Section 3

REVIEW OF TECHNOLOGIES INVOLVED IN ENERGY DEVELOPMENT

INTRODUCTION

In this review, emphasis is placed on the amounts of water required by the different technologies. Water requirements have two components: withdrawal, and consumption. Water withdrawn is water abstracted from a supply source but not necessarily consumed: part of it may return to the same supply source. Water consumed is water which becomes unavailable for further uses. For example, the once-through cooling of thermal power plants requires the withdrawal of large amounts of water ; however, only a relatively small proportion of it is evaporated, thus becoming unavailable for any other use. Our concern in this review is primarily with the consumptive uses of water by the different energy-related technologies.

Consumptive use of water has quantitative as well as qualitative aspects. The quantitative aspect is clear, especially if we refer to the example presented above. The qualitative aspect involves the removal of waste products of energy-related activities, particularly material wastes, thus rendering the water highly polluted. Almost always the waste water is unsuited for any further use, thus becoming part of the consumptive use of the production process. Reclamation of waste waters to a certain degree is possible and wherever this is done the consumptive use can be reduced by the amount reclaimed.

The following technologies involved in energy development are briefly discussed:

- coal liquefaction,
- coal gasification,
- thermal electric power generation,
- oil shale conversion,
- fuel refining,
- coal slurry pipelines,
- coal mining.

COAL LIQUEFACTION

For some time, coal liquefaction was considered to be the least advanced of the technologies involved in energy development [Dickinson et al. 1976]. Yet liquefaction is one method by which coal may be effectively upgraded so as to meet stringent environmental criteria, by reducing sulfur content and by a more complete ash removal [McNamee et al. 1978].

Early estimates of water requirements by coal liquefaction [Davis and Wood 1974] used as a rule of thumb 0.2 ac-ft/yr per barrel of fuel oil equivalent per day production capacity. This meant that a "standard" 100,000 bbl/day plant may use consumptively 20,000 ac-ft of water per year. A later assessment [Gold et al. 1977] evaluated water consumption by coal liquefaction plants, each having a capacity of 100,000 bbl/stream-day,* at four different locations in the Western United States. The following categories of water consumption were considered:

- the coal conversion process itself;
- evaporation for process cooling;
- flue gas desulfurization, where required;
- coal mining operations and land revegetation;
- disposal of solid waste and other uses within the mine liquefaction plant complex.

The results are summarized in Table 3-1.

Table 3-1

WATER CONSUMED BY COAL LIQUEFACTION[a]

Location	Water Consumption (ac-ft/yr)
Beulah, N. Dak.	10,090
Colstrip, Mont.	10,300
Gillette, Wyo.	9,230
Navajo-Farmington, N. Mex.	11,750

[a] Plant capacities, 100,000 bbl/stream-day

Source: Gold et al. 1977.

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*The ratio of stream-day to calendar-day is 0.9.

The variation in water consumption reflects local differences.

The most recent evaluation of water requirements by coal liquefaction technology [McNamee et al. 1978] considers plants having an output of 50,000 bbl/day fuel oil equivalent.* The typical plant receives the coal washed, so that the water requirements represent only the consumptive uses within the coal liquefaction plant itself.

Two types of liquefaction processes are considered: the solvent refined coal process (SRC), and the catalytic hydroliquefaction (CHL). Two cases were examined for each type: a case of normal operating conditions, and a case of more severe operating conditions, so as to lower the sulfur content of products. Some characteristics of the four cases are shown in Appendix C.

The items related to water requirements are divided into two categories: raw water, and waste water.** About 70% of raw water is being consumed (evaporated), and about 30% leaves the plant carrying waste material (waste water).

The raw water requirements and the waste water generated by a 50,000 bbl/stream-day coal liquefaction plant are summarized in Table 3-2.

Table 3-2

SUMMARY OF RAW WATER REQUIREMENTS AND WASTE WATER GENERATED
(thousand acre-feet per year)

Item	Case 1 (SRC)	Case 2 (CHL)	Case 3 (SRC)	Case 4 (CHL)
Raw water				
Process water	0.320	0.332	0.327	0.378
Boiler makeup	1.109	1.423	0.324	1.934
Cooling-tower makeup	9.225	11.898	10.373	15.694
Potable water	0.161	0.161	0.161	0.161
Total	10.815	13.814	11.185	18.167
Waste water				
Nonoily wastes	0.084	0.108	0.024	0.147
Boiler blowdown	0.399	0.518	0.452	0.678
Cooling-tower blowdown	2.689	3.420	2.996	4.482
Sanitary sewage	0.121	0.121	0.121	0.121
Total	3.293	4.167	3.593	5.428

Source: McNamee et al. 1978.

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*1 bbl fuel oil equivalent = 6.3×10^6 Btu [McNamee et al. 1978].

**See Appendix A, Glossary.

If electric power is not generated at the coal liquefaction plant but is purchased from other sources, the overall thermal efficiency of the SRC process under normal operating conditions (Case 1) will increase from 71.8% to 84.1%. Such an alternative was examined under two variants:

1. steam in excess of process requirements is used to generate electric power, thus satisfying some of the power demand -- Case 1A;
2. use of the excess steam directly in process drivers -- Case 1A1.

A comparison of power and capital requirements of these two variants with Case 1 (SRC) -- the least-cost case of the four alternatives examined above -- is shown in Appendix C. The raw water requirements and the generated waste water are identical in both variants; the comparison with Case 1 (SRC) is given in Table 3-3.

Table 3-3

RAW WATER REQUIREMENTS AND WASTE WATER GENERATED, CASES 1, 1A, 1A1
(thousand acre-feet per year)

Item	Case 1 (SRC)	Cases 1A, 1A1 (electric drive, steam drive)
Raw water		
Process water	0.320	0.320
Boiler makeup	1.109	0.530
Cooling-tower makeup	9.225	5.548
Potable water	0.161	0.161
Total	10.815	6.559
Waste water		
Nonoily wastes	0.084	0.084
Boiler blowdown	0.399	0.190
Cooling-tower blowdown	2.689	1.618
Sanitary sewage	0.121	0.121
Total	3.293	2.013

Source: McNamee et al. 1978.

Table 3-3 indicates that electric power generation at the coal liquefaction plant requires 4256 ac-ft of water per year (579 ac-ft for boiler feedwater makeup and 3677 ac-ft for cooling-tower makeup); and it will generate 1280 ac-ft of waste water per year (209 ac-ft of boiler blowdown and 1071 ac-ft of cooling-tower blowdown).

COAL GASIFICATION

Gasification of coal produces a low-Btu fuel gas (less than 400 Btu/scf),* which may be used directly in a combined-cycle system for electric power generation, or be further processed to attain pipeline quality (954 Btu/scf). The further processing involves methane synthesis and the product is often called syntane.

There are three main types of coal gasification technologies:

1. moving-bed,
2. fluidized-bed,
3. entrained-bed.

The first two involve high pressure processes (340 psig);** the other may be carried out also at atmospheric pressure. Each gasification technology can use either air or oxygen as oxidant.

There are two major variants in the moving-bed technology: (1) the Lurgi process, and (2) the BGC (British Gas Corporation) slagger. The entrained-bed technology has three major variants: (1) high pressure, (2) low pressure, and (3) Texaco process. In the Texaco process, the coal is fed to the gasification plant by means of a slurry (and its water can be used for the chemical processes and for cooling), or as a dry powder. Table 3-4 indicates the energy content of the gas produced by the different technology alternatives [Kimmel et al. 1976, Chandra et al. 1978].

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*scf, standard cubic foot

**psig, pounds per square inch gage

Table 3-4

ENERGY CONTENT OF COAL GASIFICATION TECHNOLOGIES

Technology	Symbol	Btu/scf
Moving-bed		
Lurgi, air	MACW	189
Lurgi, oxygen	MX	302
BGC slagger, oxygen	MXSC	379
Fluidized-bed		
air	FA	158
oxygen	FX	323
Entrained-bed		
air, high pressure	EAHC	174
oxygen, high pressure	EXHC	315
air, low pressure	EALC	113
oxygen, low pressure	EXL	312
oxygen, Texaco process	EXTC	281

Sources: Kimmel et al. 1976, Chandra et al. 1978.

The water consumption of a Lurgi coal gasification process followed by methane synthesis to yield high-Btu gas (954 Btu/scf) in a plant producing 250 Mscf/day is estimated as follows [Davis and Wood 1974]:

	ac-ft/yr	% of total
evaporative cooling	4,143	35.3
process water	3,075	26.2
coal mining	1,817	15.5
evaporation from waste ponds	1,258	10.7
losses within the plant	1,174	10.0
wet ash	266	2.3
Total	11,733	100.0

Most of the water (83.4%) has to be made up by exogenous supplies (river, groundwater, etc., 9784 ac-ft/yr). The moisture in the coal supplies is 9.1% of the required water(1069 ac-ft/yr); and the H_2O generated during the methane synthesis forms the remaining 7.5% (880 ac-ft/yr).

The synthane process, which yields synthetic gas of pipeline quality, consumes nearly twice as much water as the Lurgi process, which produces low-Btu gas, as seen in Table 3-5 [Gold et al. 1977].

Table 3-5

WATER CONSUMED BY COAL GASIFICATION TECHNOLOGIES[a]
(acre-feet per year)

Location	Lurgi (low-Btu)	Synthane (high-Btu)
Beulah, N. Dak.	3,310	7,670
Colstrip, Mont.	4,610	7,810
Gillette, Wyo.	4,210	7,780
Navajo-Farmington, N. Mex.	5,640	8,670

[a] Plant yield, 250×10^6 Mscf/stream-day; load factor, 0.9
Source: Gold et al. 1977.

