CHAPTER 9
Water Availability

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Introduction

The oil shale deposits are located within the Upper Colorado River Basin, which includes the Colorado River and its tributaries north of Lee Ferry, Ariz, These waters are critical resources in the semiarid region. They are used for municipal purposes, irrigated agriculture, industry and mining, energy development, and maintaining recreational, scenic, and ecological values. In the past, natural flows within the basin along with water storage and diversion projects have generally been adequate to satisfy demand. In the future, however, water resources may be taxed by rapid population growth, by accelerated mineral-resource development, and by increased recreational activities. Eventually, the availability of water may limit regional growth including the expansion of industrial developments such as oil shale.

This chapter analyzes the availability of water in the oil shale region. The following subjects are discussed:

- estimated water requirements for oil shale facilities and their related growth;
- the surface water and ground water resources of the oil shale region;
- the laws, compacts, treaties, and other documents that allocate the waters of the Colorado River system;
- the appropriation doctrine of Colorado, Utah, and Wyoming for distributing water supplies within State boundaries;
- the Federal reserved right doctrine:
- the physical availability of surface water for oil shale development;
- strategies and costs for utilizing water supplies;
- the uncertainties affecting water resource assessments;
- the impacts of water use;
- some methods for increasing water availability; and
- the policy options that might be implemented to increase the availability of water.

Summary of Findings

Surplus surface water will be available to supply an industry of at least 500,000 bbl/d through 2000 if:

- additional reservoirs and pipelines are built;

and

- demand for other uses increases no faster than the States' high growth rate projections;

and

- average virgin flows of the Colorado River do not decrease below the 1930-74 average (13.8 million acre-ft/yr).

Otherwise, surface water supplies would not be adequate for this level of production unless other uses were curtailed, interstate and international delivery obligations as presently interpreted by the Government were not met, or other sources of water were developed. On the other hand, if the reservoirs and pipelines are built, flows do not decrease, and the region develops at a *medium* rate (which the States regard as more likely), there should be sufficient surplus water to support an industry of over 2 million bbl/d through 2000.

In the longer term, surface water may not be adequate to sustain growth; surplus water availability is much less assured after 2000. If the river's flows do not decrease, and if a low growth rate prevails, demand will exceed supply by 2027 even without an oil shale industry. With a medium growth rate, the surplus will disappear by 2013. A high growth rate will consume the surplus by 2007, again without any oil shale development. This is a potentially serious problem for the region, and its implications for oil shale development are controversial. On the one hand it is argued that there is no surplus surface water and this should preclude the establishment of an industry. On the other hand, it it maintained that the facilities in a major industry could function for much of their economic lifetimes without significantly interfering with other users, and in any case would use relatively little water. (A 1-million-bbl/d industry would accelerate the point of critical water shortage by about 3 years if only surface water were used.)

Other findings are:

- Depending on the process used, production of 50,000 bbl/d of shale oil syncrude would consume 4,900 to 12,300 acre-ft/yr of water, including water for related municipal growth and power generation.
- A million bbl/d industry would require about 170,000 acre-ft/yr. * This would be about 1 percent of the virgin flow of the Colorado River at the boundary of the Upper Basin, about 3 percent of the water consumed at present by all users in the Upper Basin, and about 2 percent of projected consumption in 2000.
- Potential oil shale developers already own rights to substantial quantities of surface water. In 1968, for example, five companies claimed rights to enough water to produce several million bbl/d of shale oil.
- Existing developer rights would probably not assure supplies because surface water is overappropriated and oil shale rights could be interrupted during shortages. More reliable supplies could be provided through purchase of surplus water from existing Federal reservoirs, purchase of irrigation rights, ground water development, and importation of water from other hydrologic basins.
- Costs of the most expensive water supply option, importation from other basins, could exceed $0.80/bbl of shale oil produced. Other strategies would cost less than $0.50/bbl of oil. These costs include the amortized costs of reservoir and pipeline construction and the cost of treating the water to industrial standards. Development of high-quality ground water would be least expensive but would be limited to specific areas.
- All strategies that relied on surface water would require construction of new reservoirs and pipelines, principally in the White River basin in Colorado and Utah. About 180,000 to 230,000 acre-ft of new storage would be needed for a 1-million-bbl/d industry. Active capacity of existing reservoirs in the Upper Basin is about 34.7 million acre-ft. New construction for oil shale would increase storage by less than 0,6 percent.
- If a 2-million-bbl/d industry were developed, flows of the Colorado River would be reduced, and its salinity could increase by approximately 2 percent. Studies by the U.S. Water and Power Resources Service (WPRS)* and the Colorado Department of Natural Resources (DNR) indicate that the economic losses from these changes could reach $25 million per year by the year 2000–the equivalent of $0.04/bbl of oil produced.
- Sale of irrigation water to oil shale developers would reduce farm production. At present, developers do not plan to purchase such water in significant quantities. Therefore, effects on the farming industry should be small, especially compared with the effects of competition for labor and the purchase of farmlands for municipal growth.
- Studies by USBR and DNR indicate that environmental impacts of water-resource development for oil shale should be small overall on the Upper Basin but could be large in some areas. Fish habitats and recreational activities along the White River are expected to be the most severely affected. Impacts on the Lower Basin are not expected to be substantial.
- Regional development could be limited by water availability after 2000. Importation of water from other basins, conservation by municipal, agricultural, and industrial users, and possibly

* For comparison, irrigated [agriculture along the White River and the Colorado River consumes about 549,000 acre-ft/yr to produce 3 percent of Colorado's crop production. This is equivalent to the water needs of a 3. 2-million-bbl/d oil shale industry.

*Formerly the U.S. Bureau of Reclamation (USBR). For ease of reference, most citations in this chapter are to the USBR.

weather modification could make additional quantities available. The extent of the increase cannot be predicted accurately, and the strategies could be impeded by legal, institutional, and economic factors.

Analysis of Water Requirements for Oil Shale Facilities*

Introduction

Water will be used for oil shale mining and retorting, for shale oil upgrading, for revegetation and spent shale disposal, and for supplying the increased population and other related activities that will accompany the establishment of a shale oil industry. More water will be needed for final refining but this operation can be carried out at other locations. In the early years of the industry, some shale oil will probably be refined in the oil shale region and nearby in Denver and Salt Lake City. Water is also scarce in these areas. However, the refineries are presently consuming water for processing conventional petroleum. Shale oil will merely displace the conventional feedstocks, thus its refining will not add significantly to water requirements. In the long run, the output of a major industry would be refined in the Midwest where water is abundant.

Estimates of water consumption vary widely. In the following section the most recent estimates for alternative technologies on specific sites are analyzed, and then compared with estimates of regional water availability in order to identify the level of shale oil production at which water resources might limit further development.

*This analysis assumes that the quantity of water removed for a given purpose from a stream or aquifer (the water requirement) is numerically equa 1 to the quantity made unavailable for subsequent uses (the water (consumption].” This assumption is consistent with present developer plans for zero-discharge water management svs terns,

Process and Facility Models Analyzed

Facilities that use six retorting processes are described in table 71. The processes were selected for analysis because of their advanced development and because data have been published on their water requirements. The processes fall into three generic classes: directly heated aboveground retorting (AGR), indirectly heated AGR, and modified in situ (MIS) retorting. The facilities modeled are:

1. TOSCO 11 indirectly heated AGR,
2. Paraho directly heated AGR,

Table 71 .–Process **Models** for Oil Shale Facilities

Technology	Study	Reference[a]	Colorado location	Shale grade gall ton	Shale Oil capacity	Other major product	Byproducts, ton/d Coke	Sulfur	Ammonia
TOSCO II[b]	Colony	3	Davis Gulch	35	47,000 bbl/d syncrude	LPG 4,330 bbl/d	800	173	135
TOSCO II[b]	WPA/DRI	1	Davis Gulch	35	47,000 bbl/d syncrude	LPG 4,330 bbl/d	800	173	134
Paraho direct	McKee-Kunchal	4	Anvil Points	30	87,000 bbl/d syncrude	Low-Btu gas 32 billion Btu/d	650	136	290
Paraho direct	WPA/DRI	1	Anvil Points	29	*99,170* bbl/d crude	Electricity 155 mW[c]	0	132	146
Paraho Indirect	McKee-Kunchal	4	Anvil Points	**30**	76,000 bbl/d syncrude	Low-Btu gas 6 billion Btu/d	650	136	290
Union ‘ ‘B’ [b]	Eyring/Sutron	10	Parachute Creek	34	100,000 bbl/d syncrude	(d)		d	
Oxy MIS	Oxy	5,9	Tract C-b	24	57,000 bbl/d crude	Electricity 350 mW[e]	0	92	0
Oxy MIS	WPA/DRI	1	Tracts C-a or C-b	25	57,000 bbl/d crude	Electricity 97mW[c]	0	144	281
Oxy MIS + Lurgi	WPA/DRI	1	Tracts C-a or C-b	25	81,000 bbl/d crude	Electricity 140 mW	0	172	281

[a]See reference l ist at end of chapter [b]Electricity purchased ‘Open cycle gas turbines [d]Data not provided [e]Combined cycle system

SOURCE R F Probstein et al *Water Requirements Po l ution Effects and Costs of Water Supply and Treatment for the 011 Shale Industry* report prepared for OTA by Water Purification Associates October ‘ 979 p 4

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3. Paraho indirectly heated AGR,
4. Union Oil “B” indirectly heated AGR,
5. Occidental Oil Shale’s directly heated MIS retorts, and
6. a combination of directly heated MIS retorts and Lurgi-Ruhrgas indirectly heated AGR.

The water requirements of these facilities were scaled to a common basis of 50,000 bbl/d of synthetic crude oil. Thus, units for upgrading crude shale oil to a high-quality synthetic crude are included. Each facility generates sufficient electric power for its own needs, and all solid waste dumps are revegetated. Wastewater is recycled wherever practical, and only excess mine drainage water is discharged or reinfected. Disposing of solid wastes by slurry backfill, either to the mine or to the burned-out in situ retorts, is not included. The effects of byproduct coke, ammonia, sulfur, or gas are not evaluated. True in situ processes are not analyzed because no data are available.

With the exception of the Union “B” plant, each estimate discussed in this section is derived from a published conceptual design,[1-9] either the developer’s or one that has been modified to put plant material and energy balances on a consistent basis. Although little information has been published, the Union process is considered here because plans for a plant have been announced. ’() However, the data cannot be treated with the same confidence as for other processes.

A number of other studies’ ’-” have been completed but are not discussed in this section. Although they were based on data supplied by the developers, their conclusions did not agree because different retorting procedures, products, production rates, power supply modes, shale grades, and disposal procedures were assumed.

Water Requirements

The water requirements of the six oil shale facilities, after scaling, are summarized in table 72. As can be seen, even facilities that use similar processes (e. g., indirect AGR) require different amounts of water. However, when the requirement for each subprocess is represented as a percent of the total, there is a correlation among different plants that use similar kinds of technology, as shown in table 73. It is noteworthy that:

- Mining and dust control require considerably more water in AGR than in either MIS or MIS/AGR. This is because about

Table 72.–Water Requirements and Mine Drainage Production for 50,000-bbl/d Oil Shale Facilities (acre-ft/yr)

Retorting technology	Paraho direct		TOSCO II		Paraho Indirect	Union “B”	Oxy MIS			MIS/AGR
Study	McKee-Kunchal	WPA/DRI	Colony	WPA/DRI	McKee-Kunchal	Eyring-Sutron	Oxy 1977	Oxy 1979	WPA/DRI	WPA/DRI
Reference	4	1	3	1	4	9	5	9	1	1
Unit operation										
Mining and handling.	816	941	1,045	1,045	*934*	–	*483*	*483*	*338*	*326*
Power generation .,	665	(b)	1,233	1,233	*761*	1,233	(b)	(b)	(b)	(b)
Retorting and upgrading	2,616	2,375	5,038	3,821	3,487	1,470	9,234	2,502	3,601	3,051
Shale disposal and revegetation	1,644	1,385	3,895	3,956	4.020	3,090	2,818	1,103	1,103	1,461
Municlpal use	645	645	594	594	731	731	775	775	775	818
Net ***water requirements***										
In acre-ft/yr .,	6,386	5,346	11,805	10,694	9,933	6,524	13,310	4,863	5,817	5,656
In bbl water/bbl 011.	271	2.27	5.02	4.53	4,22	277	5.66	2.06	2.47	2.40
Mine drainage water										
In acre-ft/yr .	(b)	(b)	(b)	(b)	(b)	(b)	6,440-16,100	4.032-6,452	12,326	8,454
In bbl water/bbl oil,	(b)	(b)	(b)	(b)	(b)	(b)	2.74-6,86	1,56-2.50	5.25	3.60

[a]See reference list at end of chapter
bN applicable for projector Site analyzed

SOURCE R F Probstein et al *Water Requirements Pollution Effects and Costs of Wafer Supply and Treatment for the Oil Shale Industry* report prepared for OTA by Water Purification Associates October 1979 p 8

Table 73.–A Comparison of the Water Requirements of the Various Subprocesses

	Generic technology (in percent)		
Subprocess	Indirect and direct AGR	MIS/AGR	MIS
Mining and handling	9-18		4-1o
Power generation	8-12	(a	(a)
Retorting and upgrading	35-44	54	51-69
Disposal and revegetation	26-40	26	19-26
Municipal use	5-12	14	6-16

[a]Not applicable forproject or site

SOURCE R F Probstein et al *Waler Requirements Pollution Effects and Costs of Water Supply and Treatment for the Oil Shale Industry* report prepared for OTA by Water Purification Associates October 1979 p 9

four times as much shale is mined and handled in aboveground processing. The larger amount of material also results in high water requirements for disposal and revegetation.

- No water is needed for power generation in MIS and MIS/AGR because power will most likely be generated by burning low-Btu gases in open-cycle gas turbines that do not need to be cooled. Even if combined-cycle systems were used, very little cooling water would be needed. Cooling water is needed for AGR because solid-fuel steam-cycle systems will probably be used,
- Municipal water needs are proportional to the number of mine and plant employees. For the same output, more workers are required for MIS (about 1,800) than for AGR (about 1,400 to 1,700). It is assumed that the MIS/AGR process would require slightly more workers (about 1,900) than either technology by itself.

Retorting and upgrading require the most water. All the technologies need comparable amounts of water for upgrading, therefore, the differences among alternate technologies reflect differences in retorting efficiencies. The large differences between similar above--ground technologies result from specific operating characteristics, especially the methods for heating the retort and for disposing and reclaiming the spent shale, More water is required for indirect than for direct AGR because indirect heating has a significantly lower overall thermal efficiency,

Spent shale disposal and reclamation require large amounts of water in the TOSCO II and Paraho indirect designs (about 4,000 acre-ft/yr), while the estimate for the Paraho direct process is about 60 percent lower, Largely because of this difference, the overall requirement for Paraho direct is only about 5,900 acre-ft/yr, while the TOSCO II and Paraho indirect designs need about 10,500 acre-ft/yr or almost twice as much.

The requirements for MIS retorting and upgrading are similar to those for indirect AGR. However, because little water is needed for mining and waste disposal, overall water requirements for MIS are similar to those for direct AGR; that is, about 5,800 acre-ft/yr. For similar reasons, the requirements for MIS/AGR are similar to those for MIS alone.

It has been assumed that none of the AGR plants will produce mine drainage water. The MIS and MIS/AGR facilities, however, are assumed to produce such water in substantial quantity. This difference is not related to the technologies but rather reflects the siting assumptions made for the various plants. The MIS and MIS/AGR facilities are on tracts C-a and C-b in the ground water areas of the central Piceance basin, while the AGR operations are in drier areas along the southern fringe of the Piceance basin or the eastern portion of the Uinta basin. Mining in ground water areas produces mine drainage water that must either be used, discharged, or reinfected. The amount produced varies with location, Estimates for tract C-b range from 4,032 to 16,100 acre-f t/yr[16] and for tract C-a to at least 18,100 acre-ft/yr.[17] This water should be regarded as an alternate water resource and not as part of the process. Similar operations in other locations may not produce comparable amounts of water.

An Evaluation of Assumptions in the Estimates

Detailed breakdowns of the water required and produced by each principal operation in each model facility are shown in table 74. (Table 72 was derived from these data.)

Table 74.–Breakdown of Water Requirements and Water Production for 50,000 -bbl/d Oil Shale Facilities (acre-ft/yr)

	Paraho direct		TOSCO II		Paraho indirect	Union ' 'B'	Oxy MIS			MIS/AGR
	McKee-Kunchal	WPA/DRI	Colony	WPA/DRI	McKee[a] Kunchal	Eyring-Sutron	Oxy 1977	Oxy 1979	WPA/DRI	WPA/DRI
Water required										
Mining and ore handling	816	941	**1,045**	**1,045**	934	(a)	483	483	338	326
Power generation	832[b]	(c)	1,850[b]	1,850[d]	952[d]	1,850d	(c)	(c)	(c)	(c)
Retorting and upgrading										
Cooling tower makeup	3,849	3,854'	3,861	3,939	4,406	–	6,875[e]	**806**	4,494'	3,626[e]
Retorting	—	0	1,884	668	—	—	2,731	**3,753**	2,731	1,873
Upgrading	—	939[d]	939	939	—	—	939[d]	**939[d]**	939[d]	939
Other boiler makeup	1,224	490[e]	557	557	1,401	1,710[b]	985[e]	**525**	551[e]	529'
Steam and treatment loss	—	50	572	572	—	—	39	587	109	75
Service and fire water	—	69	60	60	—	—	(a)	2,111	67	60
Potable and sanitary	—	39	34	34	—	—	113	161	31	28
Disposal and reclamation										
Shale moisturizing	(c)	(c)	2.859	2,920	(c)	–	(c)	(c)	(c)	(c)
Disposal and compaction	1,664	972	428	428	—	2,870	1,208	346	346	1,239'
Revegetation		413	608	608	4,020	220	1,610	757	757	222[d]
Municlpal demand	1,61 4[b]	1,614[b]	1.485[b]	1,485°	1,829[b]	1,829b	1 ,937[b]	1 ,937[b]	1 ,937[b]	2,045[d]
Total required	9,979	9,378	16,182	15,105	13,542	8,479	16.920	12,405	12,300	10,962
Water produced										
Power generation	167d	(c)	617a	617d	191[d]	617d	(c)	(c)	(c)	(c)
Retorting and upgrading										
Cooling tower blowdown	768	1,653e	1,240	1,319	880	(a)	625[e]	(a)	1,038[e]	907[e]
Retort condensate	127	(a)	(a)	(a)	388	240	1,243	2,419	1,243	852
Gas condensate	752	542	728	728	125	–	(a)	3,072	2,157	1,480
Upgrading condensates	540	103[d]	103	103	618	(a)	103[d]	103	103	103
Boiler and treatment waste	270	487[e]	557	557	309	(a)	486[e]	384	530'	513e
Service water effluent	(a)	30	27	27	(a)	(a)	(a)	241	26	27
Potable and sanitary effluent	(a)	26	26	26	(a)	(a)	(a)	161	23	20
Surface runoff'	(a)	222	188	188	(a)	(a)	(a)	(a)	201	177
Municipal effluent	969[d]	969[d]	891	891[d]	1.098[d]	1,098[d]	1, 162[d]	1, 162[d]	1, 162[d]	1,227d
Total produced	3,593	4,032	4,377	4,456	3,609	1,955	3,619	7,542	6,483	5,306
Net *consumption*										
In acre-ft/yr	6,386	5,346	11,805	10,649	9,933	6,524	13.301	4,863	5,817	5,656
In bbl water/bbl oil.	271	227	5,02	453	422	2.77	565	2.06	2.47	2,40
Mine drainage										
In acre-ft/yr	(c)	(c)	(c)	(c)	(c)	(c)	6,440-16,100	4,032-6,452	12,326	8,454[e]
In bbl water/bbl 011	(c)	(c)	(c)	(c)	(c)	(c)	2.74-6.86	1.56-2,50	525	3.60[e]

[a]Not provided [b]Includes mining and retorting [c]Not applicable [d]Estimated by OTA [e]Modified for OTA

SOURCE R F Probstein et al *Water Requirements Pollution Effects and Costs of Water Supply and Treatment for the Oil Shale Industry* report prepared for OTA by Waler Purification Associates October 1979 p 14

Paraho Direct

The two estimates for Paraho direct are reasonably consistent. However, the McKee/Kunchal water management plan is not sufficiently detailed for a thorough evaluation to be made of the differences that appear. The two designs differ principally in the mode of power generation. The McKee/Kunchal design assumed that a water-cooled steam cycle would be used; the Water Purification Associates/Denver Research Institute (WPA/DRI) design assumed that low-Btu gas would be burned in open-cycle gas turbines that require no cooling water.

