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WATER-RELATED IMPACTS OF IN-SITY OIL SHALE PROCESSING

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ENERGY & ENVIRONMENT
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WATER-RELATED IMPACTS OF IN-SITU OIL SHALE PROCESSING

J. P. Fox

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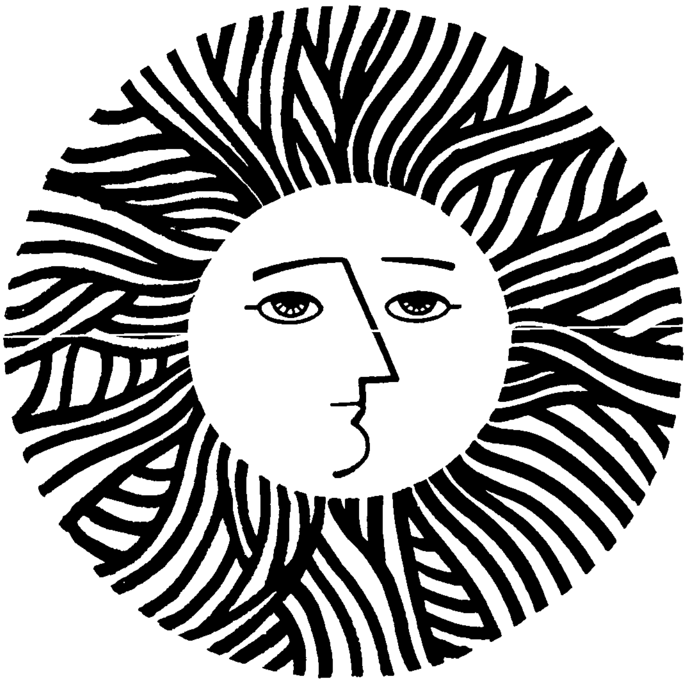

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WATER-RELATED IMPACTS OF IN-SITU OIL SHALE PROCESSING

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December 1980

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At the time this work was originally planned, seven appendices were projected as part of the overall project. However, as research and study gave way to writing and editing, it became clearly apparent that the sheer bulk of the planned work--over 1000 pages--made it impractical to publish the appendices as a part of the overall study. The following separate reports, published by the Lawrence Berkeley Laboratory, were the seven intended appendices:

G. L. Amy, <u>Contamination of Groundwater by Organic Pollutants Leached from In-Situ Spent Shale</u> (Ph.D. Dissertation, University of California, Berkeley, 1978), Lawrence Berkeley Laboratory Report LBL-10526 (1980).

D. S. Farrier, J. P. Fox, and R. E. Poulson, <u>Interlaboratory, Multimethod Study of an In-Situ Produced Oil Shale Process Water</u>, Lawrence Berkeley Laboratory Report LBL-9002 (1979).

J. P. Fox, *The Partitioning of Major, Minor, and Trace Elements during Simulated In-Situ Oil Shale Retorting* (Ph.D. Dissertation, University of California, Berkeley, 1980), Lawrence Berkeley Laboratory Report LBL-9062 (1980).

W. G. Hall, *Hydraulic Calculations for a Modified In-Situ Retort*, Lawrence Berkeley Laboratory Report LBL-10431 (1980).

E. Ossio and J. P. Fox, *Anaerobic Biological Treatment of In-Situ Retort Water*, Lawrence Berkeley Laboratory Report LBL-10481 (1980).

P. Russell, *The Effects of Oil Shale Related Effluents on Some Benthic Freshwater Organisms* (Ph.D. Dissertation, University of California, Berkeley, 1980), Lawrence Berkeley Laboratory Report LBL-9818 (1980).

P. Russell, *Catalog of Organisms in the Green River Basin*, published as an appendix of the previously cited reference (LBL-9818).

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GLOSSARY

The terms included in this glossary are primarily those unique to oil shale processing. Some expressions are also used in other industries and disciplines; the definitions cited stress the oil shale application of these terms. Common technical expressions, which have no special oil shale application, are not included in the glossary.

Abandoned in-situ retort or abandoned retort: A large chamber of spent shale remaining in the underground environment after oil has been extracted.

Backfill: The process of filling an underground cavity created by mining and retorting with material imported and/or material removed during mining. Mine overburden, spent shale, and/or raw shale would be returned to the mined-out area, which might be an abandoned retort, an underground mine, or an open pit.

Boiler blowdown: A concentrated waste stream which results when boiler makeup water is converted to steam. The constant or intermittent discharge of a portion of the boiler water in order to prevent buildup of high concentrations of dissolved salts during steam production.

Cap rock: An impervious layer of oil shale between a retort and the adjacent formation, which may be an aquifer. Normally, a cap rock is the original rock left intact between the retort and an aquifer.

Char: The carbon residue left on spent shale after kerogen is converted into oil by thermal distillation. This finely divided graphitic carbon gives indirect-heated spent shale its black color. Char represents unconverted energy which may be combusted to generate process heat during retorting in an oxygen atmosphere.

Co-current retorting process: A retorting process in which the combustion front moves in the same direction as the input gas. Also called forward retorting.

Coking: A process used to reduce the viscosity of oil by breaking down high molecular weight organic material under high pressure and low temperature. The process produces a carbon product called "coke."

Combustion zone: The area in the reaction zone where combustion of char occurs.

Control strategies: Management strategies or technologies devised to eliminate or mitigate environmental impacts.

Cooling tower blowdown: A concentrated waste stream which results when water is used for cooling. The constant or intermittent discharge of a portion of the circulating water in a closed cooling system in order to prevent buildup of high concentrations of dissolved salts.

Countercurrent retorting process: A retorting process in which the combustion front moves in the opposite direction of the input gas. Also called reverse retorting.

Dewatering: Removal of water from a geological formation. This is necessary in in-situ retorting to prevent groundwater influx into tunnels, adits, and the retort.

Direct process: Retorting mode in which pyrolysis heat is derived from the combustion of char left on spent shale.

Distillation: A process to reduce oil viscosity by physical separation of hydrocarbon components into fractions with specified boiling point ranges.

Effluents: Liquid wastes generated at an oil shale plant by mining operations, dust control, steam and power generation, compaction of spent shale, irrigation, human use of potable water, and pre-refining of shale oil. The types of effluents produced include mine waters; brines from ion exchange, reverse osmosis, filtration, and other treatment processes; storm water runoff from the plant area; and various process waters.

External heating: The use of an externally heated medium such as inert gas or ceramic spheres to pyrolyze oil shale.

Field retort: An experimental in-situ retort located in a natural geologic formation and wholly contained by oil shale and associated minerals.

Fisher Assay: A standard assay method used to determine the oil yield of shale in gallons of oil per ton of rock.

Forward retorting process: See co-current retorting process.

Gas condensate: Water removed from the gas stream in a condenser train.

Green River Formation: The geological formation containing the oil shales of Colorado, Utah, and Wyoming.

Grout: A cementitious material used for retort plugging. Grout might be produced from commercially available materials or made from on-site waste products such as spent shale.

Grout curtain: A large underground wall of grout surrounding a block of retorts. A grout curtain is intended to divert most of the groundwater flow around a retorted area.

Grouting: The injection of a cementitious fluid material into the voids of a porous or fractured media to stop or reduce water movement or to consolidate or strengthen the media. In oil shale processing, grouting is used to reduce the permeability and increase the strength of abandoned in-situ retorts.

Horizontal retort: A retort in which the reaction zone moves horizontally instead of vertically.

Hydraulic bypass: A zone of high permeability around a block of retorts, intentionally created to transport groundwater away from or around abandoned retorts.

Indirect retorting process: Pyrolysis or retorting in the absence of air, in which heat is transferred to shale by an externally heated medium such as inert gas or ceramic spheres.

In-situ processing: Thermal conversion of oil shale in its original geologic formation.

In-situ retort: An underground chamber of fractured or rubblized oil shale located in its original geologic formation and wholly contained by oil shale and associated minerals. See also modified in-situ retort and true in-situ retort.

Internal heating: The use of heat produced by the combustion of char on the spent shale to pyrolyze oil shale.

Kerogen: The disseminated organic material in sedimentary rocks that is insoluble in non-oxidizing acids, bases, and organic solvents. A high molecular weight polymer which is the principal organic component of oil shales.

LBL: Lawrence Berkeley Laboratory.

Leachate: The effluent that results when a solid such as raw or spent oil shale is contacted by a liquid; contains the soluble components of the solid.

LETC: Laramie Energy Technology Center.

LLL: Lawrence Livermore Laboratory.

Lurgi process: An indirect surface retorting process in which carbonaceous spent shale is burned and contacted with raw shale to provide heat for pyrolysis.

Mahogany Zone: A seam up to 200 feet thick containing the richest oil shale in Green River Formation.

Mine drainage: Groundwater removed from a retorting area to permit mining and retorting to proceed in a sufficiently dry environment. This water may be removed by pumping or internal drainage. See Dewatering.

Modified in-situ retorting: An in-situ retorting process in which 20 to 40 percent of the in-place shale is mined out and the balance is blasted into the void to create a bed of rubble. The in-situ rubblized shale is pyrolyzed by either a direct or indirect process.

Offgas: See retort gas.

Oil shale: A fine-grained, laminated, sedimentary rock. A marlstone rock containing organic materials, principally kerogen, which can be converted into crude oil.

Omega-9 water: Retort water from the 1976 Rock Springs Site-9 true in-situ oil shale combustion experiment conducted by LETC.

Overburden: The material or strata overlying a specified area. The material from the ground surface to the top of an in-situ retort.

Overburden support: The strength in the supporting pillars between retorts and within the retorted mass required to support the overburden.

Paraho direct process: A surface retorting process utilizing a Paraho-type retort in which char on the spent shale is combusted to supply pyrolysis heat.

Paraho indirect process: A surface retorting process utilizing a Paraho-type retort in which crushed shale is pyrolyzed by externally heated gases.

Particulate grout: A non-Newtonian fluid consisting of a suspension of fine particles. Spent shale is a particulate grout.

Piceance Creek Basin: The hydrologic drainage basin of Piceance Creek. The Piceance Basin refers to the geologic basin underlying this area.

Pillars: The unprocessed and undisturbed shale separating retorts. Pillars are required to support the overburden.

Pre-refining: A series of chemical or physical operations used to upgrade the quality of oil shale so that it is comparable with conventional crudes. "Basic" pre-refining includes all steps necessary to reduce the pour point and viscosity of the oil to permit economic transport. "Advanced" pre-refining includes all additional steps necessary to make the oil compatible with existing refineries.

Product recovery: Removal of liquid and gaseous by-products from a retort.

Pyrolysis: The decomposition of organic materials by heat in the absence of oxygen. The thermal distillation of kerogen to produce oil.

Pyrolysis zone: The area in a retort where pyrolysis occurs. In a vertical, co-current, direct-heated, modified in-situ retort, the pyrolysis zone advances ahead of the combustion zone, and pyrolysis heat is supplied by combustion of char in the trailing combustion zone.

Raw shale: Oil shale prior to processing. Oil shale in its natural state.

Retort: The containment vessel in which the organic compounds present in oil shale are pyrolyzed. In in-situ retorting, the retort is a large underground chamber whose walls are oil shale.

Retort gas: A low Btu gas produced during the conversion of oil shale.

Retorting: The process of pyrolytically decomposing oil shale to produce shale oil, gas, water, and spent shale.

Retort plugging: The process of filling the voids in an abandoned retort to minimize the flow of groundwater through the retort and/or to increase the structural strength of the retorts. Plugging may be achieved by filling the retorts with a grout.

Retort water: The water co-produced with shale oil and decanted from it. This water originates from mineral dehydration, combustion, groundwater intrusion, and steam and moisture in the input gas.

Reuse: The multiple use of a primary water source, such as surface or ground water. Effluents produced during retorting, refining, or other on-site water uses would be renovated to meet minimum standards and reused in the process.

Revegetation: The re-establishment of plant life on a disturbed area. Spent shale disposal piles will be revegetated to minimize erosion and to improve the aesthetics of the area.

Reverse retorting process: See Countercurrent retorting process.

Reverse wettability: The application of a water-repellant coating, such as wax, to in-situ spent shale as a means of reducing or preventing leaching.

Rubble: Fragmented rock; the collection of relatively uniform particles of raw shale within a modified in-situ retort which is produced by mining out 20 to 40 percent of the in-place shale and blasting the balance into the void.

Rubblize: The process of producing rubble within an in-situ retort by mining and blasting.

Shale oil: The liquid hydrocarbon product produced by condensation of organic vapors from the pyrolysis of oil shale.

Simulated in-situ retort: A surface retort designed and operated to simulate in-situ conditions; primarily used in laboratory studies.

Site selection: The process of locating an in-situ retort to minimize environmental impacts or to maximize economic returns.

Slurry: A pumpable suspension of a solid, such as grout, in water.

Spent retort: A retort in which the shale has been processed to remove oil and other by-products.

Spent shale: The solid residue remaining after oil, gas, and water have been removed from raw shale by pyrolysis and/or combustion.

Spent shale grouting: Grouting or plugging an abandoned retort with a grout prepared from spent shale.

Storm water runoff: The normal drainage resulting from rainfall or snow melt.

Subsidence: The tendency of the ground surface to sink when the underlying strata are modified. In oil shale retorting, the tendency of strata and/or the ground above an abandoned retort to sink into the void created by mining.

Surface processing: A retorting process in which relatively rich oil shale is mined and retorted on the ground surface in an above-ground retort similar to an industrial kiln.

Surface retorting: See surface processing.

Surface retort: An aboveground retort constructed of materials such as stainless steel and operated to pyrolyze and/or combust oil shale.

TDS: Total dissolved solids.

TOC: Total organic carbon.

TOSCO process: An indirect surface retorting process in which heat is transferred to raw shale by recirculating ceramic or marble balls.

Tract C-a and Tract C-b (also lease tracts C-a and C-b): 5000-acre tracts of land in the Piceance Creek Basin of Colorado leased for oil shale development as part of the Federal Prototype Leasing Program.

True in-situ retorting: An in-situ retorting process in which oil shale is fractured by electrolinking, hydraulic fracturing or other methods. These processes do not use mining to create formation permeability.

Vertical modified in-situ retorting: A modified in-situ retorting process in which the reaction zone moves vertically downward.

Visbreaking: An upgrading process in which shale oil is heated to reduce viscosity, thus making the oil suitable for pipe lining.

VMIS: Vertical modified in-situ retorting.

ABSTRACT

The United States has the largest and richest oil shale deposits in the world. The Green River Formation in Colorado, Utah, and Wyoming contains some 1.8 trillion barrels of oil in place, of which 600 billion is estimated to be recoverable with existing technology. This deposit has been considered, off and on, for decades, for the production of oil; it has not been developed due to the high cost of shale oil relative to conventional crude. However, the ever-increasing cost of imported oil and political pressures exerted by foreign oil producers have recently spurred interest in finally obtaining oil from shale. As this report goes to press, Standard of California and Exxon are launching a multi-billion dollar development effort to commercialize oil shale. Other major and minor oil companies--Occidental, Tenneco, Standard of Indiana, Gulf, and Geokinetics--have been conducting ambitious field experiments for nearly a decade and commercialization is imminent. Thus, the future of oil shale in the United States appears hopeful.

However, the commercialization of oil shale, while politically and economically attractive, could result in irreparable environmental damage if development is not carefully planned. Oil shale deposits are located in a largely pristine area characterized by a low population density, clean air, wide open spaces, and an agricultural economy. The deposits are located in the Upper Colorado River Basin where water supply and quality have long been issues of national and internatinal concern. Rapid and large scale development in such an area will overcommit the existing infrastructure and compromise environmental quality. Severe socioeconomic, air, and water quality and quantity impacts will surely result if adequate controls are not developed in conjunction with the technology.

This study discusses the water-related impacts of an in-situ oil shale industry located in the Upper Colorado River Basin. It focuses on a 50,000 barrel per day industry based on the modified in-situ process and located in the Piceance Creek Basin, Colorado. It reviews the history of oil shale development in the United States and the reserves, geology, and characteristics of domestic oil shales (Chapter 1). In-situ technologies that have been tested or are under active consideration for commercialization are reviewed, and their commercial potential is evaluated (Chapter 3). The existing hydrology and water quality of the Upper Colorado River Basin is surveyed (Chapter 4) as is water use and the statutory framework for water availability and water quality for in-situ oil shale development (Chapter 5). The major environmental problem of in-situ processing, groundwater disruption from in-situ leachates and large-scale dewatering, is analyzed, pertinent experimental results are summarized and interpreted, and recommendations are made for additional research (Chapter 6). Methods to control groundwater disruption are identified and discussed and preliminary cost projections are developed (Chapter 7). Finally, the reuse, treatment and disposal of effluents produced by in-situ retorting--retort water, gas condensate, mine waters, and others--are discussed (Chapter 8).

CHAPTER 1

INTRODUCTION

OBJECTIVES AND PURPOSES

This report investigates the water-related impacts of an in-situ oil shale industry located in the Upper Colorado River Basin. It focuses on a 50,000 barrel per day industry based on the modified in-situ process and located in the Piceance Creek Basin. The analysis is confined to impacts due to the resulting industrial complex; additional impacts due to the associated infrastructure are not addressed. When this study was initiated in 1975, there was no commercial industry. Successful field testing of proposed in-situ technologies had not been achieved, and there was little information available on the environmental impacts of in-situ technologies. These technologies, in fact, were being newly stressed in response to considerable and growing concern over the economic and environmental viability of surface technology. Although this situation is changing, this work of necessity is based on a relatively limited and very incomplete data base. It addresses the generic problems of an in-situ oil shale industry within a broad environmental framework; it discusses impacts qualitatively, where necessary, and quantitatively, where data exist. A sizeable federally funded program has been implemented during the period 1975-1980. As a result, there is today a burgeoning in-situ environmental data base derived primarily from laboratory studies. However, because there are still inadequate data concerning field in-situ processes, final conclusions and definitive statements regarding environmental impacts must await the development of a sizeable field program in which commercial-scale retorts are studied. Therefore, this work should be updated and revised as additional field experience becomes available.

The desirability and importance of developing a commercial oil shale industry cannot be overemphasized. The substantial resources of oil in domestic oil shale deposits must be considered to be one of the primary sources of alternative liquid fuels to replace, or at least lessen, U.S. dependency on imported petroleum. This study is not intended to provide a solution to the problems facing the developing oil shale industry. Instead, by reviewing the processes being considered, the requirements for and limitations on use of available water, the impacts of retorting by-products on the environment, the means of controlling those impacts, and the potential reuse of processing by-products, this study provides a comprehensive analysis of the water-related impacts of an in-situ oil shale industry.

BACKGROUND

"Why should an oil shale industry be developed when coal is a far more abundant fossil resource?" This is the question probably most often asked during any serious discussion of shale oil as a replacement for petroleum. The question arises from the fact that there is at least twenty times more energy content in known coal reserves than in oil shale (Häfele, 1974). However, there is one basic answer to that question which, surprisingly enough, is the counter-argument least advocated: the hydrogen content of shale oil, typically ten to twelve percent by weight, is much higher than the hydrogen content of the organic material in coal. De Nevers et al. (1978) stated that "...to produce liquid fuels which flow easily and behave properly in internal combustion engines, it is necessary to chemically bind enough hydrogen into the fuel to approximate the properties of the liquid hydrocarbons found in commercial petroleum. The oil fraction recovered from oil shale is already hydrogenated to nearly this composition. In order to achieve a comparable degree of hydrogenation starting with coal, one must practice heroic chemical engineering on a grand scale..." By contrast, an oil shale industry could be established without this "heroic and grand" effort because the technology required is comparatively simple, economic, and--in some cases--ready for commercial scale up. If this is true, why has no major effort been directed toward development of an oil shale industry? At least part of the reason, economics, is evident when the history of oil shale is reviewed.

The potential use of oil from shale has been known for centuries. Marine oil shale was used in the 14th century to manufacture Icthyol, a medicinal ointment named after the Greek word for "fish oil". In 1694, the first commercial patent was filed in England for distilling "...oyle from a kind of stone." Oil shale industries flourished in the 19th century in Scotland, France, South Africa, Australia, Russia, Brazil, and the United States. Today, such industries exist in Estonia, China, and Brazil (Sladek, 1974).

Shale oil was used in the United States to produce lamp oil during the 19th century. There were about fifty small companies distilling oil from shale when petroleum was discovered at Titusville, Pennsylvania, in 1859 (Sladek, 1974). Mormon settlers in Utah operated oil stills; one was visible as late as 1918 (Mitchell, 1918). Subsequently, interest in oil shale production in the United States fluctuated with the availability of conventional petroleum.

The economic concept of supply and demand has had a profound impact upon oil shale development in the United States. The initial low demand for oil had prompted the use of petroleum because of its ready availability (it is far easier to drill a well than to pyrolyze rock), abundance, and low cost. By 1920, however, the automobile had begun to assume a prominent place in the American way of life, and a gasoline shortage appeared imminent (Mitchell, 1918). Interest in oil shale processing increased, and some research and study effort was expended. The U.S. Geological Survey announcement that vast petroleum reserves were available in oil shale deposits in Colorado, Utah, and Wyoming brought a splurge of activity; but this stopped with the discovery of enormous oil reserves in eastern Texas (Sladek, 1974). Research in and development of oil shale processing decreased and stopped almost completely.