Recent analyses of coal gasification processes are based on plant capacities of 10,000 tons of coal per day [Kimmel et al. 1976]. Some of the plant characteristics are shown in Appendix C. These plants produce, in addition to low-Btu gas, liquid hydrocarbons which may also be used as fuels. Some of the steam generated in these plants, as well as some heat derived from exchange processes, may be used to generate electric power as a by-product.

Water consumption by low-Btu coal gasification processes is shown in Table 3-6.

Recent studies consider low-Btu coal gasification as part of combined-cycle systems for electric power generation [McElmurry 1977, Chandra et al. 1978]. The size of the power plants is 1000-1300 MW, and some of their characteristics are shown in Appendix C.

The consumptive use of water, in acre-feet per year/1000 MW electric, is summarized in Table 3-7. In the case of the EXTC-SF process, the water-coal ratio in the slurry feed is 0.503, by weight.

THERMAL ELECTRIC POWER GENERATION

The overall thermal efficiency of fossil-fueled power plants is less than 38%; that of nuclear plants is approximately 31% [Davis and Wood 1974]. This means that fossil-fueled plants must dispose of 1.6 MWh of waste heat for every megawatthour of electricity produced. One way to do so is to use the waste heat beneficially, either in industry or for space heating in commercial and residential buildings. Another way is to reject the waste heat by means of cooling. Most cooling methods

Table 3-6

WATER CONSUMED BY LOW-Btu COAL GASIFICATION PROCESSES[a,b]
(acre-feet per year)

Water Use	MACW	MX	FA	FX	EALC	EXL
Steam vented to atmosphere	3	3	3	3	3	3
Blowdown	97	172	103	71	73	51
Process water	3,845	5,985	1,532	1,435	69	72
Cooling water[c]	6,118	4,830	6,405	4,379	5,313	4,025
Total	10,063	10,990	8,043	5,888	5,458	4,151

Source: Kimmel et al. 1976.

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[a] Plant capacities, 10,000 tons of coal per year.

[b] For a key to symbols, see Table 3-4.

[c] Additional cooling water makeup is obtained from treated process condensate, except in EALC and EXL processes.

involve evaporation of water. When one kilogram (2.2 lbs) of water is evaporated, i.e., it passes from liquid to vapor, it loses its latent heat of vaporization of 2.5×10^6 joules (2370 Btu).

Four methods of cooling are considered:

1. once-through cooling,
2. cooling-pond,
3. wet-cooling towers,
4. dry-cooling towers [Hirsch et al. 1977].

Combinations of wet- and dry-cooling towers may also be possible [Gold et al. 1977].

Once-through cooling involves pumping water from a river, lake, or ocean, and passing it across the steam condensers. The cooling water thus heated is returned to the same river, lake, or ocean, where it mixes with the existing water. The locally increased temperature of the natural water body due to the inflow of cooling water increases its evaporation rate, and this increase should be attributable to the power plant. Once-through cooling has the advantage of lower rates of water

Table 3-7

WATER CONSUMPTION BY LOW-Btu COAL GASIFICATION COMBINED-CYCLE SYSTEMS FOR ELECTRIC POWER GENERATION[a]
(acre-feet per year/1,000 MWe)

Water Use	MACW	MXSC	EAHC	EXHC	EALC	EXTC-SF	EXTC-DF
Process water	3,553	1,343	800	1,660	253	583	1,726
Cooling tower	9,174	9,470	9,861	9,665	11,977[b]	12,217	11,681
Slurry feed	---	---	---	---	---	1,292	---
Total	12,727	10,813	10,661	11,325	12,230	14,092	13,407

Sources: McElmurry 1977, Chandra et al. 1978.

[a] For a key to symbols, see Table 3-4. SF indicates slurry feed of coal; DF direct (dry) feed of coal.

[b] If product gas is further compressed so as to increase steam turbine power at generator terminals from 307 MW to 422 MW, thus reducing the net heat rate from 8959 Btu/kWh to 8951 Btu/kWh, the cooling-tower water consumption will rise to 12,630 ac-ft/yr.

consumption, lower capital costs, and higher generating efficiency. Its main disadvantage is that it involves the withdrawal of very large quantities of water.

The cooling-pond method overcomes most of the disadvantage of the once-through cooling. After an initial filling of the pond from a river or lake, water from the pond is used to cool the power plant. The evaporation losses from a pond are 50% larger than for once-through cooling, because it includes the natural evaporation from the pond as well as that induced by waste heat rejection. This evaporation loss is made up by water from the stream or lake. However, if the makeup water would equal exactly the evaporation loss, the dissolved solids which exist in any natural water body would accumulate, increasing the salinity of the cooling water. Beyond a certain concentration, the increased salinity may cause corrosion of heat exchanging surfaces, or deposit scale on them. In order to prevent this occurrence, the makeup water is increased by about 10% and the excess is released from the cooling pond back to the river or lake, carrying with it some of the accumulated salts (blowdown). The cooling-pond method has the great advantage of requiring a much smaller amount of withdrawal (as compared with once-through cooling), but its major disadvantage is that it requires substantial land areas for the cooling pond.

Wet-cooling towers reject waste heat as the cooling water comes into close contact with moving air. The air is driven either by fans or by natural buoyancy. The makeup water must replenish also the losses caused by blowdown, which are about 10% of the evaporation loss. The main disadvantages of wet-cooling towers are additional capital costs, loss of power plant efficiency due to the energy requirements of the fans and of the pumps, and a certain loss of thermodynamic efficiency due to higher cooling water temperatures.

Dry-cooling towers reject waste heat only by the conduction of sensible heat. (No latent heat of vaporization is involved.) The principle is similar to a car radiator, where a fan blows air across finned tubes through which the cooling water circulates. The dry-cooling system is much more expensive than the other three, since it involves a radiator-type structure constructed of thin-walled metal tubing. In addition, the loss in plant efficiency due to the fan and pump requirements is quite substantial. Similarly, losses of thermodynamic efficiency can be substantial when the ambient air temperature is high.

Table 3-8 shows a comparison of the four cooling methods for a 1000 MWe fossil-fueled (coal-fueled) power plant operated at about 38% efficiency and a load factor of 83%, located in the Colorado River Basin at 6000 ft altitude.

Table 3-8

COMPARISON OF FOUR COOLING TECHNOLOGIES

Item	Once-through	Cooling-pond	Wet-tower	Dry-tower
Water withdrawal (ac-ft/yr)	537,500	11,425	11,100	0
Water consumption (ac-ft/yr)	6,950	10,375	11,100	0
Electricity generated (kWh/yr)	8.15×10^9	8.15×10^9	8.10×10^9	7.58×10^9
Electricity generated (once-through = 100)	100	100	99	93

Source: Hirsch et al. 1977

Many estimates of water consumption by thermal electric power generation published recently refer to coal-fired plants with wet-cooling towers. Incidentally, it is estimated that nuclear plants consume 50% more water than conventional facilities [Davis and Wood 1974]. The water consumption estimates refer to generating plants of 1000 Mwe capacity.

An earlier estimate [Davis and Wood 1974], considering 38% overall thermal efficiency for fossil fueled plants (1000 MWe), is as follows:

	ac-ft/yr
evaporation loss	14,475
blowdown	3,619
Total makeup water (consumption)	18,094

A detailed study [Gold et al. 1977] of six specific locations in the Western United States (Beulah, N. Dak.; Colstrip, Mont.; Gillette, Wyo.; Kaiparowits/Excalante, Utah; Navajo/Farmington, N. Mex.; Rifle, Colo.) considers coal-fired plants of 35% efficiency at 70% load factor. The water consumption averaged over the six locations is given below:

	ac-ft/yr	
evaporative cooling	7,662	(7,183- 7,941)
blowdown	1,443	(778- 1,998)
boiler makeup	338	
Total	9,443	(8,299-10,277)

A coal-fired power plant with flue gas desulfurizer of 34.4% efficiency [McElmurry 1977] yields the following estimate:

	ac-ft/yr
evaporative cooling	7,457
cooling-tower blowdown	4,379
water in scrubber sludge	615
Total	12,451

A recent estimate relating to a coal-fired power plant with gas scrubber having an efficiency of 34.4% at a 70% load factor [Chandra et al. 1978] indicates total raw water makeup at 22,773 ac-ft/yr.

Thus, the water consumption for a 1000 MWe coal-fired power plant using wet-tower cooling is estimated between a low value of 9443 ac-ft/yr [Gold et al. 1977] and a high of 22,773 ac-ft/yr [Chandra et al. 1978]. The higher value is related to a power plant having a gas scrubber.

OIL SHALE CONVERSION

The oil shale deposits of the Green River Formation in Colorado, Utah, and Wyoming contain probably the largest known oil resource in the world [Weeks et al. 1974], estimated at about 600×10^9 bbl. This quantity is found in deposits more than 10 ft thick and averaging 25 gal of oil per ton.* If deposits of same thickness but averaging at least 15 gal/ton are considered, the oil resource is estimated at 1800×10^9 bbl.

Retorting the oil shale in order to extract from it the kerogen -- an organic compound which is subsequently upgraded to yield an oil-like substance called syncrude -- can be done either on surface, i.e., after the oil shale has been mined, or in situ. It appears that in situ retorting consumes considerably less water than surface processes, but the technology is yet in the initial stages of development [Smith 1978]. The surface retorting technologies are of two kinds: hot solids-to-solids heating, and gas-to-solids heating [Dickinson et al. 1976]. The first kind involves the use of ceramic balls for heating crushed oil shale, and this process is called TOSCO II. The second kind has two variations:
(1) internal gas combustion, used by the Paraho Development Corporation;
(2) external heat generation, used by Petrobras, the Brazilian National Oil Company.

The TOSCO II process, named after the Oil Shale Corporation, is probably the most advanced technology of oil shale conversion in the sense that it is ready for commercial application, and all details regarding water requirements below will refer to it. To be sure, oil shale conversion using the TOSCO II process requires large amounts of resources.