The retorts are also operated differently. A higher retorting temperature is assumed in the WPA/DRI design, and the water produced during retorting is vaporized and exhausted, In the McKee/Kunchal design, lower temperatures cause partial condensation of the retort water. Also, upgrading was not considered by WPA/DRI, and it was necessary to adapt estimates from the TOSCO II plant design,

The chief uncertainty is the claim of minimal water needs for spent shale disposal. The WPA/DRI design, which was based on this claim, uses a conservative estimate of 5 percent by weight of water for compaction and a separate estimate for revegetation. The McKee/Kunchal estimate is not directly comparable because it combines compaction and revegetation. However, the total values are reasonably consistent.

Paraho's claim that proper compaction can be obtained with small water additions is based on evidence from disposing about 150 ton/d of spent shale. It is uncertain that sufficient moisture could be extracted from the atmosphere to dispose of 72,000 ton/d, the output of a 50,000-bbl/d plant.

TOSCO II

Although the Colony water management plan is very detailed, neither Colony nor WPA/DRI assumed onsite power generation. OTA's analysis assumed that about 85 MW of power would be generated by a steam-cycle system.

A principal difference between the designs is that WPA/DRI substituted a bag filter and electrostatic precipitator for Colony's venturi wet scrubbers, thereby reducing water consumption. Both designs assumed that the spent shale is moisturized to 14 percent by weight of water to allow proper compaction. For revegetation, both designs assumed an average value of 608 acre-ft/yr over the 20-year life of the plant. During the first 10 years, little revegetation would be done and water would be used only for compaction and dust control. In the second 10 years, revegetation programs would be expanded and water needs would increase.

Paraho Indirect

It is not possible to fully evaluate the Paraho indirect estimates because the McKee/Kunchal report lacks a detailed water management scheme. Compared with TOSCO H, retorting and upgrading requirements appear low. Also, the requirement for revegetation is much higher than for all other retorts. The reason given is the high carbon content of the spent shale, but this conclusion is not supported by Union's experience with similar retorted shale. The high estimates for revegetation may have been made to offset low estimates for compaction.[18]

Union Oil "B"

Because only crude data are available, judgment should be reserved on the low estimates for mining, retorting, and upgrading, The Environmental Protection Agency (EPA) recently published a considerably higher estimate for mining and processing that would lead to a total consumption more in line with estimates for other processes.[19] Unfortunately, the higher estimate cannot be verified because no background information was supplied. An older EPA document[20] provides a value for mining and processing consistent with the Eyring/Sutron estimate. The relatively large requirement for spent shale disposal is a consequence of Union's method for cooling the hot retorted shale by immersing it in water,

Occidental (Oxy) Modified In Situ

The older Oxy estimate differs significantly from the WPA/DRI design in both water requirements and water production. Oxy's requirements are higher for cooling water, for raw shale disposal, and for revegetation, It appears that these uses were deemed appropriate for disposing of excess mine drainage water. Much less water is wasted in the WPA/DRI design and in the newer Oxy plan. Also, the production of retort condensate was not estimated in the older Oxy plan. The WPA/DRI estimate (2,157 acre-ft/yr) was based on Oxy's estimates of the steam flows to the retorts. (Much more condensate would be produced if ground water entered the retorts during their operation.) WPA/DRI also assumed that the retort gases are not compressed prior to gas cleaning. This reduces the cooling water requirement, although it increases the cost of the gas cleaning equipment. The net difference (considering condensate production and cooling water reduction) is about 6,700 acre-ft/yr, which accounts for most of the discrepancy between Oxy's older plan and the WPA/DRI study. In general, the WPA/DRI results agree quite well with Oxy's current water management plan.

Modified In Situ/Aboveground Retorting

The only published water management plan for a combined facility is that of the Rio Blanco project on tract C-a. Details are not sufficient for a thorough evaluation and the plan is now obsolete because Rio Blanco has since revised its approach. The WPA/DRI model, which combines MIS with Lurgi-Ruhrgas retorts, is similar to the current plans for the tract.

The principal difference between OTA's process model and those of Rio Blanco or WPA/DRI is that OTA has assumed surface disposal of the spent shale, whereas the others assumed that the waste is returned as a slurry to the burned-out in situ retorts. In OTA's analysis, it is assumed that the vapor losses during moisturizing are the same as in underground slurry disposal. The estimates for both revegetation and upgrading were linearly scaled from the TOSCO II requirements. The accuracy limitations noted in the MIS discussion also apply here.

Municipal Use

It is assumed that the total population growth will be 5.5 times greater than the number of employees.[21] Because this large multiplier is applied to uncertain employment figures, the estimates of municipal water needs are approximate. An aggregate requirement of 175 gal/person/d has been assumed, with consumption at 40 percent of this figure, The net requirement—70 gal/person/d—is conservatively high. The average requirement for all the facilities considered is about 700 acre-ft/yr.

Mine Drainage Water

Probably the largest uncertainty of all, because it is highly site dependent, is the amount of mine drainage water produced. As noted above, estimates for the Federal lease tracts range from 6,400 to over 18,000 acre-ft/yr. This water should satisfy the processing needs of the technologies proposed for tracts C-a and C-b. However, these needs could probably not be satisified by ground water on sites along the edge of Piceance basin.

Range of Water Requirements

The most likely ranges of the quantities of water that will be consumed by the three generic technologies and by the combined plant are indicated in table 75, Also shown are the likely ranges of mine drainage water production on tracts C-a and C-b. Overall, the requirements range from 4,900 to 12,300 acre-ft/yr—the equivalent of from 2.1 to 5.2 bbl of water consumed for each barrel of oil produced. Given this range, a l-million-bbl/d industry could require from approximately 100,000 to 250,000 acre-ft/yr. Actual water requirements would be determined by the mix of technologies used. In table 76, these requirements are estimated for an industry that would result if present projects, both active and proposed, were completed. Some features of this industry are:

- Indirect AGR, the method with the highest unit water requirement, constitutes 51 percent of the total production.
- Direct AGR and MIS, which require less water, constitute only 33 percent of production. The balance is provided by MIS/AGR, which has an intermediate requirement.
- About 43 percent of the production will result from mining in ground water areas in the central and northern Pice-

Table 75.–Likely Ranges of Water Requirements and Mine Drainage Production for Oil Shale Facilities Producing 50,000 bbl/d of Shale Oil Syncrude

Technology	Average shale grade, gal/ton	Water requirements[a] Acre-ft/yr	Barrels per barrel of 011
Directly heated AGR	29-32	4,900-7,800	21-33
Indirectly heated AGR	32-35	9,400-12,300	40-52
Directly heated MIS	23-27	4,900-5.900	21-25
MIS/AGR	23-25	5,700-6,700	2.4-29
	Location	Water production	
Mine drainage water	C-a/ C-b	4,000-16,100	1 6-69

[a]Net water requirements Low end assumes higher shale grade open -cycle power systems high retort efficiency and lower waste disposal and reclamation needs High end assumes lower shale grade steam cycle or combined cycle systems low retorting efficiency and higher disposal and reclamation needs

SOURCE R F Probstein et al *Water Requirements Pollution Effects and Costs of Wafer Supply and Treatment for the Oil Shale Industry* report prepared for OTA by Water Purification Associates October 1979 p 22

Table 76.–Water Requirements for Active and Proposed Oil Shale Projects

Project	Location	Deposit	Technology	Design capacity: Barrels per day	Design capacity: Percent of total	Water requirements acre-ft/yr: For 50,000 bbl/d	For design capacity	Weighted contribution
Rio Blanco	Central Piceance basin	Wet	MIS/indirect AGR	76,000	16	6,200	9,424	992-
Cathedral Bluffs	Central Piceance basin	Wet	MIS	57.000	12	5,400	6,156	648
Long Ridge	Southern Piceance basin	Dry	Indirect AGR	75,000	16	10.850	16.275	1,736
Colony	Southern Piceance basin	Dry	Indirect AGR	46,000	10	10,850	9,982	1 085
Sand Wash	Uinta basin	Dry	Indirect AGR	50,000	10	10,850	10,850	1 085
EXXON	Central Piceance basin	Wet	Indirect AGR	60,000	13	10,850	13,020	1,411
White River	Uinta basin	Dry	Direct AGR	100,000	21	6.350	12700	1,334
Superior	Northern Piceance basin	Wet	Indirect AGR	11,500	2	10,850	2,496	217
			Total	475,500	100		80,903	8,508

SOURCE Office of Technology Assessment

ance basin. These plants could obtain their process water from the aquifers in the mining zone. Surface water would not be needed.

The total production from this combination (475,000 bbl/d) would require 80,903 acre-ft/yr, On this basis, a 50,000-bbl/d plant would need about 8,500 acre-ft/yr; a l-million-bbl/d industry about 170,000 acre-ft/yr.

The following sections will use these estimates in conjunction with estimates of surplus surface water availability and other critical factors to identify the level of shale oil production at which water scarcity might restrict development. The issues section of this chapter discusses the industries that might result if a different mix of technologies were used or if ground water were developed,

Water Resources: A Physical Description

Surface water is obtained from rivers and streams; ground water from underground aquifers. In some instances, these sources are physically connected and should not be evaluated independently. For example, if the ground water supplies in most Western States were fully utilized, surface flows would decrease.

Surface Water

The Colorado River system, which includes the Colorado River and its tributaries, supplies surface water to the oil shale region. The Colorado River flows 1,440 miles from source to mouth. Its drainage area of 244,000 mi^2 includes parts of seven States and Mexice. The waters of the Colorado River system are divided between the Upper Colorado River Basin (which includes parts of Colorado, Utah, Wyoming, Arizona, and New Mexico), and the Lower Colorado River Basin (which includes parts of California, Nevada, Arizona, New Mexico, and Utah). (See figures 63 and 64.) The basins are divided at Lee Ferry, Ariz., 1 mile south of the Paria River near the border between Arizona and Utah.

Six major streams enter the Colorado River in the Upper Basin, From north to south, these are the Green, the Yampa, the White, the Gunnison, the Dolores, and the San Juan. The drainage area of the Upper Basin has been divided into a number of hydrologic subbasins, each corresponding to the watershed of a major river. Oil shale development may directly affect three of these subbasins: the Green River basin in the southeastern corner of Wyoming; the White River basin, which includes parts of western Colorado and eastern Utah; and the basin of the Colorado River mainstem in Colorado.

Water quality in these streams is highly variable. The quality in most of the upstream reaches of major tributaries is good to excellent although some smaller streams that receive discharge from saline ground water aquifers are of very poor quality. Water quality is significantly poorer in most downstream areas. The gradual deterioration is caused by flows of naturally saline streams into the river system and by man-related discharges from settlements, mineral development sites, and irrigated farmlands, Water quality and the problems it causes are discussed further in chapters 4 and 8.

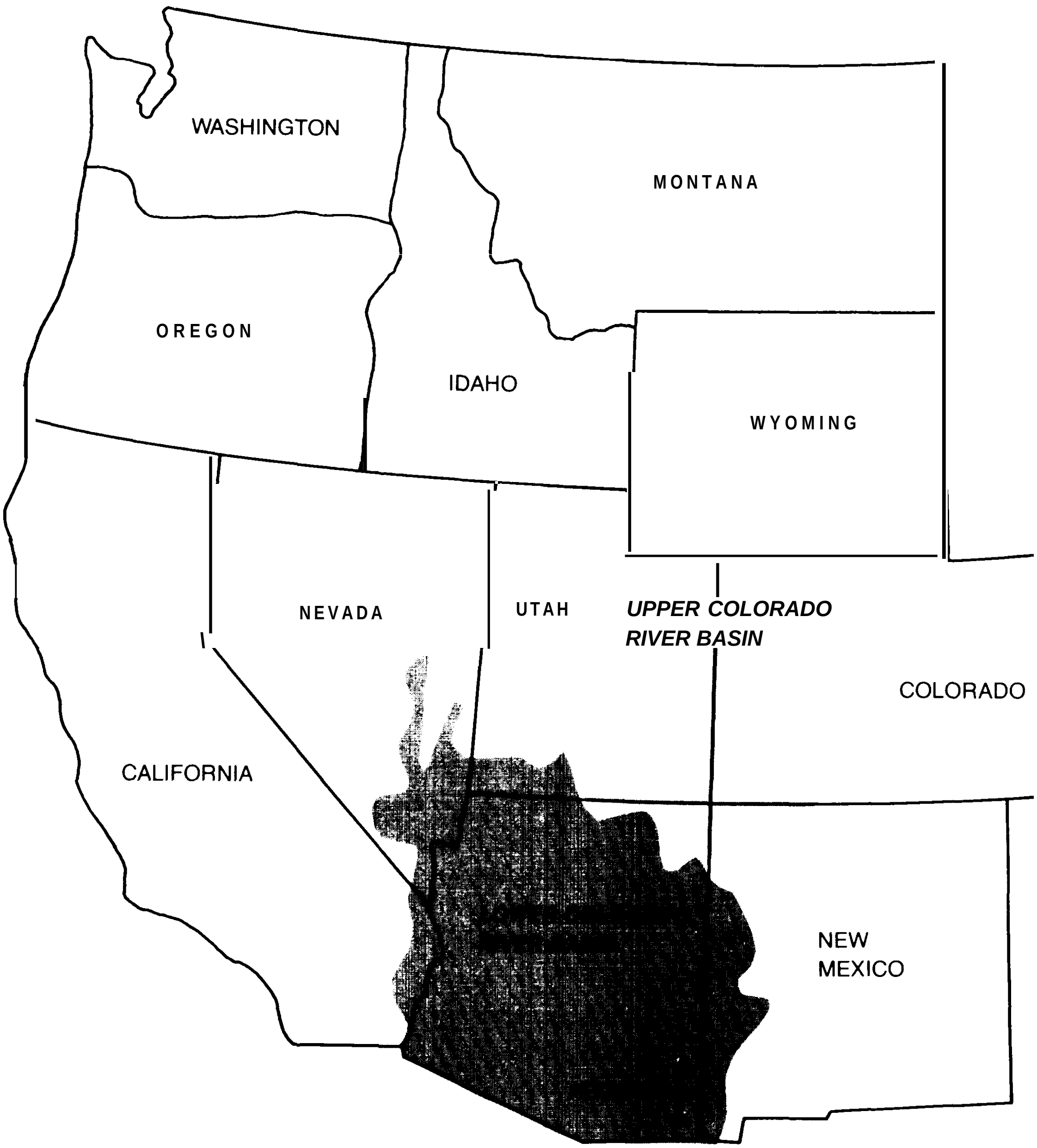
The Colorado River system drains an extensive area, but its flows are relatively small. The average annual virgin flow* at Lee Ferry was 13.8 million acre-ft/yr between

*Virgin flow is the flow that would occur in the absence of human activity. Most of the water availability analyses in this chapter deals with the 1930-74 average because of its common use in other water resources analyses. The effects of different assumptions regarding virgin flow are discussed in the issues sect ion,

Photo credit OTA staff

Upper Colorado River near Rifle, Colo.

Figure 63. —Major Hydrologic Basins of the Colorado River System

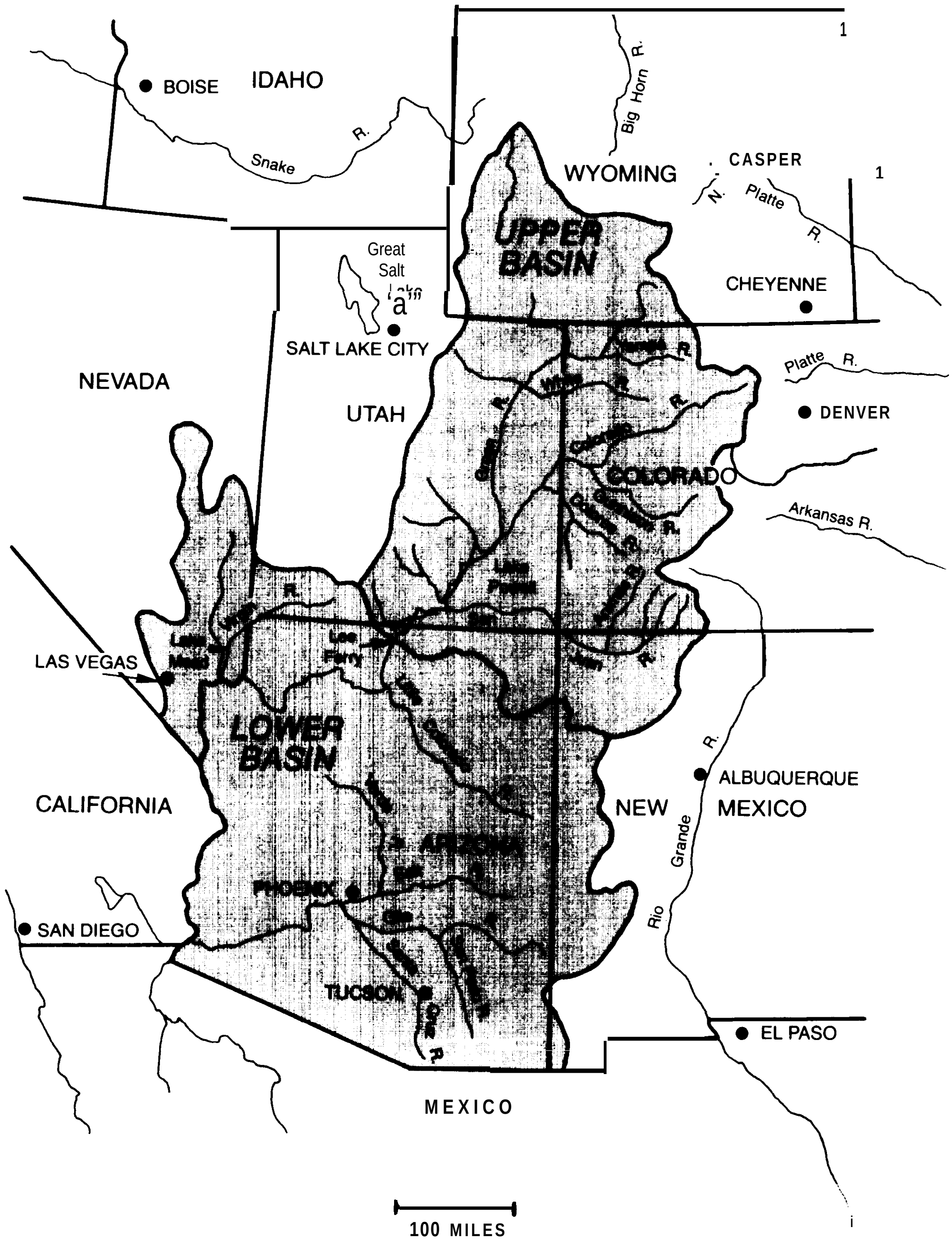


SOURCE U S Bureau of Reclamation *Critical Water Problems Facing the Eleven Western States—Westwide Study Volume I Main Report* NTIS No PB-263 981 Denver Colo April 1975

1930 and 1974, in contrast to about 180 million acre-ft/yr for the Columbia River and 440 million acre-ftlyr for the Mississippi River. Despite its relatively low flows, the system is one of the most important in the Southwest. It serves approximately 15 million people. Municipalities, agriculture, energy production, industry and mining, recreation, wildlife, Federal lands, and Indian reservations all compete for its waters.

