle system, to an estimate by the Water Resources Council (1968, p. 4–3–2) that cooling towers have consumptive use roughly twice that of once-through systems. These differences stem from a general lack of information on evaporation from open water bodies. Although makeup water for recycling systems can be measured directly with relative ease, precise measurements of evaporation from open water bodies is very difficult. Moreover, where water is in abundant supply, as where once-through cooling is employed, the question of consumptive use is rather academic. Furthermore, much of the consumption of water associated with once-through systems is of saline water, mainly seawater, or from the Great Lakes where such consumption is a small consideration. Indeed, in 1970 withdrawals of saline water (Murray and Reeves, 1972, p. 7) comprised 28 percent of the total withdrawals for thermal-electric power. This figure itself probably is disproportionately low because many power plants drawing water from estuaries or downstream of competing users are classed in Federal Power Commission reports as freshwater withdrawals, although this water would soon waste to the sea if not used in this way.

Consumptive use becomes a serious consideration only where it is in competition with other socially beneficial water consumption. Thus, the main focus on consumptive use by electric-power plants and other energy industries is in the West where freshwater has high value for alternative uses.

The table below shows the average evaporative requirement of modern thermal-electric plants by various classes. In each instance, most efficient design is assumed. As noted earlier, water consumed per kwhr (kilowatt hour) is governed mainly by thermal efficiency, although the type of cooling system employed may also affect consumption to some degree. Little future improvement can be expected in fossil-fueled plants, which already are crowding theoretical thermal-efficiency limits. Similarly, little improvement can be expected with geothermal systems, which are constrained by the relatively low temperature and pressure of the natural steam sources tapped. Nuclear generation, however, has a potential for significant improvements in thermal efficiency and water requirements. High-temperature gas-cooled reactors (HTGR) now coming into use are expected to have an overall thermal efficiency of 40 percent, as are breeder reactors now being planned.

The other principal types of energy conversion of concern with respect to water consumption are conversion of oil shale to oil, coal to gas (coal gasification), and coal to oil (coal liquefaction).

OIL SHALE

Oil shale may be mined either in open pit or in underground mines and then retorted on the surface. Below-ground retorting experiments have been tried using several methods, but until recently in situ processes were not claimed to be competitive with mining and above-ground plants. However, late in 1973 one firm announced high recoveries of oil and lower cost for a combination of underground mining and in situ retorting in which 25–30 percent of the shale is mined and retorted on the surface. The remaining shale is fractured, collapsed into the mined-out void, and retorted where it lies. Although a commercial-sized plant of any kind remains to be built, technology may change rapidly during the next decade.

The operators of the two Federal Prototype Leases in Colorado probably will use above-ground processing. Pilot plants have tested many methods of mining and above-ground and in situ retorting, but none of the processes has been done on a commercial scale. The pilot mines and plants have handled a few tons of shale up to as much as 1,000 or more tons (907 metric tons) per day; the Department of Interior's Prototype Lease

Consumptive demand of water-cooled thermal-electric plants

Type[1]	Heat rate (Btu/kwhr)	Thermal efficiency (percent)	Atmospheric dissipation (Btu/kwhr)	Percent	Evaporative dissipation (Btu/kwhr)	Gallons consumed per kwhr
Fossil fueled	9,000	38	1,350	15	4,230	0.5
Nuclear	10,700	32	535	5	6,741	.8
Geothermal	24,000	14	1,200	5	19,440	1.8

[1] Most efficient design. At normal operating rates (80 percent load factor), the water consumption of these types of plants is approximately 15 acre-ft/year/mw capacity for fossil-fueled, 22-acre-ft/year/mw for nuclear, and 48 acre-ft/year/mw for geothermal plants.

Program envisions mining more than 50,000 tons (45,359 metric tons) a day from an underground mine and more than 100,000 tons (90,718 metric tons) a day from an open pit mine.

The oil shale must be heated to about 900° F (482° C) to convert the solid organic material in the oil shale to gas and oil vapors. The three most advanced retorts developed for heating oil shale are the Union Oil Retort, the Gas-Combustion Retort, and the TOSCO Retort. The first two maintain controlled combustion of shale within the retorts, but the TOSCO process uses heated ceramic balls with finely crushed shale in a rotating cylindrical drum. The shale oil produced by all these retorts is a low-gravity, moderate-sulfur, high-nitrogen oil that has a high pour point and is rather viscous. The shale oil probably will be upgraded by hydrocracking, or some other process, to reduce its viscosity and make it suitable for pipeline transport to a refinery located where more abundant water supplies are available.