For example, a plant producing syncrude at the rate of 100,000 bbl/day will require the following [Dickinson et al. 1976]:

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*As estimated by the Fisher assay.

capital	750×10^6 1973$
oil shale	54×10^6 ton/yr or 140,000 ton/day
water	16,000 ac-ft/yr
electric power	170 MWe
labor	1,700 people

The mining operation supplying this plant will be larger than the largest mine in the U.S. -- the Bingham Canyon open-pit copper mine, which yields 110,000 ton/day -- and 10 times larger than the largest underground coal mine.

An additional environmental problem related to oil shale conversion is that of the spent shale. The spent shale volume is on the average 50% greater than the original mined shale [Gold et al. 1977] and its compaction and settlement require large amounts of water. For example, it is estimated that the spent shale of 100,000 bbl/day plant will produce every day a pile about 1000 ft long, 120 ft wide, and 25 ft high.

Estimates of water consumptive uses for a 100,000 bbl/day plant using the TOSCO II process vary from a low of 13,073 ac-ft/yr [Gold et al. 1977] to a high of 30,250 ac-ft/yr [Gardner et al. 1976]. The details of the low estimate are given below. The plant, which has a nominal capacity of 100,000 bbl/day at 90% load factor, has the following output:

fuel oil	94,000 bbl/day
liquefied petroleum gas	8,660 bbl/day
coke	1,600 ton/day

Consumptive water uses are estimated as follows:

			ac-ft/yr
mine-dust suppression			1,016
revegetation			203
crusher-dust suppression			653
dust control on processes shale			726
retorting:			
shale crushing		261	
preheating and ceramic balls circulation scrubber		900	
miosturizer scrubber		44	
moisturizer:			
from dust suppression	319		
makeup water	1,423		
		1,742	
			2,947
upgrading:			
hydrogen plant		1,619	
steam used in upgrading		639*	
wash water, gas treating unit		523*	
steam to coker		87*	
boiler blowdown		377**	
			3,245
cooling tower:			
evaporation		2,903	
blowdown		871**	
			3,774
fire, service, drinking water			436*
losses in water treatment plant			73
Total			13,073

The processed shale which exits the plant carries with it 3920 ac-ft/yr of water. This amount is made up of the cooling-tower blowdown, the boiler blowdown, and other quantities of water involved in the retorting and upgrading phases of the process. Thus, if one combines the cooling-tower blowdown (871 ac-ft/yr) with the

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*These amounts of water, totaling 1685 ac-ft/yr, may be partly reclaimed and reused. Assuming 75% reclamation efficiency, a saving of 1264 ac-ft/yr, or 9.7%, may be attained.

**These amounts are further used in retorting and upgrading.

consumptive uses of retorting and upgrading (2947 and 3245 ac-ft/yr, respectively), yielding a total of 7063 ac-ft/yr, and subtracts from it the water content of the spent shale (3920 ac-ft/yr), the balance of 3143 ac-ft/yr represents the actual amount of water which becomes part of the product (fuel oil, liquified petroleum gas, and coke). Thus, product water amounts to 24% of total consumptive use, while the spent shale carries with it 30% of the water consumption. Evaporation losses from the cooling tower form 22.2% of the total water consumed by the TOSCO II process.

FUEL REFINING

Nuclear Fuel

The estimated water demands for nuclear fuel to be supplied to a 1000 MWe light water reactor generating electricity at 80% load is as follows [Davis and Wood 1974]:

	ac-ft/yr
uranium ore milling	200
uranium enrichment, evaporative cooling	277
production of uranium hexafluoride	12
reprocessing of reactor products	11
Total	500

The generation of power used in the uranium enrichment processes requires, in addition, 490 ac-ft/yr for evaporative cooling.

Oil

In general, the refining of one barrel of oil uses consumptively one barrel of water [Davis and Wood 1974]. A refining operation of 10^6 bbl/day will use the following amounts of water:

	ac-ft/yr	% of total
evaporative cooling	33,416	71
boiler water feed	12,237	26
sanitary and other uses	1,412	3
Total	47,065	100

COAL SLURRY PIPELINES

Water used to transport coal by means of slurry pipelines usually leaves the hydrological unit where it occurs naturally, or where it is developed, and cannot be reused for other purposes in the same river basin. Hence, from a regional point of view, water for coal slurry pipelines is a consumptive use, unless there is a return water pipeline.

Water is used in coal slurry pipelines for two purposes. First, water is used to wash the coal before it is shipped. The water so used can be reclaimed through a settling tank for reuse. The amount of water involved in coal washing is relatively small and may be neglected. Second, water is used as a transport medium. At the terminal of the pipeline, the powdered coal is separated from the water in the slurry through flocculation and the water so reclaimed can be used for cooling.

In general, water makes up 50% of the slurry, by weight [Gold et al. 1977], i.e., in order to transport 10^6 tons of coal, it is necessary to use 730 ac-ft of water. A more detailed analysis [Palmer et al. 1977] indicates that, in order to move 12.5×10^6 tons of coal per year over a distance of 1000 mi (e.g., from Wyoming to Houston, Texas), the optimum (minimum cost) coal-to-water ratio is 52-48. The costs considered were those related to the size of the pipeline and those related to the energy necessary to overcome frictional resistance in the pipe. The greater the coal-to-water ratio, the smaller the diameter pipe is required; hence, the pipe-related costs decrease. However, the viscosity of the slurry increases, requiring greater energy input. The optimum ratio, as mentioned, is in the neighborhood of 52-48. This means that, in order to move 12.5×10^6 tons of coal per year over 1000 mi in a slurry containing 48% water, by weight, 8500 ac-ft of water per year are consumed, or 680 ac-ft/10^6 tons of coal. For comparison, the amount of 8500 ac-ft is equivalent to the annual water supply to a city of about 75,000 inhabitants. In order to transport the same amount of coal (12.5×10^6 tons) by rail, 1250 unit trains are required, or one unit train every seven hours approximately on the average.

Comparing a coal slurry pipeline with other coal-based energy-related activities, it uses one-third as much water as coal gasification and only one-fifth of the water required for on-site electric power generation. Regarding transportation of energy (a distance of 1000 mi), energy losses are 4.6% of the potential electrical output of coal transported by slurry pipeline; 4.2% of that of coal transported by unit train; and 6.5% of the electric power generated on site and transmitted over high-voltage (600 kV)dc transmission lines.

COAL MINING

The indirect effects of coal mining on regional water resources may be more significant than direct consumption of water by mining-related activities. Surface coal mining in the Western United States will disturb, at least temporarily, the groundwater conditions and will affect surface hydrology [Fluor Utah, Inc. 1975]. One should consider that coal seams are often water bearing (aquifer) formations, and that strip mining can produce topographic depressions where "dead" lakes may trap water and prevent it from reaching natural streams.

In general, water use for coal mining is relatively low: 25-175 ac-ft/10^6 ton [James, II and Steele 1977]. However, since the planned capacity per mine in Montana and Wyoming averages 50-75% more than the production in the largest mine existing in the United States in 1974 [Nehring et al. 1976], the aggregate effect of coal mining in the West may be substantial.

The consumptive use of water in coal mining falls within the following categories:

- mine, road, and embankment dust control;
- dust control in handling and crushing coal;
- service and fire water;
- sanitary and potable water;
- water for revegetation;
- coal washing.

Since coal is not uniform in its qualities, the amount of water consumed per Btu mined will vary from location to location. Recent work [Gold et al. 1977] investigated the consumptive uses of water in coal mining at six different locations in the Western United States: Beulah, N. Dak.; Colstrip, Mont.; Gillette, Wyo.; Kaiparowits/Escalante, Utah; Navajo/Farmington, N. Mex.; Rifle, Colo. All sites involved strip mining, except for Kaiparowits-Escalante in Utah, where underground mining is considered. Table 3-9 summarizes the information, in acre-feet/10^{15} Btu mined.

Table 3-9

CONSUMPTIVE USE OF WATER IN COAL MINING[a]
(acre-feet/10^{15}Btu mined)

Use	Beulah, N. Dak.	Colstrip, Mont.	Gillette, Wyo.	Navajo, N. Mex.	Rifle, Colo.	Kaiparowits, Utah
Mine dust control	1,340	730	360	1,010	790	2,630
Crushing, dust control	1,080	860	870	890	570	420
Service and fire	70	60	70	100	80	80
Sanitary and drinking	10	10	10	20	30	80
Revegetation[b]	---	---	---	1,360	---	50
Coal washing[c]	---	---	---	---	---	4,440
Total	2,500	1,660	1,310	3,380	1,470	7,700

Source: Gold et al. 1977.

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[a] Strip mining at all locations, except Kaiparowits, Utah

[b] Revegetation requires water where precipitation is less than 10 in/yr.

[c] Necessary only for coal mined underground

SUMMARY OF WATER USES

Energy-related activities consume the following estimated amounts of water, acre-feet/10^{15} Btu output:

Nuclear power stations (LWR)*	592,800
Fossil-fueled power stations*	395,200
Coal gasification, high-Btu gas	103,400
Coal gasification, low-Btu gas	57,700
Oil shale conversion	61,700
Coal liquefaction	57,000
Nuclear fuel processing*	41,300
Coal slurry pipeline	34,000
Oil refining	22,200
Underground coal mining	7,700
Strip coal mining, revegetation	3,400
Strip coal mining, no revegetation	1,800

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*1 kWh = 3412 Btu

Section 4

REVIEW OF ENERGY MODELS WITH REGIONAL DISAGGREGATION

REGIONALIZED MODELS

One has to make the distinction between regional and regionalized models. A regional model refers to a portion of a larger geographic entity, defined in accordance with some criteria. A regionalized model should, ordinarily, represent the interrelationships between the regions within the larger geographic entity. Both types of models imply a hierarchical structure; however, only regionalized models can have this structure explicitly expressed. A schematic representation of a regionalized model is shown in Figure 4-1. The point stressed in this figure is that constraining conditions on energy resources (e.g., import quotas on oil and gas, nuclear power development) are easier to define at the national level, while water resources and environmental restrictions can be defined meaningfully only at the regional level.