Flows vary seasonally, increasing with spring snowmelts and heavy rainstorms in

Figure 64.—The Upper and Lower Colorado River Basins



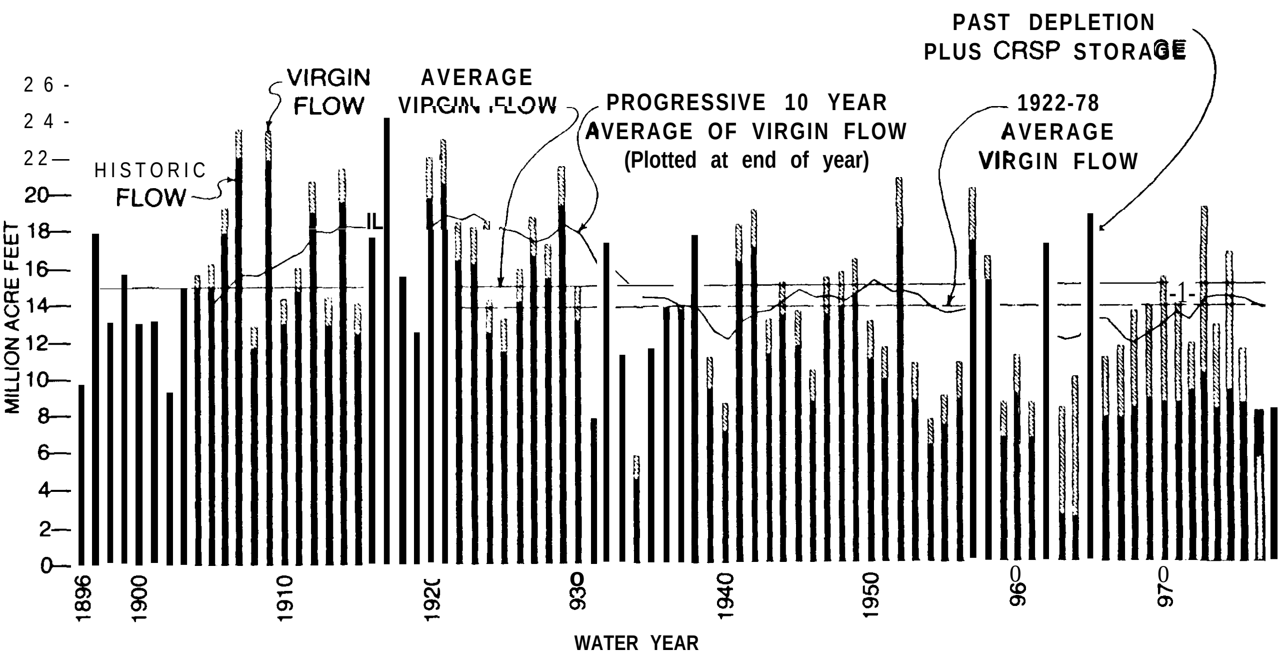
SOURCE: C. W. Stockton and G. C. Jacoby, "Long-Term Surface-Water Supply and Streamflow Trends in the Upper Colorado River Basin Based on Tree-Ring Analyses," *Lake Powell Research Project Bulletin No. 18,* March 1976, p.2

the late summer and fall and declining during the rest of the year. They also vary from year to year, as shown in figure 65. Flow records and examination of vegetation growth cycles indicate that they may also vary over a much longer period, spanning decades or even centuries. The fact that virgin flows at Lee Ferry between 1906 and 1974 averaged about 15.2 million acre-ft/yr while between 1930 and 1974 they averaged only 13.8 million acre-ft/yr is evidence of this long-term variabilit y.

The flow variations are significant because they reduce the accuracy of long-term projections of water availability. They also furnish a rationale for building reservoirs to offset seasonal fluctuations and stabilize supplies during dry years. Several reservoirs have been built in the Upper Basin for this purpose. The five largest were built by the Federal Government under the Colorado River Storage Project Act (CRSP) of 1956: Lake Powell in Arizona and Utah, Flaming Gorge in Utah and Wyoming, Fontenelle in Wyoming, Navajo in New Mexico, and the Curecanti Unit (which includes the Crystal, Morrow Point, and Blue Mesa Reservoirs) in Colorado. These projects have been completed and are now being filled, When full, the existing reservoirs will have a maximum active storage capacity of about 35 million acre-ft/yr. Lake Powell is by far the largest, and will have an active capacity of about 25 million acre-ft. Other reservoirs have been authorized by Congress but funds have not yet been appropriated for their construction. These include the Savery Pothook, Fruitland Mesa, and West Divide projects. The locations of the existing CRSP reservoirs are shown in figure 66.

Reservoirs have been effective in dampening the fluctuations in the virgin flows. This is illustrated in figure 67, which compares actual measured flows of the Colorado River at Lee Ferry with the corresponding estimates of virgin flows for the period 1953-78. The Flaming Gorge and Navajo Reservoirs began filling in 1962; Lake Powell in 1963, and Fontenelle in 1964. During prior years, actual flows varied widely, from 6 million acre-ft/yr to over 17 million acre-ft/yr. In 1962, the ac-

Figure 65.—Annual Average Virgin Flow of the Colorado River at Lee Ferry, Ariz.



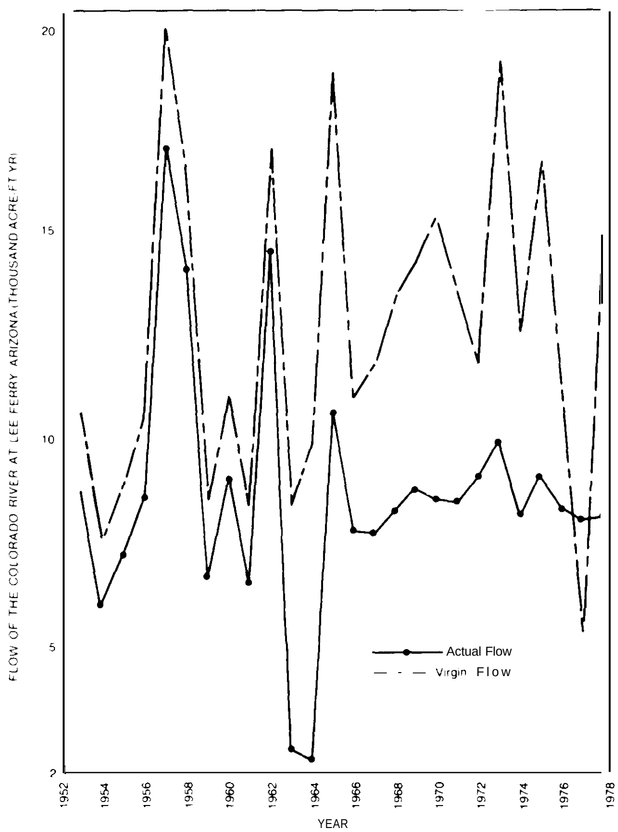
SOURCE Upper Colorado River Commission. *Thirtieth Annual Report*, Salt Lake City, Utah, Sept 30, 1978, p 44

Figure 66.—Major Dams and Reservoirs on the Colorado River and Its Tributaries

✪ **Colorado River Storage Project Act Dam and Reservoir**

SOURCE Upper Colorado River Commission, *Thirtieth Annual Report,* Salt Lake City, Utah, Sept 30, 1978. p. 44

Figure 67.—Flows of the Colorado River Between 1953 and 1978



SOURCE Upper Colorado River Commission *Thirtieth Annual Report* Salt Lake City Utah, Sept 30.1978. p 44

tual flow dropped substantially, partly because of low virgin flow and partly because of the start of reservoir filling. In 1968, the actual flow approached 8 million acre-ft/yr and has remained within the range of 8.23 million to 10.14 million acre-ft/yr ever since. Between 1968 and 1978, virgin flows ranged from 5.5 million to 19.3 million acre-ft/yr. Actual flows have not yet stabilized because the reservoirs are still filling.

Ground Water

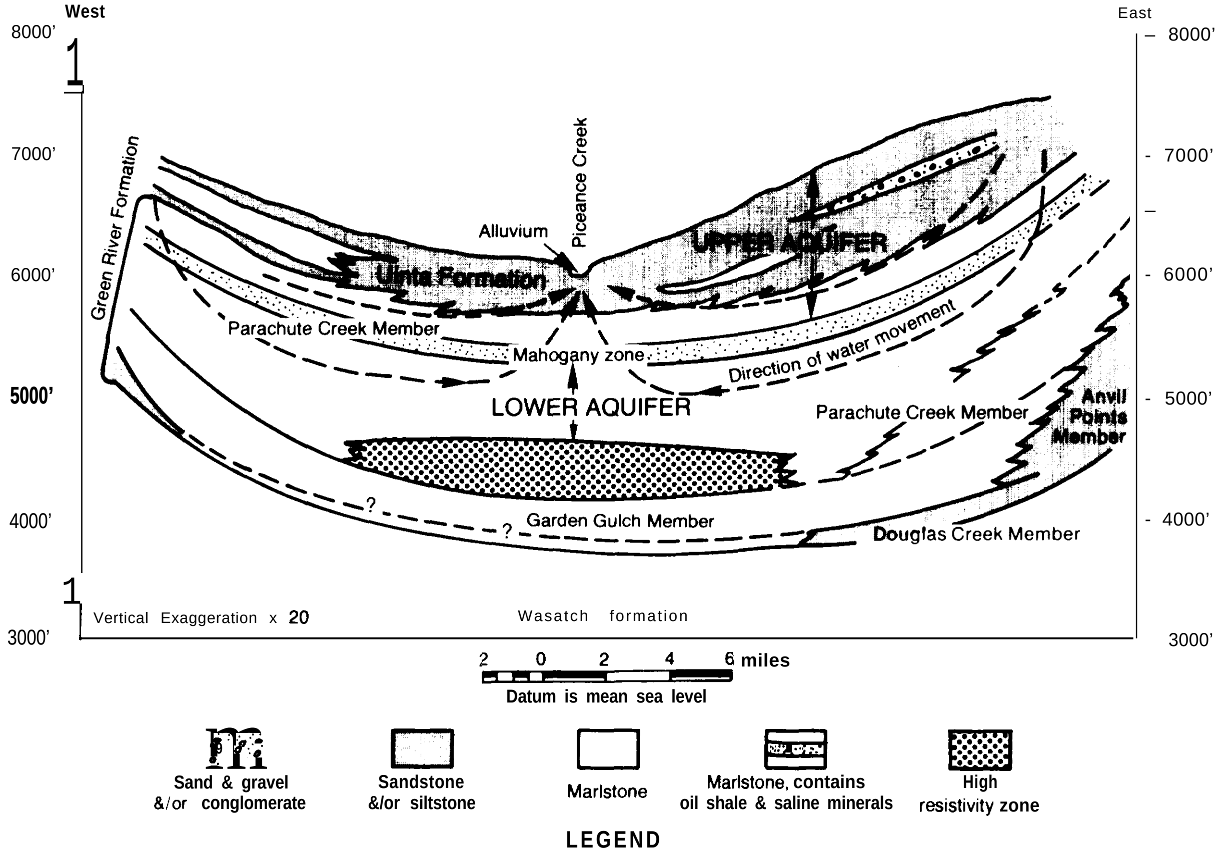
Ground water resources occur near the surface in alluvial (floodplain) aquifers and more deeply buried in bedrock aquifers. In most areas, alluvial aquifers contain relatively little water. The amount in bedrock aquifers is unknown but is though! to be very large. It has been estimated that bedrock aquifers in the Piceance basin could contain as much as 25 million acre-ft in storage. This is nearly twice the annual virgin flow of the Colorado River at Lee Ferry and is equivalent to the storage capacity of Lake Powell. The primary bedrock aquifer near Federal tracts U-a and U-b in Utah is estimated to contain at least 80,000 acre-ft.

The actual quantities of ground water that could be used for oil shale development are uncertain. The amount available is determined by the location of the aquifers relative to potential plantsites, the water quality, and physical characteristics such as the depth and the recharge rate. The physical characteristics determine the quantity of water that can be stored or extracted, the rate at which water can be added or withdrawn, and the change in water levels that will result from withdrawing a given volume of water.

The principal aquifers of the Piceance basin are located in the Uinta and Green River geologic formations. (See figure 68.) The system is characterized by two bedrock aquifers, the "upper" and the "lower," that are separated by a 100- to 200-ft-thick confining layer of rich oil shale known as the Mahogany Zone. In addition, alluvial aquifers occur in gravel, sand, and clay along the bottoms of stream and creek valleys.

The bedrock aquifers are recharged by springtime snowmelt, which replaces an estimated discharge of 26,110 acre-ft/yr. Water enters the upper aquifer along the basin margins above an altitude of 7,000 ft and moves downward through the Mahogany Zone to recharge the lower aquifer. Generally, ground water in both of these aquifers flows from the recharge areas toward the discharge areas in the north-central part of the basin. In the discharge areas water moves upward from the lower aquifer through the Mahogany Zone to the upper aquifer and is discharged both to the alluvium and by springs along the valley walls. Ultimately, the discharged ground water flows into Piceance and Yellow Creeks and then into the Colorado River system. [22]

Figure 68.— Bedrock Ground Water Aquifers in Colorado's Piceance Basin



SOURCE Department of the Interior, *Draft Environmental Statement—Proposed Development of Oil Shale Resources by the Colony Development Operation in Colorado*, Bureau of Land Management (1975), p III 34

Despite the large resources, little ground water development has taken place to date. [2] The major economic use is for watering livestock. In addition, natural seeps and springs supply water to vegetation and wildlife in many of the valley floors. Overall, relatively little water is withdrawn, and the ground water system is in hydrologic equilibrium. That is, the rates of recharge and discharge are equal and the amount of water in storage does not change significantly over time.

Allocation of the Colorado River System Waters

Because of competing demands, disputes over the proper allocation of water resources have permeated the political, social, economic, and legal histories of the seven States in the Colorado River system. As a result, a complex framework of interstate and interragional compacts, State and Federal laws, Supreme Court decisions, and international treaties has been developed to govern distribution of the system's waters. Together, the provisions of this framework comprise "the law of the river." Their interpretation is crucial to an understanding of the water availability problem.

Compacts, Treaties, and Legal Mechanisms

The Colorado River Compact of 1922

The major provisions of this compact are:

1. It divided the river system into the Upper and Lower Basins, and allocated 7.5 million acre-ft/yr to each basin for beneficial consumptive use, Authority was also given to the Lower Basin to increase its annual use by 1 million acre-ft.
2. It did not recognize a specific obligation to provide water to Mexico. However, a framework was established whereby any future obligation would be shared equally between the Upper and Lower Basins.
3. The Upper Basin was prohibited from reducing the flow at Lee Ferry to below an aggregate of 75 million acre-ft in any 10-year period. The Upper Basin was not to withhold water, nor was the Lower Basin to demand water that could not reasonably be applied to domestic and agricultural uses.

The Boulder Canyon Project Act of 1928

This Act provided for the construction of Hoover Dam and its powerplant, and for the All-American Canal. Its major provisions are:

1. It suggested a specific framework for apportioning the water supplies allocated by the compact of 1922 among the Lower Basin States of California, Arizona, and Nevada. (The States did not adopt this framework, but it was later imposed on them by the Supreme Court decision in Arizona v. California, as discussed below.)
2. It required California to reduce its annual consumption to 4,4 million acre-ft plus not more than half of the surplus water provided to the Lower Basin. (This requirement was met through the California Limitation Act of 1929.)
3. It authorized the Secretary of the Interior to investigate the feasibility of projects for irrigation, power generation, and other purposes.

The Upper Colorado River Basin Compact of 1948

In this compact, the Upper Basin States apportioned the water allocated under the compact of 1922. The negotiators recognized the problem inherent in allocating water on a strict quantity basis because of flow fluctuations from year to year. As a result, water was apportioned on a percentage basis to all States except Arizona. Major provisions of the compact are:

1. Arizona was guaranteed 50,000 acre-ft/yr, The remaining water was apportioned as follows:
   - to Colorado: 51.75 percent,
   - to New Mexico: 11.25 percent,
   - to Utah: 23.00 percent, and
   - to Wyoming: 14.00 percent,
2. It recognized that new reservoirs would be needed to assist the Upper Basin in meeting its delivery obligation to the Lower Basin. Such reservoirs, however, would increase evaporative losses from the river system as a whole, thus reducing the quantity of surplus water available to the Lower Basin. The compact provided that charges for such evaporative losses be distributed among the Upper Basin States. Each State was to be charged in proportion to the fraction of the Upper Basin's water allocation that was consumed in that State on a yearly basis, and its maximum consumptive use was to be reduced accordingly.
3. It provided for the division of water between pairs of States on a number of specific rivers. The compact did not deal with the White River, which delivers approximately 500,000 acre-ft/yr to the Utah State line and which could supply water for energy development.

Mexican Water Treaty of 1944-45

As part of negotiations over apportionment of water from the Rio Grande, Tijuana, and

Colorado Rivers, the United States guaranteed to deliver at least 1.5 million acre-ft/yr of water to Mexico. However, in times of severe drought or in the event of a failure in the delivery systems, Mexico could receive less than 1.5 million acre-ft/yr.

Colorado River Storage Project Act of 1956

This Act provided for several new storage reservoirs to assist the Upper Basin States in meeting their delivery obligation to the Lower Basin, while simultaneously increasing water consumption in the Upper Basin. The five CRSP reservoirs that have since been built were described in the earlier discussion of the fluctuating flows of the river.

The Supreme Court Decree in *Arizona v. California*

This decision (376 U.S. 340 (1964)) imposed upon the Lower Basin States the water distribution framework that had been suggested by the Boulder Canyon Project Act of 1928. The Lower Basin's water allocation of 7.5 million acre-ft/yr was to be apportioned as follows:

- to California: 4.4 million acre-ft/yr,
- to Arizona: 2.8 million acre-ft/yr, and
- to Nevada: 0.3 million acre-ft/yr.

The decree also required that approximately 1million acre-ft/yr from the allocations to California and Arizona be diverted for the five Indian tribes located along the lower Colorado River.

Colorado River Basin Project Act of 1968

This Act instructed the Secretary of the Interior to propose criteria for the coordinated long-range operation of reservoirs built under the Boulder Canyon Project Act and the CRSP Act. Criteria were subsequently established and now form the basis for operation of the reservoirs. (These operating criteria are of importance in estimating water availability in the Upper Basin States, as discussed below.) The Act also identified the Mexican Water Treaty as a national obligation, to be considered in developing any subsequent water projects. It prohibited the Secretary from studying importation of water into the Colorado River Basin until 1978. (This moratorium was subsequently extended to 1988 by the Reclamation Safety of Dams Act of 1978.)

Surface Water Allocations

Each of the above documents assumes different values for the quantity of virgin flow past Lee Ferry. They therefore differ with respect to the total amount of water to be apportioned. In general, each State can interpret the law of the river so as to maximize its water-resource position and can develop its water programs on that basis. Consequently, an analysis of the opportunities for further growth in the Upper Basin States is clouded by uncertainty, and it is not possible to predict with any exactitude the maximum size of the oil shale industry that could be accommodated.

The annual virgin flows assumed in some of these documents are shown in table 77.

Table 77.–Estimates of Surface Water Allocations to the Oil Shale States (millions of acre-ft/yr)

Source of virgin flow estimate	Virgin flow at Lee Ferry	Colorado	Utah	Wyoming	Total
Colorado River Compact of 1922 . . . ., . .	180	*5.06*	*2.25*	1.37	8.68
Mexican Water Treaty of 1944 -45...... . . .	16.2	4.12	1.83	1,12	7,07
Upper Colorado River Basin Compact of 1948. , ., .,	15,6	3.81	1.70	1.03	6.54
Colorado River Basin Project Act of 1968 . .	14.9	3.45	1.53	0,93	5.91
Average flow 1930 -74.	13.8	2.88	1,28	0.78	4.94

Assumes delivery of 823 million acre-ft/yr to Lower Basin Slates and Mexico 7500000 acre-ft/yr to Lower Basin (per 1922 compact) plus 750,000 acre-ft/yr 10 Mexico (per Mexican Waler Treaty of 1944-45) less 20 000-acre-ft/yr inflow from the Paria River below Lake Powell = 8230000 acre-ft/yr Neglects evaporative losses from Upper Basin reservoirs Assumes apportionment among the 011 shale States according to the Upper Colorado River Basin Compact *of* 1948

SOURCE Office of Technology Assessment

Also shown is the average virgin flow at Lee Ferry between 1930 and 1974. For each flow figure, the corresponding gross quantity of surface water allocated to each oil shale State is also shown. It was assumed that the Lower Basin States receive 8.23 million acre-ft/yr out of the Lake Powell Reservoir above Lee Ferry, as called for in the operating criteria prepared under the provisions of the CRSP Act of 1968. As indicated, the quantity of surface water available to the three States under the terms of the various documents could be as low as 4.94 million acre-ft/yr and as high as 8.68 million acre-ft/yr. The lower figure is more realistic for planning purposes,

Doctrine of Prior Appropriation

Introduction

The water rights policies of Colorado, Utah, and Wyoming are, in general, similar. Their respective constitutions hold that water is the property of the public, not the landholder, and that it is the State's responsibility to apportion rights to use water among competing users, Each State administers surface water rights and some ground water rights according to a doctrine of prior appropriation, This differs from the riparian doctrine that prevails in most Eastern States under which water rights are automatically the property of the owner of the land on which the water is found. Under the prior appropriation doctrine, water rights are severable from the land, and one may own water rights without owning any land whatsoever.