The largest use of water in the production of shale oil is for disposal of the dry spent shale after it has been crushed and roasted to extract the hydrocarbons. The water is used for dust control while the spent shale is being transported (possibly as a slurry), but its most important use is in compacting and stabilizing the disposal pile. Spent shale that contains 20–30 percent water will set up like a weak portland cement. In fact, if the slope of the face of the pile is 18° or less, the limiting parameter on the height to which a box canyon can be filled is the load-bearing strength of the alluvial floor of the canyon. (U.S. Department of the Interior, 1973, v. I, p. I-42–I-43.)

Estimates of the most likely amounts of water consumed by an oil-shale mine, retort, and upgrading plant of 100,000 barrels (15,899 m^3) per day capacity of shale oil range from about 7,500 gpm (gallons per minute) (28 m^3 per minute or 12,150 acre-ft per year) to about 11,400 gpm (43 m^3 per minute or 18,420 acre-ft per year). Associated urban uses would increase the estimated range to 8,350–12,400 gpm (31.6–46.9 m^3 per minute or 13,400–20,100 acre-ft per year). The average of the high and low estimates for each use is (in gallons per minute):

Processed shale disposal	4,500
Shale oil upgrading	2,300
Power requirements	1,100
Retorting	800
Mining and crushing	550
Revegetation	220
Sanitary use	30
Associated urban	900
Total	10,400

A series of mines and plants will probably be required to produce 1 million barrels (158,899 m^3) per day of shale oil. The Final Environmental Statement for the Prototype Oil Shale Leasing Program assumed a mix of 17 mines and plants including 11 underground, 2 open pit, and 4 in situ mines would be needed for 1 million bpd (barrels per day). Based on the assumed technology mix, the Final Environmental Statement estimated that 121,000–189,000 acre-ft (149 million–233 million m^3) per year of water would be consumed in producing 1 million barrels (158,899 m^3) per day of shale oil (table 1).

The source of water for oil-shale developments must be the Upper Colorado River Basin, although the initial mines on the Prototype Leases in the Piceance Basin in Colorado may develop enough ground water to satisfy all their water needs. A long-term, large-scale oil-shale industry in Colorado, Utah, and Wyoming will depend on diversion of stored surface water from the Colorado River Basin. Table 2 shows the status of water use in the Upper Basin. Water is available for an industry of more than 1 million bpd of shale oil if water not committed to other uses is made available to oil-shale developments. A much larger industry (several million barrels per day) would require purchase and transfer of water rights from agriculture to industry.

COAL GASIFICATION

As there are no modern-design coal-gasification plants of commercial scale in the United States, estimates of water demand must be based on research operations, foreign experience, and design data of projected plants. One of the chief sources of information is an engineering report of the El Paso Natural Gas Co. Burnham I Coal Gasification Complex planned for a site near Farmington, N. Mex. (Stearns-Roger Inc., 1973). The processes being considered for that complex, designed to produce 288 million scf (standard cubic feet) per day (8.15 million m^3 per day) of pipeline-quality gas (954 Btu per ft^3 or 9.87 kwhr per m^3), include coal gasification by the Lurgi process followed by shift conversion, gas cooling, gas purification, and methane synthesis. In simple terms, the Lurgi process produces a low Btu product (about 400 Btu per ft^3 or 4.14 kwhr per m^3) which is upgraded by methane synthesis to pipeline quality. In various stages water is consumed in the chemical reaction; cooling requirements contribute additionally to the overall water demand. Because water is scarce in the region of the plant, recycling will be used to the maximum, and air cooling will be used insofar as practicable. The water input will consist of about 7,000 gpm (26 m^3 per minute) diverted from the San

Table 1.—*Contingent water consumption forecasts, in acre-ft per year, for a 1-million-barrel-per-day shale-oil industry*

[After table III-6, vol. 1, U.S. Department of the Interior, 1973]