When increased military requirements during World War II made domestic oil resources appear inadequate, the Congress authorized the U.S. Bureau of Mines to develop oil shale deposits as part of the Synthetic Fuels Act of 1944. An experimental program was initiated, and a retorting facility was constructed at Anvil Points, Colorado. This spurt of activity, however, ebbed after the war and, for all practical purposes, ceased completely as military requirements declined.

Although military demands lessened, the requirements for both private and commercial consumption increased greatly following World War II. In the United States, the one-car family pattern became a two- or three-car normality. Post-war America entered an era of intense consumerism and a life style based on convenience; energy-consuming gadgetry and products proliferated. Emphasis upon clean air and the environment resulted in railroads abandoning coal-fired steam engines for oil-fueled diesels. Heating and power generation changed from coal to oil consumption. The aircraft industry produced jet aircraft which required more fuel than their propeller-driven predecessors. New industries appeared, producing synthetics based upon petroleum by-products. This rapid surge in demands for oil made severe inroads upon the already depleted petroleum resources of the United States and led to discovery of numerous oil reserves in the Middle East, on the continental shelf, and in Alaska in the 1950s and 1960s (Sladek, 1974).

Although the United States has imported small amounts of crude petroleum since the 1930s, only during the last decade has it been forced to rely on foreign supplies because of inadequate domestic production (EDC, 1979). Despite intensive domestic exploration and extensive drilling operations, production was--and is--unable to keep pace with increased consumer demands. The United States has substantially overconsumed and overindustrialized; its ability to continue domestic production is highly doubtful. Consequently, unless alternate fuel sources can be devised, reliance must be placed upon imported oil or upon the expensive off-shore resources and Overthrust Belt production to meet demands for petroleum (EDC, 1979).

Until recently, the high cost of producing oil from shale deterred any serious or extensive effort to develop a commercial industry in the United States because the end product could not compete economically with conventional petroleum. As a result, an almost lethargic attitude developed, although some research and laboratory experimental work did take place after World War II. This lethargy was intensified by a failure to properly analyze the total impact of increased reliance on imported oil--with increased prices--coupled to dwindling domestic supplies. This attitude remained relatively undisturbed until the first Arab oil embargo in 1973 when a sporadic and short-lived effort was made to start commercial production of shale oil. That effort slowed when the embargo was over, although there was increased research and laboratory experimentation. Not until the dramatic and drastic price increases of the late 1970s, with the ensuing threat of possible embargo or rationing of oil, did realization finally come to the United States that it mandatorally had to develop alternate sources of energy if it did not want to become completely subservient to foreign oil-producing states. As a result, there has been tremendous interest in developing an oil shale industry, both by the U.S. Department of Energy and by the private sector.

Fortunately, although there is no commercial oil shale industry in the United States, an extensive research and development program, designed to bring oil shale to commercial production, does exist. Goals for commercialization established by the Department of Energy (DOE, 1978) call for production of from 100,000 to 200,000 barrels of oil per day by 1985 and for from 200,000 to 750,000 barrels per day by 1990. These goals are supported by a well-focused research and development program and by incentives to encourage industry participation. The status of oil shale projects and their projected production rates are summarized in Table 1-1. If these programs are successful, the United States can have a commercial oil shale industry by 1985 (Fox, 1980).

ECONOMIC ISSUES

Nevertheless, economic uncertanties continue to constrain oil shale development by industry. Commercial developers face economic perplexities which include: a lack of definite and specific information concerning the real costs of oil shale production; the uncertainty of future noncompetitive world oil prices; the substantial amount of front-end capital required for each project; the large amount of capital risk involved compared to the assets of some companies; and the possibility of long delays which might be caused by environmental and governmental requirements and regulations (EDC, 1979). The most basic and serious economic problem, however, is the difficulty of attracting capital for development of an oil shale industry. Investment institutions are reluctant to support this development because of the risks involved and the uncertainties of present oil shale technology. If early and successful development of a commercial oil shale industry is to be accomplished, government support will probably be required, at least for the pioneer projects (EDC, 1979). Without this support, it can be anticipated that industrial development may be much slower than desired because, in some instances, proposed plant investments far exceed the present total assets of some of the companies proposing to enter commercial oil shale production. Consequently, government incentives will probably be required for any measurable production, at least 100,000 to 400,000 barrels of oil per day. These incentives might take the form of direct tax credits, capital depreciation acceleration, investment tax credits, guaranteed prices, loan guarantees, outright grants, or governmental equity positions (EDC, 1979).

U.S. OIL SHALE DEPOSITS

Oil shale deposits in the United States are shown in Figure 1-1. Although shale in the eastern and central United States extends over a wide area, these deposits are lean and occur in relatively thin beds. There is at present no known technology capable of economically extracting oil from this type deposit, although the Dow Chemical Company is investigating possible commercial production from eastern shales (DOE, 1978).

The richest deposit, the Green River Formation, underlies 34,000 square miles of Colorado, Utah, and Wyoming (Figure 1-2) and is the focus of this report. The total oil resources of only the thick, rich beds and the medium grade deposits of this formation have been estimated to be 1.8 trillion barrels of oil. At least 80 billion barrels is recoverable with known technology; this amount might be increased as additional processes are developed (Fox, 1980).

The U.S. Bureau of Mines (1975) estimated that the total resources of all oil reserves worldwide was 716 billion barrels in 1975. Thus, it can be seen that the potential oil resources of the Green River Formation alone are greater than those of all known conventional petroleum reserves! The 1.8 trillion barrel reserve present in this formation represents a 300-year

Table 1-1. Status of oil shale projects directed at Green River Formation oil shale as of November 1980[a].

Project	Technology	Production Schedule	Location	Participants	Status
Cathedral Bluffs (Tract C-b)	Vertical modified in-situ process	57,000 bbl/day by 1985-1988	Lease tract C-b, Colorado	Cathedral Bluffs Oil Shale Co. (Occidental Oil Shale Co., Tenneco).	Shaft sinking to be completed in 1982; ignition of two-retort module scheduled for 1985.
DA Shale	Vertical modified in-situ process	2500 bbl/day by 1981	DeBeque, Colorado	Occidental Oil Shale Co.	Six retorts have been burned and the seventh is underway; two retort cluster to be operational in 1982.
Rio Blanco (Tract C-a)	Vertical modified in-situ process	50,000 bbl/day by 1987	Lease tract C-a, Colorado	Rio Blanco Oil Shale Co. [Gulf Oil Corp., Standard Oil (Indiana)]	Modular program consisting of five retorts scheduled for completion by 1982. First retort burned October-November 1980.
Geokinetics	Horizontal true in-situ process	20,000 bbl/day	Book Cliffs, Utah	Geokinetics, Inc.	Several small-scale retorts have been successfully burned and work is in progress to scale up the technology.
Equity	Solution mining/true in-situ process		Piceance Creek Basin, Colorado	Equity Oil Co.	Site preparation in process.
Colony	TOSCO surface retort	46,000 bbl/day by 1985	Grand Valley, Colorado	TOSCO Corp., Exxon	Design study in progress. Construction of new city near Grand Valley, Colorado to house workers started September 1980.
Multi-mineral	Mineral recovery/ surface retorting	13,000 bbl/day	Piceance Creek Basin, Colorado	Superior Oil Co.	Company seeking land exchange with federal government.
Paraho	Paraho surface retort	100,000 bbl produced during 105 days of operation in 1977-78 for DOD and DOE.	Anvil Points, Colorado	Development Engineers, Inc.	Presently testing foreign oil shale.
Paraho	Paraho surface retort	10,000 bbl/day	Bonanza, Utah	Paraho Development Corp. (Chevron Research, Conoco, Davy McKee, Mobile Research and Development, Mono Power, Phillips Petroleum, Sohio Shale Oil, Sunoco Energy Development, Texas Eastern Synfuels, Cleveland-Cliffs Iron Co.).	Design study for 18,000 short-tons-per day plant in progress under a DOE grant.
Union	Union "B"	50,000 bbl/day	Grand Valley, Colorado	Union Oil of California	Experimental mine and plant constructed in 1978.
White River	Surface/modified in-situ process	100,000 bbl/day	Lease tracts U-a and U-b, Utah	Sohio (Standard Oil of Ohio), Sunoco Development Co.	Project delayed by lawsuit on ownership of land; U.S. Supreme Court released disputed land for oil shale development in May 19, 1980 ruling.
Naval Oil Reserves			Piceance Creek Basin, Colorado	U.S. Navy	Planning in progress for development of reserves.
Chevron	Plans to lease tested technology from another company	2000-5000 bbl/day by 1984; 50,000 bbl/day by 1988; 100,000 bbl/day by 1990s	Garfield County, Colorado	Chevron Oil Shale Co.	Resource evaluation in progress; engineering and planning studies initiated; 350 short-tons-per-day plant to be operational by 1983, and 4000 to 10,000 short-tons-per-day plant projected to be on line in 1984.
Superior	Superior surface retorting process	10,000 bbl/day	Colorado	Superior	Engineering design and demonstration plans in progress under DOE contract.
Sand Wash	TOSCO II surface retort	18,000 bbl/day	Sand Wash, Utah	TOSCO Corp.	Engineering design and demonstration plans underway.

[a] This tabulation is based on announced plans of potential developers as reflected in local newspapers, news magazines, and other sources. The reader should not assume that this listing is necessarily complete nor up-to-date due to changes in industrial plans in response to external economic and political factors and confidentially of some industrial plans.

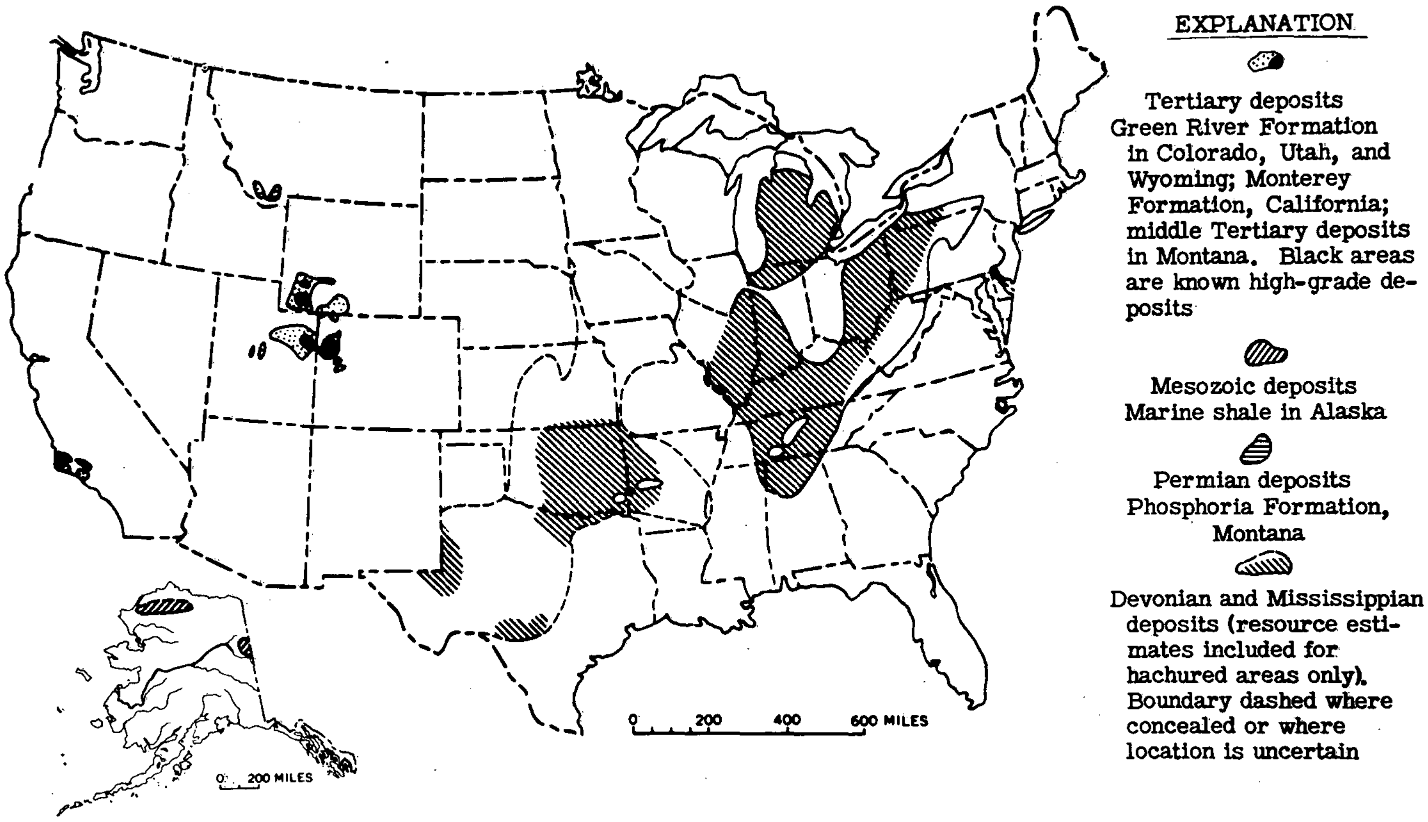

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Figure 1-1. Oil shale deposits in the United States (Duncan and Swanson, 1965).

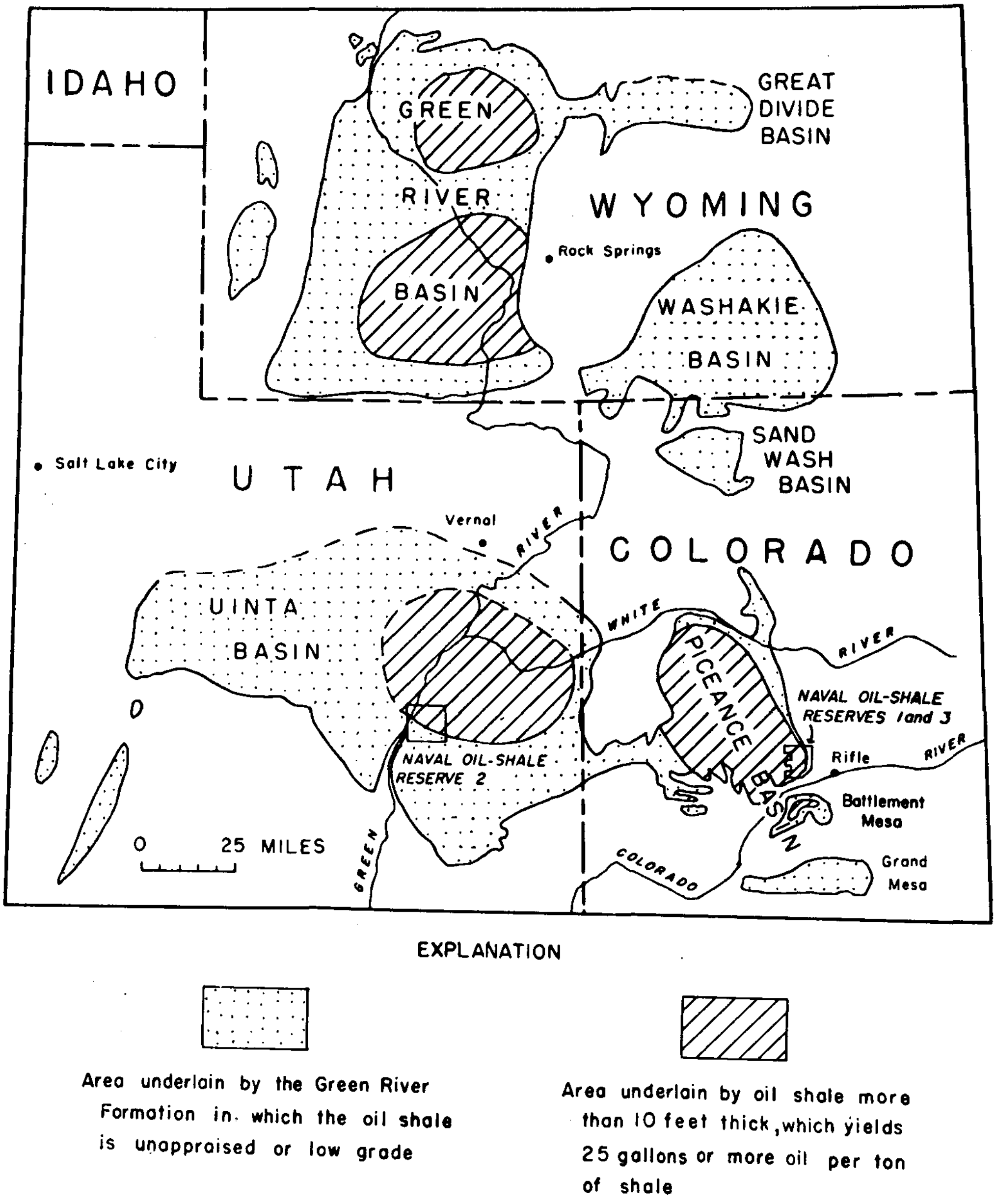

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Figure 1-2. Oil shale deposits in the Green River Formation--Colorado, Utah, and Wyoming (Duncan and Swanson, 1965).

supply of oil at 1974 U.S. consumption level. The vast amount of oil in shale and the greatly increased cost of imported oil have made shale oil competitive and contributed to the current increased interest in developing a domestic oil shale industry.

GREEN RIVER FORMATION SHALE CHARACTERISTICS

Oil shale from the Green River Formation is a fine-grained sedimentary rock. It contains appreciable quantities of organic material which varies from a few percent in low-grade shales to more than 40 percent in shales that yield 75 gallons of oil per ton of rock. The organic material is primarily kerogen and bitumen. The inorganic material is a dense, tough marlstone. About one-half of the mineral content consists of two carbonaceous minerals, dolomite and calcite; minor minerals present include feldspars, illite, analcime, pyrite, halite, nahcolite, disseminated dawsonite, and others (Fox, 1980).

Figure 1-3 shows the stratigraphy and mineralogy of the Green River Formation, which consists of oil shale interbedded with halite, trona, or nacholite. The idealized cross section shown in this figure applies primarily to the Piceance Creek Basin of Colorado, which contains much of the rich oil shale of the Green River Formation. Stratigraphy and mineralogy of other shale formations in the area are similar to those of the Piceance Creek Basin but vary in thickness of bed, richness, and saline content (Fox, 1980).

The richest beds in the Piceance Creek Basin occur in the Parachute Creek member where up to 2,000 feet of oil shale exists in alternating rich and lean beds. One of these beds, the Mahogany Zone, underlies 2,000 square miles in Colorado and Utah and is the primary target for most present development efforts. Oil shale is thickest and richest in the north-central part of the Piceance Creek Basin and leaner and thinner at the basin margins (Culbertson and Pittman, 1973).

SHALE OIL CHARACTERISTICS

Oil extracted from shale is a hydrocarbon product which, because of its origin, is considered to be a synthetic crude oil (EDC, 1979). Although similar to normal crude oil, shale oil has unique characteristics just as U.S. and foreign crude oils vary in chemical composition and constituents produced by refining. Shale oil, however, differs from petroleum because it has a high nitrogen content, is comparatively deficient in hydrogen, and has a different mix of hydrocarbon types.

Of all the synthetic liquid fuels, shale oil is the cheapest to produce and is the closest to conventional petroleum. Its hydrogen content is about halfway between that of coal-derived liquids and conventional American petroleum. Sulfur levels are comparable and nitrogen levels significantly elevated in shale oils compared with conventional crudes. Nitrogen can be removed from shale oil, as a part of the pre-refining process, using established and available technology. Although shale oil is not directly exchangeable for conventional crude oils, there are sufficient similarities to permit relatively easy integration of shale oil with other feedstocks (EDC, 1979).