Surface Rights

The key elements of the doctrine of prior appropriation are: the specific types of water rights, the seniority system for determining priority of use, the preference system for distinguishing among types of water uses, options for transfer of water rights between parties, and policies for determining the abandonment of water rights.

Types of Water Rights

There are two categories of water rights: conditional and absolute. A potential user acquires a conditional water right by filing for a conditional decree from the State water courts and then proceeding diligently towards the actual use of the water. An absolute water right is created when a holder of a conditional right perfects that right by actually diverting the water and applying it to a beneficial use. Beneficial uses have been defined to include any use in which water is not wasted.

Within each category there are two types of water rights. A direct flow or diversion right permits the diversion of water from a stream followed by its immediate application. A storage right permits the impoundment of water for later application. None of the three States recognizes the right of private parties to require that sufficient stream flows be maintained for the protection of instream uses, such as rafting and fishing. However, a Colorado law permits that State to obtain water rights for sufficient flows to preserve the natural environment to a reasonable degree.

In Colorado, the water rights are adjudicated by the State Water Courts and administered by the State engineer. The right to appropriate water is limited only in that property rights of other parties cannot be impaired. A conditional right is automatically granted if the user proceeds with due diligence towards perfection of the right and if the rights of other users are not jeopardized. Neither the courts nor the executive branch of government has discretionary authority over the type, place, or quantity of use. Furthermore, the State has no power to remove a stream or any portion of its waters from appropriation. The State engineer only monitors the system to assure that rights are protected and water is not wasted.

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In Utah and Wyoming, a permit system is employed in which the right to appropriate water must be approved by the State engineer. He must consider the water rights of others, but is also allowed to consider public interest or public welfare when passing on an application for appropriation. Thus, in contrast to Colorado, the governments of Utah and Wyoming have discretionary authority to approve some uses and deny others. Use of this power has been minimal.

It is noteworthy that the continuation of conditional decrees requires only due diligence and not actual use. In the past, rights have been granted liberally by all three States and as a result, the quantities of water covered by conditional decrees far exceed the available resources. Not all of the conditional decrees have been perfected, and relatively little of the claimed water is actually being used. Consequently, surplus surface water appears to be available in the oil shale region. However, all of it has already been claimed, in part by oil shale developers. Similar situations prevail in Utah and Wyoming.

Seniority of Water Rights

The prior appropriation doctrine is based on the principle of "first-in-time, first-in-right. " Thus, the more senior (older) the water right, the higher its priority for the use of limited resources. If shortages occur, user rights that are junior in terms of the initiation date are curtailed to assure water supplies to users with more senior rights. Only when the most senior rights have been satisfied do less senior users have any rights to water.

The date of a right, assuming the appropriation goes forward diligently to completion, is the date of the first act evidencing an intent to take water for beneficial use. In general, this is the date on which the application for a conditional decree was filed. In Colorado, a State statute makes most water rights a matter of public record. Rights to surface water are established solely by the actions of individual users, but these rights are legally protected only if they are formalized by water court decrees in Colorado or by the permitting process in Utah and Wyoming.

Preference Systems

A preference system has been established in each State to apportion water among different beneficial uses during times of shortage. Under its provisions, drinking water or municipal users have first preference, agriculture is second, and industry is third. The preference system overrides the seniority system; water rights with a lower preference may be condemned in favor of a higher preferred use, even if the preferred water right is junior to the displaced right. In most cases, just compensation would be required for displaced senior water rights.

Transfer of Water Rights

Water rights are considered real property and may be sold or transferred. [24] They are conveyed by deed and may be severed from the land on which the water was originally used, In Colorado, such transfers are reviewed by the water courts and may only be denied if other users would be harmed. In Utah and Wyoming, application for transfer is made before the respective State engineer, who decides whether harm will occur to other users and also considers public interest and other factors. Sale and transfer of water rights is complicated by the need to protect junior appropriators, seasonal rights of some users, appurtenance (right-of-way) of water rights to land, and preferred use as defined by the individual States,

Abandonment of Water Rights

In all three States, absolute water rights may be partially or completely lost by abandonment. In Colorado, failure to use an absolute right for a period of 10 years constitutes prima facie evidence of abandonment. The status of water rights is reviewed periodically by the division engineer in each of the State's water divisions. In Utah and Wyoming, abandonment is defined as nonuse for a period of 5 years. Unlike Colorado, these States have no provisions for a continuing review of the status of water rights.

Ground Water Rights

In Colorado, tributary ground water (ground water that is hydrologically connected to the surface water system) is treated essentially the same as a surface flow and thus is subject to the prior appropriation doctrine. Nontributary ground water (ground water that does not reach surface streams) is divided into two categories: designated ground water basins and nondesignated ground water areas, Nontributary ground water resources in designated basins are controlled by a permit system through the State Groundwater Commission. Nontributary ground water in nondesignated ground water areas, on the other hand, is subject to prior appropriation. Permits for wells must be obtained from the State engineer, and ground water rights must be adjudicated by the water courts to assure legal protection, just as with a surface right. Small wells (less than 15 gal/rein) for livestock or domestic use have been defined by law to cause no injury and are exempt from such regulations.

In Utah, all ground water is subject to the appropriation doctrine. Rights are administered by the State engineer and permits for wells may be sold as any other water rights. In Wyoming, permits must be obtained for any ground water use. Livestock watering and domestic uses have preference over all other rights, regardless of seniority.

Federal Reserved Rights

The Federal reserved rights doctrine originated in the Supreme Court decision in Winters v. United States (207 U.S. 564 (1908)) regarding Indian water rights. It was held that when Indian reservations were established by treaty with the United States, sufficient water to supply all Indian lands was also reserved. The Court did not quantify sufficiency. Rather, it reflected the opinion that Indian reservations were created to transform a nomadic people into permanent settlers and that those people required sufficient water for irrigation.[25]

A major effect of this decision is that the vater rights set aside for Indian reservations vere interpreted to be superior to those of all ther subsequent appropriators who obtained their rights under State law, even though the Indian tribes had not yet put their rights to beneficial use. Federal rights were thus entered into the prior appropriation system of each affected State, together with 11 other applicants and appropriators.

In Arizona v. California, the Court exended the reserved right doctrine to Indian reservations created by Executive order and to other Federal reservations such as national recreation areas, wildlife refuges, and national forests. In addition, the Court addressed the question of the quantity of water reserved for Indian use. It held that water was intended to satisfy the future as well as the present needs of Indian reservations, and ruled that sufficient water would be reserved to irrigate all the practicably irrigable acreage on the reservations.[26]

A further Supreme Court decision in United States v. New Mexico (98 Sup. Ct. 3012 (1978)) attempted to resolve the uncertainty over the qualification of Federal reserved water rights for areas other than Indian reservations. The Court concluded that the doctrine applied only to the original purposes of the reservations, and that reserved water rights could not be used for other purposes.[27] For example, the rights associated with a national forest could be used for maintaining the forest and its wildlife, but not for industry, farming, or oil shale development.

While the Supreme Court has served notice that it will interpret the purpose of Federal reservations narrowly, a number of uncertainties remain concerning the quantities of water that could be claimed to serve these purposes. With regard to Indian reservations, for example, it is still uncertain how much water will be claimed, how much will be used, whether the use must take place on the reservation, and whether rights can be sold or leased for uses outside the reservation.

Physical Availability of Surface Water for Oil Shale Development

Introduction

The size of the industry that could be supported by surplus surface water is affected by the following factors:

- the long-term average virgin flow in the Colorado River system (this determines the gross quantity of water that is available);
- the compacts and other documents that constitute the law of the river (these determine how the gross water supply is allocated among the basins and States);
- the demands of other users (these consume part of the allocation to each State, the remainder is the surplus);
- the oil shale technologies employed (these determine how much water the industry would need);
- the siting of the facilities (this determines how the industry's water demands will be distributed among Colorado, Utah, and Wyoming); and
- the timing of their construction and the duration of their operation.

The final factor is particularly important. The region's surface water resources are finite, and they are not large. In the past, they have generally been adequate, when supplemented by reservoir storage, to satisfy the demands of all users. At present, there is plenty of surplus water for a very large oil shale industry, but the surplus is shrinking because of population growth (both in the Upper Basin and in the urban areas to which its waters are exported), accelerated mineral resource development, increases in irrigated agriculture, and expansions of other activities.

In the future, there may not be enough water for oil shale unless the demands of other users are partially curtailed. When this will occur is not known. If it happens before the plants are built or during their useful life, then social and economic dislocations would result. If, on the other hand, it occurs after conservation and the development of other energy sources have sufficiently diminished the demand for liquid fuels, then the disturbances caused by the temporary presence of an industry may not be overwhelming.

This section evaluates whether the surface water resources in the Upper Basin are physically adequate, and legally available, to support a large industry. Availability is analyzed for the Upper Basin as a whole, and for the hydrologic subbasins that are likely to be affected. The factors analyzed were highlighted above. Following is a summary of the assumptions made and of the sources of supporting information.

Virgin Flow

An annual average flow of 13.8 million acre-ft/yr past Lee Ferry is assumed. This is the running average between 1930 and 1974. Virgin flows have been calculated since 1896, and the 1896-1974 average is considerably higher-15.2 million acre-ft/yr. However, the natural flows (the basis of the calculated virgin flow) have been measured more accurately since 1930, and the 1930-70 average is considered a better estimate. The effects of flow fluctuations around the 13.8 million acre-ft/yr average are discussed in the issues section.

Law of the River

It is assumed that the allocation to the Upper Basin is determined by the operating criteria promulgated for CRSP reservoirs by the Department of the Interior (DOI). These criteria require a minimum discharge of 8.23 million acre-ft/yr from the Lake Powell Reservoir into the lower Colorado River. This incorporates the Lower Basin's allocation under the Colorado River Compact of 1922 (7.5 million acre-ft/yr), plus one-half of the Mexican treaty obligation (750,000 acre-ft/yr), less the contribution of the Paria River (20,000 acre-ft/yr), which discharges into the Colorado River between Lake Powell and Lee Ferry. The Upper Basin States do not agree with these criteria. The effects of other interpretations of the law of the river are discussed in the issues section.

It is also assumed that flows allocated to the Upper Basin are distributed according to the Upper Colorado River Basin Compact of 1948. As indicated previously, this compact allocated 50,000 acre-ft/yr to Arizona and, of the remainder, 51.75 percent to Colorado, 23 percent to Utah, 14 percent to Wyoming, and 11.25 percent to New Mexico,

Demands of Other Users

Section 13(a) of the Federal Nonnuclear Energy Research and Development Act of 1974 directed the U.S. Water Resources Council to assess the water requirements of emerging energy technologies and the availability of water for their commercialization. Studies were to be undertaken at the request of the Energy Research and Development Administration (ERDA), In 1977, ERDA requested three such "l3(a)" assessments, one directed to the water-resource aspects of oil shale development and coal gasification in the Upper Basin. Oversight for these projects was transferred to the Department of Energy (DOE) in 1978.

The Upper Basin 13(a) assessment was organized under the management of DNR of the State of Colorado. DNR's work has been reviewed by an interagency, intergovernmental steering committee that includes representatives of the Arizona Water Commission, the Colorado Water Conservation Board, the New Mexico Interstate Stream Commission, the Utah Division of Water Resources, the Wyoming State Engineer's Office, the U.S. Soil Conservation Service, the Department of Commerce, DOE's Denver Project Office, the Region VIII Office of the Department of Housing and Urban Development, USBR, and EPA. Technical assistance and studies were provided by USBR (hydrologic modeling), the U.S. Fish and Wildlife Service (USFWS) (fishery and recreational impacts), the U.S. Heritage Conservation and Recreation Service (recreational data), Los Alamos Scientific Laboratory (economic modeling), the U.S. Soil Conservation Service (agricultural water consumption and conservation), the U.S. Geological Survey (USGS) (water quality), and several private contractors.

Because of this broad support and review base, DNR's estimates of present and future water depletions appear to be the best available for the period between 1980 and 2000. OTA has relied on the values provided for "conventional'" (nonoil shale) depletions to define the baseline water-demand conditions under which the oil shale industry could be established. DNR"s results have also been used to evaluate water-supply options in the areas in which oil shale development is most likely to occur.

DNR projected water consumption patterns for conventional activities in 2000 based on low, medium, and high regional growth rates. The medium-growth scenario, which was based on declared plans by the various users for expanding their water needs, is considered by the States to be the most realistic. The high growth rate scenario was derived from the medium scenario by assuming that announced projects would be finished sooner than expected or would consume more water than anticipated. A few projects not considered in the medium-growth scenario are included in the high-growth scenario. The low-growth scenario was derived by assuming project delays or lower than anticipated water consumption. In this section, OTA considered only the medium growth rate. The low and high rates are considered in the issues section.

Oil Shale Technologies

It is assumed that the technology mix used by any future industry will resemble that of the projects presently active or proposed. The characteristics of this industry were described in table 76. About 51 percent of the facilities use indirectly heated AGR, 33 percent directly heated AGR and MIS, and 16 percent a combination of MIS and indirectly heated AGR. On this basis, each plant would require about 8,500 acre-ft/yr for production of 50,000 bbl/d of shale oil syncrude. The effects of other technology mixes are discussed in the issues section.

Distribution of Facilities

If the siting pattern of the present projects were extended to a major industry, 68 percent of the production would be based in Colorado, 32 percent in Utah, and none in Wyoming, Although they are of lower quality, some development of Wyoming shales may occur if a major industry is established. Therefore, it was assumed that approximately 5 percent of future production will come from Wyoming, about 70 percent from Colorado, and about 25 percent from Utah. This assumption determines which hydrologic subbasins will be impacted. It also determines how much of the production could be sustained by the extensive ground water resources of the Piceance Basin. In this section, it is assumed that all of the plants rely on surplus surface water. The possible substitution of ground water is discussed in the issues section.

Timing and Lifetime of the Projects

It is assumed that the facilities will be installed before 2000, regardless of the industry's size. As discussed in the other chapters, establishing a large industry this quickly may be difficult.

The Availability of Surface Water in the Upper Colorado River Basin

Water Consumed by Conventional Activities

At present, the following activities consume surface water in the Upper Basin:

- thermal power— for steam-electric power generation;
- agriculture— for irrigation, watering stock, and other agricultural purposes;
- wildlife and recreation—for maintenance of fish, wildlife, and recreational areas;
- minerals—for extraction, processing, and transporting ores and concentrates;
- municipal and industrial—for domestic, commercial, retail, and manufacturing facilities, including final processing of raw materials into finished products; and
- exportation— for diversion and transportation to other basins or to other areas within the Upper Colorado River Basin.

Water consumption patterns for these activities, at present and as projected to 2,000, are shown in table 78. Agriculture presently depletes nearly 71 percent of the total, water exports are the second highest category at 24 percent, and the remaining 5 percent is distributed fairly evenly among the other uses. A comparison with the year 2000 projections indicates shifts both in the absolute quantities of water consumed and in the distribution of consumption among the various activities. The following trends are indicated:

- Agricultural water consumption is projected to increase by 19 percent. However, agriculture's share of total consumption is projected to decrease to 61 percent from its present level of 71 percent.
- Thermal power's water consumption is projected to increase by a factor of 6.
- Exportation of water is projected to in-

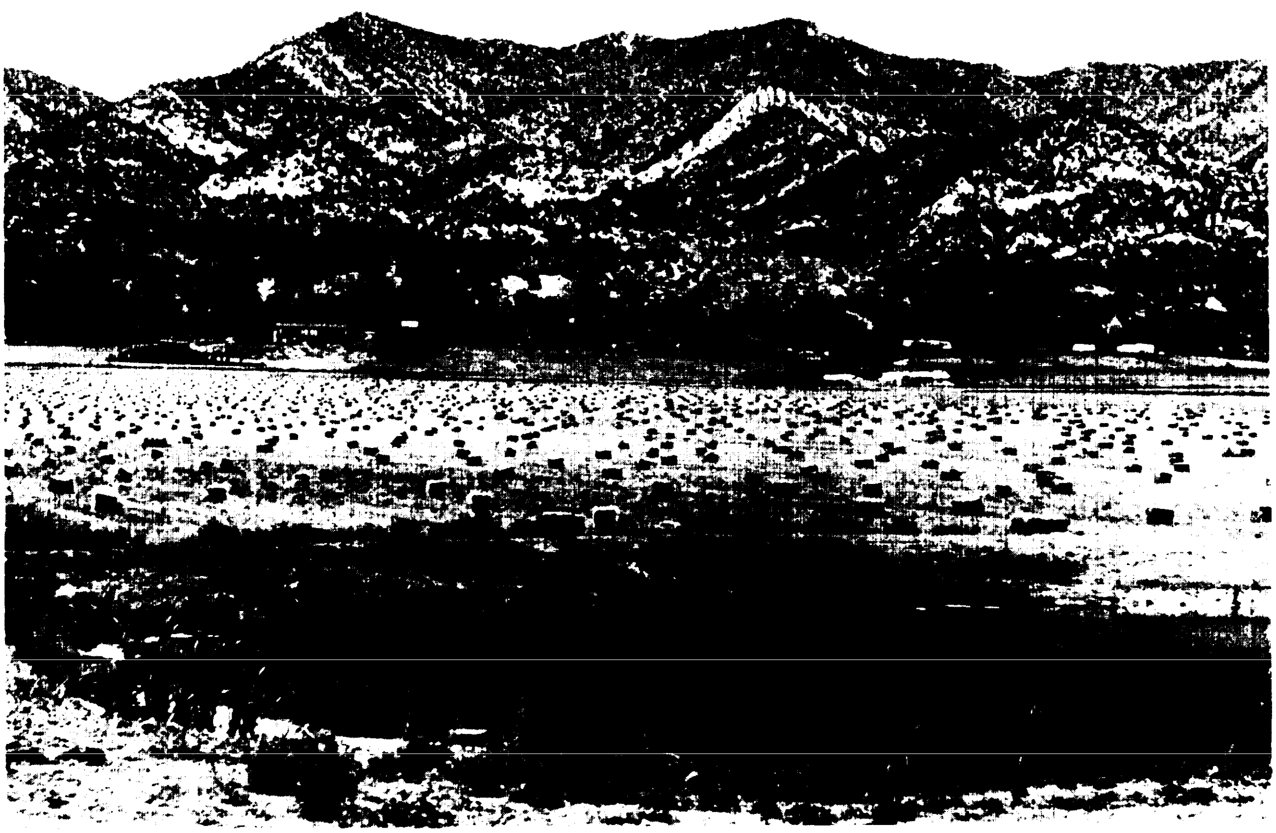

Photo credits: OTA staff

Feed for livestock consumes large amounts of the available water

Table 78.–Present and Projected Water Depletions for Activities Other Than Oil Shale Development in Colorado, Utah, and Wyoming (thousand acre-ft/yr)

	Present					Year 2000				
	Colorado	Utah	Wyoming	Total	Percent	Colorado	Utah	Wyoming	Total	Percent
Thermal power.	10	7	18	35	1,2	74	64	83	221	5,7
Agriculture	1,197	527	279	2,003	70.7	1,380	671	330	2,381	61.3
Wildlife and recreation	15	9	6	30	1,1	28	9	20	57	1,5
Minerals .,	19	12	21	52	1.8	33	12	64	109	2.8
Municipal and industrial	21	10	4	35	1,2	49	19	8	76	2.0
Exportation	541	132	7	680	24,0	757	262	22	1,041	26.7
Total	1,803	697	335	2,835	100.0	2,321	1,037	527	3,885	100,0

SOURCE Colorado Department of Natural Resources, *Upper Colorado River Region See//on 13(a) Assessment A Report to the U S Water Resources Council* draft August 1979

crease by **53** percent. The proportion of total depletions exported, however, will remain at about 25 percent.

- At present, the oil shale States together consume about 2.84 million acre-ft/yr. The total depletion would increase 37 percent to 3.89 million acre-ft/yr.

These trends are considered below in conjunction with law of the river allocations to estimate the quantities of surplus water that would be available to support additional regional growth.

Estimation of Surplus Water in the Upper Basin

Surplus water is defined as the difference between the water allocated and the total water consumption, which includes water used for beneficial purposes plus reservoir evaporative charges. * As discussed previously (see table 77), the oil shale States should be entitled to a total of 4.94 million acre-ft/yr: 2.88 million to Colorado, 1.28 million to Utah, and 0.78 million to Wyoming. In table 79, estimates are given for the quantities of surplus surface water at present and in 2000. At present, approximately 1.66 million acre-ft/yr of surplus water is available. By 2000 the surplus would be reduced to about 469,000 acre-ft/yr. These surpluses are legally available to the States. If all the present surplus were reserved for oil shale development, an industry of about 9.76 million bbl/d could be accommodated. The projected surplus in 2000 would support a 2.76-million-bbl/d industry without disrupting other users.