	Lower range	Most likely	Upper range
Process requirements			
Mining and crushing	6,000	6,000– 8,000	8,000
Retorting	9,000	9,000– 12,000	12,000
Shale oil upgrading	17,000–21,000	29,000– 44,000	44,000
Processed shale disposal	24,000	47,000– 70,000	84,000
Power requirements	10,000	15,000– 23,000	37,000– 45,000
Revegetation	0	0– 12,000	18,000
Sanitary use	1,000	1,000– 1,000	1,000
Subtotal	67,000–71,000	107,000–170,000	204,000–212,000
Associated urban			
Domestic use	9,000–11,000	13,000– 17,000	17,000
Domestic power	0	1,000– 2,000	2,000
Subtotal	9,000–11,000	14,000– 19,000	19,000
TOTAL	76,000–82,000	121,000–189,000	223,000–231,000
Ancillary development			
Nahcolite/dawsonite	....	....	[1] 32,000– 64,000
GRAND TOTAL	76,000–82,000	121,000–189,000	255,000–295,000

[1] Estimates based on one or two plants; however, future markets may support three plants (see Chapter I, Section C-1-f). With three plants, the upper limit would approximate 327,000 acre-ft of water per year. Development above the 1-million-barrel-per-day level, including a commitment to develop the Naval Oil Shale Reserves, would require additional water.

Table 2.—*Present and future water use, in thousands of acre-ft per year, in the Upper Colorado River Basin*

[After table II-4, vol. 1, U.S. Department of the Interior, 1973]

Use	Colorado	Utah	Wyoming	Total
Allocated share of 5,750,000 acre-ft[1]	2,976	1,322	805	5,103
1970 use	-1,788	-684	-304	-2,776
Committed future use	-955	-397	-392	-1,744
Evaporation from storage units	-342	-152	-92	-586
Credit for water salvage	+121	+18	+31	+170
Not identified as to use	12	107	48	167
Committed future use that could be made available for oil shale	[2] 155	....	[3] 19	174
Total potential water that could be made available for depletion for oil-shale development[4]	167	107	67	341

[1] Arizona received the right to the consumptive use of the first 50,000 acre-ft per year.

[2] From the existing Green Mountain and Ruedi Reservoirs and the authorized West Divide Project.

[3] From the existing Fontenelle Reservoir—Seedskadee Project.

[4] This includes water not presently identified for a particular use, plus water from authorized projects committed to oil-shale development and water from existing reservoirs not presently committed to a particular use. Additional water can be made available if the States permit the industry to purchase some of the water rights from those presently using water and if the use category is changed from some of the future commitments.

Juan River plus 765 gpm (2.89 m^3 per minute) of moisture in the coal input, and 630 gpm (2.38 m^3 per minute) produced by the methane-synthesis reaction. Of this total input, some 2,200 gpm (8.3 m^3 per minute) will react to form gas, 1,300 gpm (4.9 m^3 per minute) will be piped to the coal mine and other offsite users, 900 gpm (3.4 m^3 per minute) will evaporate from waste ponds, 190 gpm (0.72 m^3 per minute) will leave as wet ash, 2,965 gpm (11.2 m^3 per minute) will escape in the cooling system, and the remaining 840 gpm (3.2 m^3 per minute) is accounted for in numerous small plant discharges. This represents an extreme case of water conservation as the plant is engineered so that only 15 percent of gross cooling requirements is met by evaporative cooling. In other areas and under other conditions water consumption might be considerably higher. In terms of annual consumption at an assumed load factor of 91 percent, the above estimates indicate total water consumption of 14,000 acre-ft (17 million m^3) per year of which about 2,500 (3 million m^3) is supplied to the mine and other offsite uses, leaving a consumptive demand for the plant of about 11,500 acre-ft (14 million m^3) per year. Of the total consumption of 14,000 acre-ft (17 million m^3) per year, 11,700 acre-ft (14 million m^3) per year is supplied by imported water, 1,300 acre-ft (1.6 million m^3) per year is moisture contained in the input coal, and the remaining 1,000 acre-ft (1.2 million m^3) per year is produced in the methane-synthesis reaction.

The Synthetic Gas-Coal Task Force (1973, p. XII–3) calculated substantially higher make-up water demands for typical coal-gasification plants. The following table summarizes their estimates of the annual water requirements of a typical 250 billion Btu per day ($\simeq$ 250 million scf per day or 7 million m^3 per day) plant as follows:

It was assumed in the first instance that the above plants would be totally water cooled; the different rates of make-up reflect different requirements for blowdown which depends upon the quality of input water. The 3-percent rate would apply to high-quality supply water while the 7-percent rate would apply to brackish or highly turbid supplies. The lower line of the table estimates water demand for in-plant use based on partial air cooling; the lower ranges of these estimates are comparable to the design estimates for the Burnham Complex.