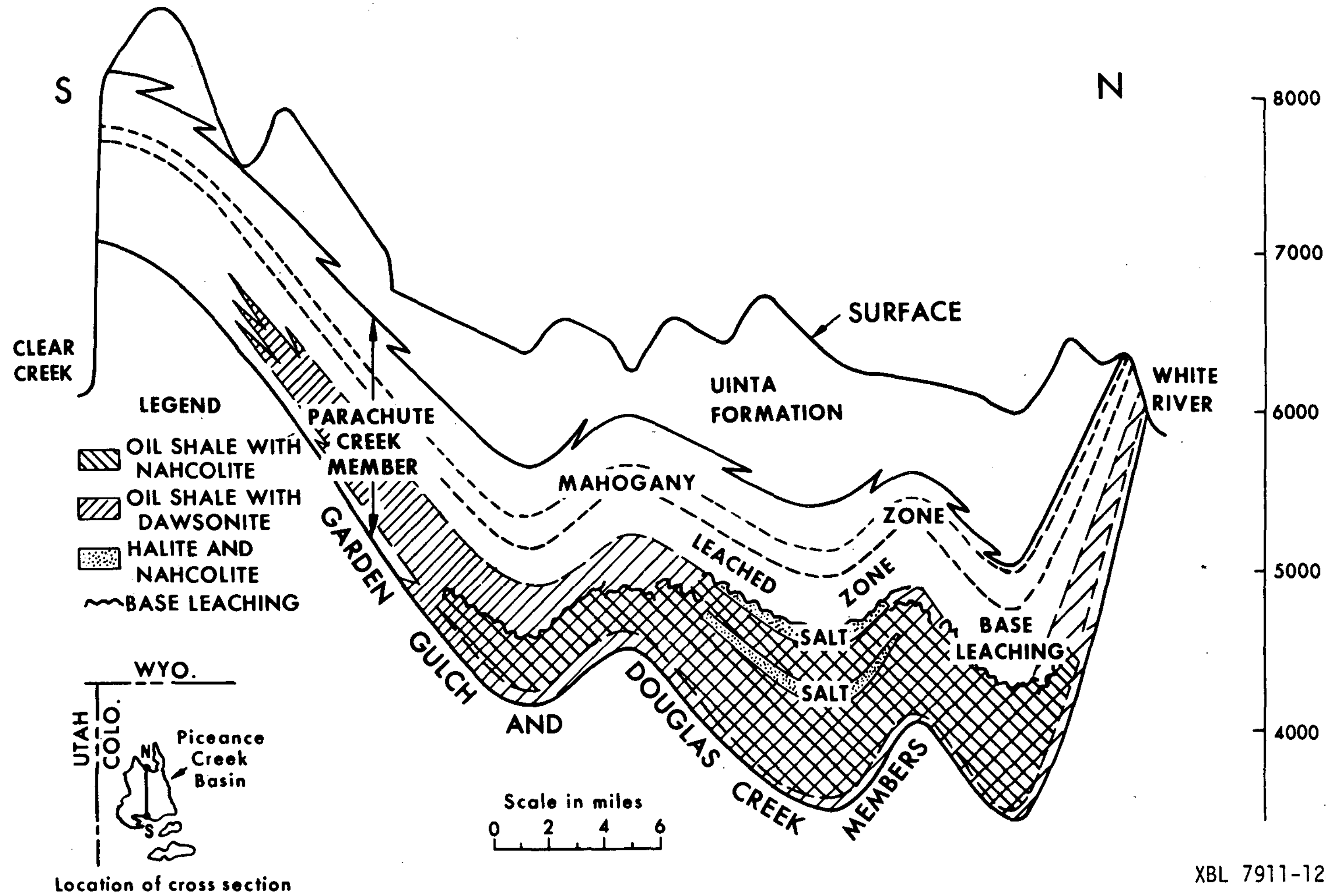

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Figure 1-3. South-north diagrammatic cross-section of the Green River Formation in Colorado's Piceance Creek Basin (Smith et al., 1978).

PROCESSES FOR EXTRACTING OIL FROM SHALE

Shale oil is produced by pyrolytically decomposing the organic material present in shale. This process, "retorting," is accomplished either by mining oil shale and heating it above ground (surface retorting), by fracturing and retorting oil shale in place (in-situ retorting), or by a combination of these two processes. Retorting produces oil, water, noncondensable gases, and a solid residue called spent shale. The relative proportion of each by-product depends upon the grade of shale and the retorting process used. Chapter 3, "In-Situ Technologies," discusses in detail the various processes being considered for commercial production of oil from shale.

WATER REQUIREMENTS FOR AN OIL SHALE INDUSTRY

Water is essential for development of an in-situ oil shale industry. Water will be consumed by oil recovery and upgrading processes and by nearby communities in which the labor force resides. Water demands depend on the size of the industry and the recovery techniques used. It has been estimated that water requirements for surface retorting may be from 207 to 224 gallons per barrel of oil produced; modified in-situ retorting requires relatively less or more water, from 71 to 278 gallons per barrel of oil, depending on the technology used for retort abandonment. These requirements may be lessened by reuse of water generated as a by-product of the retorting process. Chapter 5, "Statutory Framework for Water Availability and Water Quality for In-Situ Oil Shale Development," analyzes water requirements for various processes being considered for commercial oil shale production.

The availability of water in the Upper Colorado River Basin--or the lack thereof--may have a profound impact upon development of an oil shale industry in that area. The Green River Formation is in a water-short, undeveloped area in northwestern Colorado, northeastern Utah, and southwestern Wyoming. Most of the water in the basin has already been allocated or earmarked for municipal, industrial, and agricultural requirements. Colorado, although possessing most of the rich oil shale deposits, has only 20 percent of the unallocated water resources. If oil shale is to supply a major portion of U.S. demands for crude oil, water must be made available from other sources. Chapter 4, "Hydrology and Water Resources," discusses the availability of water in the area and projected future allocations compared to the water requirements of an oil shale industry.

ENVIRONMENTAL IMPACTS OF AN OIL SHALE INDUSTRY

The processing techniques required to extract oil from shale may result in adverse impacts upon the environment due to both the geographical location of oil shales and the nature of the processing technology. By-products of the retorting processes include large volumes of highly contaminated gas, water, and solids. These by-products must be isolated or renovated prior to release into the environment. Industry plans call for reuse and on-site containment of these residuals, as discussed in Chapter 8, "Reuse and Disposal of Effluents from In-Situ Oil Shale Industry." However, stringent air and water quality standards govern the disposal of by-products in the area, and available control technologies may not be able to meet the standards imposed by these regulations. These mandatory requirements are reviewed in Chapter 5, "Statutory Framework for Water Availability and Water Quality for In-Situ Oil Shale Development." Additionally, underground spent shale may be leached by groundwater and the leached material transported into aquifers where they may be withdrawn in wells or discharged into springs and streams. The potential impacts of leaching of surface and in-situ spent shale are discussed in Chapter 6, "Water Quality Effects of Leachates from an In-Situ Oil Shale Industry."

CONTROL STRATEGIES TO LESSEN ENVIRONMENTAL IMPACTS

Eliminating or alleviating the potentially adverse impacts of retorting processes is one of the most challenging problems facing the emerging oil shale industry. Leaching of in-situ spent shale may be controlled by several methods such as grouting of abandoned retorts, intentional leaching, and modification of local geohydrology. These techniques, which are based upon processes used in other industries, have not been tested in an oil shale environment. Such testing, both in the laboratory and in the field, should be initiated at an early date. Additionally, certain by-products of retorting, such as spent shale, may be used to mitigate environmental impacts. For example, if a suitable grouting material can be developed using spent shale as a major component, the cost of grouting would be decreased; and the problem of disposing of spent shale would be eased. These and other concepts are discussed in Chapter 7, "Control Strategies for Abandoned In-Situ Oil Shale Retorts," which reviews possible methods of mitigating these undesirable impacts and projects costs for the various control processes discussed.

Reuse of aqueous effluents, followed by evaporation of residuals, may reduce impacts associated with point sources of pollution. Additionally, water requirements may be lessened by reuse. This may not only provide some relief from the critical water-availability situation, it might also reduce processing costs. Reuse concepts are explored in Chapter 8, "Reuse and Disposal of Effluents from an In-Situ Oil Industry."

THE FUTURE OF OIL SHALE AS AN ALTERNATE SOURCE OF ENERGY

Barring the unexpected discovery of large new sources of conventional petroleum in the United States, there is little doubt that alternate sources of energy must be developed if reliance upon imported oil is to be reduced. There is also little question that oil extracted from shale can be one of the primary replacements for imported petroleum if processing methods can be perfected for industrial use and if adverse impacts on the environment can be eliminated. None of the problems involved are insurmountable, either technologically or economically. One of the greatest challenges facing the emerging oil shale industry is the development of environmentally sound processing technologies. An adequate water supply must be developed without significantly sacrificing other beneficial uses, and technology must be developed to mitigate water-related impacts--leaching and effluent disposal. This study discusses those problems, suggests methods of solving them, and recommends areas of further study which would assist the rapid development of this important source of energy.

CHAPTER 2

SUMMARY AND CONCLUSIONS

Vast resources of oil shale--more than 600 billion barrels of recoverable syncrude--exit in the Green River Formation in Colorado, Utah, and Wyoming. The richest of these deposits, and the ones scheduled for early development, are located in the Piceance Creek Basin of western Colorado. The Mahogany Zone and adjacent oil shales, the target of commercial development, are largely impermeable and separate layers of fractured leaner shale which act as confined or unconfined aquifers.

Current industrial plans call for the development of this resource by vertical modified in-situ (VMIS) retorting. Figure 2-1 shows a schematic of the relative positions of the Mahogany Zone, aquifers, and VMIS retorts. Large chambers of rubblized shale, about 300 to 750 feet high and 200 feet square in cross section, will be formed in the Mahogany Zone and surrounding oil shale some 1000 to 2000 feet below the surface. About 20 to 40 percent of the in-place shale will be mined out to create void space and the balance blasted into the void to create a chamber full of rubble. The mined out shale will be brought to the surface where it may be processed in a surface retort. Vertical pillars, representing nearly 50 percent of the in-place shale, will be left between the underground retorts to support the overburden. The retort chambers will be pyrolyzed vertically from the top to the bottom by propagating a reaction zone down the packed bed of shale using air and steam. Oil, water, and gaseous products will be pumped to the surface for processing. Following processing, the retort will be abandoned and large underground chambers of retorted shale left behind.

This type of oil shale processing may result in a number of environmental impacts, including surface water and groundwater disruption, subsidence, and low resource recovery (Figure 2-1). These impacts originate from extensive site dewatering, in-situ and surface leaching of spent shale, and effluent disposal. During processing, the surrounding aquifers are dewatered. This will alter groundwater quality and reduce the flow in local springs and streams. On abandonment, groundwater will reinvade the area, leaching retorted shale and transporting leached material into the aquifers where it may be withdrawn in wells or discharged to springs and streams that feed the Colorado River system. Additionally, formerly separated aquifers will now be in communication, allowing waters of different quality to mix. Similarly, surface spent shale from above-ground retorting of the 20 to 40 percent of the raw shale that was mined will be leached by rainfall and snowmelt and the leachate transported to surface and ground waters by runoff or percolation. An adequate water supply must be made available in the water-short area, and effluents produced during retorting must be treated and disposed of. There is considerable concern that the large overburden and high void fraction presently under consideration will result in overburden cracking and subsidence over the retorts. Finally, resource recovery in VMIS retorting is poor because large pillars must be left in place to support the overburden, and the oil shale above and below the retorts is not extracted.

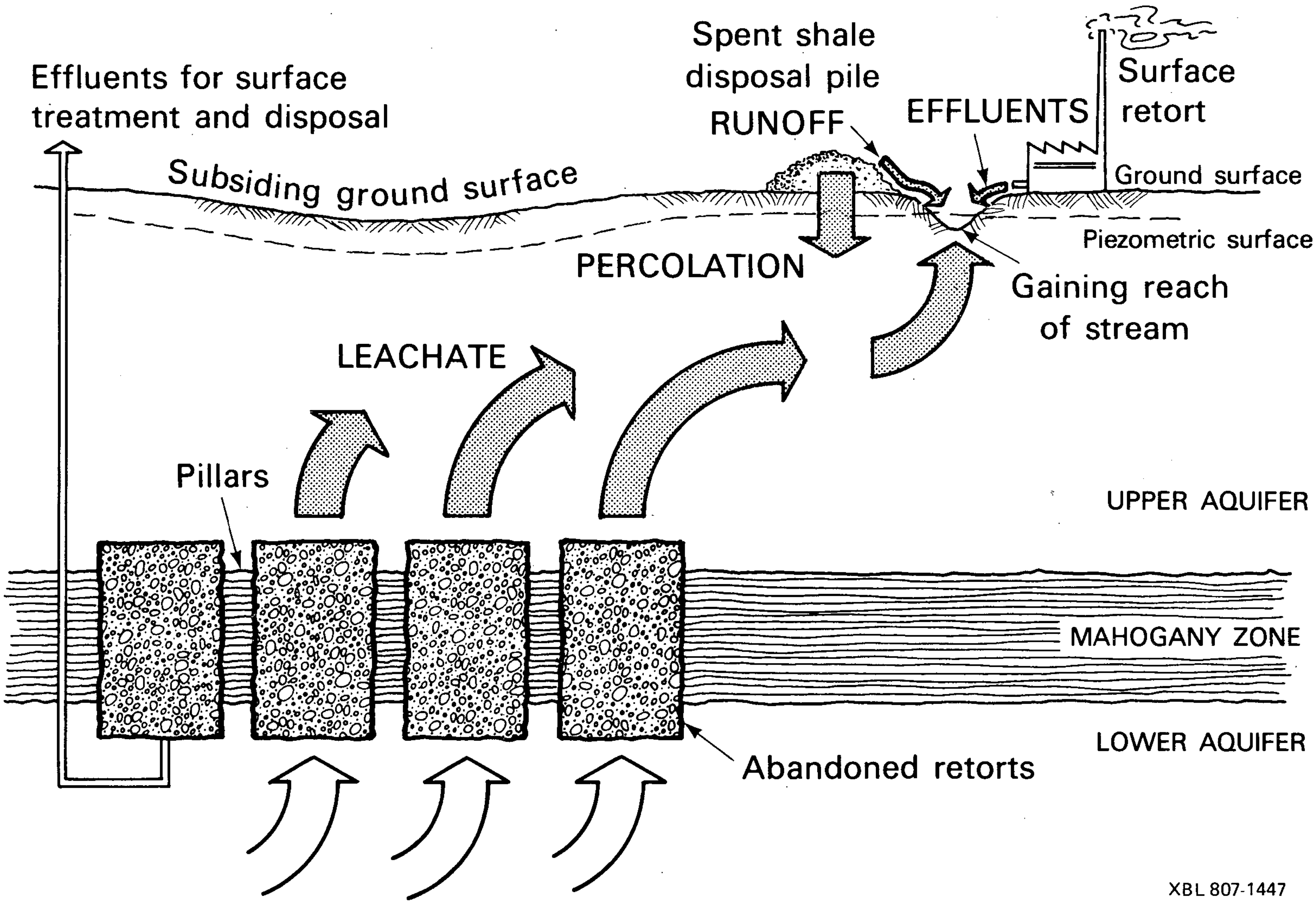


Figure 2-1. Schematic representation of environmental impacts resulting from VMIS retorting.

This report investigates the water-related impacts of an in-situ oil shale industry located in the Upper Colorado River Basin. It focuses on a 50,000 barrel per day industry based on the modified in-situ process and located in the Piceance Creek Basin. The purpose of this chapter is to summarize the results of this investigation and to present the pertinent conclusions that emerged from the work.

THE TECHNOLOGY

Oil shale is a marlstone that contains organic material, primarily kerogen. It may be converted into a liquid hydrocarbon by pyrolytically decomposing the organic material. This process, referred to as "retorting" is carried out by either mining oil shale and heating it above ground (surface retorting) or by fracturing and retorting the shale in place (in-situ retorting). Chapter 3, "In-Situ Technologies" reviews those in-situ methods that have been tested or are under active consideration for commercialization and evaluates their commercial potential.

This survey revealed that two basic types of in-situ processes have been considered for commercial development in the past three decades--true in-situ processes and modified in-situ processes. The true in-situ technologies, those that do not use mining to create formation permeability, received earliest attention. Void space is provided by electro-fracting, hydro-fracting, nitro-fracting, solution mining, or surface uplift. Several different types of true in-situ processes have been investigated since Sinclair Oil Company tested one of the first in-situ processes in 1953. The only successful true in-situ process demonstrated to date is the Geokinetics process which uses surface uplift to create in-situ voids. This process is slated for near-term commercialization. The other processes--those tested by Sinclair Oil Company, Equity Oil Company, Talley Energy Systems, and the Laramie Energy Technology Center--have been largely unsuccessful due to inadequate void distribution.

In modified in-situ retorting, the in-place shale is removed by mining, and the void volume is distributed by blasting. Vertical modified in-situ retorting (VMIS), in which the reaction zone is propagated vertically downward, is presently being pursued by Occidental Oil Shale, Inc. on the D-A shale property at Logan Wash, Colorado, by a joint venture of Occidental and Tenneco on lease tract C-b, and by the Rio Blanco Oil Shale Project on lease tract C-a. The VMIS process has been successfully demonstrated by Occidental on the D-A property, and additional work is underway to refine the process and resolve operating problems. Although these processes are presently under development, the configuration of the final, commercialized process is presently unknown. A number of technical problems must be resolved before commercialization, including methods to effectively rubblize the retort and control the reaction zone.

This review indicated that the only in-situ technologies that have been successfully tested are the Occidental modified in-situ process and the Geokinetics process. Since the former is suitable for a much larger part of the resource, it was selected for detailed analysis in this study. Subsequent chapters therefore focus on this technology.

HYDROLOGY AND WATER RESOURCES

The Green River Formation oil shale deposits are located in the Upper Colorado River Basin where water supply and water quality have long been issues of national and international concern. Chapter 4, "Hydrology and Water Resources", surveys the existing hydrology and water quality of the Upper Colorado River Basin and focuses on the Piceance Creek Basin. This chapter reviews and summarizes basic information on surface and ground water quantity and quality needed in subsequent chapters to assess water-related impacts.

The Upper Colorado River Basin, which includes about 109,600 square miles of drainage and covers about 45 percent of the Colorado River Basin, covers portions of Wyoming, Colorado, Utah, New Mexico, and Arizona. The climate is characterized by dryness and extreme temperature variations; relative humidity is low and evaporation rates are high. Precipitation ranges from less than six inches to 40 inches annually and is heaviest in the winter and spring in most of the basin. Surface stream runoff and quality are characterized by extreme annual and monthly variability. Surface water is of relatively good quality throughout, and the principal water quality problems are elevated TDS and suspended sediment concentrations. Salts and sediment originate primarily during runoff in the Upper Basin and are concentrated downstream due to consumptive use of the water. Groundwater, which underlies much of the region, is largely unused. The main consumptive uses of water in the Upper Basin are irrigation, basin exports, and reservoir evaporation with 50 percent of the water used for irrigation.

The Piceance Creek Basin contains most of the richer oil shale and will probably be the site of the first commercial oil shale industry. The major surface waters within the Basin are the Piceance Creek and Yellow Creek which receive about 80 percent of their flow from groundwater discharge. Surface water quality is generally poor, although it varies from place to place; TDS ranges from 392 mg/l to 2590 mg/l. Groundwater occurs throughout the basin in two locally confined aquifers separated by the Mahogany Zone and an alluvial aquifer. The chemical quality of these groundwaters varies within and between the aquifers; and the principal ions are carbonate species, sulfate, chloride, and sodium with elevated concentrations of boron and fluoride in some areas.

WATER AVAILABILITY

The western oil shale deposits are located in areas where natural water supplies are already in short supply--in western Colorado, eastern Utah, and southwestern Wyoming. Water supply and demand in the Upper Basin are complicated by international water treaties, by complex federal legislation and state water law doctrines, and by the absence of reliable estimates of actual water demands. Chapter 5, "Statutory Framework for Water Availability and Water Quality" discusses the statutory framework that governs the use of water and controls the disposal of waste effluents from an in-situ oil shale industry.

This review indicates that there is a great deal of uncertainty associated with the issue of water availability in the Upper Colorado River Basin. This uncertainty is due to the complex legal framework applying to the Colorado River and the absence of definitive information on water demands for an oil shale industry. Water will be consumed at an oil shale plant for retorting, upgrading, solid waste disposal, revegetation, and other operations and will have to be supplied by local surface and ground waters. The amount of water required for these operations has been variously estimated to range from 207 to 224 gallons of water per barrel of oil for surface retorting processes and from 71 to 278 gallons per barrel for in-situ processes. However, definitive estimates are not available as no commercial industry exists and only a few processes have even been tested at the pilot scale. Water for an oil shale industry could be made available from unallocated surface supplies, by purchasing water rights from other users, or by using groundwaters. Recent studies on the availability of surface water in the Upper Basin indicate that an oil shale industry producing from 1.0 million to 7.0 million barrels of oil per day could be supported without significantly reducing other projected consumptive uses. If the annual groundwater recharge in the Piceance Creek and Uinta basins was used for oil shale development, an additional 0.6 to 2.1 million-barrel-per-day capacity could be developed. Thus, the maximum size of an oil shale industry, based on water supply alone, would be about 9.1 billion barrels per day, or about 50 percent of the 1979 crude oil consumption in the United States. However, it is uncertain whether all of the projected water supply could be made available to an oil shale industry. Because there is a poor match between location of the rich oil shale deposits and water supply, trans-basin imports and large-scale storage facilities may be required. Additionally, unpredictable climatic variations which may affect stream flows, unresolved rights, claims still to be adjudicated, inaccurate data, and shifting political climates and social goals may further affect the amount of water available. This study indicates that there will probably be adequate water for the first few commercial plants; however, as the industry expands much beyond one million barrels per day, water supply may become increasingly problematic and could result in significant delays as new supplies are sought or as the complex regulatory framework governing water is grappled with.