Models related to regions can be classified into three groups:

1. national models which may be applied to regional energy planning [Hoffman 1973];
2. regional energy models, e.g., the Rocky Mountain States [Bullock-Webster 1974]; the State of Illinois [Brill, Jr. et al. 1976]; the Upper Colorado River Basin [Morris 1977];
3. regionalized models.

The models considered in this section are Battelle, ICF, Gulf-SRI, Bechtel, Brookhaven, ETA-MACRO, and Upper Colorado.

The discussion which follows will focus on regionalized models and will include the model developed by Morris for the Upper Colorado River Basin. Morris' model, although restricted in extent to one region, subdivides it into three subregions, thus developing an interesting methodology for approaching hierarchically structured regionalized models.

An earlier review of regional energy modeling [Cohen and Costello 1975] specifies the following criteria for model evaluation:

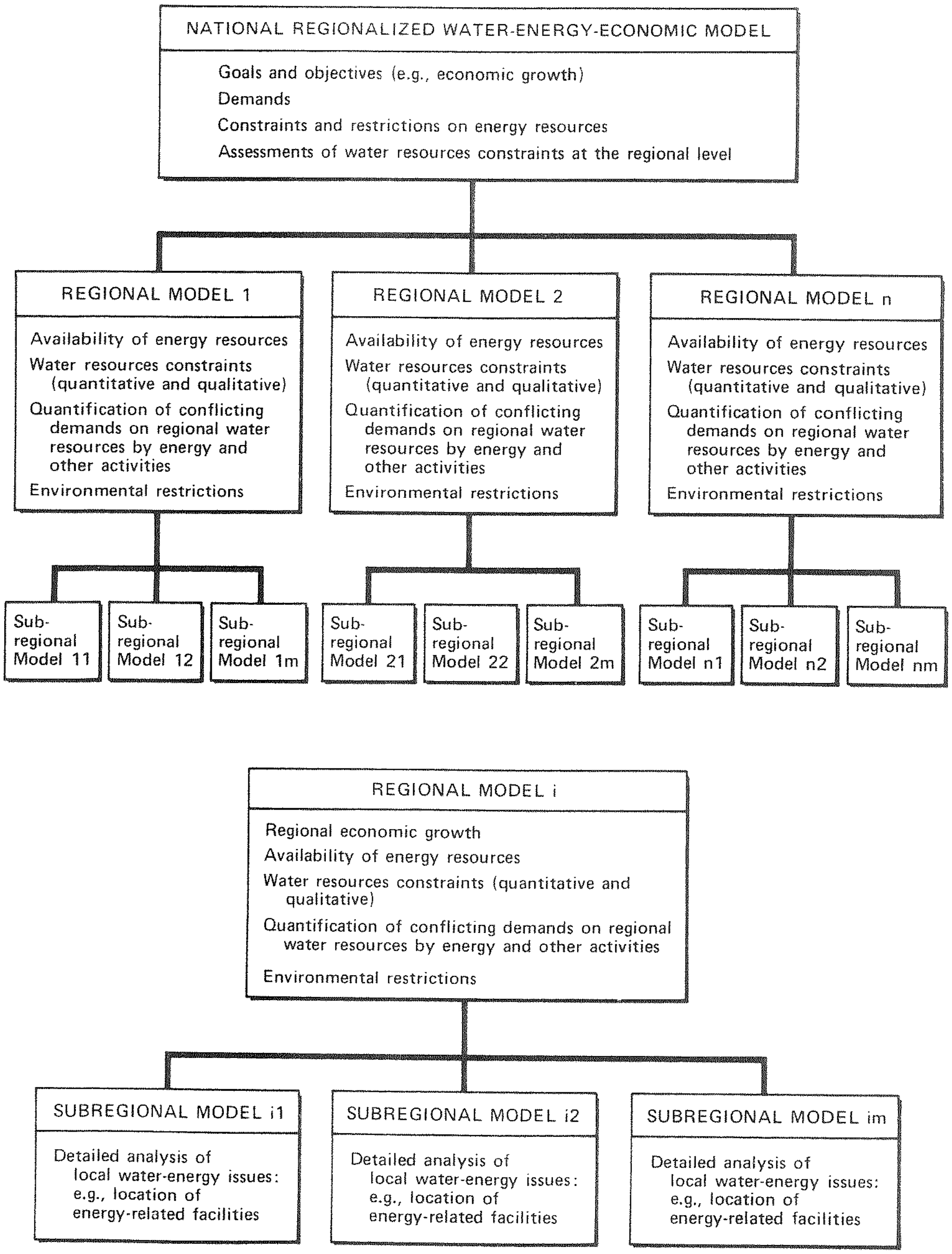


Figure 4-1. An Outline of Regionalized Water-Energy-Economic Models Showing a Hierarchical Multilevel Structure

- their comprehensiveness regarding detail (spatial, i.e., regions, energy supply sources, energy demand sectors);
- economic aspects included in the models (determinants of total supply and demand, such as prices and incomes, interfuel competition, interregional competition);
- their capabilities to reflect policy changes (e.g., import quotas, conservation measures) and technology changes, such as the introduction of solar energy.

Nine models were reviewed by Cohen and Costello, but only three were found to include relevant regional disaggregation: the Battelle Columbus-EPA Energy Quality Model, the Energy Management Simulation and Analysis System (EMSAS), the Project Independence Evaluation System (PIES). The first model is restrictive in the sense that it focuses primarily on air quality requirements in each of 238 air quality control regions and it omits important details in the demand sectors (e.g., no transportation sector). The second model (EMSAS), a simulation model, does not allow for interregional competition. The PIES model, structured by Census regions, allows for interdependence among them. The model reflects competition between producing and consuming regions, as well as interfuel competition. Its main disadvantages include lack of production constraints, omission of environmental costs, and an underestimated market share of coal.

A regionalized model of the electric power industry alone [Reardon 1975] refers to the nine regions defined by the National Electric Reliability Council (NERC). The model uses a linear programming formulation to optimize the long-range development of the U.S. electric generating industry. Regionally dependent characteristics, such as coal and oil prices, availability of alternate energy sources (hydro, geothermal), energy demands and systems loads, are processed by means of submodels and then used as inputs to a linear programming model formulated at the national level. The thrust of the model is to determine the minimum present value of the costs of building and operating all power plants in the U.S. between 1968 and 2000, with special emphasis on nuclear power generation. Because of this emphasis, all variables related to the nuclear fuel cycle are considered to be regionally independent and are, therefore, represented adequately at the national level. As mentioned before, all regional characteristics are dealt with in submodels, only to appear as constraining conditions on the national scale. Because of its emphasis on only one energy-related activity, this model was not used in the more general study of integrating water constraints into energy models.

Another regionalized model restricted to only one part of the energy sector is the National Coal Model [ICF 1977, ICF 1978]. This is a detailed linear programming model which has 40 different coal types, 35 demand regions, 30 supply regions, and six consuming sectors. This formulation yields equilibrium solutions reflecting the impact of various scenarios on the supply of and demand for energy; thus, it is price-sensitive. The model is static, but it can be used to study arbitrarily chosen "case years." For example, Table 4-1 summarizes a sensitivity analysis of the western coal produced in 1990. The analysis shows that the western coal production in 1990 will increase significantly (22.6% above base case) if there is a surge in the growth rate of the electric power generation (sensitivity run No. 3). On the contrary, coal production in the West in 1990 will be depressed by 17.4% if rail transportation rates will increase 50% by 1985 (run No. 11). (Coal slurry pipeline was not considered as an alternative.) The western coal production in 1990 also is sensitive to low severance tax (as opposed to actual state severance taxes in the base case), to low rates of growth of electric power generation, to the absence of sulfur removal from the western coal, and to the 2% annual escalation in labor costs. In all other sensitivity runs (No. 1, 5, 6, 7, 10, and 12), the results were within ±10% of the base case. The model is insensitive regarding the quantities of western coal used in 1990 for synthetic fuel production. In all cases, the western coal consumption for this purpose was 0.625 quad. Being restricted to only one energy source -- coal, the ICF model was not used in this study.

The SRI energy model is described by a network [Cazalet 1976] which has 14 resource regions, six refinery regions, nine demand regions, and three groups of end-use locations (residential-commercial, industrial, transportation). The network has a hierarchical structure in the sense that the flow is generally from a resource region to a refinery region, to a demand region, to end-use locations. An important exception is that transportation may be allowed between locations at the same level in the hierarchy. Thus, interregional transportation networks reflect transportation processes of western and/or eastern coal, via unit trains or by slurry pipeline.

Given end-use energy demands in each of the nine demand regions, the Gulf-SRI model indicates the market share of different energy resources and technologies satisfying these demands. The model is dynamic in character, covering a span of fifty-one years (1975-2025), which can be divided into a number of timeperiods. Different mixes of energy sources and technologies may be obtained for the satisfaction of end-use demands, depending upon different scenario assumptions. A version of the Gulf-SRI model developed by the Lawrence Livermore Laboratory was used in this study.