A more precise analysis, which considered seasonal flow fluctuations, return flows from irrigated fields, effects of fill rates, and sustained depletions on reservoir evaporation, was performed for DNR with USBR's Colorado River system simulation model. The model predicted a natural discharge from Lake Powell of 8.63 million acre-ft/yr in 2000 —400,000 acre-ft/yr more than the minimum discharge requirement, but 69,000 acre-ft/yr less than the year 2000 surplus shown in table 79. The surplus would support an oil shale industry of 2.35 million bbl/d in the Upper Basin. However, the industry's total capacity would be further reduced by the Upper Colorado River Basin Compact of 1948 that governs how water can be distributed among the individual States in the Upper Basin. The effects of this compact are indicated in table 80, where the 400,000-acre-ft/yr surplus is distributed among Colorado, Utah, Wyoming, and New Mexico according to the compact's percentage formula. As shown, the total shale oil capacity would be 2.09 million bbl/d: 1.22 million in Colorado; 541,000 in Utah; and 320,000 in Wyoming.

It is important to note that these calculations apply to average flow conditions in the Colorado River system. During dry years, natural flows out of Lake Powell might not be sufficient to satisfy the delivery requirement to the Lower Basin and might have to be aug-

*The term "reservoir evaporative charges" refers to the total amount of water that evaporates from certain reservoirs in the Upper Basin, The States are charged on a percentage basis for losses from reservoirs that are built to serve the entire Upper Basin. Evaporation from reservoirs built for a specific State are charged entirely to that State.

Table 79.–Estimation of Surplus Surface Water in Colorado, Utah, and Wyoming at Present and in 2000 (thousand acre-ft/yr)

	Present				Year 2000			
	Colorado	Utah	Wyoming	Total	Colorado	Utah	Wyoming	Total
Total water use[a]	1,803	697	335	2,835	2.321	1,037	527	3,885
Evaporation [b]	259	115	70	444	334	148	104	586
Total consumption	2,062	812	405	3,279	2,655	1.185	631	4,471
Allocatlon[c]	2,880	1,280	780	4,940	2,880	1,280	780	4,940
Surplus.	818	468	375	1,661	225	95	149	469

[a]Data from table 78
[b]Estimated charges for CRSP reservoirs Present values provided by Roland Fischer Colorado River Water Conservation District year 2000 estimates by the Colorado Department of Natura Resources
[c]Assumes 13 8 million acre-ft yr virgin flow al Lee Ferry 8 23 million acre ft yr Lake Powell discharge distribution of flows and evaporative charges per the percentage formula of the Upper Colorado River Basin Compact of 1948

SOURCE Office 01 Technology Assessment

Table 80.–Maximum Shale Oil Production Based on Surplus Surface Water in 2000[a]

Assumed virgin flow at Lee Ferry, million acre-ft/yr[b]	138
Surplus surface water available, acre-ft/yr[c]	
New Mexico	45,000
Colorado	207,000
Utah	92,000
Wyoming	56,000
Total	400,000
Shale 011 capacity, million bbl/d[d]	
Colorado	1 22
Utah	054
Wyoming	033
Total	209

[a]Assumes 823 million acre ft yr annual discharge from Lake Powell Distribution among the Upper Basin Slates according 10 the Upper Colorado River Basin Compact of 1948
[b]1930 74 annual average
[c] Based on year 2000 depletion projections fo'nonoil shale users Medium growth rate scenario
[d]Based o, 8 500 acre ft/yr for production 0150000 bbl d Of shale oil syncrude

SOURCE Office of Technology Assessment

mented by discharge from the Upper Basin reservoirs. As noted earlier, these were built to allow the Upper Basin States to satisfy their delivery requirements to the Lower Basin. Their active capacity is expected to be about 35 million acre-ft in 2000. If virgin flows dropped to say, 12.9 million acre-ft/yr and stayed there, * the reservoirs could offset the 0.9-million-acre-ft/yr shortfall for only about 39 years.

In summary, surplus surface water legally available to the oil shale States could support a shale industry of about 2.1 million bbl/d through 2000. This conclusion is based on one interpretation of the law of the river, one set of depletion estimates for conventional users in 2000, one assumed value of virgin flow, and an industry that employs a technology mix similar to that being developed in the present projects. If a different basis were selected, the estimated capacity of the industry could be significantly different. Some other bases are discussed in the issues section of this chapter.

*This appears to be the lower limit for long-term virgin flows in the Colorado River system. See the issues section of this chapter.

The conclusion also does not account for regional and local supply impediments that could affect facility siting and thereby determine the ultimate size of the industry. The next section evaluates water availability with respect to specific development sites within specific hydrologic basins in the oil shale area.

Water Availability in Hydrologic Basins Affected by Oil Shale Development

Oil shale development is likely to affect three hydrologic subbasins:

- the Green River basin in the southwestern corner of Wyoming, which includes the northern mainstem of the Green River and its tributaries;
- the White River basin, which encompasses the northern portion of the Piceance basin and the eastern portion of the Uinta basin, and whose tributaries include the White and Yampa Rivers to their confluence with the Green River in

eastern Utah, plus streams flowing north out of the Piceance basin into these rivers; and

- the Colorado River mainstem basin, which includes the Colorado River mainstem in Colorado, streams that flow south from the Piceance basin into the Colorado, and upstream tributaries at higher elevations.

The impacts on these subbasins can be estimated only after certain assumptions are made regarding the locations of the oil shale plants and the timing of their construction. If the trend indicated by the present oil shale projects were continued, about 40 percent of the shale oil production would come from the White River basin in Colorado, 30 percent from the Utah portion of that basin, and 25 percent from the basin of the Colorado River mainstem in Colorado. The remaining 5 percent might come from as-yet unannounced projects in Wyoming's Green River basin. The water requirements for a l-million-bbl/d industry distributed in this manner are indicated in table 81. Also shown are the water requirements for conventional uses in 2000, as projected by DNR under its medium growth rate scenario. As shown, the industry would increase the total water consumption in the three subbasins by about 10 percent. The increases in the Green River and Colorado mainstem basins would be relatively small, but water demands in the White River basin would increase by nearly 150 percent.

The Adequacy of Surface Water Resources by Hydrologic Basin

In the Green River basin, water depletions for a l-million-bbl/d oil shale industry would be approximately 8,500 acre-ft/yr. Two major Federal reservoirs within this basin, Flaming Gorge and Fontenelle, have well over 100,000 acre-ft/yr of surplus water in storage that is available for sale to industrial users such as oil shale developers. Consequently, there is more than enough water available within the basin to provide for projected growth. It is unlikely that any new reservoirs will be needed.

Oil shale development would have **a** greater effect on the White River basin. With **a** 1-million-bbl/d industry, depletions would approach 200,000 acre-ft/yr by 2000. About 60 percent would be used for oil shale. These depletions would strain the water resources of the White River because its total annual flow at the boundary of the basin is only about 568,000 acre-ft/yr, 61 percent of which occurs between April and July. Although several oil shale plants could be supplied from existing resources, new reservoirs would be needed and river flows would be substantially reduced.

According to DNR, only about 6,000 acre-ft/yr could be obtained from streams within the Piceance basin because of their low streamflows. A l-million-bbl/d industry would require an additional direct-flow diversion of 4,500 acre-ft/yr from the White River below

Table 81 .–Water Requirements by Hydrologic Subbasin for a 1-Million-bbl/d Industry in 2000

Subbasin	Water for conventional uses, acre-ft/yr[a]	Oil shale industry: Oil capacity bbl/d	Oil shale industry: Water acre-ft/yr[b]	Total water acre-ft/yr	Increase due to 011 shale, percent
White River, Colo. and Utah	80,000	700,000	119,000	199,000	149
Colorado mainstem, Colo. .	1,220,000	250,000	42,500	1,262,500	3 5
Green River, Wyo.	482,000	50,000	8,500	490,500	1 8
Total. .,	1,782,000	1,000,000	170,000	1,952,000	9.5

aConventional uses include thermal power agriculture wildlife and recreation, minerals municipal and industrial and exports Estimates for the Colorado Department of Natural Resources medium growth rate scenario
bBased on 8 500 acre. ft/yr for production of 50000 bbl/d Of shale 011 syncrude

SOURCE Off Ice of Technology Assessment

Meeker, a reservoir with an active capacity of 60,000 acre-ft on the south fork of the White River in Colorado, and a 120,000-acre-ft reservoir on the White River mainstem in Utah. An industry of more than 2 million bbl/d would require these facilities plus a 35,000-acre-ft reservoir on the White River mainstem between Meeker and Piceance Creek, a total of 35,000 acre-ft of active capacity in several smaller reservoirs along ephemeral streams in the Piceance basin, and a reservoir of about 10,000 acre-ft/yr along Piceance Creek. All reservoirs would store spring runoff. Water from the White River would be pumped to the reservoirs in the Piceance basin during the rest of the year.

Within the Colorado mainstem basin, oil shale development would increase water depletions only slightly. However, large water demands would be imposed by the growth rates projected for other uses, especially irrigated agriculture. Reservoirs may be needed to supply both irrigation and oil shale development. DNR considered four siting schemes for reservoirs in this basin.

In the first scheme, reservoirs would be built at high elevations along tributaries like the Roaring Fork and Eagle Rivers. Springtime runoff would be trapped for release over the dry months. The released water would be recovered from the Colorado River below Rifle and pumped to the oil shale plants. The only appreciable inflows to the reservoirs would occur in the spring and large active capacities would be needed to sustain outflows during the dry seasons. Total capacities might exceed 50,000 acre-ft for a l-million-bbl/d industry.

The second scheme also involves reservoirs on upstream tributaries but at lower elevations to permit capture of agricultural return flows and of water from secondary streams. A total storage capacity of 30,000 to 50,000 acre-ft would be needed. The third scheme involves direct flow diversions from the Colorado River below Rifle, in conjunction with reservoirs on the Colorado mainstem or in side canyons in the Piceance basin. A l-million-bbl/d industry could be supplied with a 30,000-acre-ft/yr diversion and a 15,000-acre-ft reservoir. The reservoir could be located in a dry canyon because it would be supplied with pumped water from the Colorado mainstem and would not rely on local stream flows.

In the fourth scheme, 50,000 acre-ft/yr of surplus water would be purchased from existing USBR reservoirs (such as Reudi Reservoir) and pumped to the oil shale facilities. This would supply all of the water required for that portion of a l-million-bbl/d industry projected for the Colorado mainstem basin. Larger levels of production could be supported by any of the other three schemes, with reduced storage and diversion requirements.

In summary, new storage requirements for a l-million-bbl/d industry could range from 180,000 acre-ft, with reservoirs in the White River basin and no storage in the Colorado mainstem basin, to about 230,000 acre-ft for storage in both basins. The maximum storage requirements would be encountered if high-altitude reservoirs were built. Less storage would be needed if most water was obtained by direct diversions from the mainstem rivers. The additional reservoirs would increase reservoir capacity in the Upper Basin by about 0.6 percent. Evaporative losses from the new reservoirs should also be charged against the industry. Their precise magnitude would depend on the characteristics of the new reservoirs and their sites, but should add only a small percentage to each shale plant's annual water requirements.

Water Acquisition Strategies and Their Costs

The following strategies could be used either alone or in combination to supply water to oil shale facilities:

- perfection of conditional water right decrees,
- purchase of surplus water from Federal reservoirs,
- purchase of water supplies and water rights from irrigated agriculture,
- ground water development, and
- interbasin diversions.

A brief discussion of each strategy and its associated costs follows. Constraints and impacts are discussed later.

Perfection of Developer Water Rights

Description

Most potential oil shale developers have already acquired water rights. Some were obtained by direct filings through the prior appropriation system. These are now in the form of conditional decrees both for storage and for direct-flow diversions. Exact yields are not available because they are considered proprietary information by the companies. The rights are believed to be large but relatively junior. The oldest was acquired in 1949.

Other rights were purchased from irrigated agriculture. Most of these are relatively senior absolute rights that were perfected by the seller. To avoid a declaration of abandonment, some developers have allowed the sellers to continue to use the water for farming. Little information is available regarding the potential yields of these rights. However, total historic consumption, which would determine the quantities of water that could be transferred to oil shale development, could be as low as 10,000 to 20,000 acre-ft/yr.[28]

An idea of the extent of developers rights can be gotten by examining their water positions in 1968.[29] Conditional storage rights held by some potential developers at that time are tabulated below:

Developer	Storage rights, acre-ft
EXXON	122,000
Mobil	66,000
Getty Oil	53,000
Sinclair	51,500
Tosco	34,600
Total	327,100

These companies also owned conditional decrees to over 1 million acre-ft/yr of direct-flow diversions from the Colorado and White Rivers and their tributaries. Substantial rights were also held for ground water. Superior Oil, for example, held conditional decrees to over 2,400 acre-ft/yr of ground water in the Piceance basin.

The rights of the limited sampling of companies shown above could support an industry of nearly 8 million bbl/d and would be sufficient for the shale oil production levels projected for the near term.

Developers who do not presently own rights could file for new ones. In general, this option is considered undesirable because the quantity of water covered by rights issued to date already exceeds the resources of the river system. Any new rights would be junior to those of all other users and therefore the most likely for curtailment during water shortages.

Filing for new rights might be feasible for near-term development, however, because of the improbability that all of the water covered by present conditional decrees will be put to use for several decades. The long-term feasibility of this strategy is highly uncertain because supply curtailments will become more likely as regional growth proceeds. To assure supplies in the long term, new filings would have to be merged with other strategies.

costs

The costs of acquiring these kinds of rights are negligible, comprising only legal fees for recording the water claim, and for pursuing any resultant litigation, and small annual investments to demonstrate due diligence. The costs incurred by developers when they purchased their current irrigation rights are unknown but were probably small. Therefore, the costs of water supplies obtained through the prior appropriation system comprise only the costs of transporting the water from the diversion point to the oil shale site, Transportation costs are discussed later with respect to intrabasin diversions.

Purchase of Surplus Water From Federal Reservoirs

Description

Oil shale developers could also purchase surplus water from reservoirs operated by USBR and other entities. Various amounts of water are presently available from existing reservoirs in the oil shale area. As noted previously, the Flaming Gorge and Fontenelle Reservoirs in the Green River basin have sufficient surplus water for much more shale oil production than is likely to occur in the basin in the near term. This water is not being used for any purpose and could be made available to oil shale developers.

In the basins of the White River and the Colorado River mainstem, surplus water in storage is adequate for initial development. For example, Green Mountain and Reudi Reservoirs in the Colorado mainstem basin could supply about 100,000 acre-ft of surplus water, which would be sufficient for nearly 600,000 bbl/d of shale oil production. However, existing reservoirs could not support a larger industry unless other users were partially curtailed. Therefore, new reservoirs would have to be built. New pipelines would also be needed in all three basins to divert water to the oil shale plants.

costs

Reservoir construction costs are highly site-specific and are reflected in the charges for purchased water. These charges vary widely from reservoir to reservoir. Although charges for existing reservoirs are known, only rough estimates are available for new reservoirs,

Some examples of long-term contracts for water from existing USBR reservoirs are shown in table 82. As shown, charges in the late 1960's were from $7 to $11/acre-ft while previous charges were less than $1/acre-ft. The highest charge, $22.54/acre-ft in 1972, is for a small diversion from the Emery County reservoir. Because future contracts will be negotiated individually, water costs cannot be accurately predicted, although it seems unlikely that they would be much higher than $25/acre-ft.

Table 82.–Examples of the Charges for Purchasing Surplus Surface Water From U.S. Bureau of Reclamation Reservoirs

Project/reservoir	River basin	Purchaser	Year of contract	Quantity of diversion, acre-ft/yr	Unit cost, $/acre-ft
Seedskadee/Fontenelle	Green	State of Wyoming	1962	60,000	$0.40
Seedskadee/Fontenelle	Green	State of Wyoming	1974	60,000	500
Emery County	Central Utah	Utah Power & Light and others	1972	6,000	2254
Glen Canyon/Lake Powell	Colorado	Resources Co and others	1969	102,000	7.00
Glen Canyon/Lake Powell	Colorado	Salt River project	1969	40,000	7.00
Navajo	San Juan	New Mexico Public Service	1968	20,200	700
Navajo	San Juan	Utah International	1968	44,000	700
Navajo	San Juan	Southern Union Gas Co.	1968		7.00
Missouri River/Bighorn and Boysen	Yellowstone	Various	1967-71	658.000;	11,00
Boulder Canyon/Lake Mead	Lower Colorado	Colorado River Commission	1966	30,000	050

SOURCE R F Probstein H Gold and R E Hicks *Water Requirements Pollution Effects and Costs of Water Supply and Treatment for the Oil Shale Industry* eport prepared for OTA by Water Purification Associates October 1979

Some cost estimates for new reservoirs in Western Colorado are summarized in table 83. Unit construction costs in 1979 dollars vary from $120 to $740/acre-ft of storage capacity. To obtain estimates of water costs from these reservoirs, assumptions must be made about financing methods and operating characteristics of the reservoirs. A rough estimate can be made if it is assumed that storage and delivery capacities are equal, and 10 percent of construction costs are charged to water purchasers per year. Then the charges for the water would range from about $10 to about $75/acre-ft, which is substantially higher than costs from existing reservoirs.

Table 83.–Estimated Construction Costs for Proposed Reservoirs Within the Colorado River Water Conservation District

	Storage capacity, acre-ft	Construction costs, million$	Unit capital costs, $/acre-ft
Haypark ,,	20,000	$60	$300
Azure	30,000	11.4	380
Toponas, .,...,.. ,,	18,000	3,3	180
Iron Mountain,	60,000	289	480
Yoeman Park . ~ ~ ~ ~	7,000	49	740
Bear Wallow. .	49,000	11.9	240
Kendig, ., ., . ., ~	15,000	5.0	320
Una.	196,000	363	190
Yamcolo ,,. ,.	9,000	5.8	640
Bear, .., ,,. .	12,000	30	260
Grouse Mountain.	79,000	9.2	120
Rampart. .	12,000	4.0	350
California Park	37,000	52	140
Rangely ..,, .,, ,	55,000	112	200
Dunkley.	57,000	13,2	230
Pothook .,,	60,000	85	140

SOURCE R F Probstein H Gold and R E Hicks Wafer *Requirements Pollution Effects, and Costs of Water Supply and Treatment for the Oil Shale Industry* report prepared for OTA by Water Purification Associates October t979

Purchase of Irrigation Rights

Description

Most oil shale developers have indicated that they plan no further purchases of irrigation rights. However, the strategy warrants discussion because large quantities of water are currently consumed by farming and the water laws allow rights to be transferred from willing sellers to willing buyers.

The feasibility of using irrigation rights for oil shale development is site specific and depends on their cost in comparison with other strategies, the proximity of irrigation diversions to potential plantsites, and the seasonal nature of irrigation rights. Transfer is unlikely in the Green River basin, for example, because adequate and inexpensive water appears to be available from existing Federal reservoirs. On the other hand, it could occur in the White River and the Colorado mainstem basins because of the limitations of existing storage capacity.

In the White River basin, irrigated agriculture consumes about 37,000 acre-ft/yr, This amount of water could supply a 250,000-bbl/d oil shale industry. If this water were transferred to oil shale, additional storage would probably be needed because of the seasonal nature of irrigation rights. These rights generally rely on direct diversions from a river, and river flows might not be sufficient during dry seasons to satisfy the oil shale water requirement.

In the basin of the Colorado River mainstem, irrigated agriculture currently consumes about 430,000 acre-ft/yr, which is much more than would be required for any projected level of oil shale development. Purchase of irrigation rights would reduce, but probably not eliminate, the need for new storage capacity. Irrigation water from the Colorado mainstem could also be diverted to oil shale facilities in the White River basin, thus reducing the need for new storage in that basin. Some new interim storage would be needed near the plantsites. In any case, new pipelines would be needed to transport water from current diversion points to the oil shale facilities.

costs

It is important to distinguish between the purchase of a specific quantity of water for use in a given year and the purchase of a water right that would authorize use in all future years. In recent years, the cost in Colorado of purchasing irrigation water for one year's use has ranged from about $10 to $25/acre-ft, which is similar to the costs of purchasing water from existing Federal reservoirs.[30] The cost of purchasing a water right for use in perpetuity, however, could range from $1,000 to $2,500 for each acre-ft/yr covered by the right.[31] If capital to purchase the right were borrowed at lo-percent interest, annual costs might range from $100 to $250/acre-ft. These costs are substantially higher than current prices for single-year diversions. The reason is that most farming could not be conducted without irrigation. Selling water rights essentially puts a farmer out of business.