WATER QUALITY IMPACTS

The principal water quality problem associated with in-situ oil shale retorting is the leaching of surface and in-situ spent shale. Oil shale leachates may enter local waters by runoff from surface piles, by percolation through surface piles into groundwaters, or by underground leaching. The quality of surface waters is controlled by both federal and state regulations and presently envisioned surface-disposal-pile design will probably largely control and confine surface leachates. However, standards governing the quality of groundwaters have not been as clearly defined and current plans will not adequately control percolation and in-situ leaching. Thus, groundwater disruption has emerged as the key water quality issue.

In in-situ retorting, large chambers of retorted shale and allied mining works, including shafts, adits, and drifts, are left underground where they may act as sources of pollution. If the retorting site is located in a wet region, groundwater may enter the site following abandonment and leach soluble organic and inorganic constituents from this raw and spent shale. These materials may then be transported in local aquifers, withdrawn in wells, or discharged into local springs and streams. Additionally, in some areas of the Green River Formation, such as on lease tract C-b, water quality in adjacent aquifers is of widely differing qualities, and highly saline pockets of water exist. If in-situ retorting connects these aquifers and/or saline pockets, local groundwaters may be degraded by mixing with poorer quality water.

Similarly, shale mined during preparation of the underground retorts may be processed in a surface facility. The spent shale from this operation will be disposed of in local canyons, where it may be leached by precipitation if not properly stored; and resulting leachates may reach surface waters and groundwater by runoff or percolation through the piles.

These types of impacts are regulated by a complex set of state and federal regulations. These are discussed in Chapter 5, "Statutory Framework for Water Availability and Water Quality" and include the Federal Water Pollution Control Act (PL 92-500), the Surface Mining Control and Reclamation Act (PL 95-87), the Resource Conservation and Recovery Act (PL 94-580), the Safe Drinking Water Act (PL 93-523), Colorado River Basin Salinity Control Forum Standards, and water quality criteria and effluent limitations set by the states of Colorado, Utah, and Wyoming. However, many uncertainties surround these regulations because specific standards for an in-situ oil shale industry have not been established.

The principal water quality effects of in-situ oil shale retorting are discussed and research needs are recommended in Chapter 6, "Water Quality Effects of Leachates from an In-Situ Oil Shale Industry." This study indicates that there is a great deal of uncertainty surrounding water quality issues due to an incomplete data base. Deficiencies in present information and research required to amend these deficiencies are discussed below for in-situ leachates, other leachates, and groundwater impacts.

In-Situ Leachates

Although leaching has been identified as one of the principal water quality problems facing an in-situ oil shale industry, there is still inadequate information to properly assess this problem. Available data indicate that the major components of spent shale leachate, SO_4, HCO_3, CO_3, Na, Cl, Si, and K, are not highly toxic, are not detrimental for many water uses, and may be tolerated at rather high levels under certain circumstances. On the other hand, the minor components, which include As, Pb, F, phenols, organonitrogen compounds, and others, are considered to be toxic at the levels at which they are present in leachates. However, there has been inadequate investigation of these minor components to properly evaluate their importance.

The composition of leachates is still uncertain even though a large number of studies has been conducted due to the absence of representative field samples and inadequate simulations of field conditions. Most leaching work has been conducted using spent shales produced by simulated in-situ retorts, laboratory reactors designed and operated to simulate as nearly as possible actual field conditions. However, it is argued by some that leachates from field in-situ retorts will differ chemically from those produced by simulated in-situ retorts and that most dissolved constituents will occur at lower concentrations in field leachates. This contention is based on the fact that field retorting may produce relatively insoluble silicate mineral phases, such as members of the akermanite-gehlenite series rather than the more leachable oxides due to the higher temperature and longer residence time of hot spent shale within field retorts. Generally, work completed to date suggests that field retorting may reduce the conductivity and alkalinity of leachates related to simulated retorts, but that it increases, or has little effect on, the minor constituents such as boron and fluoride. However, there are presently inadequate data to completely characterize field leachates and thus determine whether or not these leachates represent a significant environmental concern.

The actual composition of field leachates is further obscured by the lack of field experience and the difficulty of obtaining reasonable simulations of the leaching process under laboratory conditions. Existing studies have used distilled water at ambient temperatures and pressures, contact times between the shale and leach water of 30 days or less, and a uniform and small particle size range. Although this is a key first step in understanding leachate chemistry, it must be expanded and combined with other approaches to model the complex leachate--groundwater system which will actually be encountered. In the field, relatively large nonuniform particles of hot spent shale will be leached by slowly moving groundwater, a few feet per year, with a high TDS; initial leach water temperatures and pressures will be greater than ambient; and contact times may be on the order of one to ten years. Trapped retorting gases will be dissolved by invading waters, and the bottom section of a field retort may act as a source of contamination. This bottom section is exposed to different conditions than the rest of the retort; it will contain a plug of partially retorted shale wet with oil, condensed material, and other retorting byproducts, and will chemically react very differently from the rest of the retort. Therefore existing data, including that developed using field spent shales, may not be adequate to describe field leachates.

Field tests are needed to transfer laboratory experience to the field. These tests should be designed to verify the results of laboratory experiments and to determine differences caused by field conditions which could be duplicated or simulated in the laboratory. Field programs are also needed to monitor backflood waters and surrounding aquifer waters. These programs should be long term, spanning a decade or more, and should include complete elemental and organic characterizations.

Other Leachates

In-situ processing will also produce other types of solid wastes that will probably be disposed of in surface piles. These may include spent shale, raw shale, other mine spoils, and solids from water and wastewater treatment facilities and air pollution control facilities. Disposal piles containing these types of solids will affect water quality as a consequence of runoff from and percolation through the piles. If these piles are adequately designed and constructed, the water quality impacts should be minimal under normal operating conditions. However, there is considerable controversy surrounding the proper design of the piles due to the large quantities of material that must be handled and its unique composition.

The primary effects of spent-shale disposal piles will be felt during pile construction and vegetation. During this period, control measures--dikes, a retention dam, and vegetation--will not be in place; and runoff and percolation will reach surface and ground waters. Subsequently, runoff and percoltion will be controlled by terracing, compaction, revegetation, and by diversion works designed to collect and evaporate leachate. Long-term custodial care of the diversion works following site abandonment must be provided or they will silt out, and overflow will occur. However, if vegetation has been adequate, the runoff at this time may resemble that from native areas and will probably contain nutrients, plant material, and suspended solids. Erosion of the soil cover is a long-term concern and provision for erosion control should be made in disposal plans. Percolation, in contrast, is a concern during and following pile construction and after site abandonment. Present plans do not provide for collection and evaporation of percolation because it is maintained that consolidation and cementation on compacting with water will reduce the permeability of the piles. However, recent research suggests that this may not occur. Additional work is needed to clarify the conditions under which cementing occurs in these piles and the ability of this mechanism to effectively reduce percolation.

Although quantitative data exist on raw and spent shales, little information is available on other oil-shale related solid wastes such as catalysts and sludges. The composition and leaching potential of these other solid wastes should be investigated. Preliminary data indicate that raw oil shale, contrary to opinion, is not inert and may release large quantities of substances such as boron and fluoride. This should be further substantiated by laboratory studies designed to simulate the effects of rainfall and snowmelt on the leachability of raw oil shale. Similar studies should also be conducted to compare the effect of rainfall and snowmelt on native soils with the same effects on raw oil shale.

Groundwater Impacts

Groundwater disruption is a key concern because it is largely irreversible and may have long-term consequences. The effects of in-situ leachates on groundwater will not be immediate. After dewatering ceases, it will take from decades to centuries for groundwater to invade and leach the retorts. Even longer periods of time will be required to renovate the aquifers once they have been contaminated. Upper and lower aquifer waters in the vicinity of an in-situ facility may be degraded with large increases occurring in pH, SO_4, Na, HCO_3, and CO_3, and in certain organics, such as phenols and organic nitrogen compounds. Since serious problems may not occur until long after a site has been abandoned, preventative measures will have to be taken at the time the retorts are abandoned in order to prevent long-term consequences.

The importance of these impacts depends on the uses to which a water is put and the quality requirements for those uses. The upper and lower aquifer waters in the Piceance Creek Basin are not used extensively at the present time; users of groundwaters rely on alluvial aquifers. Therefore, short-term impacts on upper and lower aquifer waters may not be serious. However, in the long-term (for centuries following abandonment), upper and lower aquifer waters would be unsuitable for municipal supply or stock watering without a high degree of treatment, although these waters might be adequate for irrigation of certain salt-resistant crops. The regulatory framework protects state waters for potential future uses, and degradation cannot be justified based on no present use. Future uses are protected by a complex set of state and federal regulations which govern the quality of waters.

The effect of in-situ leachate will be highly site-specific due to large variations in local hydrology. Estimates presented in this report indicate that if a facility were located on Tract C-a, leachate release from a single retort could continue for two to six years, the leachate would be transported in the lower aquifer at about 160 feet per year, and it could take from one to four centuries for it to discharge into the nearest stream. If the same retort were located on Tract C-b, it might release leachate for from six to 60 years, the leachate would be transported in the upper aquifer at about 20 to 30 feet per year, and it might take from two to 14 centuries for it to discharge into the nearest stream. These analyses suggest that the consequences of leaching on Tract C-a may not be as significant as on Tract C-b if predevelopment flow conditions are re-established on site abandonment. On Tract C-a, leachate is discharged into the lower aquifer which does not directly recharge surface streams and is not used locally. It could take millenia for lower aquifer leachates to degrade the upper aquifer, and thus surface streams, by slow leakage through vertical cracks in the Mahogany Zone. The water quality impacts on Tract C-b would be more immediate because leachates discharge into the upper aquifer which recharges local surface streams and is used for stock watering and irrigation.

As noted above, in-situ leachate may reach surface streams by discharge into Piceance Creek or Yellow Creek several centuries after the completion of retorting. The quality in local streams may then approach that of the initial leachate. This would render these streams unsuitable for drinking water, irrigation, or stock watering without treatment. This effect would be greatly diluted at downstream points. The TDS in Piceance Creek at the White River may increase by 4,100 to 46,100 mg/l and at Lees Ferry on the Colorado River by 5 to 56 mg/l.

Recommendations

Research on water quality impacts is too incomplete or too inadequate to quantitatively evaluate effects or to define control technology requirements. The following are specific areas where additional work is required.

1. Laboratory leaching of in-situ spent shales has focused on simulated spent shales and used distilled water and contact times typically less than 30 days. These conditions do not adequately represent field conditions. The contact time between the leach water and the spent shale may be of the order of one to ten years, the composition of the leach water will be significantly different from distilled water, and simulated spent shales may differ in important ways from those generated in the field. The most important difference may be maximum retorting temperature and retorting rate. Field temperatures and residence time at peak temperatures will exceed those encountered in the laboratory. Therefore, more realistic laboratory simulations of field leaching need to be performed. High-temperature spent shales should be leached with local groundwater in continuous-flow columns using approach velocities similar to those anticipated in field retorts. Mass-transfer theory should be used to design experimental simulations. Complete elemental surveys and organic characterizations need to be performed on select samples and the potential toxicity of the leachates determined.

2. Some technological development is required to obtain definitive estimates of the effect of in-situ spent shale leaching and to study control strategies. Experimental programs such as those under way at tracts C-a and C-b should go forward so that much needed data can be obtained to better design commercial-sized plants. These field programs should be coordinated with laboratory studies. If the results of field environmental studies indicate that the effects of these experimental facilities on groundwater quality will be significant, plans to mitigate the effects should be made. These plans would probably include collecting the leachates and treating them above ground.

3. The effect of the leachate on local ground and surface waters must be better evaluated. This will require the development and application of a computerized model of the retort system and local aquifers that is capable of handling hydraulics and chemical transformations in fractured aquifers for unsaturated flow. In conjunction with this, laboratory and field studies need to be conducted to develop model input parameters.

4. No quantitative data are available on the potential for attenuation of constituents on passage through the retort or during aquifer transport. The leaching columns described in (1) above needed to be followed by columns containing aquifer media to determine the retardation of leachate components.

5. Available hydrologic data are inadequate to quantitatively predict leachate transport. Hydrologic investigations, pump tests, and tracer studies should be conducted to determine hydrologic variables including transmisivity, effective porosity, and the relationship between saturation and hydraulic conductivity; to characterize fracture systems; and to determine flow directions.

6. There is inadequate definition of the nature and leachability of solids other than raw and spent oil shale that will be disposed of in surface piles. The composition and leaching potential of those other solids should be investigated.

7. Preliminary data suggest that raw oil shale is not inert and may release large quantities of some substances, such as fluorine and boron. This should be investigated in greater detail in laboratory studies designed to simulate the effect of rainfall and snowmelt on the leachability of raw oil shales. This should be contrasted with similar experiments using native soils to determine the net effect.

8. Field studies at demonstration sites such as lease tracts C-a or C-b are required to transfer laboratory experience to the field. Cores or bulk samples need to be taken from experimental field retorts, analyzed in the laboratory for major, minor, and trace elements, and leaching studies conducted. Field programs need to be established to monitor backflood waters and surrounding aquifer waters. These programs should be long term, spanning a decade or more, and should include complete elemental and organic characterizations.

9. Measures may have to be taken to control the release of leachate from the retorts. This is apt to be a technically challenging problem requiring a long lead time. Research should be initiated immediately to identifiy technically and economically feasible control techniques.

CONTROL STRATEGIES FOR IN-SITU LEACHING

The leaching of underground spent shale is one of the major environmental problems facing in-situ oil shale processing. Technologies or strategies must be developed to control this problem before a large-scale industry can be developed. Chapter 7, "Control Strategies for Abandoned In-Situ Oil Shale Retorts," identifies a number of methods, including retort plugging, hydrogeologic modifications, intentional leaching, and others, that could be used to mitigate underground leaching of spent shales. Literature from related fields is used to define these methods and to develop preliminary cost data. The control strategies discussed are summarized in Table 2-1 with projected costs and unresolved technical issues.

Site Selection

The purpose of this strategy is to locate VMIS retorts in groundwater-free zones. This would minimize or eliminate in-situ leachate formation and transport, and represents the most desirable condition for protecting groundwater from degradation. There are presently inadequate data to determine with certainty whether or not VMIS retorts can be completely contained in dry zones, and, if so, what fraction of the resource can be recovered using this control strategy. It is recommended that an in-depth study of site selection be completed. Existing core hole logs and hydrologic data should be reviewed to determine the fraction of the resource that can accommodate in-situ retorting in dry zones. This should be supplemented with new field data, as required. This survey should form the basis of further selection of sites for experimental and commercial programs.

Table 2-1. Candidate control strategies for VMIS retorts.

Control Strategy	Projected cost[1] per barrel of oil		Unresolved technical questions
	C-a	C-b	
Site selection	Not applicable		Fracture of resource that is recoverable.
Grout abandoned retorts with spent shale	\$0.49[3] \$0.65[4]	\$0.35[3] \$1.30[4]	Penetration of grout through rubble; permanence of non-cementitious grout. Ultimate permeability of retort.
In-place precipitation of calcite to seal pores[2]	\$1.88	\$1.15	Eventual solution of precipitates.
Grout curtain	\$0.74	\$2.85	Feasibility of drilling closely spaced, parallel holes 1000 to 2000 feet deep.
Design retorts with hydraulic bypass[2]	\$0.46	\$1.76	Effectiveness is uncertain; feasibility of producing adequate permeability by grouting a tight formation.
Cap rock in place	Not applicable		Long-term stability of cap rock.
Recover and treat leachate	\$0.67	\$0.59	Economics of treatment process and brine disposal.
Treat leachate in situ by adsorption and ion exchange	Too costly		
Modify retort operating conditions	0	0	Effect of operating conditions on minor constituents; adequacy of process control.
Reverse wettability of spent shale	Too costly		Method to "coat" spent shale in-situ; permanence; non-biodegradability.
Self treatment[2] (no action)	0	0	Effectiveness uncertain.

[1] Cost per barrel in 1979 dollars based on combined surface and in-situ retorting, 40 percent voids on Tract C-a and 23 percent voids on Tract C-b.

[2] Possible application in conjunction with another technology; not adequate by itself.

[3] Air-level drilling.

[4] Ground-level drilling.

Grouting

The three principal environmental problems associated with VMIS retorting--contamination of surface and ground waters, subsidence, and low resource recovery--may be alleviated by filling the abandoned in-situ retorts with a grout based on surface spent shale. This grout would fill some of the voids, reducing the permeability of the retorts and provide protection against subsidence by increasing retort stiffness and strength. If adequate strength could be developed in the grouted retort, it may be feasible to retort some of the pillars, thus improving resource recovery. A cheap material, such as spent shale, would have to be used as the basis of such a grout because 9 to 12 ft^3 of voids must be filled for each barrel of oil recovered. Thus, conventional grouting materials are too costly for this application.

The sucessful application of this proposal requires the development of grouting criteria, formulation of an adequate grouting recipe, and development of methods to successfully distribute the grout within the retort. Work to date has focused on the development of a grout; little or no research has been conducted on grouting criteria and grout distribution. Experimental work has consisted of exploratory laboratory research focused on the development of a grout from raw or spent shale.

Grout Curtain

Constructing a grout curtain to route flow around retorting sites is one possible control technology to prevent groundwater from leaching abandoned retorts. The use of a grout curtain to stop groundwater flow is not a novel concept. However, there are special conditions of this proposed application that may make it difficult or expensive.

The first condition is the depth at which the curtain must be constructed. Holes must be drilled about 1000 feet, with very small deviation, in order to form a continuous curtain. This may be difficult to achieve. A second problem arises because the formations which are to be grouted (the aquifers) are of very low permeability and it may be difficult to inject grout, especially a suspension grout such as portland cement, into so tight a formation. The selection of a grout for this application will depend upon the distribution of fracture sizes in the formation to be grouted. If permeability is due to a few large fractures (>0.025 inch), these may be satisfactorily grouted by portland cement. However, if permeability is due to the presence of many small fractures, a more expensive chemical grout would be needed. The amount and cost of grouting material needed would be determined by the porosity of the formation.

Little information is currently available in the literature to answer any of these questions, and there are no oil-shale specific investigations on this control method. Exploratory drilling and a test grouting program will be necessary to assess the feasibility of this control technology. A groundwater flow model should be used to evaluate the efficacy of a grout curtain. Groundwater quality and leachate transport, as a function of curtain location, thickness, and permeability, should be studied. If these results are encouraging, field studies should be conducted to determine engineering feasibility. Geological exploration will be required to determine the fracture size distribution and density.

Modification of Retort Operating Conditions

Several studies have shown that the leachability of spent shale depends upon retort operating conditions. Conditions which would minimize the leachability of spent shale include: combustion retorting to burn off char; use of a sweep gas to remove CO_2; high temperatures, about 1000°C, to promote silication reactions; steam retorting; and a slow retorting rate. If these conditions are used, it may be possible to produce a spent shale with adequate strength and a sufficiently low leachability to minimize water quality and structural problems of in-situ retorts. These conditions approximately coincide with those presently proposed for use by the developers of lease tracts C-a and C-b. However, it is presently uncertain whether the conditions proposed by the developers are adequate to mitigate leaching problems. Related issues--namely composition of the leachate, pollutant transport, and the controlling regulatory framework--need to be addressed.

Additional research is required to further explore the effect of retorting conditions on the solubility of a broader range of constituents, including trace organic and inorganic compounds. The effect of shale composition, retorting temperature, retorting rate, input gas composition, and particle size on the solubility of major and minor elements needs to be determined. Tradeoffs between oil production and leachability need to be explored in economic studies.

Intentional Leaching

Control technologies discussed thus far are based on minimizing the flow of groundwater through abandoned retorts. An alternative strategy is to intentionally leach the retorts, recover the leachate, treat it, and either dispose of it or reuse it for further leaching. Several laboratory investigations have shown that the concentration of organics and inorganics decrease rapidly with leaching flow. Thus, treating a finite volume of leachate may be sufficient to remove enough of the leachable material in spent retorts to protect groundwater quality.

Little experimental work has been conducted on this control technology. Before it can be adequately evaluated as a control method, data need to be developed on the availability of water for leaching, the quality of leachate, the kinetics of leachate formation, the volume of water that must be treated, and methods of leachate treatment. A large amount of water is needed for leaching. Estimates indicate that 10 to 14 million gallons per day of water would be required for two pore volumes of leaching per 50,000 barrel-per-day capacity. Detailed estimates of water availability for this purpose should be made. A plan for handling, storing, and reusing leachate and disposing of the brine streams from treatment must be worked out. The volume of leachate that must be treated needs to be defined so that treatment costs, which are nearly proportional to leachate volume, can be determined. This will require the development and use of a kinetic model of the leaching process. Methods of treating the produced leachate must be selected and tested in laboratory- and pilot-scale treatability studies. These studies should be conducted using field spent shales and the result of this work corroborated in larger scale field tests.