Table 4-1

WESTERN COAL PRODUCTION, 1990

Sensitivity Run		Production	
No.	Description	10^6 tons	Index
0	Base case	652.1	100.0
1	Coal severance tax: 30%, except in Arizona	612.4	93.9
2	Coal severance tax: 5%, except in Arizona	763.1	117.0
3	Electricity growth rate: 5.8%/yr (1975-1985) 5.0%/yr (1985-1990)	799.6	122.6
4	Electricity growth rate: 3.8%/yr (1975-1985) 3.0%/yr (1985-1990)	572.5	87.8
5	Oil price: \$20/bbl (1985); \$30/bbl (1990)	668.4	102.5
6	Oil price: \$13/bbl (1985 and 1990)	596.9	91.5
7	Sulfur removal requirements: 90%	640.6	98.2
8	Sulfur removal requirements: 1.2 lb/10^6 Btu (no scrubbing for western coal)	721.9	110.7
9	Labor cost escalation: 2%/yr	722.6	110.8
10	Labor cost escalation: none	627.6	96.2
11	Rail transportation costs: increase 50% by 1985	538.9	82.6
12	New combined-cycle oil-fired plants included	642.7	98.6

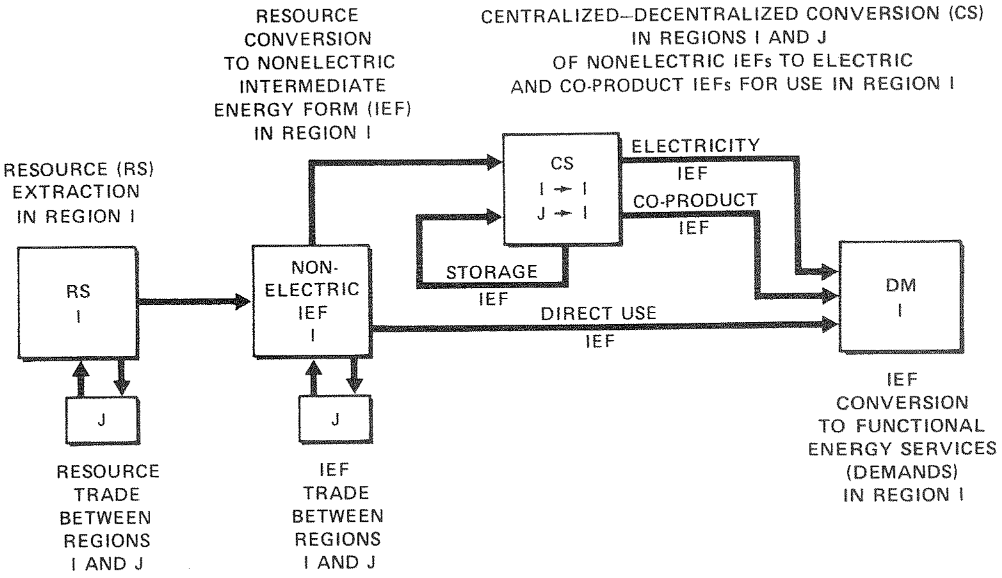
Sources: ICF 1977, ICF 1978.

The Bechtel Energy Supply Model [Carasso et al. 1975] simulates the capital, labor, materials, and industrial production capacity required for the construction and operation of energy supply and transportation facilities within the 1975-1995 time frame. The simulation can be performed so as to analyze alternative energy policies and their impacts on a national and regional scale. The model has 14 regions, including three which refer to the continental shelf (Atlantic Coast, Gulf of Mexico, Pacific Coast) and converts a specified scenario into direct annual requirements for facilities and resources. The level of detail may be regional or national. An important aspect of this model is that future energy mixes for any year of interest within the time frame are considered to be matters of policy and have to be specified. These specifications are inputs to a submodel which generates a fuel mix. The fuel mix is input to national and regional energy facilities generators which output energy facilities schedules. These schedules are input to a further submodel which generates interregional fuel allocation and transportation facilities schedules. The transportation facilities, the energy facilities, and the facility resource data are input to national and regional resource requirements generators which output the final result -- the resource requirement schedules. These may be exhibited on a yearly basis, or cumulatively for the entire time horizon. The Bechtel model was considered too cumbersome for this exploratory study.

A detailed multiregional energy and interindustry model was developed recently at the Brookhaven National Laboratory [Goettle, IV et al. 1977]. This model allocates optimally energy resources produced regionally, and indicates the optimal mix of energy supply, conversion, and demand technologies, in accordance with a specified criterion (e.g., least-cost). The linear programming formulation of this model links the nine Census regions by interregional energy and industrial flows. It allows for intraregional interfuel substitution and preserves the dependence of the energy sector on the broader regional economic system of which it is a part. The model is static, single-period, yet may be used for multiobjective analyses. A schematic representation of a regional energy system is shown in Figure 4-2. The regional energy submodel is fairly detailed and includes the following components:

- regional resource extraction activities, represented with the aid of step-function approximations of concave supply curves;
- renewable energy resources (hydro, geothermal, solar);
- regional resource availability, distinguishing between interregionally tradeable (coal, crude oil, shale oil, uranium ore) and interregionally nontradeable resources, thus allowing for interregional imports and exports of energy resources;
- regional resource conversion to nonelectric intermediate energy forms (IEF) via appropriate conversion technologies;
- regional production of nonelectric IEFs, which sums up, for each IEF, the yields of the conversion processes defined in the previous paragraph;
- regional nonelectric IEF availability, which distinguishes between interregionally tradeable and nontradeable IEFs;
- regional use of available nonelectric IEFs, for the generation of electricity and co-product IEF, and/or to satisfy interregional end-use demands;

- regional end-use demands, specified exogenously as nonsubstitutable quantities (e.g., Btu of residential space heat);
- the regional electric sector, reflecting details such as baseload, electric space heat, or off-peak load;
- additional components, showing capacity constraints on conversion activities and technologies, export-import limitations, environmental effects, etc.



Source: Goettle, IV et al. 1977

Figure 4-2. A Generalized Diagrammatic View of a Regional Energy System

The interindustry part of the model is represented by a multiregional input-output model of the form

$$X = C(AX + Y) \quad , \qquad (1)$$

where

X is a column vector of total production, by industry and by region;

Y is a column vector of final demands, by industry and by region;

A is a block-diagonal square matrix of interindustry technological coefficients;

C is a square matrix of main-diagonal submatrices of trade flow coefficients.

The energy sectors are represented in this structure by the resource, supply, and conversion activities, as well as by end-use demands for energy. This model was used for studying the integration of water constraints.

The ETA-MACRO energy-economy model [Manne 1977] represents a dynamic nonlinear optimization process, combining an assessment of energy technology with a macroeconomic growth model. This is not a truly regionalized model, since all activities are described at the national level. However, the model does specify explicitly production of synthetic fuels and shale oil conversion. If one can assume that these activities are restricted to the western part of the United States, then ETA-MACRO can be considered as a two-region (East-West) model. This model is too aggregated to be useful in a study of integrating water constraints.

The Upper Colorado River Basin was modeled as a regionalized model consisting of three regions: the upper main stem of the Colorado; the Green River; the San Juan River [Morris 1977]. The model has an interregional input-output scheme imbedded into a linear programming framework. The formulation allows for two alternative objective functions: either the maximization of the regional income, or the specification of the level of activities which will yield a given minimum regional income. The objective function of the first alternative is expressed as

$$\max \quad Z = \sum_i c_h^i x_h^i \quad , \tag{2}$$

where

x_h^i is the total gross output of the household sector of the i-th region;

c_h^i is a weight coefficient applicable to the total gross output of the household sector in region i.

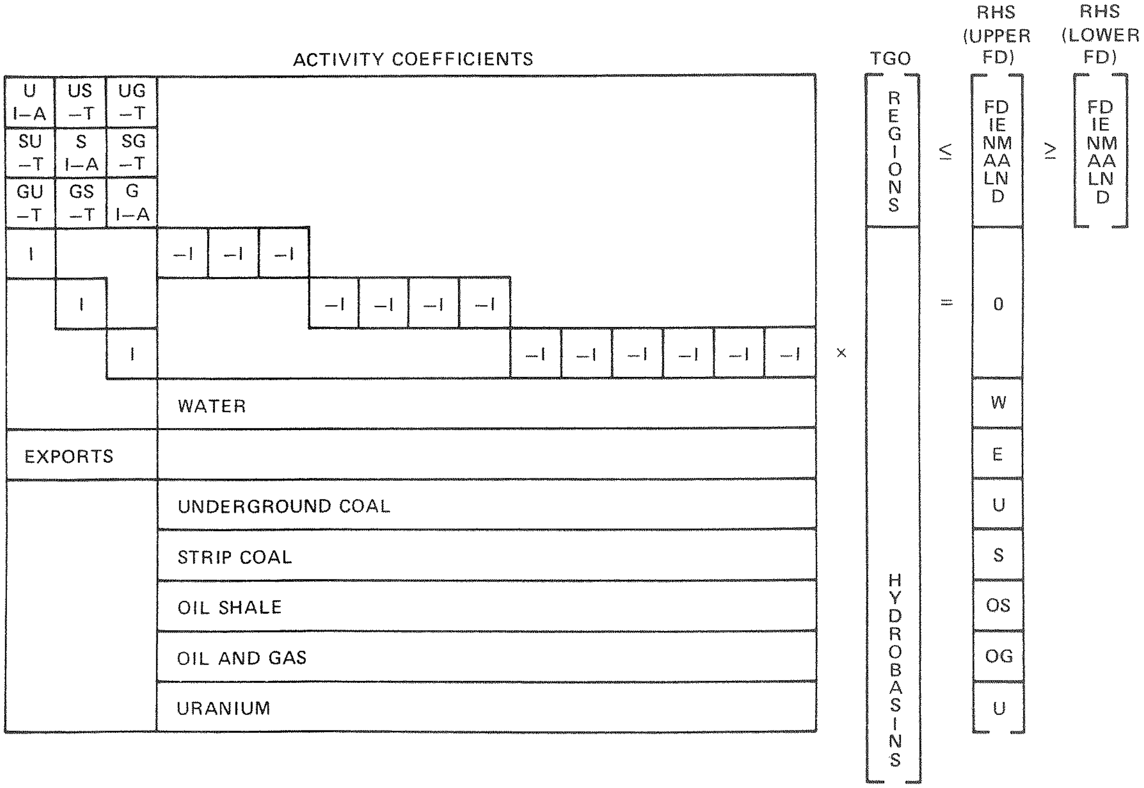
Observe that, by omitting the coefficients c_h^i from the objective function, interregional income distribution effects are ignored. The constraints of the model are represented schematically in Figure 4-3.