Ground Water Development

Description

Ground water aquifers could be feasible water sources for oil shale development if they are favorably located relative to plantsites, if the water quality is suitable for industrial applications, and if physical characteristics (such as burial depth, storage volume, and discharge rates) are advantageous. Although knowledge is incomplete, existing data suggest that selected aquifers in the Upper Basin are worthy of consideration for some, if not all, potential oil shale facilities.

In the Piceance basin, for example, up to 25 million acre-ft is estimated to be stored in two major bedrock aquifers that are separated by rich oil shale beds. This resource is currently being used in limited amounts for livestock watering, for irrigated agriculture, and for localized domestic consumption. The water is generally high in dissolved solids and fluoride. For this reason, its use for conventional purposes will probably not increase. It is likely that an oil shale industry would be the only large-scale application for which this ground water would be suitable. * With proper pretreatment, much of it could be upgraded for such use. If this were done to the fullest extent, the aquifers could supply a 1-million-bbl/d shale oil industry for from 200 to 500 years, depending on the processing technologies used.

*Water in the upper aquifer generally contains less than 2,000 mg/l of dissolved solids, while in the lower aquifer these may range from 1,000 to 63,000 mg/l. The fluoride content is typically from 10 to 70 mg/l. Federal drinking water standards recommend a dissolved solids limit of 500 mg/l and a fluoride content of less than 1.0 mg/l.

Less is known about ground water in the White River basin in Colorado and Utah and about Utah's water resources in general. It is known that the Uinta basin contains large artesian aquifers, one of which discharges in the vicinity of Federal lease tracts U-a and U-b. The water is not potable but could be treated for use in oil shale processing.

Because bedrock aquifers in the Piceance and Uinta basins often coincide with minable oil shale zones, ground water will be an important consideration in most development plans. Even if ground water is not intentionally developed for use as process water, it will be produced on most tracts during mine dewatering and the preparation of in situ retorts. In many locations, the water could satisfy all processing needs, In some areas, an excess will be produced that will have to be disposed of through evaporation, by reinjection, or by discharge to surface streams. Purifying excess ground water to discharge standards could be costly.

In the Piceance and Uinta basins, yields from test wells vary with location from less than 1,000 to over 4,000 acre-ft/yr. Two to four of these wells would be sufficient to satisfy the needs of an oil shale plant producing 50,000 bbl/d by directly heated AGR. Several additional wells would probably be drilled to provide backup capacity.

costs

The cost of ground water development will vary with site, with water quality, and with the water management program of the developer. In a recent study the geohydrologic characteristics of three wellsites in the Piceance basin were analyzed, and estimates were prepared of drilling capital and pumping costs.[32] For two of the sites, which had prolific water-bearing zones extending to about 1,000 ft below the surface, a minimum cost of about $30/acre-ft was estimated for delivery of 1,500 to 4,000 acre-ft/yr. The third site contained much less permeable rocks, which reduced maximum flows and thus increased costs. The estimate of the maximum flow from this well was 700 to 900 acre-ft/yr, with a minimum cost of about $90/acre-ft. In the DNR study, water costs from a well yielding 3,000 acre-ft/yr from a depth of 500 ft were estimated to be $22 to $30/acre-ft. [33] Another estimate is about $55/acre-ft for a 1,000-ft well yielding 1,500 acre-ft/yr. [34]

The costs of well drilling and pumping could, therefore, range from $20 to $60/acre-ft, assuming that aquifers occur at reasonable depths and in reasonably permeable formations. These costs are comparable to those for surface water. Ground water could offer a major economic advantage in that wells could be located near the oil shale facilities, thus avoiding transportation costs. On the other hand, the poor quality of some ground water would necessitate costly purification.

Water from some aquifers is highly saline or brackish. It would not need to be purified for use in dust control and spent shale compaction, but would have to be for use as boiler feedwater or cooling water. Purification can be quite costly. For example, treating brackish water to cooling water standards can cost from $200 to $300/acre-ft,[35] and treatment to boiler feedwater standards can cost from $650 to $ 1,000/acre-ft. [36] These high treatment costs would not be needed for all of a plant's water supply, because some requirements could be satisfied with water of any quality. If the overall water management plan of an AGR facility is considered, a brackish ground water supply would add about $250 to $530/acre-ft to the costs of water acquisition.

Thus, the overall costs of ground water development and use could range from $20 to $600/acre-ft/yr. The lower estimate corresponds to a high-quality ground water from permeable rocks at reasonable depths. The higher estimate corresponds to brackish water from relatively impermeable formations.

Interbasin Diversions

Description

Interbasin diversions move water from one major hydrologic basin to another. Exports from the Upper Basin to the cities of Colorado's Front Range Urban Corridor (Denver, Colorado Springs, etc.) are examples of interbasin diversions. Diversions could also be used in the future to increase overall water availability in the Upper Basin by relocating water from other major basins such as the Columbia River Basin or the Upper Missouri River basin.* As an illustration, diverting 1 percent of the net water supply of the State of Washington in the Columbia River Basin would provide 2 million acre-ft/yr of additional water to the oil shale area, an amount equal to two-thirds of the present water consumption in all of the Upper Basin States.

costs

Costs of interbasin diversions vary with pipeline construction and pumping costs, which in turn depend on the route, diameter, and length of the pipelines; on the number and capacity of pumping substations; and on the cost of purchased power for the pumps. These costs are highly project-specific, but, in general, decrease with pipeline throughput and increase with distance. Variations in unit costs can be illustrated by considering two alternate pipelines; one providing water to a single oil shale plant and the other supplying water to an entire industry. An oil shale plant producing 50,000 bbl/d by directly heated surface retorting would consume about 6,000 acre-ft/yr of water. This quantity could be transported to the site in an 18-inch-diameter pipe at a unit cost of about $12/acre-f t/mile. In comparison, about 240,000 acre-ft could be conveyed through a 90-inch-diameter pipeline at a unit cost of $1 .90/acre-ft/mile.[37]

*Under the CRP Act, the Secretary of the Interior was required not to undertake reconnaissance studies of any plan for the importation of water into the Colorado River Basin until 1978. The Reclamation Safety of Dams Act of 1978 extended this moratorium until Nov. **2, 1988.** Thus. no water imports from other major basins will be allowed until well after 1988, Four options illustrate typical distances and costs that might be encountered with interbasin diversion for a large oil shale industry. One option would be to bring water to the White River basin from the Oahe Reservoir on the mainstem of the Missouri River in South Dakota. The distance would be 500 to 600 miles, and the unit costs would be $950 to $1,150/acre-ft. A second alternative would be to transport water from the Missouri River at Kansas City to the John Redmond Reservoir in Kansas, then to Denver, and finally over the Rocky Mountains to the White River basin.[38] The pipeline would be about 700 miles long, and the unit transportation cost about $1,130/acre-ft. A third option would be to transport water about 800 miles from the Columbia River Basin to the White River basin. Unit costs would be about $1,520/acre-ft. A fourth possibility would be to divert water to the White River area from the Yellowstone River, a distance of approximately 400 miles, This would cost about $750/acre-ft,

In summary, interbasin transfers for a large industry would require 400- to 800-mile-long pipelines and would entail unit costs of $750 to $1,500/acre-ft. Exact costs vary widely but are, in general, quite high. To these costs must be added the purchase price of the water that is moved through the pipeline.

Intrabasin Diversions

Description

The total cost of a water supply includes the cost of acquiring the water and the cost of moving it to the oil shale facility. As indicated above, transportation costs can outweigh acquisition costs if the facility is far from the water source. The costs of transporting water acquired in the oil shale area will also be high, although less than for transfers from other major basins. The following discussion describes some of the typical intrabasin diversions that could occur within the oil shale region, and estimates the costs of moving water through such diversion systems. This cost can then be added to the purchase price of the water to obtain the overall cost of developing a given water supply.

Intrabasin diversions redistribute water within a major hydrologic basin such as the Upper Basin, They include transfers between individual subbasins such as the basins of the Green River, the Colorado River mainstem, and the White River. Intrabasin diversions are not an acquisition strategy, but are a method for relocating acquired water to oil shale plants. Except for selected tracts using ground water and for the few oil shale plants built very close to major tributaries, new intrabasin diversions will be needed.

Intrabasin diversions would not reduce the strain on the resources of the Colorado River system. They would simply redistribute water among individual subbasins. They could be used, for example, to augment the sparse natural flows of the White River with surplus surface water from the Colorado River mainstem. They could also be used to transport stored surplus water from Federal reservoirs in the Green River basin to developments along the White River or the Colorado River mainstem. Such diversions would be required regardless of whether the oil shale water supplies are obtained from new or from existing reservoirs,

costs

The costs of transporting water by an intrabasin diversion pipeline will depend on the fees charged by the supplying reservoir and the costs of building and operating the pipeline between the reservoir and the plantsite. Some USBR estimates of the unit costs of selected intrabasin diversion projects are summarized in table 84. Reservoir charges and operating costs for the pipeline are estimated, but not the costs of acquiring the water that is moved through the pipeline, Several types of supply systems and flow rates are shown, and both existing and new reservoirs are considered. The range of unit transportation costs is from $70 to $550/acre-ft. If the highest and lowest are excluded, the range is reduced to from $180 to $440/acre-ft.

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Table 84.–Summary of Cost Estimates for Intrabasin Diversions Within the Oil Shale Area

Data source	Type of reservoir	Destination	Flow volume, acre-ft/yr	Unit transportation cost, $/acre-ft
USBR[a]	New	Tract C-a	57,000	$240-390
USBR	New	Tract C-b	18,000	260-280
USBR	New	Tracts C-a and C-b	75,000	240-440
USBR	Existing	Tracts C-a and C-b	75,000	310-350
USBR	New	Tracts U-a and U-b	8,000	280-400
USBR	New	Tracts U-a and U-b	36,000	70-160
USBR	Existing	Tracts U-a and U-b	36,000	190-230
USBR	New	Tracts C-a, C-b, U-a, and U-b	111,000	180
DNR[b]	Existing	Green River basin	14,000	280
			30,000	260
DNR	New	Colorado River mainstem basin	29,000	550
			84,000	400
DNR	New	White River basin	141,000	380
			240,000	360

[a]U S Bureau of Reclamation *Alternative Water Sources for Prototype Oil Shale Development* Salt Lake City Utah September 1974
[b]Colorado Department of Natural Resources *Upper Colorado River Basin Section 13(a) Assessment A Report to the U S Water Resources Council (Draft)* August 1979

SOURCE Office of Technology Assessment

Summary of Supply Costs

Estimates of the costs of supplying industrial-quality water to oil shale sites by means of the several acquisition and transportation strategies discussed previously are summarized in table 85. The strategy costs include the costs of purchasing the water, of transporting it from the point of acquisition to the point of use, and of treating it for use in the facilities. The estimates are approximate. They were derived using the following assumptions:

- All surface water acquired in the oil shale region is transported over substantial distances through intrabasin pipelines.
- Water for interbasin diversions is purchased at a cost of $25/acre-ft.
- Surface water is of good quality and does not require substantial purification prior to use.
- Ground water quality is variable. Only brackish ground water must be treated prior to use.
- All ground water is developed in the immediate vicinity of the oil shale plants. Pipelines to points of use are of insignificant length.
- Surplus water from existing reservoirs costs $25/acre-ft. Water from new reservoirs costs $100/acre-ft.

The lowest cost strategy is the development of good quality ground water. Unit costs

Table 85.–Summary of Approximate Water Supply Costs for Several Acquisition Strategies

	Component cost, $/acre-ft			Strategy costs	
Strategy	Purchase	Transportation	Treatment	$/acre-ft	$/bbl of oil[a]
Perfection of conditional decrees	nil	$180-440	nil	$180-440	$0.09-0.23
Purchase from existing Federal reservoirs ...	$25	180-440	nil	205-465	0.11-0.24
Purchase from new Federal reservoirs, ., .,	100	180-440	nil	280-540	0.14-0,28
Purchase of senior Irrigation rights ., .,	100-250	180-440	nil	280-690	0.14-0,36
High-quahty ground water . .	20-60	nil	nil	20-60	nil-0.03
Brackish ground water	20-60	nil	$250-530	270-590	0.14-0.30
Interbasin diversions ., .,	25	750-1,500	nil	775-1,525	0.40-0,79

[a]Assumes that 8500 acre-ft/yr IS consumed per 50,000-bbl/d Plant

SOURCE R F Probslem H Gold and R E Hicks, ***Waler Requirements Po//u(lorr E/lecls, and Cos(s of Wafer .SWIp/y arrd Trealmerrf for fhe 0// S/ra/e induslry*** report prepared for OTA by Water Purification Associates Oclober 1979 range from essentially zero to about $0.03/bbl of oil. The perfection of conditional water decrees is more costly, with unit costs ranging from $0.09 to $0.2/bbl of oil. It is comparable to purchasing surplus water from existing Federal reservoirs. Purchasing water from new Federal reservoirs is comparable in cost to developing brackish ground water—about $0.14 to $0.28/bbl of oil. Water obtained by purchasing senior irrigation rights costs a little more. Interbasin diversions are by far the most expensive, with unit costs from $0.40 to $0.79.The higher unit cost for interbasin diversions was calculated under the assumption that water would be transported for 800 miles from the Columbia River Basin.

Except for interbasin diversions, the costs of water supplies range from essentially zero to about $0.36/bbl of upgraded shale oil. Such water costs, which would have seemed unattractively high in the early 1970's when oil prices were about $3.00/bbl, are less consequential with current oil prices.

Legal and Institutional Considerations

The previous sections evaluated the physical and economic requirements of several water supply strategies. The feasibility of any of them also depends on a number of legal and institutional factors, some of which are examined below.

The Law of the River

As discussed previously, water development in the Upper Basin will be constrained by the following factors:

- The operating criteria for Federal reservoirs in the Upper Basin, which require a minimum discharge of 8.23 million acre-ft/yr from Lake Powell.
- The Upper Colorado River Basin Compact of 1948, which limits the percentage of total Upper Basin depletions that can be consumed by each State.

Different assumptions about virgin flow, regional growth rates, processing technologies, and plantsites can lead to widely different projections of the maximum size of the oil shale industry that could be supplied by surplus surface water in 2000. Assuming 13.8-million-acre-ft/yr virgin flow, medium growth rates, and an industry with an average water requirement of 8,500 acre-ft/yr per plant, the limit appears to be about 2 million bbl/d.

This estimate assumes that the States in the Upper Basin concur with the constraints identified above. This is a questionable assumption because several aspects of the law of the river are in direct conflict and not all have been accepted by the States, particularly in the Upper Basin. For example, the Colorado River Compact of 1922 assured delivery of 7.5 million acre-ft/yr to both the Upper and Lower Basins. This would be possible with virgin flows of at least 15 million acre-ft/yr; it would not be possible with the lower flows that have prevailed since 1930. The delivery obligation of the Mexican Water Treaty of 1944-45 is another source of conflict. The treaty has not been a constraint on the Upper Basin States because of their low water demands in the past. However, it could significantly affect future development programs. If the obligation were imposed on the Upper Basin under the percentage formula of the Upper Colorado River Compact of 1948, Colorado's share would be 388,000 acre-ft/yr, Utah's 173,000 acre-ft/yr, and Wyoming's 10 105,OOO acre-ft/yr. If the Upper Basin States were able to avoid the obligations through litigation, much higher levels of regional growth and energy development would be possible.

The States may choose to follow this path. For example, Colorado Governor Richard Lamm maintains that Colorado and the other Upper Basin States are not responsible for satisfying the Mexican treaty obligation.[39] The director of the Colorado Water Conservation Board describes the State's position as follows:[40]

> There has been a considerable amount of study, together with a considerable amount of speculation, concerning the amount of water which is still available to the State of Colorado under the terms of the Colorado River Compact and the Upper Colorado River Basin Compact. The problem with any study is that no one can actually define the precise amount of water to which Colorado is entitled under the terms of the compacts. In addition to existing uncertainties concerning the compacts, the Mexican Treaty of 1944 further complicates any water supply study. There are some basic disagreements among the various states of the Colorado River Basin as to the obligation of each State for the release of water to satisfy the Mexican Treaty. At some future time it appears likely that these differences will be taken to the United States Supreme Court for resolution.

Analysis of the legal position of the States in this controversial matter is beyond the scope of this assessment. It is possible, as the above citation implies, that resistance to supply obligations could be directed at the Mexican treaty itself. However, because the treaty is a national commitment, it is more likely that resistance will be manifested against the operating criteria for Federal reservoirs in the Upper Basin. These criteria have been implemented by DOI through requirements for minimum annual discharges from Lake Powell. The 8.23 -million-acre-f ft/yr discharge requirement incorporates both the Lower Basin allocation of 7.5 million acre-ft/yr and the Upper Basin's share of the Mexican obligation. The Upper Basin States do not agree with the operating criteria. [41,42]

The Doctrine of Prior Appropriation

As stated earlier, most of the water rights held by potential oil shale developers are either conditional decrees, which are large in quantity but junior in date of appropriation, or absolute irrigation rights, which are small but senior. Under the appropriation doctrine, only the irrigation rights would provide secure water supplies. They would be limited to about 10,000 to 20,000 acre-ft/yr. If the more junior decrees were perfected, they could be curtailed during dry periods to provide water to more senior users, with severe economic repercussions unless sufficient water storage had previously been constructed. Any new rights obtained through the prior appropriation system would be extremely junior and even more susceptible to curtailment. Any large-scale use of ground water for oil shale development would have to protect the water rights of senior surface water users.

Thus, the prior appropriation doctrine reduces the attractiveness of developing water supplies through perfection of existing or future conditional decrees. Given the constraints of the appropriation system, it appears that the most reliable strategies would be additional purchase of highly senior irrigation rights, purchase of surplus surface water from reservoirs, ground water development in selected areas, or interbasin diversions.

Federal Reserved Rights Doctrine

Under this doctrine, water has been set aside for use on Federal lands, but the amounts of water affected have not yet been quantified. An important aspect of the doctrine is that Federal rights, when perfected, will be senior to most others. Any more junior user will face curtailment in times of water shortage. The doctrine is an example of the constraints imposed by prior appropriation.

The doctrine would affect any acquisition strategy that relied on flows originating within the Upper Basin. The only strategies that would avoid the doctrine's constraints would be the development of nontributary ground water, interbasin transfers specifically for use in oil shale facilities, or the purchase of irrigation rights that are senior to the Federal rights. The latter would be difficult because many of the potential Federal rights date back to the late 19th century.

It is possible, although uncertain, that the Federal reserved rights could be used to assist oil shale development. Because the

Supreme Court has decided that the affected water may only be used to further the purposes for which a reservation was established, it appears that the only relevant rights would be those that might be claimed for the Naval Oil Shale Reserves in Colorado and Utah. These reserves were established in the 1920's and the rights, if they could be implemented, would be quite senior. However, the legal position of the rights in Colorado is complicated because the reserves do not border on the Colorado River and they contain little ground water. The Government has indicated that it intends to claim water for the Colorado reserves; the claim is in the early stages of litigation by the State,

Environmental Legislation

There are a number of environmental laws which do not directly restrict water use but which could affect the siting of facilities, the scale of operation, and particular water acquisition strategies, It is difficult to predict their effects on development of water resources in the oil shale region, but it is important to note their existence and to recognize that they could be of considerable consequence. Included are the following laws:

- The Fish and Wildlife Coordination Act. This Act required that all Federal agencies which direct, impound, or modify water bodies must consult with USFWS. Plans for water resource development are reviewed by the Service to assure that they include appropriate protective measures for fish and wildlife.
- The Endangered Species Act, Under this Act, Federal agencies are to conserve threatened or endangered species. In the Upper Basin there are species of endangered fish—the humpback chub and the Colorado River squawfish—which might influence the siting of reservoirs for energy development.
- The National Wild and Scenic Rivers Act. This Act is designed to preserve portions of selected streams in a natural state. The addition of any streams in the Upper Basin to this system might affect their future use for energy development,
- The Wilderness Act. This Act establishes a National Wilderness Preservation System composed of federally owned wilderness areas as designated by Congress. The Act also stipulates the conditions under which reservoirs and other facilities can be built within these areas. As a consequence of this Act, reservoirs and other water facilities needed for energy development might be restricted in certain areas.