Costs

In addition to discussing various control strategies which might mitigate aquifer disruption and alleviate undesirable impacts of in-situ leaching, Chapter 7 also projects costs of the various strategies. Review of several proposed control measures showed that some may be economically feasible and technically attainable in the near term. However, no conclusions have been drawn concerning the cost-desirability of one control measure compared to others because cost projections were based upon preliminary laboratory work or field experience by non-oil shale industries. Additionally, some control methods, which appear to be economical, fail to provide full protection against adverse environmental impacts. For example, although leachate collection and treatment has a low cost per barrel of oil produced, this strategy would provide no protection against mixing of upper and lower aquifer waters.

Recommendations

The problems concerning the development and use of various control strategies discussed in Chapter 7 clearly indicate that additional study is required. Data from field testing of various control measures are required. Retort grouting, intentional leaching, grout curtain, and hydraulic bypass strategies should all be evaluated by both laboratory and computer studies. A basin-wide hydrologic model should be used to determine the effectiveness of each of these control measures and used to compare them upon a systematic and uniform basis. Recognized construction and grouting contractors should be consulted to assess the feasibility of grout curtain and hydraulic bypass construction.

Field operational tests should be conducted on those control strategies judged most cost-beneficial as a result of laboratory and computer studies. When a selected control system or systems is applied operationally, a long-term monitoring program should be instituted to determine the actual effectiveness of the control measure compared to the predicted effects developed by laboratory, computer, and field studies.

REUSE AND DISPOSAL OF EFFLUENTS

It is not unreasonable to anticipate that the combination of several factors--stringent state and federal standards governing the discharge of wastes into local waters, limited water availability in the Upper Colorado River Basin, and the requirements for large amounts of water by an oil shale industry--will encourage oil shale producers to reuse process effluents to the maximum extent possible and to evaporate the residuals. Chapter 8, "Reuse and Disposal of Effluents from an In-Situ Oil Shale Industry," characterizes the effluents from an oil shale industry and places in perspective the disposal options available within the legal framework existing in the oil shale region.

Because reuse of effluents and evaporation of the residuals would eliminate the requirement to discharge effluents into local waters, the detrimental effects of discharging these wastes into surface or ground waters would be minimal. The principal water quality impacts, if effluents were to be reused, would be caused by accidental spills of oil and aqueous effluents and by salinity increases due to stream flow reductions from diversions for in-plant use.

Water is used at an oil shale plant for mining operations, dust control, steam and power generation, compaction of processed shale, irrigation, human consumption, pre-refining, and other processes. Each use produces an effluent which must be collected, treated, and disposed of. The effluents produced include: mine waters; brines from ion exchange, reverse osmosis, filtration, and other treatment processes; storm water runoff from plant areas; and various process waters. Only process waters are peculiar to the oil shale industry; all other effluents are normally found in other types of industrial operations and can be treated with conventional control technology.

During oil shale retorting, two unique types of water are produced from combustion, mineral dehydration, input steam, and groundwater intrusion. Referred to as retort water and gas condensate, they are produced in rather large volumes. Retort water has proven to be difficult and costly to treat. Combined production of these two waters is 0.1 to 22 barrels of water per barrel of oil. For a 500,000 barrel-per-day plant, which is about six percent of the 1977 U.S. crude oil production, this represents a total of about of about 2 million to 500 million gallons of water per day, depending on the type of process and the plant location. Water production for surface processes is at the lower end of this range (0.10-0.30 gal/gal), while it is at the upper end for in-situ processes (0.4-22 gal/gal). The high value of 22 gallons of water per gallon of oil is due primarily to groundwater inflow and is probably not realistic for a commercial industry if the site is carefully dewatered.

Retort water has high concentrations of organics, NH_3, dissolved CO_2, sulfur compounds, and elevated levels of some trace elements such as As, Se, F, and B. Gas condensate has elevated levels of dissolved gases and low total dissolved solids. Retort water treatment is presently uncertain, and no viable system has been developed. Most research on retort water has centered on removing dissolved gases and organics. These studies indicate that dissolved gases may be removed by steam stripping, weak acid cation exchange resins, or spent shale, while no economic method has been found to remove organics from retort water. Additional study is needed to develop treatment methods for retort water. In contrast, the treatment of gas condensate appears straight forward, and little work will be required in this area.

Large volumes of mine water are produced during site dewatering. This water might be used to meet a substantial part of on-site water requirements if existing water doctrines permit its consumptive use. However, stream flow augmentation may be required to protect downstream water rights, if dewatering affects tributary rights. Treatment would be required before mine water could be applied for most on-site requirements.

Most of the anticipated on-site uses of water require disposal of brine streams, which include treatment plant sludges and blowdown streams. To achieve zero discharge, the various brines must be solar evaporated in lined ponds. Because of the large volumes of water involved, this treatment may be costly and require large land areas.

Storm water runoff from surface facilities, parking lots, on-site roads, and transport facilities may also have an impact on local surface and groundwaters. The potential impacts of storm water runoff from sources other than surface disposal piles (for the effects from this source, see Chapter 6) differ for short-term and long-term activities. Short-term effects will be caused by activities involved with plant construction: building roads, erecting buildings, preparing disposal sites, for example. Long-term effects may be caused by spills at all stages of the recovery and upgrading processes (even the best-managed operation can be expected to have some accidental spillage), vehicles, and other sources associated with normal industrial activities. The major concern for short-term runoff is sediment loading since sediment loss in newly exposed surfaces can be extensive. Long-term runoff may include toxicants, organics, and salts as well as suspended solids. Treatment and reuse of storm water runoff is not anticipated to present any technical difficulties.

Although the amount of domestic waste produced is small when compared to the volume of other wastes, domestic sewage must be treated or otherwise disposed of in the area. No great problem should be encountered because this waste will be similar to municipal sewage except that laundry and kitchen wastes will not be included to any great degree.

The effluents produced at an oil shale plant may be discharged into surface or ground waters or reused on site. Most options require treatment to meet water quality standards or criteria as discussed in Chapter 5. The type and degree of treatment required depends upon the characteristics of the water and its use. For example, if water is to be used for cooling tower makeup or boiler feedwater, a high quality water is required; if water is to be used for dust control or spent shale disposal, a poor quality water is adequate and many available supplies, such as dewatering effluents, can be used directly without any treatment.

Three factors will largely control water disposal decisions for an oil shale plant. Western shale deposits are located in the Colorado River Basin where water is a limited resource and water impacts are inextricably linked with decisions surrounding the use of the Colorado River. Oil shale processing produces a large volume of poor quality water, a volume of water which would be sufficient to meet some of the in-plant water requirements after treatment. Finally, existing water quality standards and effluent limitations require a high degree of treatment before discharging wastes into receiving waters and additional limitations may be imposed in the future. These three factors suggest that an oil shale industry will probably reuse most of the effluents generated during processing and will evaporate any residuals. Reusing waste waters will partially solve the problem of water availability discussed in Chapter 4 and will also be economically desirable since treatment for reuse may be less expensive than treating effluents for discharge into surface or ground waters. The lower economic implications and the requirements for large volumes of water for processing oil shale should foster support of extensive research and study of means of treating effluents for reuse.

SUMMARY

Although oil shale resources in the United States are capable of meeting a significant share of petroleum demands in this country, production of oil from shale may have a serious and undesirable impact upon the local environment, particularly water resources. The generation of solid and liquid wastes as by-products of oil shale production necessitates the development of new methods of control and treatment of these wastes or the modification of methods used by other industries. Institution of control methods is technically and economically feasible; treatment and reuse of effluents will materially lessen requirements for large amounts of water and will eliminate the expensive treatment of effluents required to meet discharge standards. However, acceptable solutions to these problems are not presently available and must be derived from future research. Continued research and testing in both laboratory and in the field should resolve the major issues--retort abandonment and retort water treatment--and make production of oil from shale a viable and important source of petroleum.

CHAPTER 3

IN-SITU TECHNOLOGIES

Shale oil is produced by pyrolytically decomposing the organic material found in oil shale. This process, referred to as "retorting," is carried out by either mining oil shale and heating it above ground (surface retorting) or by fracturing and retorting shale in place (in-situ retorting). Because surface retorting has been described extensively in publications by others (Sladek, 1974-75; Colorado School of Mines, 1964-79), it is discussed only in general terms in this chapter.

The production of oil and gas from oil shale by in-situ retorting involves three basic steps:

- Retort Preparation. A retort is prepared in the oil shale bed. If natural permeability is low, the shale is fractured in place or mined and rubblized to increase porosity so that gases and liquids may move freely through the rock.

- Retorting. Organic compounds contained in the shale are thermally decomposed by heat derived either from external sources or from combustion within the retort.

- Product Recovery. The retorted oil and gas products are removed to the surface.

Many methods to accomplish the above steps or operations have been described in the literature. The purpose of this chapter is to identify in-situ technologies and allied operations, assess probabilities of implementation, and select those most likely to be developed on a commercial scale. The selected technology will be described in some detail. Allied operations, water demands, and effluents are discussed in Chapters 5 and 8. The resulting collection of information will be used in subsequent chapters to assess the impact of in-situ oil shale development on water resources.

SHALE OIL PRODUCTION

Oil shale has been described as a marlstone rock containing organic material. Typical analyses of inorganic and organic constituents found in Green River oil shale are shown in Tables 3-1 and 3-2. About one-half of the total mineral content is made up of two carbonaceous minerals, dolomite and calcite. About 80 to 90 percent of the organic component is kerogen, a high molecular weight polymer; the remaining 10 to 20 percent is bitumen. At the present time, the molecular structure of kerogen remains unsolved. It has been defined as primarily heterocyclic with smaller amounts of aliphatic and aromatic hydrocarbons. Individual monomer molecules are three-dimensional and are estimated to have a molecular weight of 3200 (Smith, 1961). The individual molecules are postulated to be tied to each other by oxygen and sulfur cross-links. The kerogen acts as a binder for the mineral components. When it has been removed, the shale loses cohesive strength and can be easily crushed to powder. Kerogen, because of its

Table 3-1. Analysis of the inorganic fraction of Green River oil shale.

Mineral	Chemical formula	Weight percent of total minerals
Dolomite	$CaMg(CO_3)_2$	32
Calcite	$CaCO_3$	16
Quartz	SiO_2	15
Illite	(silica clay)	19
Low-albite	$NaAlSi_3O_8$	10
Adularia	$KAlSi_3O_8$	6
Pyrite	FeS_2	1
Analcime	$NaAlSi_2O_6 \cdot 2H_2O$	1
	TOTAL	100

Source: Sladek, 1974.

Table 3-2. Analysis of the organic fraction of Green River oil shale.

Element	Weight percent of total organics
Carbon	76.5
Hydrogen	10.3
Nitrogen	2.5
Sulfur	1.2
Oxygen	9.5
TOTAL	100.0

Source: Sladek, 1974.

high molecular weight and cross-linking, is not soluble in conventional petroleum solvents. Since bitumen is soluble, this leads to a commonly accepted differentiation between the two compounds and a definition by implication of bitumen. Kerogen is the insoluble portion of the organic content of raw shale, and bitumen is the soluble portion.

Richness or organic content of an oil shale is indicated by its oil yield measured in gallons of oil per ton of rock (gpt). This quantity is determined by a standard assay method called a Fischer Assay. A small quantity of finely ground raw shale is heated in an electrical retort, and the kerogen therein is thermally decomposed to oil and gas. A small amount of water is also produced. The liquid components, the oil and water, are captured, measured, and reported in gallons per ton. The total organic content of the shale is not determined. Variations in test procedures permitted in the widely used U.S. Bureau of Mines Fischer Assay method may cause significant differences in the results obtained. Modified assay procedures has been developed to alleviate some of the problems that have been observed in the Bureau of Mines method (Heistand, 1976), and the American Society of Testing and Materials is developing a standard Fischer Assay method (Smith, 1979).

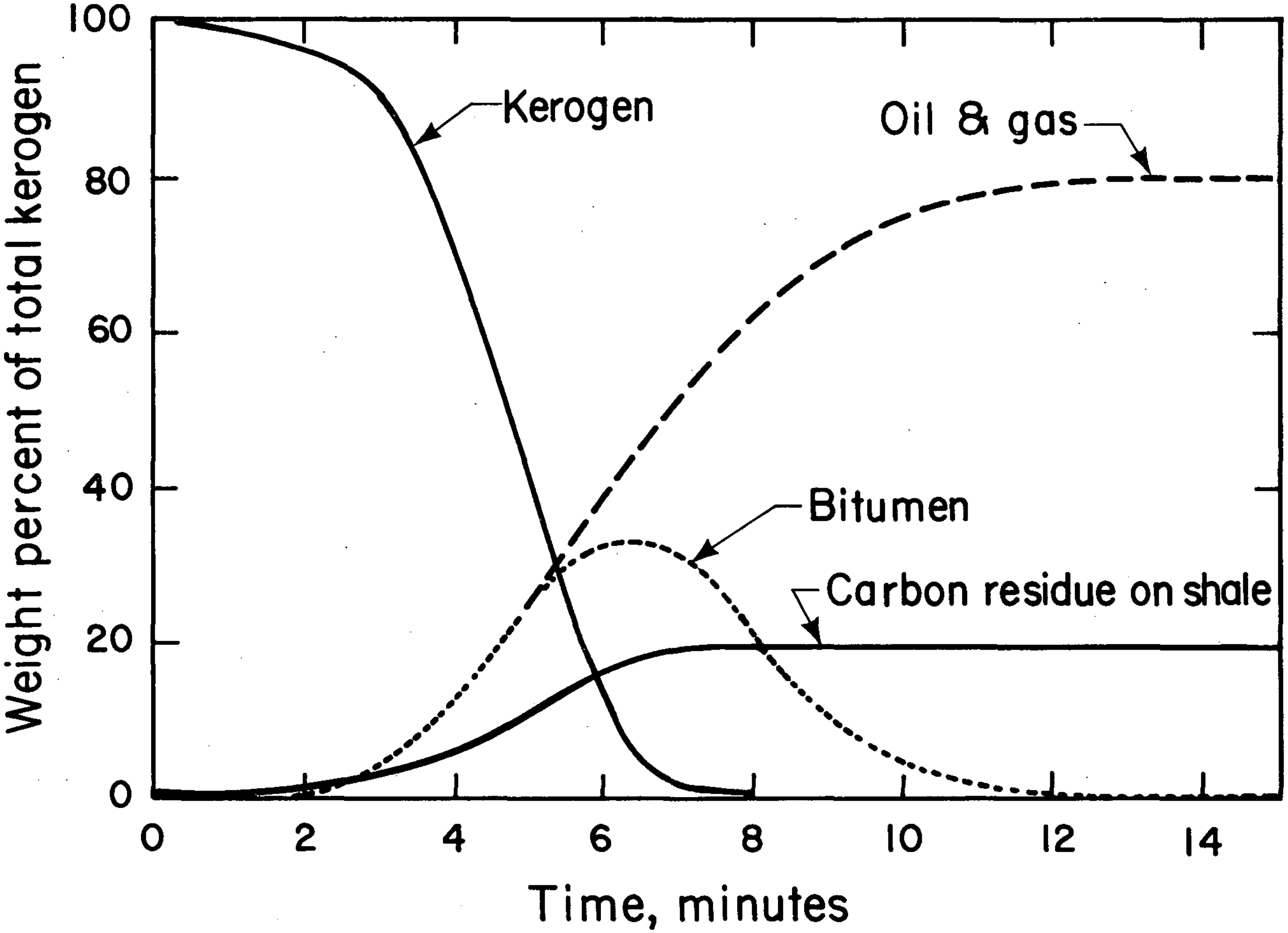
Organics in oil shale are most readily extracted by heat. Heating of kerogen yields oil, gas, and carbon residue. The relative proportions of decomposition products from a 26.7-gpt shale sample are shown in Table 3-3. A graph of the decomposition of kerogen heated at a constant temperature is included as Figure 3-1. Amounts of kerogen and its decomposition products are plotted against time. The kerogen drops to zero fairly rapidly as it is converted. The total amount of bitumen peaks about the same time as the kerogen is exhausted and then drops to a low level. The quantities of oil and gas and carbon residue rise and then level off. The kinetics of the reactions have been described by first, second, and higher order relationships (Johnson et al., 1975).

Table 3-3. Products from pyrolysis of 26.7-gpt Colorado oil shale at 900°F.

Product	Weight percent of organic constituent in raw shale	Weight percent of total raw shale
Oil	63	10.4
Noncondensable gas	15	2.5
Fixed-carbon residue	13	2.2
Water vapor	9	1.4
TOTAL	100	16.5

Source: Sladek, 1974.

Thermal decomposition of the oil shale is a function of the retorting temperature. As the temperature rises, more of the kerogen is converted. Results of one experiment are shown in Figure 3-2. About 30 percent of the total organics is removed in the form of CO_2, light hydrocarbons, and water vapor by the time the shale reaches 765°F. The remaining 70 percent is removed in the form of oil and gases in the range between 765° and 880°F. Above 1130°F, carbonate decomposition of the mineral matrix occurs. The effective range of retorting temperatures is thus defined. Below 880°F the kerogen is not completely converted to oil, and above 1130°F heat is lost in carbonate decomposition.



XBL 777-1397

Figure 3-1. Thermal decomposition of kerogen. Source: Allred, 1967.

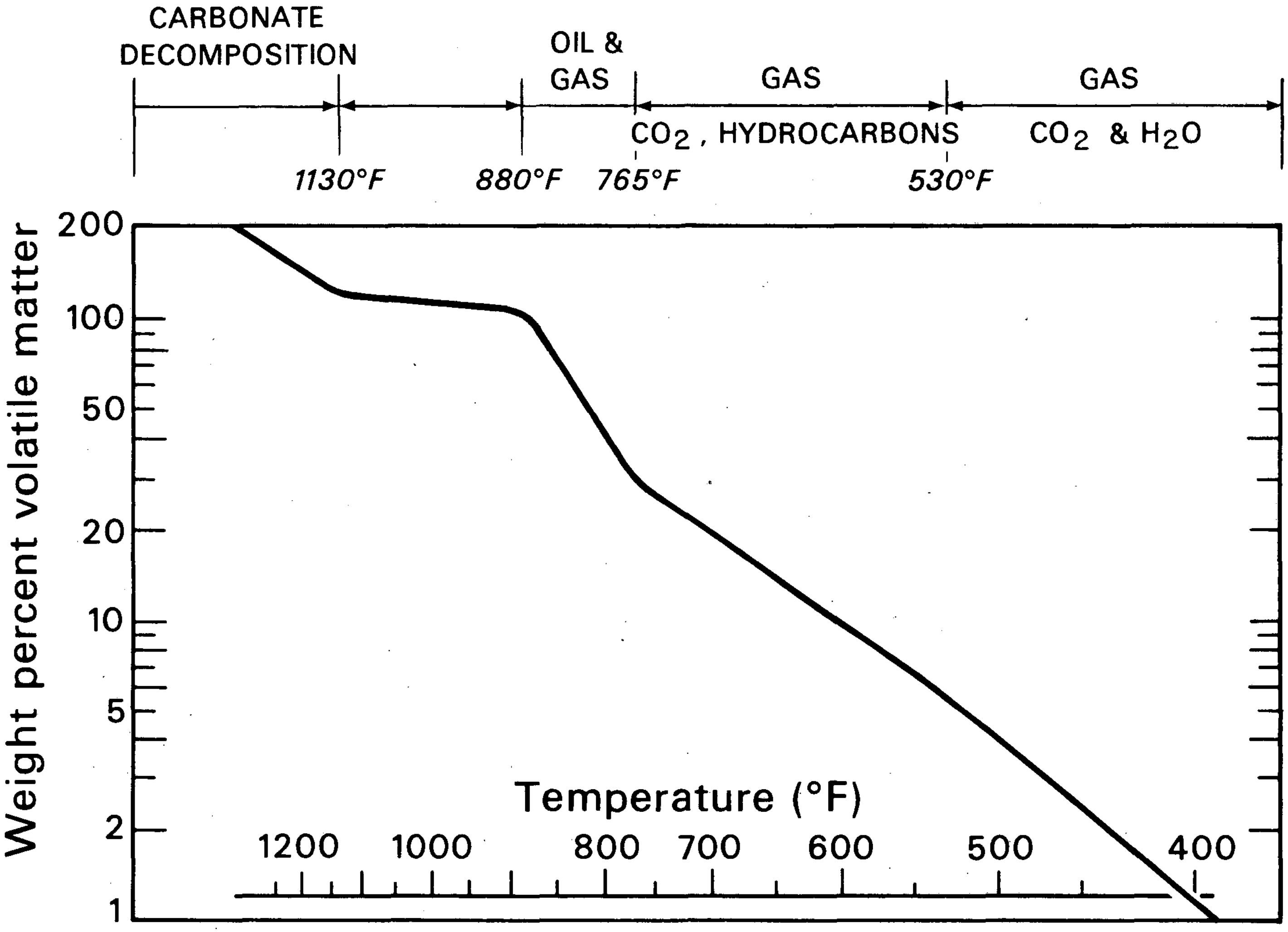


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Figure 3-2. Steady-state thermal decomposition of oil shale.
Source: Allred, 1967.