The notation which is not clear in the documentation is as follows:

TGO -- total gross output
FD -- final demand
-- food production
IE -- industry
NM -- mining

AA -- all other services
LN -- local government
D -- new energy technologies
U -- upper main stem of Colorado region
-- underground coal
-- uranium availability
S -- San Juan River region
-- strip coal
G -- Green River region
I-A -- Leontief matrix
T -- a square matrix of estimated trade coefficients for trade between region i and region j
W -- water availability
E -- exports
OS -- oil shale
OG -- oil and gas

The model is one-period static, with all coefficients estimated for 1980. It is too restricted in area to be useful in this study.



Source: Morris 1977

Figure 4-3. Schematic Diagram of the Upper Colorado River Basin Policy Optimization Model

REGIONAL WATER SUPPLY AND DEMAND PROJECTIONS

These projections refer to regions defined by the Water Resources Council. The 48 conterminous states are divided into 18 regions, roughly hydrologic boundaries [U.S. Water Resources Council 1977]. These regions are further divided into subregions, as shown on the map in Figure 2-1 (page 12).

When considering demand projections, distinction should be made between withdrawal and consumption requirements.* To illustrate this distinction, the total water withdrawal in the U.S. in 1975 was 371.6 Maf, the consumptive use was 115.1 Maf (31% of the withdrawal), leaving a return flow of 256.5 Maf.

An important factor in estimating surface water supply is the storage capacity of the various reservoirs. Due to the mismatching in time between supply and demand, and because of the stochastic characteristics of the hydrological phenomena, storage facilities are necessary for the development of surface water resources. In order to supply every year with certainty an amount of water equal to the long-term average annual flow, an infinitely large reservoir is necessary. The aggregate storage available in 1975 in the U.S. enables the supply of 30% of the long-term average annual flow 95% of the time. Table 4-2 shows regionally aggregated streamflows, their mean values and select values of their probability distribution. The 5% exceedance values indicate that once in 20 years, on average, a flow of the specified magnitude, or larger, will occur; such flows may cause flooding. The 95% exceedance values indicate the levels of water shortages which may occur, on average, once in 20 years [U.S. Water Resources Council 1978a].

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*For definitions of terms, see Appendix A.

Table 4-2

STREAMFLOW ANALYSIS
(million acre-feet per year)

Region	Mean	Percentage Exceedance			
		5%	50%	80%	95%
New England	87.6	120.6	86.7	70.2	54.1
Mid-Atlantic	88.7	128.9	87.1	68.5	54.2
South Atlantic-Gulf	255.4	300.4	245.5	183.8	136.4
Great Lakes	81.4	116.4	80.3	64.2	50.3
Ohio	199.4*	284.5*	199.4*	157.9*	117.6*
Tennessee	45.7*	64.8*	45.7*	40.2*	35.2*
Upper Mississippi	135.5*	211.7*	135.5*	102.8*	73.1*
Lower Mississippi	485.0	847.8	485.0	315.8	226.2
Souris-Red-Rainy	6.7	12.8	6.3	3.8	2.0
Missouri	49.4*	83.2*	48.4*	33.5*	19.7*
Arkansas-White-Red	70.1*	135.2*	66.2*	41.9*	24.2*
Texas-Gulf	31.7	69.9	25.6	13.8	7.1
Rio Grande	1.3	4.9	0.7	0.3	0.2
Upper Colorado	11.2*	17.4*	11.2*	7.8*	4.4*
Lower Colorado	1.8	1.9	1.8	1.6	1.3
Great Basin	2.9	21.3	11.0	7.5	5.2
Pacific Northwest	285.9	386.1	284.8	238.9	201.3
California	53.1	99.3	50.6	34.0	22.4
Total	1,381.4	2,191.7	1,356.2	996.1	756.3

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*These numbers are not included in total because they are inflows to another region.

Source: U.S. Water Resources Council 1978a.

Table 4-2 illustrates the variability of annual streamflow, expressed in terms of flow that is expected to be exceeded in a specific percentage of years. The differences between mean annual flows and flows with 50% probability of exceedance reflect the asymmetry of streamflow probability distributions. Mean annual flows are only part of the water supply generated in a region. Estimated water supply figures are shown in column "Runoff" of Table 4-7.

Groundwater is an important water resource in the U.S. It is estimated that within 2500 feet below ground surface there are about 100×10^9 ac-ft, half of which can be economically extracted. (To give an idea of this enormous water resource, note that the total amount of water in Lake Michigan is about 4×10^9 ac-ft; and the entire amount of water discharged by the Mississippi into the Gulf of Mexico during the last 200 years is approximately 94×10^9 ac-ft.) Table 4-3 summarizes the groundwater supplies, as estimated in 1975.

Table 4-3

GROUNDWATER SUPPLIES, 1975

Region	Current Withdrawals		Currently in Storage		
	Total (Maf/yr)	In excess of recharge* (Maf/yr)	Less than 2500 ft deep (Maf)	Feasible** to withdraw (Maf)	Depletion of amount feasible to withdraw, at current rate (years)
New England	0.7	0	na	na	?
Mid-Atlantic	3.0	0.03	4,946	1,271	424
South Atlantic-Gulf	6.2	0.3	na	13,692	> 2,000
Great Lakes	1.3	0.03	na	801	616
Ohio	2.0	0	4,295	1,176	588
Tennessee	0.3	0	na	1,627	> 2,000
Upper Mississippi	2.7	0	14,239	6,886	> 2,000
Lower Mississippi	5.4	0.4	7,970	3,905	723
Souris-Red-Rainy	0.1	0	2,158	528	> 2,000
Missouri	11.6	2.8	3,432	1,366	118
Arkansas-White-Red	9.9	6.2	2,038	1,532	155
Texas-Gulf	8.1	6.3	8,605	4,402	543
Rio Grande	2.6	0.8	49,221	5,753	> 2,000
Upper Colorado	0.1	0	3,236	239	> 2,000
Lower Colorado	5.6	2.7	1,753	na	?
Great Basin	1.6	0.7	2,898	525	328
Pacific Northwest	8.3	0.7	4,227	553	67
California	21.5	2.5	1,004	252	12

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*Seepage into aquifers from rain, snow, and surface water bodies.
**From aquifers of reasonable thickness, making pumping of groundwater economically attractive.

Source: U.S. Water Resources Council 1978a.

The projections for water withdrawal and consumption are given in Tables 4-5 and 4-6. Table 4-4 summarizes the situation in 1975. From these tables, we can see that in the year 2000 withdrawals will be only about 90% of their 1975 value. The consumptive use, however, will increase in the same interval by about 26%. In these tables, the withdrawals and consumptive uses are detailed in the following categories:

- Municipal and domestic: Average withdrawal is 107 gal per capita per day; consumption is 87 gal per capita per day. The difference is mainly water for city parks, street cleaning, etc. The average per capita withdrawal and consumption is not expected to change substantially during this century.

- Industrial use: 25% of the work force generates 27% of total earnings. By the year 2000, gross water requirements, including saline water, will increase 230%, yet total withdrawal will decrease about 52% due to recycling of water, about 20 times. Fresh water withdrawals will decrease 62%, from 56.9 Maf in 1975 to 21.8 Maf in 2000.

- Mining requirements: Include metals, nonmetals, and fuels; fuel mining uses about 62% of total mining consumptive use.

- The energy sector: Total energy use in 2000 is estimated at 162 quads, 45% of which will be converted to effective work. The remaining 55% will have to be dissipated, requiring substantial amounts of cooling water. Water withdrawals will decrease about 10%, from 99.3 Maf in 1975 to 89.4 Maf in 2000, although electricity use may grow 400% during the same period because of technologies using higher consumption/withdrawal ratios.

- Irrigation: Total cropland in the U.S. is about 460×10^6 acres, of which 42×10^6 are irrigated. Agricultural exports in 1975 are valued at over $\$20 \times 10^9$. Irrigation consumptive use is expected to drop from 83% of total consumptive use in 1975 to 71% in the year 2000, due to some increase in irrigation efficiency, to a decrease of withdrawals from groundwater because of depleted aquifers, and to higher consumption/withdrawal ratios in non-agricultural sectors.

Water supply and requirements in 1975, 1985, and 2000 are summarized in Table 4-7.