To summarize, water consumption in coal gasification plants producing pipeline gas of 250 million scf per day (7 million m^3 per day) capacity can be expected to range from about 10,000 acre-ft (12 million m^3) per year where water is at a premium to 45,000 acre-ft (55 million m^3) per year where abundant but poor-quality water is used for cooling. The principal differences are in evaporative cooling requirement and relate to the extent to which air cooling is employed and greater waste-water disposal where input water is of low quality.

Production of low Btu gas for power-plant consumption onsite rather than high Btu pipeline-quality gas is considered feasible in many situations. This can be accomplished in essentially the way planned at the Burnham Complex except that the methane-synthesis process is omitted. As the methane synthesis does not play a major role in water consumption, it is believed that this alternative mode of gas production would have little bearing on consumptive demand for comparable Btu outputs.

COAL LIQUEFACTION

Estimation of unit values of water consumption in producing oil from coal is tenuous at best because no

Make-up rate, in percentage of cooling water circulation

	Bituminous and subbituminous			Lignite		
	3	5	7	3	5	7
Process water, gpm	1,742	1,742	1,742	1,705	1,705	1,705
Boiler make-up, gpm	396	396	396	359	359	359
Cooling make-up, gpm	12,107	20,178	28,249	10,096	16,828	23,559
Total, gpm	14,245	22,316	30,387	12,160	18,892	25,623
Total, acre-ft per year at 90 percent load factor	20,714	32,451	44,187	17,682	27,472	37,259
Minimal demand assuming partial air cooling, acre-ft per year at 90 percent load factor	10,358	16,225	22,094	8,845	13,682	16,630

commercial-scale operations exist in the United States and none of several possible processes has been shown to be competitive with alternate fuels. Among processes under consideration are the following: Consol, solvent refining, H-Coal, and COED (Hottel and Howard, 1971, p. 161–182). Unit water-consumption estimates range from as little as 0.2 acre-ft (247 m^3) annually per bpd of synthetic-oil output to as much as 1.3 acre-ft (1,600 m^3) per year per bpd capacity. The National Petroleum Council (1973) adopted a unit consumptive-use value of 0.2 acre-ft (247 m^3) per year per bpd capacity. Until better data become available, this figure is probably as good an estimate as any other for planning purposes. The 0.2 acre-ft (247 m^3) per year per bpd capacity translates into 20,000 acre-ft (25 million m^3) per year for 100,000 barrels (16,000 m^3) per day of oil.

SUMMARY

Consumptive demand for water in various energy processes is summarized in table 3 and figure 4. Here consumption of water is compared on the basis of energy output in millions of Btu. The larger consumptive uses are associated with large cooling requirements, particularly in thermal-electric power generation, where under the best present design nearly two-thirds of the energy input is dissipated as waste heat, mostly through evaporation of water. It should be noted that figure 4 includes both refining and conversion processes; hence, at least some of the fuel produced in oil refining becomes energy input in fossil-fueled electric generation, and the uranium fuel processed becomes energy input in nuclear-electric generation. To this extent these water requirements are additive in the total fuel cycle; however, much of the fossil-fuel product goes to other energy uses such as transportation, space heating, and industrial uses, and is not additive. Conversely, much of the electric power is not used to produce heat (measured in Btu's) but is used to make light or, in electric motors, to perform work. The work output of electric motors relative to input of electric current generally exceeds 80 percent compared to the efficiencies of engines using fossil fuels which are generally less than 30 percent. The comparatively large consumption of energy and water in generating electricity is largely compensated for if the electricity is used to produce torque.

Table 3.— *Water consumption in refining processes*

Process and product	Consumptive use (gallons per 10^6 Btu)	Remarks
Uranium	14.34	Reactor fuel for 1,000 mw nuclear plant annualized for 80 percent load factor. Includes water consumed at power plants supplying electricity for processing.
Oil	6.7	Average for U.S. refineries (Otts, 1963).
Pipeline gas from coal	....	Lurgi gasification followed by methanation stage. Product about 1,000 Btu per standard cubic foot.
a. Water cooling (90 percent load factor).	72–158	Consumption varies with amount of blowdown required; directly proportional to mineral content and turbidity of cooling supply.
b. Partial air cooling (90 percent load factor).	37–79	Assumes 85 percent of cooling demand met by nonevaporative air cooling.
Synthetic oil from coal	31–200	General estimate based on several potential processes using pressure hydrogenation technology.
Oil from shale	19–29	Includes water requirement for spent shale disposal.