IN-SITU SHALE OIL RECOVERY

Processing of oil shale in its original geologic formation is called an in-situ process or operation. As outlined earlier, the three basic steps taken to produce oil from oil shale by in-situ means are retort preparation, retorting, and product recovery. A schematic outlining general techniques for each of these steps is shown in Figure 3-3. Some of these techniques have been the subjects of field experiments; others are only proposals. Following are, first, a general discussion of in-situ shale oil recovery, in which some pertinent terms are defined; and, second, more detailed descriptions of the basic steps and techniques as shown in Figure 3-3.

The region in which the organic compounds are thermally decomposed is defined as a retort. There must be sufficient porosity in the shale layer to permit passage of air, hot gases, and liquids. Oil shale is nearly impermeable and also has a very low coefficient of thermal conductivity. Without porosity it is nearly impossible to sustain combustion and to transfer heat to the shale. There are, however, a few areas where natural porosity exists. Some oil shale beds in the Green River Formation contain deposits of water-soluble minerals in which groundwater has leached out solution channels. Dewatering of the aquifer leaves a porous structure which may be suitable for in-situ retorting. There are also naturally occurring fissures and fractures that can be used for passage of the heated retorting fluids. If, as is more likely, there is insufficient porosity, it must be created artificially.

It has been customary to consider in-situ processes to be either true or modified. True in-situ oil shale operations are characterized by the preparation of the retort in shale beds with no removal of materials before retorting. Modified in-situ processes are taken to mean that a portion of the shale is removed from the shale layer by mining and the resulting void space distributed throughout the intended retort. True in-situ operations include situations in which natural porosity is adequate and those in which porosity is artificially created by displacement or other means.

Once the retort has been formed, the shale is retorted to produce shale oil. Retorting is a pyrolytic process in which the shale is heated in the absence of oxygen. The heat source may either be external or internal with respect to the retort. Externally heated gases with temperatures above those required for complete kerogen breakdown may be passed through the bed. The other option is to use hot gases generated by combustion of organic compounds within the retort itself. The fuel for the internal combustion source is the carbon residue left on the shale.

Product recovery is the removal of the liquid and gas by-products from the retort. The method selected depends primarily on the means used to prepare the retort. Products may be removed through shafts, wells, or galleries. Retorting offgases may be collected and recirculated through the retort or disposed of by flaring or other means. Oil is collected for upgrading and transport to refineries.

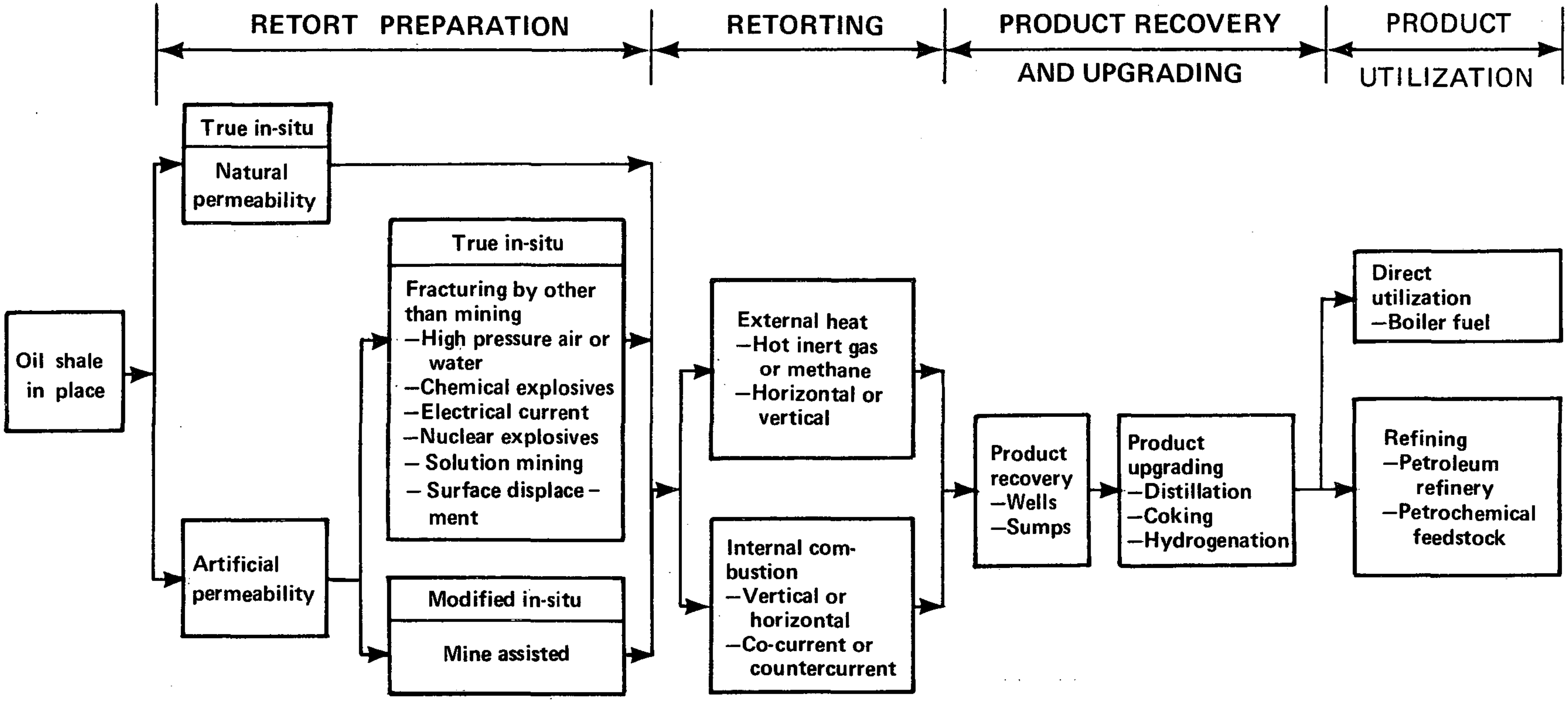

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Figure 3-3. In-situ recovery of oil from oil shale.

Retort Preparation - True In-Situ Process

In general, access to the shale beds in true in-situ processes is through boreholes drilled to the bed from the surface. Ideally, the operation consists of a centrally located injection well and a series of recovery wells located around the periphery of the intended retort. The retorting ideally proceeds uniformly from the center to the periphery. The injection well serves as a conduit for combustion air, recycle gases, and fuel for starting combustion. The recovery wells are used to remove the oil, gas, and water from the retort. In reality, additional injection wells and recovery wells may be needed as the retorting proceeds, depending on the direction in which the "burn" moves.

If natural porosity of the shale is adequate to sustain combustion and to permit movement of the retorting fluids from the injection wells to the recovery wells, then retorting may be begun, as discussed in the next section. If there is insufficient porosity, then permeability is artificially created. Techniques include:

1. Fracturing with high-pressure air or water (hydro-fracting)

2. Fracturing with chemical explosives (nitro-fracting)

3. Fracturing with electrical current (electro-fracting)

4. Massive fracturing with nuclear explosives

5. Solution mining of saline deposits to create porosity

6. Creation of voids by surface disturbance.

Fissures present in the shale may be enlarged with high-pressure air or water. Packers are inserted in the borehole above and below the zone to be fractured. High-pressure fluid is then introduced into the isolated sector to widen the cracks. A modification of this process is sand-propping, in which sand is included in injected water. When the hydraulic pressure is released, the sand grains remain in the cracks, thus propping them open.

Chemical explosives may also be used as fracturing agents. Nitroglycerine, introduced into the fissures and exploded, forms voids by displacing the overburden. Solid explosives may be detonated in the borehole, but there is some evidence that this is not as effective as injected liquid explosives.

Electro-fracting is the passage of electrical current between electrodes inserted in wells. Carbon paths created by the current become resistance elements which heat the surrounding shale and drive off oil and gas.

Solution mining of the soluble deposits found in oil shale beds has been proposed (Beard and Smith, 1976), and is under development by Equity (Dockter, 1978). Liquid would be injected into the bed to dissolve the nahcolite ($NaHCO_3$) and dawsonite [$NaAl(OH)_2CO_3$] minerals contained therein. The resulting solution channels would then become void spaces in the retort.

Minerals could later be recovered from the leachate and processed for sale to other industries.

Surface uplift may be used in shallow oil shale deposits and is presently under development by Geokinetics (Lekas, 1979). In this method, the overburden is lifted by detonating explosives in the shale bed.

The use of nuclear explosives for retort preparation has been proposed (Lekas, 1966) but has not been tested due to the great potential for environmental damage. Seismic waves may damage structures and nearby mining operations. Massive fracturing outside the retort may provide passageways for oil to escape collection, thus creating an economic loss and a potential for pollution of groundwater aquifers. In addition, the effect of the residual radioactivity from the blast on groundwater and the oil by-products is unknown.

Retort Preparation - Modified In-Situ Process

In modified in-situ retorting, an underground bed of rubble is prepared by mining 20 to 40 percent of the in-place shale and blasting the balance into the mined-out void. The resulting bed should have a uniform particle size distribution with a minimum of large blocks to eliminate flow channeling and to minimize combustion of oil. Methods to successfully create such a bed are presently unavailable and are the subject of intensive laboratory and field experimental programs. Conventional blasting technology is applicable only to free-face blasting; and modified in-situ bed preparation requires blasting to a fixed face, i.e., the confining walls of the underground retort. This is presently one of the major technical barriers to the commercialization of modified in-situ technology.

The methods presently being pursued to prepare a vertical modified in-situ rubble bed are summarized in Figure 3-4. The retort area is accessed by shafts, adits, and drifts excavated by conventional mining techniques. About 20 to 40 percent of the volume to be retorted is mined from several vertical or horizontal sections or from a single section, as shown in Figure 3-4. Explosives are placed in drill holes and the unmined material is blasted into the mined-out void. The bottom of the retort is sloped to collect the oil, the access shafts are sealed off, the top and bottom of the retort are plumbed, and the retort is ignited.

Retorting

The fractured or naturally porous shale is heated in the underground retort to convert the kerogen into oil and gas. The heat source may be either external or internal. Most in-situ research is presently directed at internal heat sources. In both methods, the shale is heated to above 900°F, the point above which the kerogen is essentially completely decomposed. There are, however, fundamental differences in the two methods.

Externally heated inert gases passed through the retort will thermally decompose the kerogen to oil, gas, and carbon. In the absence of oxygen, there is no combustion of hydrocarbons. Carbon remains on the spent shale in the retort. The temperature of the heated retorting gas is controlled so that the kerogen is most efficiently converted. Temperatures much below 880°F leave kerogen on the spent shale, and temperatures above 1130°F begin

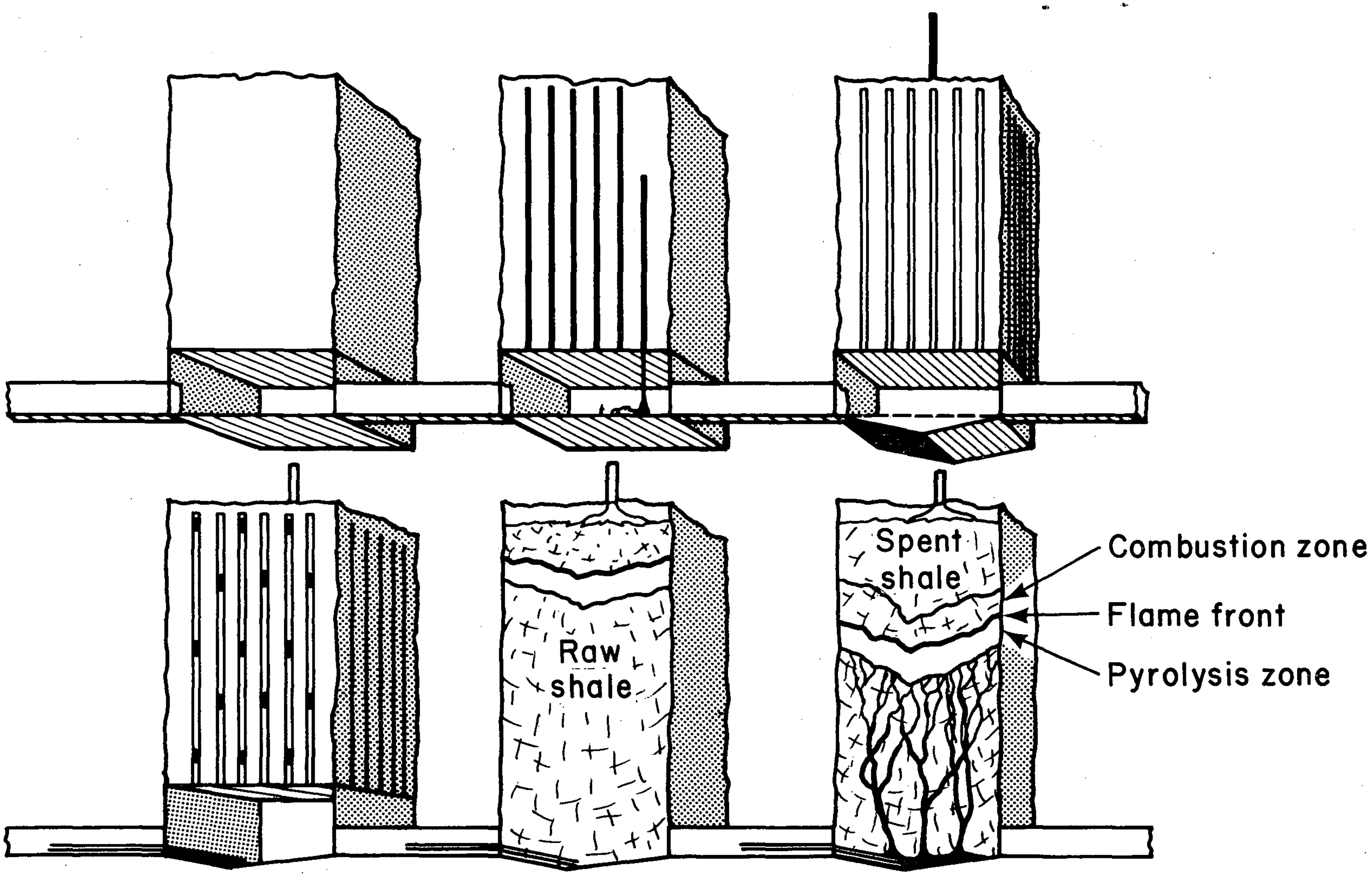

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Figure 3-4. Schematic of the modified in-situ retorting process.

to decompose the mineral carbonates and, thus, decrease the overall efficiency of the retorting process. Minimum facilities required are a source of inert gas such as nitrogen; a gas heater, piping, and wells to convey the hot gas to the shale; and a means of gas recovery so that the retorting gas may be reheated and recycled.

Retorting with heat supplied by internal combustion within the retort is more complex. A schematic of the process is shown in Figure 3-5. The top of the rubblized shale is first ignited by using an external heat source such as a gas burner; combustion air is supplied. As soon as the shale is ignited, the process becomes self-sustaining, and the external heat source is shut off. In the early stages of burning in the retort, the carbon, oil, and gas from the shale are all consumed. A pyrolysis zone is formed immediately below the combustion zone. In this oxygen-free region, kerogen conversion continues without further combustion of hydrocarbons. As the flame front is driven down the retort by the incoming air, combustion is sustained by the residual carbon that has remained on the shale after the decomposition of the kerogen and bitumen. The oil and gas products are also driven through the raw shale by the combustion air supply. As the combustion and pyrolysis zones move downward, a zone of spent shale is left behind. The process continues until the pyrolysis zone reaches the bottom and all of the retorted oil and gas is removed from the retort. The air supply is then shut off and the retort abandoned.

This same basic process occurs irrespective of the specific technology involved. For example, modified processing may proceed in the vertical or horizontal mode or in the co-current or countercurrent mode. In each case, however, the process fundamentals are the same. A pyrolysis zone followed by a combustion zone is moved through a shale bed by incoming gases. Products move out of the reaction area, and spent shale is left behind as the reaction front passes.

A side-by-side comparison of several aspects of the internal and external methods is shown in Table 3-4. Selection between the two processes is best made on an economic basis. The capital and operating costs and the quality and quantity of oil produced for each would be compared and the more favorable selected. Some of the economic factors which must be considered are shown in Table 3-4.

Some variations to the internal heat retorting method illustrated in Figure 3-5 have been proposed. The flame front may also be made to move horizontally instead of vertically downward. The combustion zone may also move with or against the current of the combustion air supply. This movement with respect to the air current is called co-current or countercurrent, respectively.

In the forward or co-current process, shown schematically in Figure 3-6, the flame front moves in the same direction as the air stream furnishing the oxygen. There are several advantages. The combustion air is heated by the burned material, and the hot combustion products warm up the raw shale before the retorting zone arrives. Combustion is sustained by the carbon remaining on the shale, and more valuable oil and gas products are less likely to be consumed. The principal disadvantage is that heavy oil is cooled by passage through the raw shale. Since shale oil, in general,

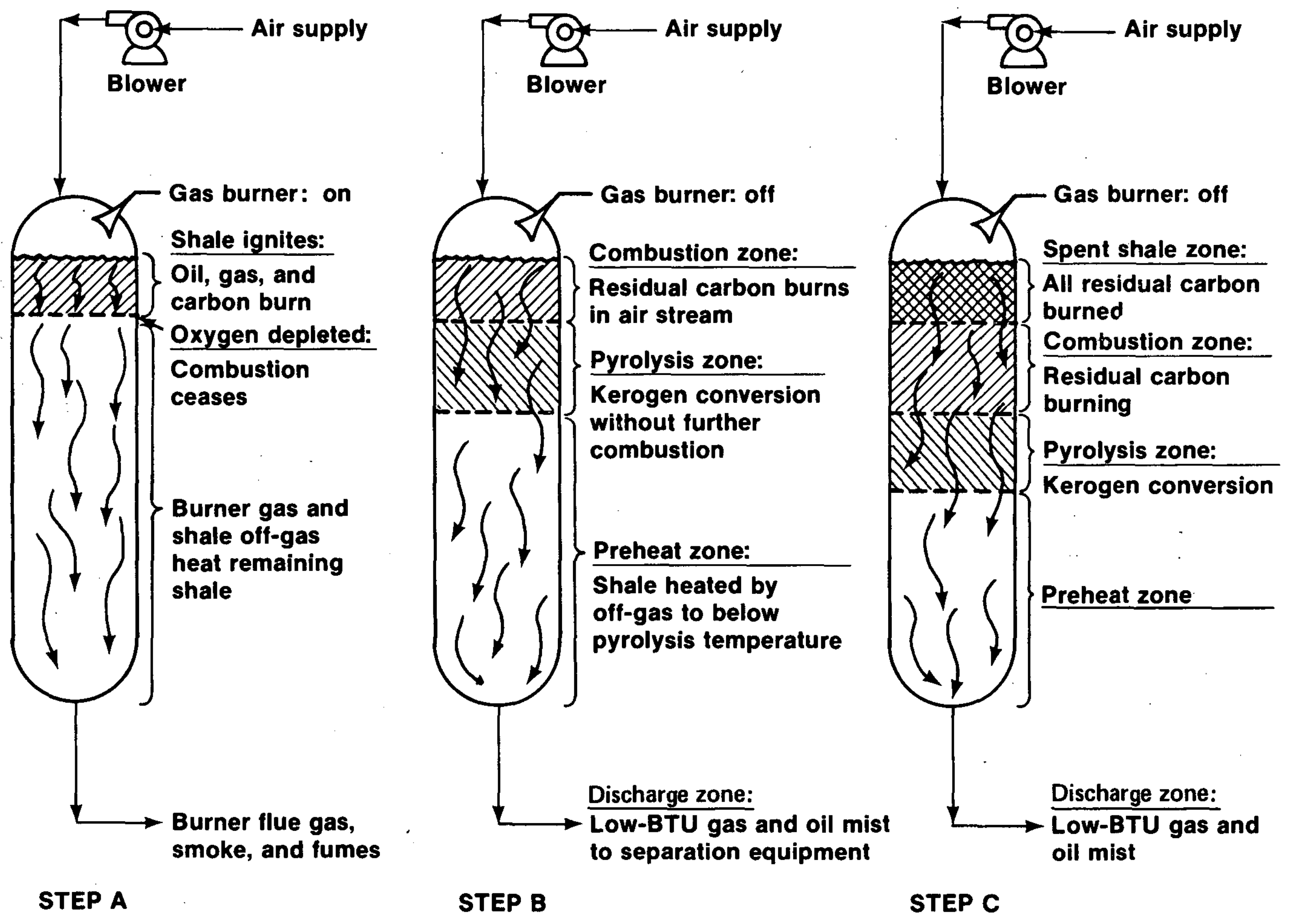

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Figure 3-5. In-situ retorting using an internal heat source.
Source: Sladek, 1975.

Table 3-4. Comparison of external and internal heat sources for in-situ retorting.