These laws should not reduce the availability of water within the Green River hydrologic basin because there are presently no known endangered species or designated water areas within this basin. Furthermore, flows of the Green River will be insignificantly affected by the projected levels of shale oil production.

In contrast, environmental legislation could constrain oil shale development in the White River basin. High levels of shale oil production are projected for this basin, and the associated water requirements could significantly reduce river flows. Furthermore, the Colorado River squawfish, a federally designated rare and endangered species, is known to inhabit the lower portions of the White River. In addition, the Flat Tops Wilderness area, an existing Federal wilderness, includes portions of the headwaters of the north and south forks of the White River. Flat Tops could affect oil shale development in that reservoirs and other structures would not be permitted within the wilderness area, except under presidential approval.

Water availability within the basin of the Upper Colorado mainstem might be affected by the Endangered Species Act, the Wilderness Act, and the National Wild and Scenic Rivers Act. The Colorado River squawfish inhabits the Colorado River from the backwaters of Lake Powell upstream to the confluence of Plateau Creek. The humpback chub is found in the Colorado mainstem downstream from the Colorado/Utah State line.

This basin also contains three designated wilderness areas, and additional areas are being considered for inclusion in the wilderness system pursuant to the ongoing Roadless Area Review and Evaluation (RARE II) review. ' New reservoir storage would probably not be permitted in these areas. However, they are in high-elevation watersheds and thus would probably not contain potential sites for reservoirs. In addition, several rivers within this basin are being considered for wild and scenic designation.

Thus, these environmental laws might affect the siting of storage reservoirs and limit the amount of water that could be diverted from certain rivers. Water supply strategies that require extensive storage, such as the purchase of irrigation water, could be affected.

Instream Water Flow

Instream flow requirements are legally considered only in Colorado, where the State has retained the right to obtain water for preserving the natural environment to a reasonable degree. Instream rights are subject to the prior appropriation system, and have priority over consumptive rights only if they are more senior in time. The State recognized instream rights in 1973, and thus these rights are quite junior and should not impede the perfection of rights held by oil shale developers, some of which date back to 1949. However, if the oil shale industry were to file for additional surface rights they would be junior to the instream rights and would have a lower priority in times of water shortage. Other water acquisition strategies—such as the purchase of senior irrigation rights, transbasin diversions, and ground water development—would not be significantly affected. The purchase of surplus water from Federal reservoirs would be affected only if the perfection of instream rights reduced the amount of surplus water available for sale.

On the other hand, minimum flow bypasses around reservoirs and dams are required for aquatic life under the Clean Water Act. Depending on the interpretation given this Federal statute by the States, the total amount of surplus surface water could be decreased.

Finally, USFWS is engaged in a study to develop strategies for reserving flows to maintain fish and wildlife habitats. Although they are not yet part of the legal system, such strategies might ultimately reduce surface water availability for any type of growth in the oil shale region.

Interbasin Transfers

Several legal barriers constrain interbasin transfers of water to the oil shale region. The Yellowstone River Basin Compact of 1950 (65 Stat. 663) requires approval of Wyoming and Montana before transfers of Yellowstone water can occur. Moreover, the Colorado River Basin Project Act of 1968 (82 Stat. 885) specifically prohibits the Secretary of the Interior from undertaking feasibility studies of any plan to import water into the Colorado River Basin until 1978. This moratorium on water feasibility studies was extended under the Reclamation Safety of Dams Act (92 Stat. 2471) until November 1988. Thus, until this moratorium is removed no new imports can occur.

Salinity Standards

The States within the Colorado River system are committed to maintaining salinity at or below the average 1972 levels in the lower mainstem of the Colorado River. They have developed salinity criteria for three points in the Lower Basin—Hoover Dam, Parker Dam, and Imperial Dam. The criteria have been approved by EPA, but are tentative and subject to revision.

Salinity criteria could constrain oil shale development because such development has

*The Forest Service, in its RARE 11 program, is evaluating over 66 million acres of land to determine their suitability for designation as wilderness. During the period of initial evaluation and up to final disposition of the wilderness recommendation by Congress, these lands will be in some form of restrictive management.

been linked, through theoretical calculations, to salinity increases in the river system. Increases could occur through either of two mechanisms: salt loading (in which saline wastewaters are discharged from an oil shale plant) or concentration (in which waters of higher than average quality are removed from the Upper Basin tributaries for use in oil shale processing). Salinity increases from concentration are discussed in the next section of this chapter; those from salt loading are discussed in chapter 8.

It is possible that salinity criteria could affect oil shale operations if such operations acted to increase the salinity in the lower mainstem. If this were the case, acquisition strategies that increase the total depletions from the river system would be constrained. These would include the perfection of surface water rights and the purchase of stored surface water. Ground water development would be little affected, and interbasin diversions would not be constrained as long as the salinity of incoming water was lower than upstream surface flows within the basin. The transfer of senior irrigation rights would probably not be impeded because, as discussed in chapter 4, irrigation return flows are the chief man-related source of salinity in the Colorado River system. A reduction in these flows through diversion to oil shale processing should decrease the salinity of the lower mainstem.

In summary, the effects of emerging salinity standards cannot be predicted with any confidence. Certain water acquisition strategies would feel them more than others. They should not severely affect any strategy if water released from oil shale sites is treated to achieve the discharge standards promulgated under the Federal Water Pollution Control Act.

Critical Uncertainties

The previous analyses have calculated that an oil shale industry of up to 2 million bbl/d could be supported to the year 2000 by surplus water that is legally available to the oil shale States. This calculation is based on four key assumptions:

- The long-term average virgin flow is 13.8 million acre-f ft/yr—the running average between 1930 and 1974.
- The industry continues to use a mix of mining and processing technologies similar to that which would be used if presently active and proposed projects were completed.
- Water demand for conventional uses in the Upper Basin increases at a medium rate.
- The industry relies solely on surface water; ground water is not ‘developed.

Following is a discussion of how the industry’s capacity might be affected if other assumptions were made in these areas. Consideration is also given to the problems of water availability beyond 2000.

Virgin Flow

As noted, the flows of the Colorado River vary widely. Estimates of future water availability have been based on the flows measured at Lee Ferry after 1930 because earlier estimates of virgin flow were less accurate. (Before 1922, flows were not measured at Lee Ferry; they were estimated from the measured flows of upstream tributaries.) However, it is not clear that the flows encountered in the past will continue into the future. The 13.8-million-acre-ft/yr average could sustain a large industry through 2000, but if the long-term average decreased by 3 percent, to 13.4 million acre-ft/yr, there would be no surplus surface water available then. Measurements of tree rings in the Colorado River Basin suggest that the long-term average flow may be closer to this level than to 13.8 million acre-ft/yr.[43] On the other hand, if the flows increased to 14.2 million acre-ft/yr, 3 percent above the 1930-74 average, there would be sufficient surplus water in 2000 for a 4-million-bbl/d industry. The average flow between 1906 and 1974 was 15.2 million acre-ft/yr. The average between 1922 (when flows were first measured at Lee Ferry) and 1974 was 14.2 million acre-ft/yr.

Technology Mix

The industry's actual average water requirement may be substantially higher or lower than the 8,500 acre-ft/yr per plant that would result if present trends continued. An industry based solely on directly heated AGR would consume only about 4,900 acre-ft/yr per plant. The amount of surplus surface water projected for 2000 would be sufficient for a 3.5-million-bbl/d industry if only this technology were employed. On the other hand, an industry of indirectly heated AGR facilities (at 12,300 acre-ft/yr per plant) could produce only 1.4 million bbl/d from the same surplus.

Conventional Depletions

Although the medium growth rate for conventional water uses is regarded by the States as most likely, it is possible that demands could increase at a much higher or lower rate. DNR analyzed the effects of low, medium, and high growth rates. Although the medium rate would allow an industry of up to 2 million bbl/d, a high rate would reduce the surplus surface water by 247,000 acre-ft/yr in 2000. Only a 550,00@ bbl/d industry could be accommodated. On the other hand, a low growth rate would increase the surplus by 326,000 acre-ft/yr and would allow an industry of up to 3.9 million bbl/d.

In any case, surplus water availability is much less assured after 2000. If the low growth rate prevails, demand will exceed supply by 2027, even without an oil shale industry. With a medium growth rate, the surplus will disappear by 2013. A high growth rate will consume the surplus by 2007, again without oil shale development. The implications of this potential problem for oil shale are controversial. On the one side it is argued that possible long-term water shortages should preclude the establishment of an industry. On the other side, it is maintained that a major industry could function for much of its economic lifetime without interfering with other users, and in any case would use relatively little water. (A l-million-bbl/d industry would accelerate the point of critical water shortage by about 3 years.)

Ground Water Development

If the presently active and proposed projects were completed, more than 40 percent of the shale oil production would come from ground water areas in the central and northern Piceance basin. If additional Federal leasing were pursued, a much higher percentage of the industry's facilities would be sited in this area. Ground water will have to be developed on these sites in order to allow mining or in situ retorting. The ground water extracted would have to be reinfected into the source aquifer, or treated for discharge to surface streams, or used in the facilities. If it were used as process water, the need for surface water would be substantially reduced. If 15 percent of the roughly 25 million acre-ft in the Piceance basin bedrock aquifers were used for oil shale, it could support a l-million-bbl/d industry for 20 years. However, this rate of consumption would exceed the recharge rate for the aquifers. Thus, the ground water levels would decrease and some of the surface streams that are supplied by ground water discharge would dry up. This would have relatively minor economic ramifications because the rate of ground water discharge is only about 20,000 acre-ft/yr. The environmental effects woulds be mixed, as discussed in the next section.

The Impacts of Using Water for Oil Shale Development

Introduction

The use of water by an oil shale industry will cause economic, social, and ecological changes in both the Upper and the Lower Basins of the Colorado River system. The effects of salinity increases are of special concern because salinity levels in the Colorado River have been identified as a matter of national concern.[44]his section discusses the salinity increases that are expected to result from use of surface water for oil shale development. The overall impacts of water diversion on the Upper and Lower Basins are then discussed. Because of time restrictions, OTA did not perform an independent analysis of these impacts, However, assessments have recently been completed by DNR, USBR, USGS, and USFWS. The following discussion is largely based on the results of these studies.

Impacts From the Construction and Operation of Water Supply Facilities

Construction of dams, wells, and diversion facilities would create jobs and increase disposable income. However, pressures on housing and on community facilities and services would result. Both the positive and the negative effects would diminish once construction was completed. Operation of the facilities would require fewer than 10 employees per plant, out of a total work force of approximately 1,500. Consequently, relatively few of the socioeconomic impacts that may accrue from creating an oil shale industry can be associated with the water supply systems.

New reservoirs will flood land that may presently be used for farming or grazing or that may have special scenic or ecological value. Homes, farms, businesses, roads, and utility lines would have to be relocated, and riparian and aquatic systems could be disturbed. These impacts should be minor compared to those of the mining and processing operations. Because the reservoirs will be relatively small, the overall impacts would be small compared to those that were associated with the construction of existing reservoirs. (The new reservoirs needed for a l-million-bbl/d industry would increase the total water storage in the Upper Basin by 0.6 percent.) These impacts will be site specific and have not yet been analyzed.

Impacts From Changes in Surface Flows

Extraction of surface water will decrease the instream flows of the Colorado River and its tributaries. These changes will have direct effects on water users and indirect effects on water quality and aquatic ecosystems. The direct effects are considered in this section; the indirect effects in the section that follows.

Decreased flows would reduce hydroelectric power production at specific CRSP reservoirs. According to the DNR assessment, revenue losses could reach $7 million per year in 2000 as a result of a 2.44-million-bbld/ industry. ’5 Flow reductions would also decrease deliveries to the Central Arizona project and force the agricultural industry in the Lower Basin to rely on more expensive ground water pumping. Net farm income would be reduced by about $2.3 million per year by 2000 as a result of a 2.44 million-bbl/d industry.[46]

According to USBR, environmental impacts in the Lower Basin depend more on reservoir operating criteria than they do on the quantity of water in a particular stream, and flow reductions in the Lower Basin would have significant effects only in that portion of the Colorado River between Glen Canyon Dam and Lake Mead.[47]

Reductions in instream flow will also affect recreational use of some stream reaches. Although most recreational activities, such as rafting, boating, and kayaking, would remain unchanged in 2000 even with high levels of oil shale development, negative impacts would occur in two river reaches. In the Colorado River between Rifle, Colo., and its confluence with the Gunnison River, rowing and rafting conditions would be degraded from the present fair condition to poor if a 2.44-million-bbl/d industry were established. Fishing conditions would be reduced from fair to poor with substantially lower levels of development. In the White River from Meeker, Colo., to Ouray, Utah, conditions for canoeing, kayaking, and fishing would be reduced from excellent to good. Adverse public reaction should be expected. Secondary impacts on tourism and recreational service suppliers may occur, although no detailed analysis of these impacts has been undertaken.

Impacts on Water Quality

Withdrawal of water of relatively high quality from upstream tributaries of the Colorado River system will increase salinity levels in the lower reaches of the Colorado River by making the water unavailable for dilution of more saline streams that enter the river below the withdrawal point. Some of the estimates that have been made of this salt concentration* effect are summarized in table 86.[48-54] Included for each source are estimates of salinity increases for the project or industry originally analyzed and estimates scaled to a common basis of a l-million-bbl/d industry. As shown, a l-million-bbl/d industry in the Upper Basin could increase salinity levels at Lower Basin measuring stations by 0.2 to 2.4 percent. The estimates incorporate widely differing assumptions regarding plantsiting, types of processing technologies, water requirements, and quality of water diverted. A very approximate average salinity increase for a l-million-bbl/d industry might be about 1 percent.

It should be noted that similar effects would be experienced if the same amount of water were used for other purposes. The University of Wisconsin study cited in table 86 estimated that diversion of 300,000 acre-ft/yr of upstream water to oil shale would increase salinity at Imperial Dam by about 20 mg/l. If the same quantity of water were used for irrigation, the salinity increase would be about 57 mg/1. Exportation of the water from the Upper Basin would increase salinity by about 24 mg/l.[55]

The economic losses, including damage to agricultural, municipal, and industrial users

*Increases in salt loading are discussed in ch. 8.

Table 86.–Projected Salinity Changes in the Lower Colorado River From Oil Shale Development

Source of estimate	Reference	Shale 011 capacity modeled, bbl/d	Measuring station	Present salinity, mg/l[a]	Salinity increase from 011 shale: For model Industry mg/l	For 1 million bbl/d mg/l	For 1 million bbl/d Percent
Colorado Department of Health	48	1,000,000[b]	Glen Canyon Dam	609	4	4	0.7
National Academy of Sciences	49	800,000	Hoover Dam	745	2	1,6	0 2
		1,600,000			4	2 5	0 3
Stanford Research Institute ., .,	50	250,000	Hoover Dam	*745*	1	4	0.7
Unversity of Wisconsin	51	1,000,000	Imperial Dam	*850*	20	20	2 4
Department of the Intenor	52	1,000,000	Hoover Dam	*745*	10-15	10-15	1 3-20
Bureau of Land Management	53	47,000	Hoover Dam	*745*	0 1	2 6	0.3
U S. Bureau of Reclamation	54	1,300,000	Imperial Dam	850	7	5	0 6
		2,440,000			15	6	0 7

[a]Data from reference 59
Calculated from estimates for Increases in the White River and the Colorado Mainstem

SOURCE Off ice of Technology Assessment

in the Lower Basin could reach $5.4 million per year in 2000 for a 2.44-million-bbl/d industry. This estimate is based on a salinity increase at Imperial Dam of 18.1 mg/l—l.8 percent of present salinity levels.'"

The full salinity impacts of water used in the Upper Basin are not felt until much later in the Lower Basin because of the dampening effects of Lake Powell and Lake Mead. For example, the Colorado River Basin Salinity Control Forum estimates that the full effects do not occur until after 17 years. The forecasts for 2000 therefore underestimate salinity effects on the Lower Basin, In addition, an assumption of the USBR analysis is that three authorized desalinization plants will be in operation by 2000, removing over 700,000 ton/yr of salt.

To a lesser extent other water quality parameters will be affected by the use of water for oil shale development. Sediment loading will increase in some reaches as the result in changes in land use associated with the dams, pipelines, and roads for the water supply facilities. Changes in river flow from reservoir operation could alter sediment transport and the biochemical oxygen demand in some reaches. These impacts have not yet been assessed in detail.

Impacts on River Ecology

Changes in instream flow can affect the aquatic ecosystem including the habitat of sport fish and rare and endangered species. Of special concern are the effects on rainbow trout, a major sport fish, and the Colorado River squawfish and humpback chub which are endangered species. Analyses of the impact of water use for oil shale on the rainbow trout, the squawfish, and numerous other fish species have been undertaken by USFWS and the U.S. Heritage and Conservation Service,[57] but the effects on the humpback chub have not been assessed due to lack of criteria in the USFWS study, These assessments do not include studies of the complete aquatic ecosystem and exclude impacts on the ecology of smaller streams at high elevation so no conclusions can be drawn on impacts on these streams at present.

Limited effects on fishery habitats were indicated for the Upper Basin as a whole, except for the White River. For rainbow trout in the Green River, the fry, juvenile, and adult stages would be little affected by a 2.44-million-bbl/d industry. Spawning conditions would remain poor. Adult Colorado River squawfish in the Yampa River would not be affected, but conditions for squawfish fry in the same stream would improve from their present poor level to fair. Conditions for adult squawfish in the White River would degrade from their present level of excellent to good.

Assessment of impacts on plants, invertebrates, and other components of the aquatic ecosystem have not been undertaken,

Transfer of Water From Irrigated Agriculture

Although it is not necessary to take water from irrigated agriculture to supply oil shale developments, such transfers are legally permitted. Because the economic value of an acre-foot of water to an oil shale developer is much greater than to irrigated agriculture, transfers of water rights could occur in some areas. These transfers would have social and economic ramifications, including a redistribution of income. Farm income would be reduced, but these reductions would be countered by a regional income gain because of increased employment in the oil shale industry,

According to DNR, the gain would be 10 to 100 times greater than the loss.[58] The number of farming families would also be reduced. Significantly larger impacts would be experienced, however, from factors not directly related to water use patterns, such as the competition for local labor and the purchase of agricultural lands for municipal expansion.

Irrigated agriculture diverts large quantities of surface water, but only a portion is actually consumed. The balance eventually returns to the water systems through agricultural return flows and/or percolation into ground water aquifers. Oil shale developers can only purchase rights to the consumptive portion of the diversion. Therefore, if irrigation rights were transferred to oil shale development, less water would be diverted from surface streams, and stream flows would increase. The effects of these increases were not modeled for DNR because of their small size and because a significant diversion of agricultural water to oil shale development is not anticipated in most areas. If significant effects occurred at all, they would most likely be in the White River Basin, where fish habitats and recreational opportunities would be improved as a consequence.

Ground Water Development

The impacts caused by well-drilling and maintenance would be similar to those for the construction of reservoir and pipeline facilities for surface water development—relatively small and of short duration. After the wells are drilled, only a few workers would be needed for maintenance. The number would be small in comparison with the estimated total work force of an operating oil shale plant. Unlike purchase of irrigation rights, ground water development should not have significant effects on the economic base of the oil shale region.

Stream flows would not be significantly reduced for the overall basin, although substan-

Photo credit OTA staff

Pumping water from the White River for agricultural purposes

tial reductions would occur in those areas in which ground water discharge supplies a major portion of surface flows, For example, some streams in the Piceance basin are fed by ground water discharge during most of the year. Aquifer drawdown as a result of ground water development would reduce flows in these streams, and in some cases would completely eliminate them except during the spring snowmelt. Fishery habitat in these streams would be severely affected.

According to DNR, the overall effects of ground water development on fish habitats and recreation would be much less than would be encountered with water acquisition strategies that relied solely on surface water diversions.[5]’ However, heavy dependence on ground water could lead to using underground water resources faster than the rate of recharge and in some instances to mining geologically old water. The use of such water constitutes an irrevocable decision to exploit a nonrenewable resource, hence precluding its use for other purposes in the future.

Oil shale projects that use low-quality ground water may produce a net decrease in salinity in Colorado. For example, the Superior Oil project in Colorado’s Piceance basin will use water from the lower bedrock aquifer that has a salinity concentration of about 26,000 mg/l—about 30 times the salinity of the Colorado River at Imperial Dam. Withdrawal of this water would reduce the quantity of salts discharged into Piceance Creek by about 24,500 ton/yr. As a result, the salinity of Piceance Creek would decrease by about 1,040 mg/l. Salinity in the near reaches of the White River, into which Piceance Creek discharges, would be reduced by about 40 mg/l.[60] Salinity at Glen Canyon Dam would decrease by about 1.6 mg/1—about 0.3 percent of its present level.