Average water consumption in electrical generation

[Most efficient design assumed; at 80 percent load factor]

Process	Water consumption, (gallons per kwhr)	Water consumption (gallons per 10^6 Btu of electrical output)
Fossil-fueled	0.5	146
Nuclear	.8	234
Geothermal	1.8	527

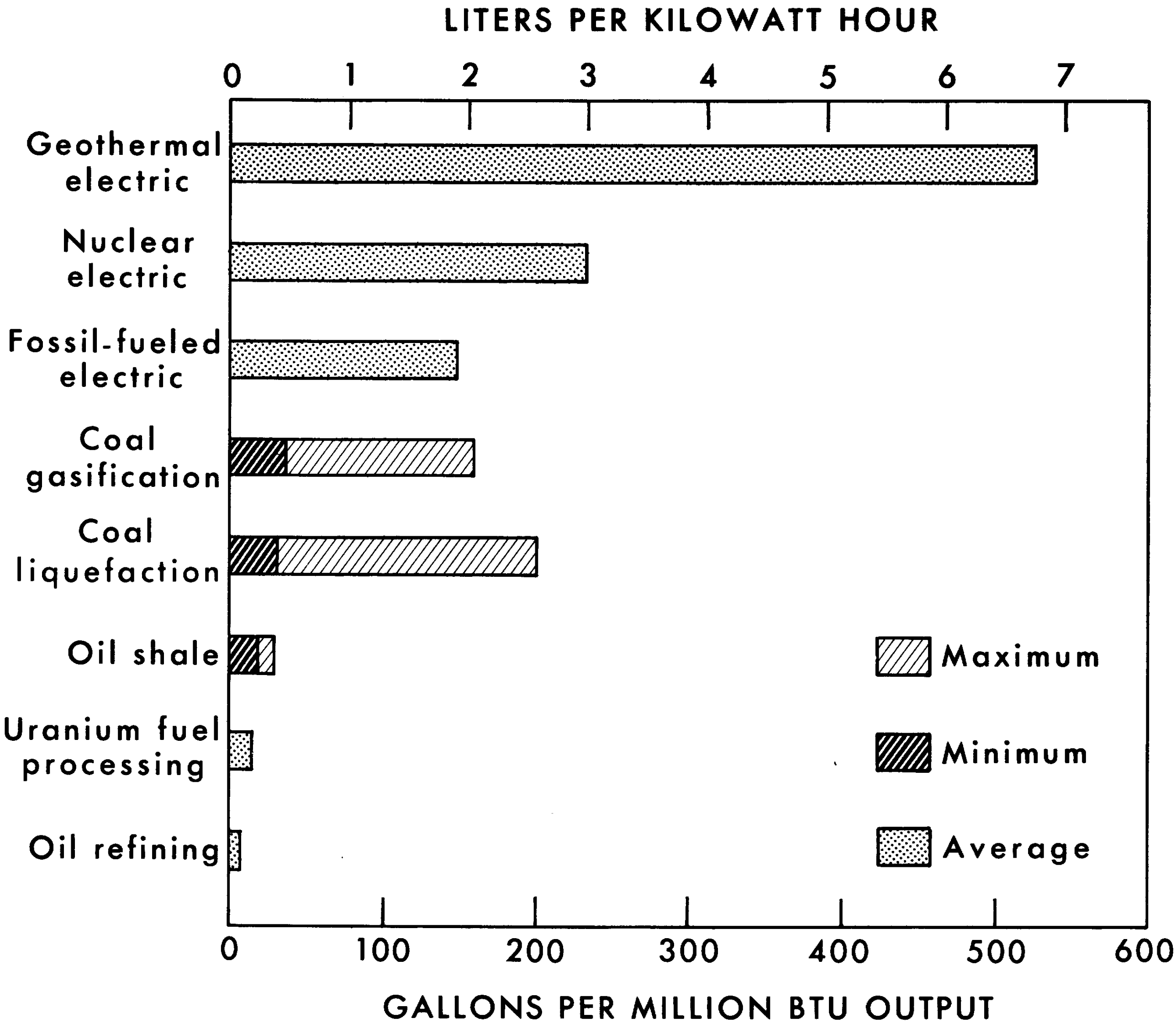

Figure 4.—Water consumption in refining and conversion processes.

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