	External	Internal
Source of heat	Inert gas is heated outside of the retort. The hot gas is passed through the shale rubble to decompose the kerogen. Carbon remains on the spent shale after retorting.	A combustion zone is driven through the retort. A hot oxygen-free zone moves ahead of the combustion zone and decomposes the kerogen. The fuel for the combustion is the carbon left on the spent shale after the oil and gases are removed.
Control of the pyrolysis zone	Since there is no oxygen and the temperature of the inert retorting gas can be controlled carefully, there is no consumption of hydrocarbons and there is no decomposition of carbonates.	The advance of the flame front is a function of many variables, including particle size, combustion air and recycle gas supply, and porosity. It is difficult to provide close control of temperature and movement of the pyrolysis zone. Consequently, the front may advance unevenly. Temperatures may not be within favorable retorting ranges and kerogen may be left unconverted, hydrocarbons consumed, and carbonates decomposed.
Internal heat exchanges	The hot gas passing through the retort ultimately raises the entire quantity of rock to the temperature of the incoming gas. This heat remains in the retort after shutdown unless recovery is made.	There are several chances for heat exchanges. Incoming air is heated by the hot spent shale, which is simultaneously cooled. The hot retorted gases and oil are cooled by passage through the raw shale, thereby heating the shale.
Production of retort water	Small amounts of free and bound water in the shale are released in the retorting. About 0.15 barrel of water per barrel of oil is produced.	Water is produced by the combustion of hydrocarbons. This is in addition to the free and bound water. Approximately 1 barrel of water per barrel of oil is produced.
Economic factors to be considered	• Energy for heating gas • Initial supply and replacement of inert gas • Cost of facilities - Gas heater - Pipes - Gas recovery and storage devices - Oil recovery equipment • Cost of heat energy left in retort • Quality and quantity of recovered oil	• Combustion of useful hydrocarbons • Additional retort water for separation and disposal • Fuel cost for ignition • Cost of facilities - Air pump - Off-gas recycle and disposal equipment - Oil recovery equipment - Initial ignition equipment • Quality and quantity of recovered oil

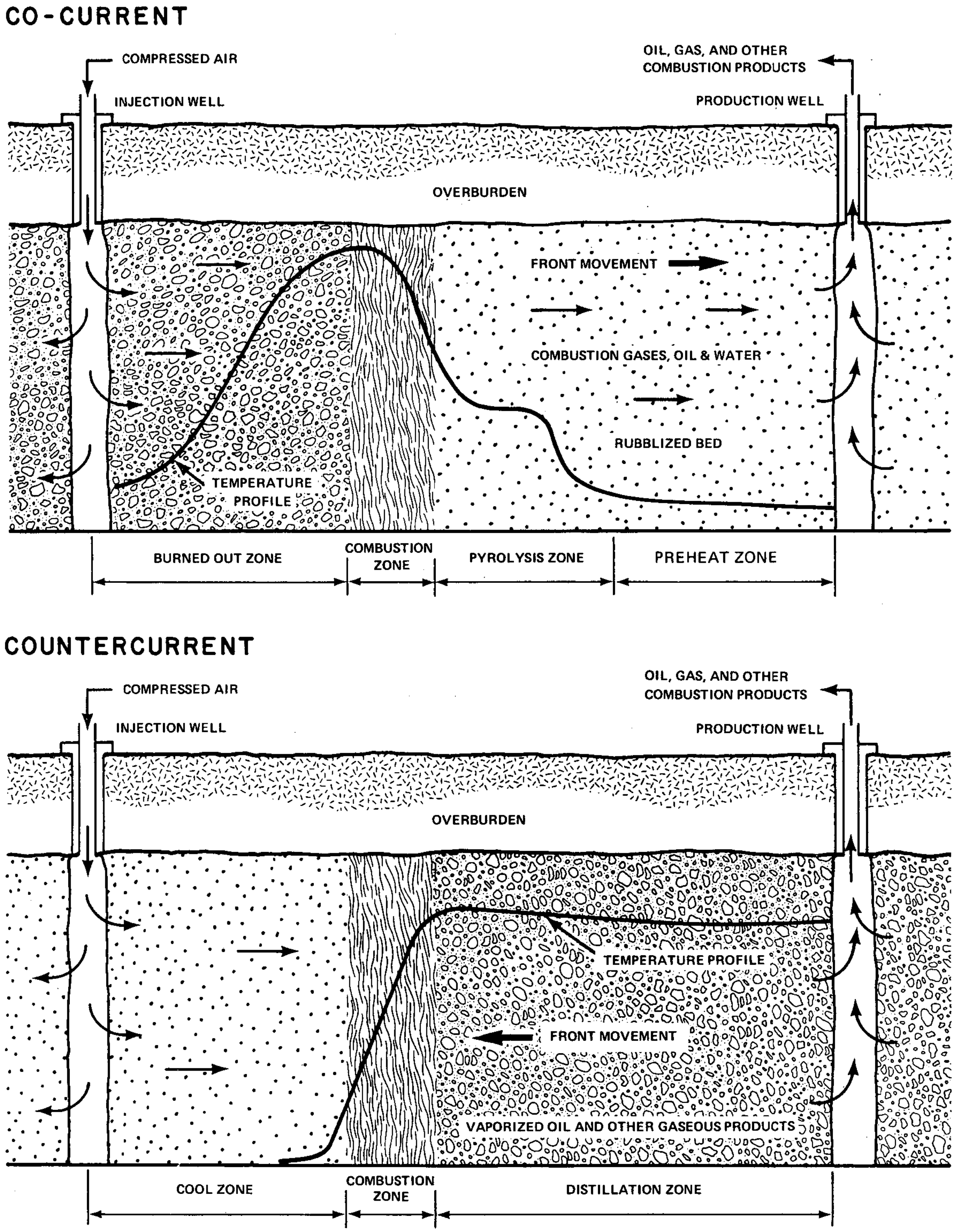

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Figure 3-6. Co-current and countercurrent front movements. Adapted from Allred, 1967.

is relatively viscous, the cooling oil clogs the pores in the fractured shale, resulting in decreased yields and bed plugging.

In the reverse or countercurrent process, also shown in Figure 3-6, the flame front moves into the air stream. The combustion products are passed through the hot spent shale and are thus maintained at a higher temperature. Consequently, they are less likely to clog pores. In addition, spent shale has a greater permeability than raw shale since organics have been removed and some carbonate decomposition has occurred. The net effect of the improved viscosity due to higher oil temperature and the greater shale permeability might be that less fracturing would be required. The passage of the oil through the hot shale may also accomplish in-situ refining by removing some of the heavier hydrocarbon fractions. The resulting oil might have a lower pour point and would thus be easier to transport. The principal disadvantage of the reverse process is that valuable light hydrocarbons are consumed. At the end of retorting, the formation remains at a high temperature since it has not been cooled by the incoming air. At the present time, the in-situ oil shale countercurrent process is only a proposal; no experiments of any size are known.

A portion of the combustion offgases may be recycled through the retort by injection into the combustion air supply. This has the effect of controlling the oxygen content of the incoming air and thereby controlling the advance of the combustion zone. It also reduces the amount of gas which must be disposed of by other means.

Product Recovery

Retorting of one ton of 30 gpt shale may produce from 0.4 to 0.7 barrels of oil, 3 to 660 gallons of water, about 0.8 tons of spent shale, and 50 to 14,000 scf of gas depending on retort operating conditions. For a modest-sized 50,000 barrel per day industry using the modified in-situ technology, this amounts to about 2.1 million gallons per day of water, 7×10^8 scf of gas, and 57,000 tons of in-situ spent shale. These materials must be separated, upgraded, stabilized, or treated before release to the environment.

Shale oil is the hydrocarbon product produced by the condensation of vapors from the pyrolysis of oil shale. Typically, shale oils are black, waxy liquids that have a high pour point. Methods for removal of oil from the retort depend to a large degree on the techniques used for retort preparation. For true in-situ operations, recovery wells are drilled around the periphery of the retort. Offgas escapes from these wells. Liquid oil and retort water collect at the bottom of the wells, where they may be pumped to the surface. In the modified in-situ processes, galleries are excavated at the bottom of the retort as part of the construction procedure. Sumps are constructed in the lowest galleries to collect the oil and some of the water (Figure 3-4). Gases are removed through pipes for recycling, salvage, or disposal (Figure 3-12).

Water co-produced with shale oil and decanted from it is referred to as retort water. This water is produced as an emulsion with the oil and must be separated by heating and decantation. Retort water originates primarily from four sources: combustion, dehydration of minerals, input steam, and groundwater. The ratio of water to oil ranges from 0.10 to 22, depending on the type of retort, retorting atmosphere (air or inert gas), and the geographical location of the oil shale reserve (Farrier et al., 1978). Typically, surface retorting processes have a water-to-oil ratio of 0.1 to 0.3, and in-situ processes have a ratio of 0.5 to 1.0. Higher values are due largely to groundwater intrusion during in-situ retorting.

Retort gas is a low Btu gas produced during the conversion of oil shales and which remains after the shale oil has been condensed out. Gas composition and yield are specific to the retorting process and depend on whether the retort is indirectly or directly heated. These gases, referred to here as offgases, generally contain water vapor, gaseous hydrocarbons, carbon dioxide, and hydrogen sulfide. The hydrocarbons are from the decomposition of kerogen, the water vapor comes from the sources discussed above, and the carbon dioxide comes principally from the water-gas reactions and carbonate decomposition. These gases must be collected and treated prior to use and/or discharge into the environment.

TRUE IN-SITU TECHNOLOGIES

True in-situ technologies are those that do not use mining to create formation permeability. Void space may be produced by electro-fracting, hydro-fracting, nitro-fracting, solution mining, or surface uplift. Several true in-situ technologies have been tested by private industry and the Department of Energy. The focus of most of this work has been on fracturing technology. The development of adequate permeability without mining and blasting remains one of the most troublesome technical constraints to the successful development of most true in-situ processes.

Sinclair Oil Company, Equity Oil Company, Talley-Energy Systems, Geokinetics, and the Laramie Energy Technology Center have field tested various true in-situ processes. The only successful true in-situ process that has been demonstrated to date is the Geokinetics process which uses surface uplift to create the in-situ voids. The other processes have failed largely due to inadequate void distribution. Each of these field demonstrations is briefly described below.

Sinclair Oil

Sinclair Oil Company conducted true in-situ tests in 1953 and 1954 in the Piceance Creek Basin (Grant, 1964). Wells were drilled to the oil shale bed, and existing bed fractures between wells were widened with high-pressure air. A gas burner was lowered into one of the wells and the shale set on fire. The burning zone was then moved outward from the injection well by the introduction of air and, in some cases, recycled offgas. The heat from combustion retorted the surrounding shale. The hydrocarbons from the pyrolysis were forced through the fracture system to peripheral wells from which they were removed. A small amount of shale oil was produced. A schematic of the operation is shown in Figure 3-7.

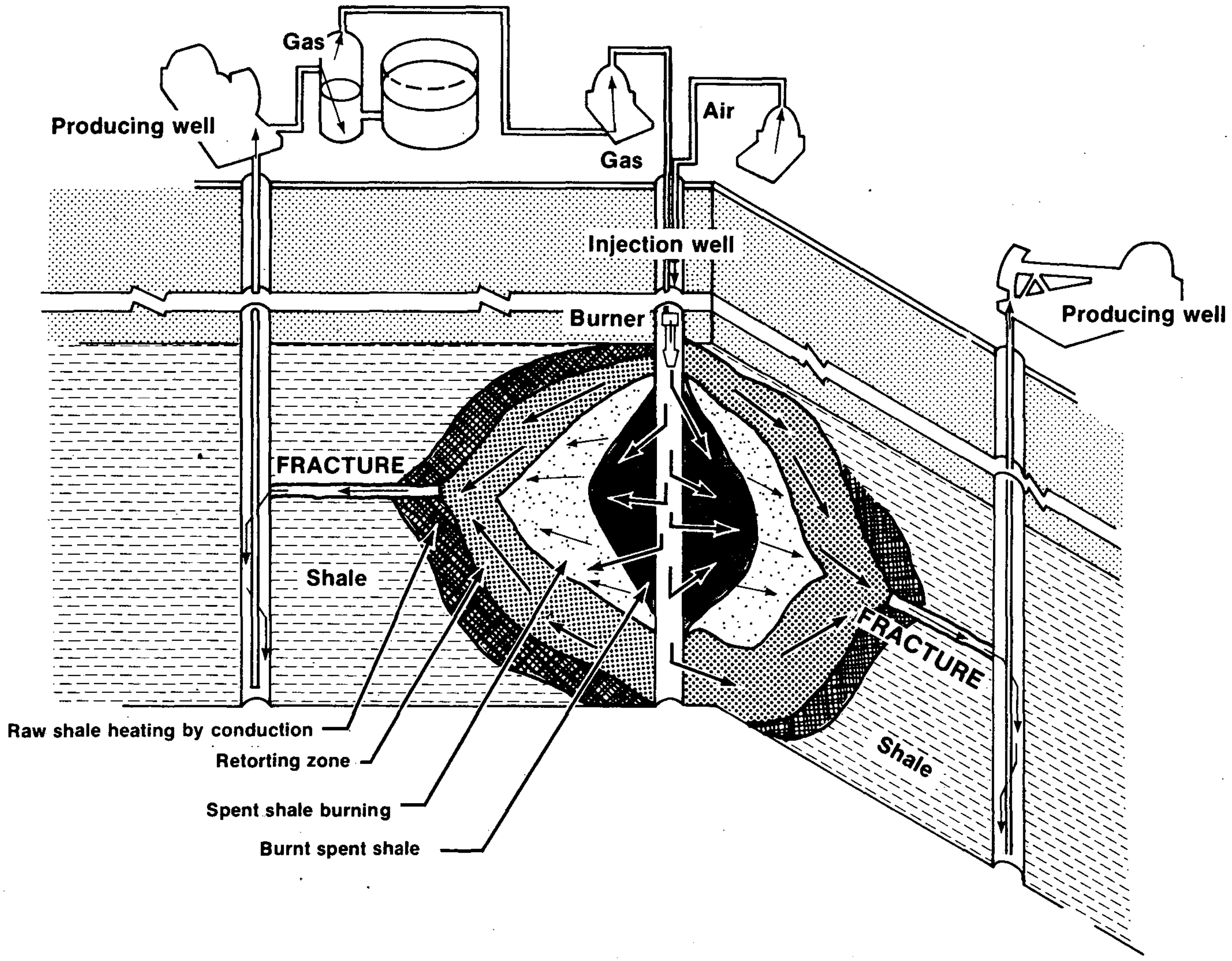

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Figure 3-7. Sinclair true in-situ retorting process. Source: Grant, 1964.

Equity Oil

Equity Oil Company has been investigating in-situ shale oil production since 1961 (EDC, 1979). Through late 1966, the firm experimented with the use of heated methane and natural gas that involved 5 to 600 days gas injection at 600 to 1,000 psig and 800 to 850°F. In 1968, ARCO acquired a 50 percent participation in the technology and development continued for several years thereafter.

From 1965 to 1967, Equity field tested in the Piceance Creek Basin a process in which hot natural gas or methane was injected into a naturally permeable oil shale bed through an injection well (Sladek, 1975). The hot gas heats the porous shale and decomposes the kerogen. Shale oil, offgas, and the cooled retorting gas move together toward the production wells. The retorting gas is reclaimed, reheated, and recycled. Several advantages were claimed. The gas temperature is maintained below the decomposition temperature of dolomite and calcite minerals. Oxygen-induced polymerization of the oil does not occur because there is little oxygen in the natural gas. The methane in the retorting gas also acts as a solvent for organic compounds in the shale.

In the early 1970s, the process was modified to use superheated steam, rather than natural gas, as the heat carrying medium. After only a few months of operation, the project was terminated due to inability to control the path of the injected gas and because of high operating costs.

Profitable operation of such processes depends on high recovery of the heat carrier. High recovery in an unconfined formation is not likely since the gas may become trapped or may migrate beyond the recovery wells. In light of present high natural gas prices, the economics of the process are probably still unfavorable.

In 1977, Equity signed a contract with the Department of Energy to evaluate a new, true in-situ technology. The new concept involves solution mining of the leached zone using superheated steam. Mineral dissolution would provide permeability for retorting. The preliminary concept for the field tests involves eight injections in five production wells oriented in a one-acre pattern. The production target will be the 550-foot-thick leached zone in the Piceance Creek Basin. Superheated steam will be injected at the rate of 64 million Btu's an hour at 1,400 to 1,500 psig maximum pressure. The minimum downhole operating temperature is expected to be 840°F. Equity forecasts a two-year injection period to be followed by a post-operation core-hole program in order to evaluate the degree of retorting. The total project should be completed in four and a half years, by 1982. Site construction is in progress (Docter, 1978).

LETC True In-Situ Field Studies

The Laramie Energy Technology Center (LETC) has been conducting oil shale research since the 1940s. Much of their more recent work, since 1966, has been on the development of a true in-situ process. The field program was carried out on federal tracts north of Rock Springs, Wyoming, and evaluated various fracturing techniques. These experiments were based on the concept of igniting the shale in an injection well and then forcing combustion products to recovery wells located in a ring around the injection well. Fracturing research was conducted as part of the investigations. This work to date (April 1980) has not been successful. Oil yields have been low due to inability of fracturing techniques to produce adequate porosity. Extensive R&D is required in fracturing techniques before true in-situ processes are viable (Boade, 1978). The LETC true in-situ work is summarized by Burwell et al. (1973); Long et al. (1977); Lawlor et al. (1979); and Jee et al. (1977); and it is briefly reviewed here from a recent summary by Energy Development Consultants (1979).

The first experiment at Site #1 was first drilled for electro-fracting experiments. The results of the tests were inconclusive because the formation was found to contain substantial natural permeability due to a two-inch layer of volcanic tuff. This site was also used for preliminary tests of nitro-fracting in which fifty quarts of nitroglycerin were injected into the natural permeable zone and detonated. Significant increases in formation permeability were observed.

At Site #2, both electro-fracting and nitro-fracting experiments were conducted. After the electro-fracting phase the fractures were then subjected to a series of nitro-fracting experiments, that is, explosive fracturing in which conventional well-bore shots of nitroglycerin were detonated at levels corresponding to the electrode positions during the previous electro-fracing tests. Air flow tests between bore holes indicated that the flow had been appreciably increased after the shots. Two in-situ recovery experiments were attempted on Site #2. The first consisted of the injection of 100 psig superheated steam. The formation plugged after one day of injection, and the steam approach was abandoned. The second experiment consisted of the injection of a preheated 1200 to 1400°F diesel engine exhaust gas. This run was attempted for two weeks unsuccessfully.

Site #3 was subjected to a series of nitro-fracting tests that were successful in improving the formation permeability. No combustion evaluation was made at this site.

Site #4 involved electro-fracting, hydro-fracting (injecting fluid under high pressure), and nitro-fracting to improve the formation permeability. The electro-fracting was a failure, however. The hydro-fracting and nitro-fracting were successful in creating substantial permeability increases at the five spot formation. At the conclusion of the fracting tests, Site #4 was subjected to combustion evaluation. A total of 200 barrels of shale oil were recovered; and an analysis of the combustion project revealed that approximately 700 gallons of shale oil had been retorted, although not all was recovered.

Site #6 covered an area of approximately 150 feet by 300 feet. The oil shale formation was electro-fracted and then explosively fractured to increase the permeability of the formation. A one-year combustion test at Site #6 was conducted without recovering any significant amount of oil.

At Site #7 the objective was to study problems associated with the ignition of rubblized oil shale and with the detonation of explosives in well bores. This test began in early 1970 and was terminated as soon as it was established that the oil shale had been successfully ignited.

Site #8 was used to evaluate electro-fracting and acid leaching of resulting fractures. No combustion experiments were conducted at this location.

Initially, Site #9 involved a nine-spot well pattern which was hydraulically fractured followed by explosive fracturing with slurry-type explosives. The oil shale bed was ignited in early 1976. During 150 days of combustion, it was apparent that considerable amounts of shale were being retorted underground. However, repeated failure to produce because of mechanical problems resulted in only minimal recovery of shale oil at the surface. It was felt that considerable quantities of oil had migrated past the production wells; therefore, three additional wells were drilled outside the original pattern. Material balances of the formation following the combustion experiment indicated that of 7,800 barrels of oil available, over 1,000 were retorted. However, only 60 barrels of shale oil were recovered at the surface.

Talley-Energy Systems

Talley-Energy Systems, under contract with the Department of Energy, conducted fracturing experiments for a true in-situ burn in 1978 near Rock Springs, Wyoming (Hecht-Nielson, 1978). These experiments did not produce a suitable fracture pattern for retorting, and the work was terminated.