Table 4-4

FRESH WATER WITHDRAWAL AND CONSUMPTION, 1975
(million acre-feet per year)

Region	Withdrawal						Consumptive Use					
	Municipal and domestic	Industrial use	Mining (including fuels)	Steam-electric generation	Irrigation	Total	Municipal and domestic	Industrial use	Mining (including fuels)	Steam-electric generation	Irrigation	Total
New England	1.7	2.4	0.1	1.4	0.04	5.64	0.2	0.2	0.01	0.02	0.03	0.43
Mid-Atlantic	5.2	6.1	0.5	8.4	0.3	20.5	0.9	0.7	0.1	0.1	0.2	2.0
South Atlantic-Gulf	3.2	4.6	1.3	14.3	3.9	27.3	1.1	0.7	0.2	0.2	3.1	5.3
Great Lakes	4.8	14.8	0.8	27.3	0.2	47.9	0.7	1.6	0.2	0.2	0.1	2.8
Ohio	2.6	12.2	0.6	23.5	0.1	39.0	0.5	0.9	0.1	0.4	0.04	1.94
Tennessee	0.4	2.3	0.1	5.4	0.02	8.22	0.1	0.2	0.02	0.05	0.01	0.38
Upper Mississippi	2.2	2.3	0.4	8.6	0.2	13.7	0.4	0.3	0.05	0.1	0.2	1.05
Lower Mississippi	0.9	4.7	0.9	4.7	5.1	16.3	0.4	0.4	0.2	0.06	3.4	4.46
Souris-Red-Rainy	0.1	0.1	0.01	0.1	0.1	0.41	0.01	0.01	0.003	0.003	0.04	0.066
Missouri	1.4	0.7	0.3	4.0	35.4	41.8	0.4	0.2	0.1	0.08	15.9	16.68
Arkansas-White-Red	1.1	0.8	0.5	0.2	11.2	13.8	0.4	0.2	0.2	0.1	7.9	8.8
Texas-Gulf	1.7	2.2	1.2	0.8	12.9	18.8	0.6	0.6	0.6	0.1	10.5	12.4
Rio Grande	0.4	0.02	0.2	0.04	6.4	7.06	0.2	0.01	0.1	0.02	4.4	4.73
Upper Colorado	0.1	0.004	0.1	0.1	7.2	7.504	0.03	0.002	0.05	0.04	2.5	2.622
Lower Colorado	0.6	0.1	0.2	0.1	8.9	9.9	0.3	0.1	0.2	0.07	4.5	5.17
Great Basin	0.4	0.1	0.2	0.04	7.8	8.54	0.2	0.03	0.03	0.003	3.6	3.863
Pacific Northwest	1.2	2.6	0.1	0.3	37.2	41.4	0.3	0.4	0.02	0.01	12.3	13.03
California	3.8	0.9	0.3	0.03	38.8	43.83	1.6	0.3	0.2	0.03	27.2	29.33
Total	31.8	56.9	7.8	99.3	175.8	371.6	8.3	6.9	2.4	1.6	95.9	115.1
Percent	8.6	15.3	2.1	26.7	47.3	100.0	7.2	5.9	2.1	1.4	83.4	100.0

Source: U.S. Water Resources Council 1978a.

Table 4-5

FRESH WATER WITHDRAWAL AND CONSUMPTION, 1985
(million acre-feet per year)

Region	Withdrawal						Consumptive Use					
	Municipal and domestic	Industrial use	Mining (including fuels)	Steam-electric generation	Irrigation	Total	Municipal and domestic	Industrial use	Mining (including fuels)	Steam-electric generation	Irrigation	Total
New England	1.8	1.1	0.1	1.2	0.05	4.25	0.3	0.4	0.02	0.02	0.03	0.77
Mid-Atlantic	5.8	2.8	0.6	8.0	0.4	17.6	1.0	1.0	0.1	0.3	0.3	2.7
South Atlantic-Gulf	3.8	3.8	1.7	14.5	4.5	28.3	1.4	1.4	0.3	0.8	3.6	7.5
Great Lakes	5.3	4.6	0.9	25.4	0.2	36.4	0.7	1.9	0.2	0.6	0.2	3.6
Ohio	2.9	3.7	0.7	23.5	0.1	30.9	0.5	1.2	0.1	0.7	0.1	2.6
Tennessee	0.5	0.9	0.2	6.4	0.02	8.02	0.1	0.3	0.02	0.3	0.02	0.74
Upper Mississippi	2.4	1.0	0.5	7.1	0.3	11.3	0.4	0.3	0.1	0.4	0.3	1.5
Lower Mississippi	1.0	1.8	1.1	10.4	5.1	19.4	0.4	0.6	0.3	0.1	3.6	5.0
Souris-Red-Rainy	0.1	0.05	0.01	0.03	0.2	0.39	0.03	0.02	0.003	0	0.1	0.153
Missouri	1.5	0.3	0.4	6.5	44.1	52.8	0.4	0.1	0.2	0.3	19.7	20.7
Arkansas-White-Red	1.2	0.5	0.5	1.1	11.7	15.0	0.4	0.3	0.2	0.3	8.4	9.6
Texas-Gulf	1.9	2.9	1.3	1.1	10.5	17.7	0.6	1.1	0.7	0.3	8.5	11.2
Rio Grande	0.4	0.05	0.2	0.02	6.2	6.87	0.2	0.02	0.1	0.01	4.4	4.73
Upper Colorado	0.1	0.002	0.2	0.2	8.1	8.602	0.03	0.001	0.1	0.1	3.0	3.231
Lower Colorado	0.7	0.1	0.3	0.2	8.2	9.5	0.3	0.06	0.2	0.2	4.4	5.16
Great Basin	0.5	0.1	0.2	0.1	6.9	7.8	0.2	0.05	0.05	0.05	3.5	3.85
Pacific Northwest	1.3	1.5	0.2	0.2	38.8	42.0	0.3	0.6	0.02	0.1	15.0	16.02
California	4.3	0.9	0.4	0.2	39.0	44.8	1.8	0.4	0.3	0.1	28.2	30.8
Total	35.5	26.1	9.5	106.2	184.4	361.6	9.1	9.8	3.0	4.7	103.3	129.9
Percent	9.8	7.2	2.6	29.4	51.0	100.0	7.0	7.5	2.3	3.6	79.6	100.0

Source: U.S. Water Resources Council 1978a.

Table 4-6

FRESH WATER WITHDRAWAL AND CONSUMPTION, 2000
(million acre-feet per year)

Region	Withdrawal						Consumptive Use					
	Municipal and domestic	Industrial Use	Mining Including fuels)	Steam-electric generation	Irrigation	Total	Municipal and domestic	Industrial Use	Mining (including fuels)	Steam-electric generation	Irrigation	Total
New England	2.0	0.9	0.2	0.4	0.1	3.6	0.3	0.6	0.02	0.2	0.04	1.16
Mid-Atlantic	6.7	2.2	0.8	5.2	0.5	15.4	1.1	1.5	0.1	0.7	0.4	3.8
South Atlantic-Gulf	4.8	3.7	2.3	15.6	5.1	31.5	1.7	2.8	0.4	2.1	4.0	11.0
Great Lakes	5.9	3.2	1.2	18.0	0.3	28.6	0.8	2.3	0.2	1.6	0.3	5.2
Ohio	3.3	2.6	0.9	11.8	0.1	18.7	0.6	2.0	0.2	1.9	0.1	4.8
Tennessee	0.6	0.8	0.2	5.1	0.02	6.72	0.1	0.6	0.03	0.5	0.02	1.25
Upper Mississippi	2.7	0.8	0.6	4.0	0.4	8.5	0.4	0.6	0.1	1.2	0.4	2.7
Lower Mississippi	1.1	1.5	1.5	18.7	5.0	27.8	0.4	1.2	0.5	0.3	3.7	6.1
Souris-Red-Rainy	0.1	0.03	0.01	0	0.2	0.34	0.03	0.03	0.003	0	0.4	0.463
Missouri	1.7	0.3	0.5	5.5	40.6	48.6	0.4	0.2	0.2	0.7	19.7	21.2
Arkansas-White-Red	1.3	0.5	0.6	1.1	10.9	14.4	0.5	0.4	0.2	0.5	8.0	9.6
Texas-Gulf	2.2	2.7	1.4	2.5	8.3	17.1	0.7	2.1	0.7	1.1	6.8	11.4
Rio Grande	0.4	0.04	0.3	0.01	5.5	6.25	0.2	0.03	0.2	0.01	4.0	4.44
Upper Colorado	0.1	0.002	0.4	0.2	7.5	8.202	0.04	0.002	0.2	0.2	3.1	3.542
Lower Colorado	0.9	0.2	0.3	0.2	7.1	8.7	0.4	0.1	0.3	0.1	4.2	5.1
Great Basin	0.6	0.1	0.3	0.1	6.5	7.6	0.2	0.1	0.1	0.1	3.6	4.1
Pacific Northwest	1.4	1.3	0.2	0.6	33.6	37.1	0.3	1.0	0.03	0.4	14.8	16.53
California	4.9	0.9	0.4	0.4	38.9	45.5	2.1	0.6	0.2	0.3	29.5	32.7
Total	40.7	21.8	12.1	89.4	170.6	334.6	10.3	16.2	3.7	11.9	103.0	145.1
Percent	12.2	6.5	3.6	26.7	51.0	100.0	7.1	11.2	2.6	8.2	70.9	100.0

Source: U.S. Water Resources Council 1978a.