Methods for Increasing Water Availability

Sufficient water should be physically available in the Upper Basin to support a large oil shale industry while simultaneously satisfying the needs of other users. However, water scarcity could constrain regional growth after 2000. Additional surface flows could be provided through conservation (i.e., more efficient use of water), interbasin diversions, and possibly by weather modification. Water use efficiency and weather modification are discussed below; interbasin diversions were discussed earlier.

More Efficient Use

By reducing demand, water conservation would increase net water availability. Opportunities exist in municipalities, in irrigated agriculture, and in industrial activities including oil shale development.

Municipal

Because municipalities in the oil shale region consume little water, conservation strategies would have to be focused on the larger cities in Colorado’s Front Range Urban Corridor that import water from the Upper Basin. For example, if Front Range cities lowered consumption by 20 percent, exports would be reduced by about 100,000 acre-ft/yr.[61] Demand could be reduced by methods such as restricted lawn watering or imposed peak-use surcharges, seasonal pricing differentials, and price incentives. Recycling systems could also be considered, but implementation could be hindered by high costs and their unfavorable image.

Irrigated Agriculture

Present irrigation methods are inexpensive to the farmer but relatively inefficient. Even small improvements could release large quantities of water for other purposes and decrease the quantity and perhaps salinity of agricultural return flows. Losses from canals could be reduced by adding impermeable linings or pipelines. Sprinkler systems or trickle irrigation would reduce evaporation from

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field soils. Losses to noncrop vegetation could be reduced by eliminating the vegetation. Crop evapotranspiration and loss of cropcaptured water could be reduced by substituting crops that need little or no irrigation water.

Few of these strategies could be introduced on a large scale, however, without substantial economic, social, and environmental penalties. Mechanical irrigation, for example, would be very expensive, as would fabricated pipelines. Vegetation removal could threaten the ecological balance along stream courses and manmade waterways. Dryland farming might not be technically or economically feasible. Furthermore, conservation could be risky because if a farmer did not use all of the water covered by his water rights, abandonment could be declared.[62]

Estimating possible reductions by conservation is technically straightforward. Estimating likely reductions is much more difficult because of the social and economic complications. DNR concluded that reductions would probably not exceed 120,000 acre-ft/yr even with vigorous programs.

Industrial

Oil shale plants will use water efficiently. This is a consequence more of the nature of the processing technologies and the desire to avoid having to treat excess process water to discharge standards than it is of an interest in water conservation. * However, different technologies consume different amounts of water for the same production rate and the overall requirements of the industry could be reduced by encouraging the use of processes with the lowest water requirements. It is unlikely that technologies would be chosen solely on this basis because water costs are a very small fraction of total processing costs.

*The U.S. Water Resources Council states that an AGR plant would consume about 89 percent less water than a steam- electric powerplant with the same net energy output, 25 to 87 percent less than a comparable coal gasification plant, and 40 to 90 percent less than a comparable coal liquefaction facility.’)’

Offsite powerplants to support municipal growth could adopt conservation methods without substantially increasing power costs. It has been estimated that water requirements for power generation in the oil shale States will increase by as much as 221,000 acre-ft/yr before 2000, If the new powerplants relied on a combination of wet and dry cooling, water consumption could be reduced by about 175,000 acre-ft/yr, sufficient water for production of 1 million bbl/d of shale oil.[65]

Weather Modification

Cloud seeding could be used to enhance precipitation and thereby increase surface water and ground water resources. The results of three major projects during the last two decades suggest that overall increases in snowfall could range from 5 to 20 percent. It appears that if snowfall were increased by 10 percent, runoff might increase by from 5 to 20 percent and might add up to 2.0 million acre-ft/yr to normal surface flows. Ground water aquifers would also be affected because they are recharged principally from snowpack. USGS has estimated that a 10-percent increase in snowfall in the Piceance basin would add over 10,000 acre-ft/yr of ground water that could be withdrawn without disrupting the aquifer equilibrium.[66]

Preliminary cost estimates range from $1 to $10/acre-ft of additional runoff, There would be additional costs for capturing and transporting the augmented flows, and storage facilities would still be needed, Any additional runoff would be subject to the prior appropriation system because the augmented flows would be indistinguishable from natural flows. Because of the problem of uncertain ownership, the delivered water cost might well exceed the costs of other supply methods.

The consequences of weather modification are not well understood, but a successful program could be expected to have widespread effects on the region's ecosystems. Species composition, vegetation growth rates, and wildlife habitats might be altered. Although there could be recreational benefits from increased snowfall and higher streamflows, agriculture and transportation could be hampered. Losses in precipitation to areas beyond the zone of augmented rainfall or snowfall could have severe ecological, agricultural, and economic impacts. There could be legal difficulties if cloud seeding were linked to drought in downwind areas.

Policy Options

The distribution of water from the Colorado River system is governed by a complex framework of interstate and interregional compacts, State and Federal laws, Supreme Court decisions, and international treaties. Policy decisions affecting the use of this water for oil shale development must take into account both the provisions of these documents and the need to protect the rights of competing water users. A number of policy options that would affect the availability of water for an oil shale industry in the Upper Colorado River Basin are examined below. Their implementation could involve actions by Congress, the administration, State governments, and the oil shale developers.

The Determination of Water Needs

In order to more accurately assess the total amount of surplus surface water that will be available for additional growth in the Upper Basin, the amount needed by all projected users must be determined. The uncertainty about the future availability of water supplies to the Upper Basin would be reduced if the necessary determinations were carried out by Congress, by Federal and State governments, and by private developers. Some possible options are:

The development of a water management system.—Preliminary water management studies have been conducted by the Bureau of Reclamation and by individual developers and other users. However, no systematic basin-wide evaluation of water management alternatives has compared water supply options with respect to their water and energy efficiency, their costs and benefits, and their environmental and social effects. Such an assessment—involving Federal, State, and local governments; regional energy developers; other users; and the general public—may be an appropriate prelude to actions to construct new water storage and diversion projects. It could be especially useful in evaluating and coordinating such controversial options as the importation of water. Funding could be provided by DOI, DOE, or other agencies. The study could be managed by the Bureau of Reclamation or by Colorado River Compact Commission.

The determination of the amount of water needed by the Federal Government.—This could be done for Federal lands for which water rights are set aside under the Federal reserved rights doctrine. One possible alternative for Congress is to provide legislation to facilitate this determination in coordination with one of the administration's task forces devoted to evaluating Indian and Federal reserved water rights.

It is anticipated that the largest Federal claims in the oil shale region will be for the Naval Oil Shale Reserves. The U.S. Navy has made a preliminary filing with the Colorado water court for 45,000 acre-ft/yr. In addition, small amounts of water may be needed for diversions, impoundments, wells, and stream flows. Although filings are being made under this doctrine, most indications are that the total amount of water that will be claimed by the Federal Government in the oil shale region will not be excessive. The exact quantities, however, have not been determined. Because the extent of future filings is unknown, reliable estimates of water availability for regional growth cannot be made. The uncertainty would be reduced if there were some indication in the near future of the amounts that will be claimed under this doctrine.

The determination of water needs by the Colorado State Government.—In Colorado, the requirements for instream flows are legally considered only where the State has retained the right to obtain water for preservation of the natural environment. Colorado recognized instream rights in 1973; thus, these rights are junior and should not impede the perfection of rights held by other users prior to this date. However, such rights could affect the amount of water available to users who file in the future for additional surface rights—any additional rights would have a lower priority in times of water shortage. The State is presently in the process of filing for rights for instream water needs. Completing this process would further clarify the total amount of water available for development in this region.

The determination of water needs by municipalities, private developers, and other water users.—Water rights in the oil shale States have been granted liberally. As a result, the quantities of water covered by conditional decrees far exceed the available resources of the river. At the same time, not all the conditional decrees have been perfected, and relatively little of the claimed water is actually being used. If it could be determined how much of the water allocated under the conditional decrees will actually be beneficially used in the near term (for municipal, agricultural, or industrial purposes), then the Upper Basin States would have a clearer indication of the actual amount of surplus water available.

Reservoir Siting and Direct-Flow Diversions

All water acquisition strategies that rely on the large-scale development of surface water resources within the oil shale area would necessitate the construction of new reservoirs and direct-flow diversions (e.g., pipelines). Such construction might be hampered, delayed, or even disallowed under provisions of the Endangered Species Act, the National Wild and Scenic Rivers Act, and the Wilderness Act. Potential problems could be reduced through several mechanisms.

Identification of endangered or threatened species.—The Endangered Species Act provides for the Federal identification of endangered and threatened species of fish, wildlife, and plants; prohibits private activity that imperils such species; and requires Federal agencies to avoid any activities that would jeopardize such species or result in the destruction of critical habitats. A number of studies are underway to identify endangered and threatened species in the Upper Basin. To date, two federally designated rare and endangered fish species have been found in the waters of the oil shale region. The Colorado River squawfish inhabits the lower portions of the White River and the Colorado River from the backwaters of Lake Powell upstream to the confluence of Plateau Creek. The humpback chub lives in the Colorado mainstem downstream from the Colorado/Utah State line, Additional species requiring protection may be found in the future.

The Act may be interpreted as restricting activities that might adversely affect the critical habitats of such species, although none has been declared for the squawfish or the humpback chub. Knowing their approximate locations would be helpful because the timely siting of reservoirs and direct-flow diversions could be affected by agency interpretations involving instream flows. Should construction of these facilities begin before the critical areas were identified, there could be opposition to their completion, and water supplies from a particular reach of a river could be delayed or interrupted. If the locations of all designated critical habitats were identified by DOI and the required biological opinions obtained, the facilities could be sited to minimize interference and delay.

Designation of rivers to be set aside under the Wild and Scenic Rivers Act.—Any river area possessing one or more scenic, recreational, archeologic, or scientific values and in a free-flowing condition, or under restoration to such condition, may be considered for inclusion in the Wild and Scenic Rivers System. A number of rivers have already been designated under this legislation, and Congress is considering adding others. To date none in the oil shale region has been designated; however, several within the Colorado mainstem basin are being considered for wild and scenic designation. The amount of water that could be diverted from specific river reaches could be reduced if these rivers are set aside, thus an early designation of rivers eligible under this legislation would be of value in planning for future shale oil production. Given this information, direct-flow diversions could be sited downstream to those portions of rivers designated as wild and scenic rivers. This would avoid a direct conflict within a given river stretch but could add to the water supply cost.

Designation of wilderness areas.—The Wilderness Act created the National Wilderness Preservation System to provide "the benefits of an enduring resource of wilderness" for the whole Nation. In keeping with the purpose of preservation, the use of these areas is highly restricted. To date four areas in the White River basin and the Colorado mainstem basin have been designated under this legislation. Also, additional areas are being considered for inclusion in the system pursuant to the ongoing RARE II review. New reservoir storage would probably not be permitted in these areas, once designated. Since they are located at higher elevations in upper watersheds, they would probably not contain potential sites for reservoirs; however, additional wilderness areas at lower elevations could pose problems in siting storage facilities. A complete listing of wilderness areas that might be considered in the near uture would aid potential developers in locating their facilities in other areas.

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Financing and Building New Reservoirs

New reservoir and storage facilities would need to be constructed if a large shale industry were to be created. There area number of possible policy options for the financing and construction of such facilities.

Federal financing.—Congress could provide for the construction and funding of new Federal water projects through two mechanisms. First, Congress could appropriate funds for those Federal water projects that already have been authorized. Several projects have been evaluated by WPRS (formerly USBR), and their construction approved. Actual construction of these projects cannot begin until they are funded. However, not all of these projects have been evaluated for their suitability to supply water for oil shale development, and some project features may not be optimally located to serve oil shale projects.

A second option available to Congress is the passage of legislation that would specify the construction and funding of new, not previously authorized Federal water projects. However, unless language was included to expedite construction, these projects would require a long review process. They could, however, be designed and sited with their purposes as water sources for oil shale (as well as other possible uses) in mind. An example would be constructing irrigation reservoirs with additional capacity for oil shale requirements.

Under either option, DOI, through USBR, could operate these reservoirs in accordance with State water laws. Their costs could be recovered over the operating life of the facilities from revenues generated by selling water to oil shale developers and other users and in accordance with authorizing legislation.

State participation.—A State organization, such as the Colorado River Water Conservation District (CRWCD), could finance and construct new storage facilities. CRWCD holds large storage decrees in the basin of the Colorado River mainstem. The river district maintains that these decrees will likely be used as a source of supply for an oil shale industry. Several possibilities exist for the funding of reservoirs. One possible funding arrangement might be to sell water from existing State-administered reservoirs, such as Green Mountain and Reudi, to oil shale developers at very high cost (e.g., $250/acre-ft/yr). The short-term needs of many potential oil shale developers, depending on the siting of their facilities, could be met from such existing reservoirs. The profits from such sales could be used as leverage capital for marketing public revenue bonds. The capital generated from these bonds could then be used to finance the new reservoir facilities that would be needed by an oil shale industry in the longer term. A second funding scheme, which has been practiced by CRWCD in the past, is to sell options for water from proposed reservoirs to potential water users, thus raising the funds needed for the construction of the reservoirs.

Developer financing.—Reservoir and storage facilities could be financed and constructed by the oil shale industry itself.

Financing and Implementing More Efficient Practices and Water Augmentation

Surface flows in the Upper Basin could be increased if water conservation procedures were practiced by irrigated agriculture, municipalities, and industry. Weather modification is another possibility. Since carrying out these approaches could be quite costly for a particular developer or municipality, their chance of being implemented might improve if Federal and State governments were to supply some special funding or incentives. The following are some possible ways this could be done.

Funding and implementing water use practices.—Techniques for more efficient water use in irrigation and farming were illustrated earlier. As noted, farmers would be taking risks by adopting water conservation strategies because capital recovery would be uncertain and they might lose water rights. At the sometime, improvements in irrigation and farming practices could substantially reduce the demands for water in the Upper Basin. A number of options are available that would encourage such improvements. Congress could provide financial incentives, through such mechanisms as tax advantages, to those farmers who used water more efficiently, Technical assistance teams specializing in conservation techniques could also be provided to cooperating farmers by the Federal and State governments. In addition, Congress could give direct financial assistance through grant programs, administered either by Federal or by State agencies.

Individual municipalities could institute voluntary education programs and regulatory strategies aimed at reducing overall water consumption. Regulatory programs could restrict the watering of lawns and promote the use of water-saving devices. Cities could establish peak-use surcharges, seasonal pricing differentials, and price incentives to reduce usage. Local municipalities could also adopt water conservation techniques for their wastewater treatment facilities.

Municipal conservation techniques, whether voluntary or mandatory, are costly. Financing is needed to pay for administrative personnel as well as to produce and distribute educational materials. While these programs would probably be administered at the local level, they could be financed at the Federal or State level by direct grants or cost-sharing programs. To help pay for carrying out costly conservation procedures in municipal wastewater treatment facilities, Congress could provide tax incentives for such expenditures.

Although oil shale facilities are expected to be efficient water users, a number of water-conserving techniques could be used to minimize overall consumption. For example, some development technologies require less water than others—directly heated AGR has the lowest requirement (4,900 acre-ft/yr for 50,000 bbl/d of shale oil), while indirectly heated AGR has the highest (about 12,300 acre-ft/yr for the same output). Total industry consumption could be reduced by encouraging the use of the lowest water-consuming process. One congressional option would be to provide financial incentives to those facilities that implemented this process. Another would be to provide tax advantages to any facility that introduced specific water-conserving techniques. Also, through Government contracts, Federal agencies could specifically fund R&D by developers to improve the efficient use of water.

Funding of weather modification programs.—A number of Federal agencies, including the Departments of Commerce and of the Interior, have sponsored programs relating to winter orographic weather modification, The Federal Government could continue to fund programs in the Upper Basin with the aim of eventually increasing overall regional surface flows. If programs are funded, they should include work to better understand the impacts of weather modification.

Weather modification programs, although costly, could be undertaken by a State organization, municipality, or private developer. However, the ownership of any additional surface runoff would be uncertain under the current water appropriation system, and legal complications could arise if cloud seeding were linked to drought in other areas. It is unlikely that a particular municipality or private developer would undertake such a program without some assurance that a portion of any additional runoff would be available for its own use.

Federal Sources of Water for Oil Shale Development

Congress, under its constitutional powers, could make water available for oil shale developments from Federal water projects, or potentially from the reserved right doctrine. If Congress decides that water from congressionally funded projects should be made available for oil shale development, then any legislation enacted should provide that the term "industrial use or purpose" includes the use of water for oil shale development. * Congress could also amend the authorizing legislation for those projects from which water for oil shale development might be sought to permit the use of their water for that purpose. In such a case, legislation may be required if the project authorization does not list among the contemplated purposes for its water "industrial purposes" or some other category that could encompass oil shale facilities. The objective of such legislation would be to overcome any administrative reluctance to permit the use of water for oil shale development under an authorization that did not specifically mention it.

The power of Congress over reserved waters is more limited than its power over waters in congressionally funded projects. The use of water under the reserved right doctrine must be "in furtherance of the purpose of the reservation. " For this reason, Federal water rights do not seem to be likely sources for oil shale development, except perhaps in the case of lands set aside for the Naval Oil Shale Reserves. This matter, however, is in the early stages of litigation. New reservations of land set aside for the purpose of making water available for oil shale development would not appear to be a feasible alternative, since Federal reserved water rights are subject to rights vested prior to the date of the reservation.

A final option available to Congress would be to deny Federal water for oil shale development, if it decides that such development should not be given a high priority.

*A Memorandum of Understanding exists between DOI and the State of Colorado with respect 10 the use of water from existing or authorized WPRS (formerly USBR) projects. The State desires that the water not be changed from agricultural, municipal, or light industry uses to energy production (including oil shale), that are inconsistent with State policies. Under this memorandum, the State will review any application to redistribute water from conventional uses to energy production. The memorandum could be superseded by congressional directives of overriding national importance.

The Allocation of Water Resources

If Congress were to pass legislation encouraging the development of an oil shale industry it might wish to address the issue of how the necessary water would be supplied and how oil shale legislation might affect water allocation.

Water in the oil shale region is presently distributed by a complex framework of interstate and interregional compacts, State and Federal laws, Supreme Court decisions, and international treaty and administrative decisions. Within Western States, water rights are apportioned by the States to competing users according to a doctrine of prior appropriation under which water rights are a form of property separate from the land.

If control over the water supply for oil shale is to be left to the States, then Congress should probably so specify in oil shale legislation to avoid any question of the preemption of State water laws. Legislation that would confirm preservation to the States of the same power over water for oil shale as they have over other water supplies should require the developer to comply with State procedures in securing a water supply and provide that the established State appropriation system has the same authority to grant, deny, or place conditions on water rights and permits as would prevail in the absence of the legislation.

If Congress were to attempt to remove the water supply for oil shale production from the control of the States, strong legal and political resistance would ensue. Such resistance could delay oil shale development.

Interbasin Diversions

Interbasin diversion is a technically feasible although costly* option for bringing additional water to the oil shale region. There are also serious political obstacles to this alternative. The Reclamation Safety of Dams Act of 1978, amending the Colorado River Basin Project Act, prohibits the Secretary of the Interior from studying the importation of water into the Colorado River Basin until 1988. If it were decided to pursue this option as a means of supplying water to an oil shale industry coming on line in 1990, this prohibition would have to be lifted.

Interbasin diversions could be used to relieve the water problems of the region in several ways. Water could be transferred directly to the area, either exclusively for oil shale development or for all users. Alternatively, the water needs of Colorado's eastern slope cities, presently being supplied in part from the Upper Colorado River Basin, could be met from other hydrologic basins. The water presently being exported from the Upper Basin then could be used for oil shale development. In a third application of interbasin transfers, all or a portion of the 750,000 acre-ft/yr presently being supplied to Mexico by the Upper Basin States under the Mexican Water Treaty of 1944-45 could be taken from another hydrological basin (perhaps the Mississippi basin). The water thus freed in the Upper Basin could be assigned in part to oil shale development (750,000 acre-ft/yr would be sufficient for a 3,000,000- to 7,500,000-bbl/d shale oil industry).

The transfer of water from another hydrologic basin could have detrimental impacts on that basin, and impact analysis should precede diversion.

*The cost of supplving water by interbasin transfers is estimated to be no more than 5 percent of the total cost of producing a barrel of shale oil.

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