Table 4-7

SUMMARY OF U.S. WATER SUPPLIES AND REQUIREMENTS, 1975, 1985, 2000
(million acre-feet per year)

Region	Year	Stream* Inflow	Supply			Requirements			Remaining Stream Outflow	Instream Flow[d] (approx.)
			Runoff[a]	Imports	Mined ground-water	Consumed	Evaporation[b]	Exports		
New England	1975	0	88.0	0	0	0.5	0	0	87.5	77.3
	1985	0	88.0	0	0	0.7	0	0	87.3	
	2000	0	88.0	0	0	1.2	0	0	86.8	
Mid-Atlantic	1975	0	90.1	0.5	0.04	2.1	0	0	88.54	77.1
	1985	0	90.1	0.5	0	2.8	0	0	87.8	
	2000	0	90.1	0.5	0	4.0	0	0	86.6	
South Atlantic-Gulf	1975	0	260.45	0	0.38	5.45	0	0	255.38	202.33
	1985	0	260.45	0	0	7.59	0	0	252.86	
	2000	0	260.45	0	0	11.26	0	0	249.19	
Great Lakes	1975	0	84.29	0.02	0.03	2.90	0	0	81.44	71.63
	1985	0	84.29	0.02	0	3.69	0	0	80.62	
	2000	0	84.29	0.02	0	5.26	0	0	79.05	
Ohio	1975	45.70	155.68	0	0	2.01	0	0	199.37	179.78
	1985	45.33	155.68	0	0	2.83	0	0	198.18	
	2000	44.81	155.68	0	0	4.85	0	0	195.64	
Tennessee	1975	0	46.05	0	0	0.35	0	0	45.70	43.10
	1985	0	46.05	0	0	0.72	0	0	45.33	
	2000	0	46.05	0	0	1.24	0	0	44.81	
Upper Mississippi	1975	49.39	85.15	2.31	0	1.28	0.05	0	135.52	124.04
	1985	41.92	85.15	2.31	0	1.79	0.05	0	127.54	
	2000	40.18	85.15	2.31	0	3.01	0.05	0	124.58	
Lower Mississippi	1975	404.99	84.01	0	0.46	4.51	0	0	484.95	402.12
	1985	388.64	84.01	0	0	5.10	0	0	467.55	
	2000	382.82	84.01	0	0	6.17	0	0	460.66	
Souris-Red-Rainy	1975	0	6.87	0	0	0.13	0.02	0	6.72	4.11
	1985	0	6.87	0.06	0	0.23	0.02	0	6.68	
	2000	0	6.87	0.72	0	0.50	0.02	0	7.07	
Missouri	1975	0	68.90	0.46	2.86	17.32	5.51	0	49.39	38.03
	1985	0	68.90	0.55	0	21.51	5.96	0.06	41.92	
	2000	0	68.90	0.56	0	22.30	6.27	0.72	40.17	
Arkansas-White-Red	1975	0	75.82	0.18	6.11	9.03	2.93	0.03	70.12	51.68
	1985	0	75.82	0.23	0	9.82	3.26	0.03	62.94	
	2000	0	75.82	0.26	0	9.93	3.48	0.03	62.64	
Texas-Gulf	1975	0	39.90	0.03	6.25	12.61	1.91	0	31.66	25.67
	1985	0	39.90	0.03	0	11.45	2.10	0	26.38	
	2000	0	39.90	0.03	0	11.79	2.23	0	25.91	
Rio Grande	1975	0	5.95	0.26	0.74	4.75	0.82	0	1.38	2.56
	1985	0	5.95	0.22	0	4.84	0.85	0	0.48	
	2000	0	5.95	0.22	0	4.50	0.88	0	0.79	
Upper Colorado	1975	0	15.60	0	0	2.73	0.80	0.90	11.17	8.90
	1985	0	15.60	0	0	3.38	0.81	1.10	10.31	
	2000	0	15.60	0	0	3.62	0.82	1.23	9.93	
Lower Colorado	1975	11.17	-0.68	0.02	2.70	5.15	1.35	5.02	+1.69	7.69
	1985	10.31	-0.68	0.04	0	5.33	1.37	4.61	-1.64[c]	
	2000	9.93	-0.68	0.04	0	5.27	1.38	4.40	-1.76	

Table 4-7 Cont.

Region	Year	Stream Inflow	Supply			Requirements			Remaining Stream Outflow	Instream Flow[a] (approx.)
			Runoff	Imports	Mined groundwater	Consumed	Evaporation	Exports		
Great Basin	1975	0	15.63	0.12	0.66	4.23	0.37	0.002	11.808	9.16
	1985	0	15.63	0.200	0	4.215	0.371	0.002	11.242	
	2000	0	15.63	0.283	0	4.518	0.373	0.002	11.020	
Pacific Northwest	1975	0	300.737	0.053	0.702	13.334	2.256	0	285.902	269.924
	1985	0	300.737	0.053	0	16.369	2.302	0	282.119	
	2000	0	300.737	0.053	0	17.016	2.333	0	281.441	
California	1975	0	77.187	5.023	2.461	29.833	0.749	0.053	54.036	37.106
	1985	0	77.187	4.610	0	31.280	0.760	0.053	49.704	
	2000	0	77.187	4.399	0	33.263	0.768	0.053	47.502	
Total	1975	0	1499.77	3.00	23.40	118.22	16.75	0	1391.20	1165.40
	1985	0	1499.77	3.00	0	133.62	17.86	0	1351.29	
	2000	0	1499.77	3.00	0	149.67	18.61	0	1334.49	

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*See Appendix A, glossary.

[a] Estimated water supply generated within each region. Negative values indicate that evaporation and transpiration are greater than rainfall in the region.

[b] From manmade reservoirs, including those supplying water to hydropower plants. If precipitation exceeds evaporation, the value is zero.

[c] Negative values show the amount of excess water use without groundwater overdraft.

[d] Estimates prepared by the U.S. Fish and Wildlife Service for optimal fish and wildlife habitat conditions.

Source: U.S. Water Resources Council 1978a.

In two of the 18 water resources regions covering the conterminous 48 states, there will probably arise serious water resources constraints before the end of this century [Green and Skold 1976]: the Upper Colorado (Region 14) and part of the Missouri Basin (Region 10). In Region 10, only some of the aggregated subareas (ASA) forming the Upper Missouri Basin will probably exhibit significant water constraints [Gertsch et al. 1977]: 1001, 1002, 1003, 1004, and 1005.

A PROPOSED REGIONAL SCHEME

From the foregoing discussion, it is quite clear that, in order to determine the feasibility of integrating water resources constraints into energy models, formulations at the national level are too aggregated to be meaningful. Constraining conditions imposed by water resources on energy-related activities will appear in different parts of the country at different times in the future. It seems appropriate, therefore, to study water-energy interactions on the basis of a regionalized scheme.

There are many different ways in which to regionalize the United States. Some of the models reviewed in this section refer to regions defined by the U.S. Bureau of Census; other models use coal regions, or regions delineated by electric utilities. If one were to use any of these formulations, one would have difficulties in estimating streamflows and water availabilities within these arbitrarily defined regions. It is proposed, therefore, to use a scheme based on water resources regions, as defined by the U.S. Water Resources Council. (See Figure 2-1, page 12).

The regionalized scheme proposed for this study is based on Census regions, yet emphasizes major areas where water restrictions may inhibit significantly the rate at which energy resources could be developed using currently available technologies. The proposed scheme combines the nine Census regions and the 18 water resources regions to form eight new regions. The proposed regions and their relation to those of the U.S. Bureau of Census are shown in Table 4-8. They are shown schematically in Figure 4-4.

Table 4-8

A PROPOSED REGIONALIZED STRUCTURE FOR MULTIREGIONAL WATER-ENERGY MODELS

Water-Energy Regions	Census Regions and States	Water Resources Regions and Subbasins[a]
1. Eastern States	1,2,3,5,6	Regions 1,2,3,4,5,6 Subbasins 702,704,705
2. Central States	4,7	Regions 8,9,12 Subbasins 701,703,1005, 1006,1008,1009,1010,1011, 1101,1103,1104,1105,1106, 1107,1303,1305
3. Upper Missouri	Montana, Wyoming	1001,1002,1003,1004
4. Eastern Rockies	Wyoming, Colorado New Mexico	1007 1102,1301,1302,1304
5. Upper Colorado	Wyoming, Utah, Colorado	Region 14
6. Lower Colorado	Arizona	Region 15
7. Great Basin	Idaho, Utah, Nevada	Region 16 1701,1703,1704
8. Pacific	Washington, Oregon California	1702,1705,1706,1707 Region 18

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[a] Defined in U.S. Water Resources Council 1978

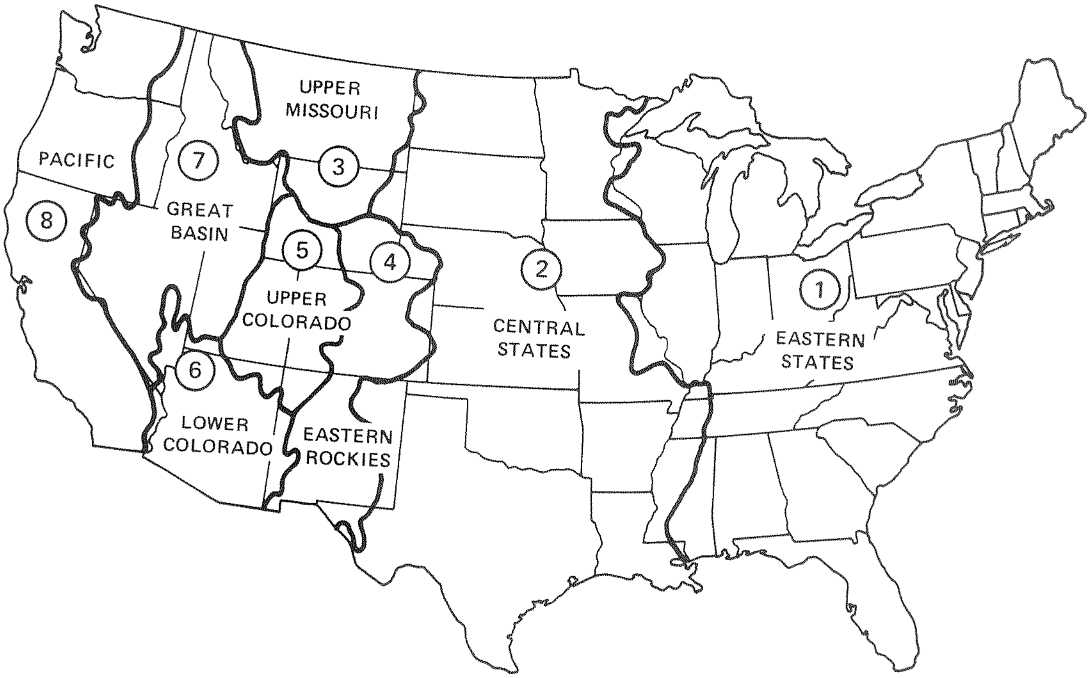

Figure 4-4. Proposed Water-Energy Regions in the United States