Geokinetics

Geokinetics, Inc. is presently (April 1980) field testing a true in-situ process using surface uplift. This process is designed for areas where oil shale beds are relatively thin and close to the surface. Explosives are located in a pattern of blastholes in a shallow shale bed and detonated, uplifting the overburden to create porosity (Lekas, 1979). The bottom of the retort, which is the fragmented zone, is sloped to provide drainage for the oil. Air injection holes are drilled at one end of the retort, and offgas holes are drilled at the other end. The shale is ignited at the air injection wells, and a burn front is propagated horizontally through the fractured shale towards the offgas wells. A schematic of this process is shown in Figure 3-8. To date, 18 retorts have been blasted; 11 have been burned; oil recoveries of 50 percent have been obtained in two retorts; and 5,000 barrels of oil have been produced (Lekas, 1979). Based on these early successes, work is underway to optimize oil recovery and to prepare and burn full-sized retorts and retort clusters.

MODIFIED IN-SITU TECHNOLOGIES

In these processes, in-place shale is removed, and the void volume is distributed by blasting. This concept is being pursued by Occidental Oil Shale, Inc. on the D-A shale property at Logan Wash, Colorado, by a joint venture of Occidental and Tenneco on lease tract C-b, and by the Rio Blanco Oil Shale Project (Gulf Oil Corp. and Standard Oil of Indiana) on lease tract C-a. Additionally, LETC and LLL are studying modified in-situ retorting in simulated in-situ retorts.

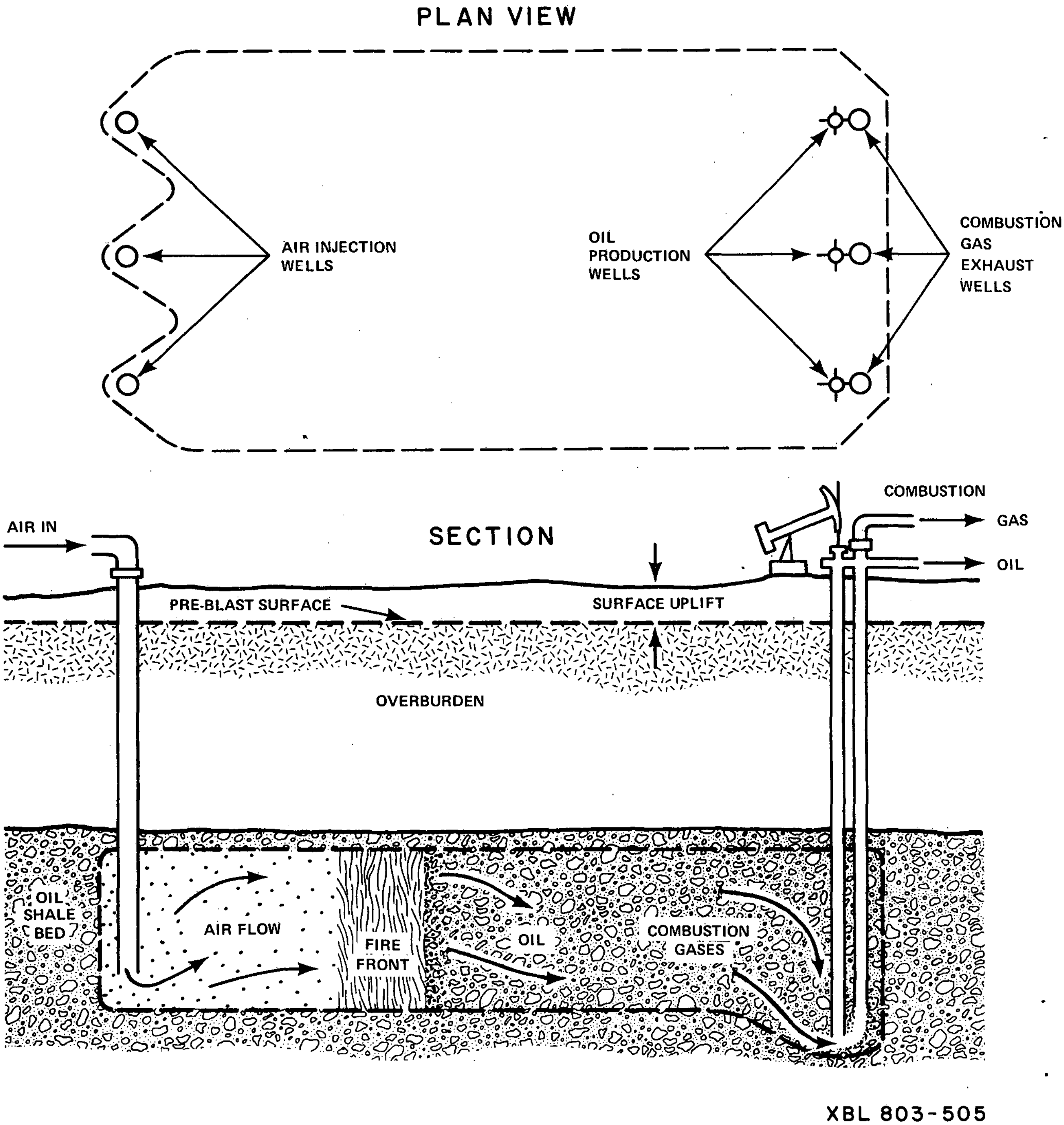

Figure 3-8. Plan and section of a typical Geokinetics horizontal in-situ retort. Source: Lekas, 1979.

The present development programs are focusing on the vertical modified in-situ process (VMIS). The VMIS process is shown schematically in Figure 3-9. About 20 to 40 percent of the in-place shale is removed and the remaining shale is blasted into the mined-out void. Air and steam are injected into the top of a vertical retort, and combustion is initiated at the top of the rubblized bed with a gas burner. Retorting proceeds vertically downward, and residual carbon is consumed as fuel. Steam is used to control retorting temperatures and to improve the Btu content of the offgas through the char-steam reaction. Products drain to a bottom sump from which they are pumped to storage.

Field and laboratory experiments conducted on modified in-situ processes are described below. The technology is experimental and will change as research proceeds. The work completed to date indicates that the VMIS process is viable if advances are made in fracturing techniques. Oil recoveries of up to 60 percent have been obtained in field demonstrations and of over 80 percent in pilot-scale studies.

Simulated In-Situ Retorts

These are surface retorts designed and operated to simulate in-situ conditions. These retorts consist of a stainless steel tube fitted at the top to allow a gas to flow through and at the bottom to collect products. The tube is filled with crushed shale, and pyrolysis is initiated as previously described for in-situ processes. The principal use of these retorts is to study retort chemistry and the variables that affect oil production. The principal simulated in-situ retorts are those operated by LETC and LLL.

LETC Simulated In-Situ Retorts. The Laramie Energy Technology Center has constructed two above-ground retorts designed to simulate in-situ retorting conditions. An experimental above-ground retort, with a capacity of 10 tons of shale, was put in operation in 1965 at LETC. The retort operation is similar to that shown in Figure 3-5. A combustion zone is moved from the top toward the bottom. Oil and combustion products are removed from the bottom. Oil yields of as high as 80 percent of Fischer Assay were obtained from retorting pieces of mine-run shale up to 20 inches. It was observed that oil recovery is a function of particle size, air injection rate, recycle gas injection rate, and retorting temperature.

Since most pieces of mined shale would be larger than 20 inches, a larger retort of 150-ton capacity was built to continue the research (Cotter et al., 1978). A schematic of the retort is shown in Figure 3-10. The retorting chamber is about 45 feet high and has an internal diameter of 11.5 feet. Shale is loaded through a 6-foot diameter hatch at the top. Combustion is started at the top, and retorting products are removed from the bottom. Gaseous products are passed through packed towers to remove entrained material, such as water and oil mist, and through a heat exchanger. A portion of the reclaimed gas can be recycled through the retort and the remainder may be burned in a waste-gas stack. Monitoring instrumentation is installed throughout the system.

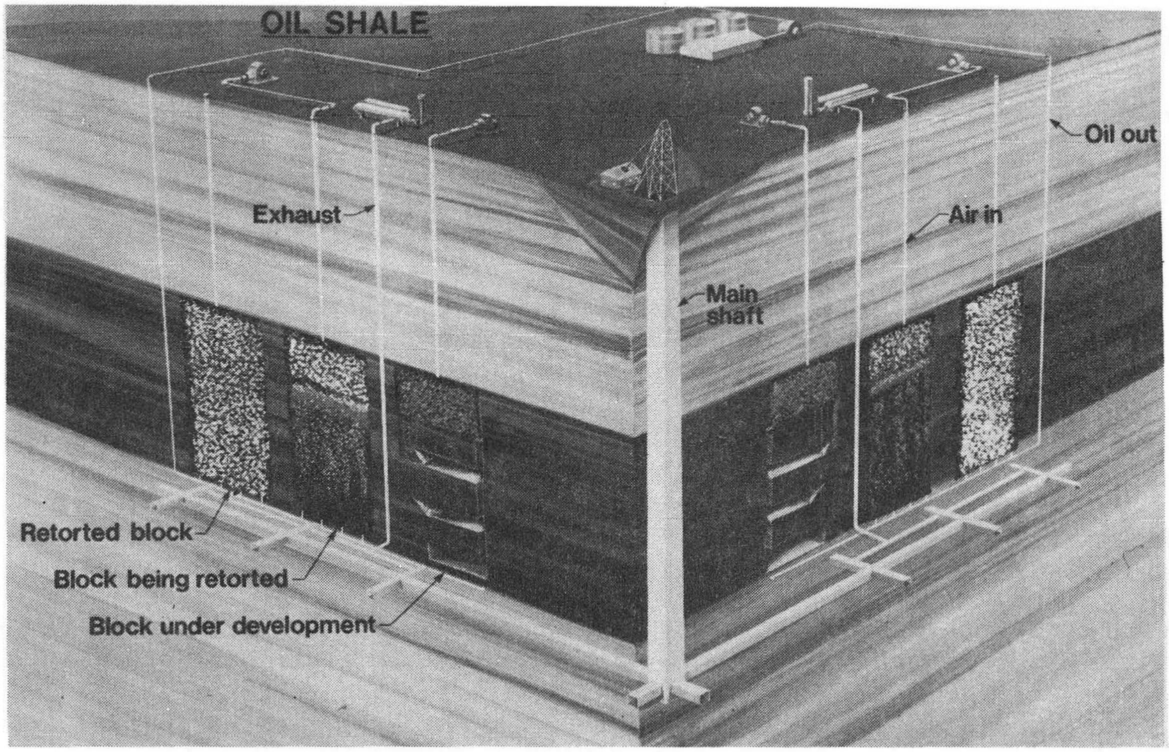

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Figure 3-9. Schematic of the vertical modified in-situ (VMIS) process.

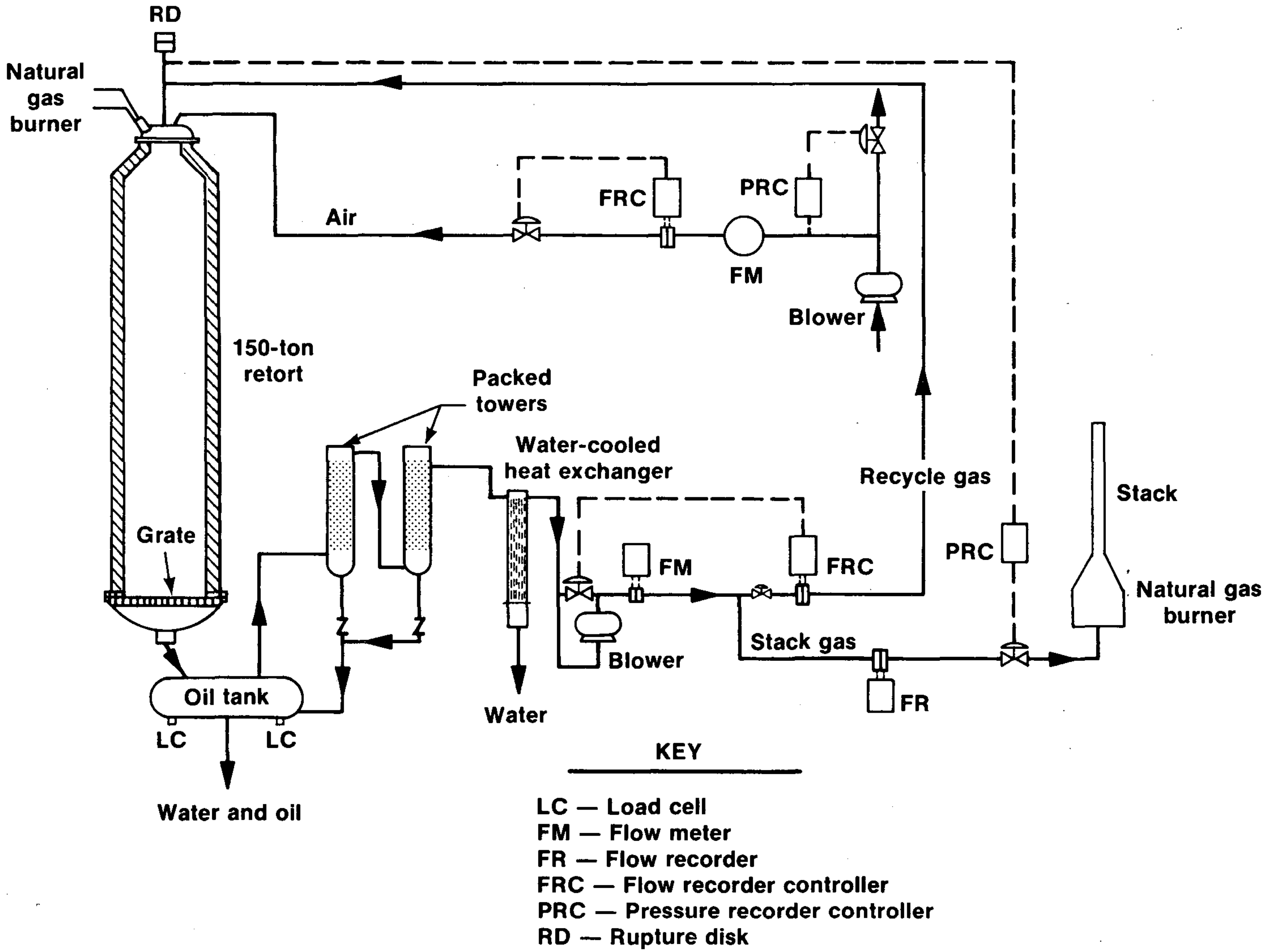

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Figure 3-10. LETC 150-ton simulated in-situ retort.
Source: Harak et al., 1974.

LLL Simulated In-Situ Retorts. LLL is presently (1980) engaged in a comprehensive program to model in-situ retorting. This program has two parts: the development of mathematical models of various steps for the retorting process and the construction and operation of two surface retorts designed to simulate the in-situ retort (Rothman, 1975).

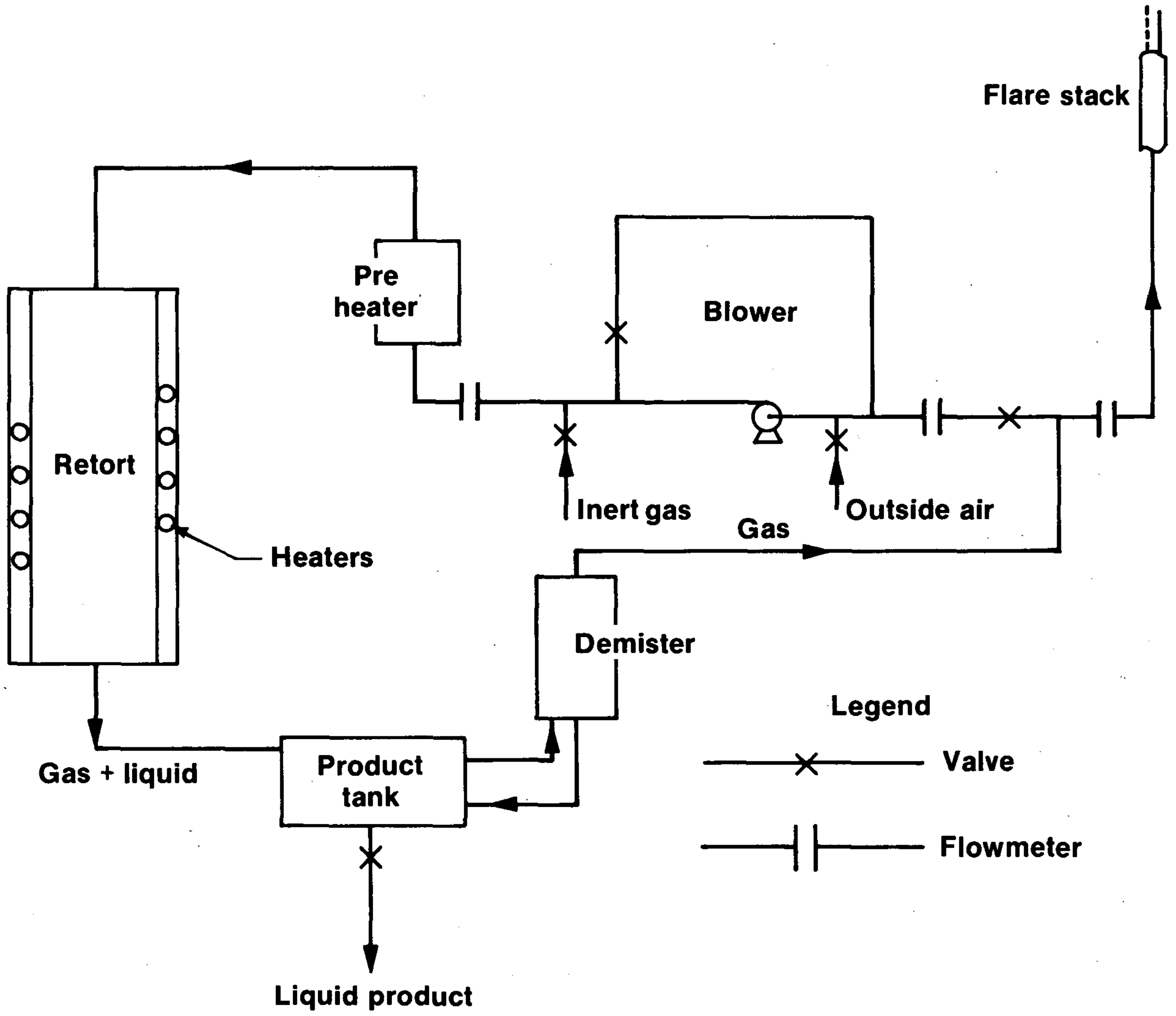
The first retort was constructed in 1974. It is 12 inches in diameter, 60 inches high, and has a capacity of 125 kilograms of crushed shale. A schematic of the retort and auxiliary equipment is shown in Figure 3-11. The retort can be operated to simulate in-situ retorting with both externally heated inert gas and internal combustion of carbon on the spent shale. Because of the relatively small diameter of the retort cylinder, shale particles have been limited to less than about 1 inch.

A bigger retort has recently been built so that retorting of larger particles can be investigated. This retort is 3 feet in diameter, 20 feet high, and has a capacity of 6000 kilograms. Particle sizes up to about 6 inches can be retorted. The retort is operated as a vertical, co-current process. The shale is set on fire at the top by electrical heater units, and the combustion front is driven downward by injecting air. Recycled gas can be added to the combustion air if desired.

These retorts have been used to study the effects of feed-gas composition, shale particle sizes, and bed porosity on retorting rate, temperature maxima and profiles, offgas composition, and oil yield. These experiments, which have included 19 runs of the smaller retort and four runs of the larger retort, have considerably expanded understanding of in-situ retorting. Recent studies have revealed that steam in the feed gas increases retorting rate, oxygen efficiency, and hydrogen content of the product gas. Retorting of a narrow particle size range, high porosity shale bed with near-uniform gas flow, produced oil yields of 93 percent Fischer Assay. Beds with broad-size particle distribution and lower porosity were characterized by process complexities and lower oil yields. Nonuniform gas flow resulted in intermingling of combustion and pyrolysis zones, providing an opportunity for oil oxidation. Pressure drop and oil holdup increased with the fines content of the bed, and holdup may contribute to yield loss (Raley et al., 1978).

Occidental Modified In-Situ Process

Occidental Oil Shale Inc., formerly Garrett Research and Development Company, a subsidiary of Occidental Oil Company, has developed a modified in-situ process to retort shale oil (McCarthy, 1976b; Cha and Fernandes, 1977; Ashland, 1977). Chambers are constructed by conventional mining techniques above and/or below the intended retort. An amount of shale equal to about 15 to 20 percent of the total volume of the retort is removed to the surface for disposal. A sketch of the construction of the chambers and retort was shown in Figure 3-4. Vertical boreholes are drilled through the intended retort and loaded with explosives. Controlled blasting is then done so that the entire retort is filled with fractured rock. The space that was in the chambers is thus distributed throughout the rubble. The top and bottom of the retort are sealed and connections made to the air supply, offgas recycle, and oil recovery systems. The operation is shown schematically in Figure 3-12. Air is circulated through the rubble, and combustion is started at the top with the help of an external fuel supply. The retorting



XBL 777-1393

Figure 3-11. LLL 125-kg simulated in-situ retort. Source: Rothman, 1975.

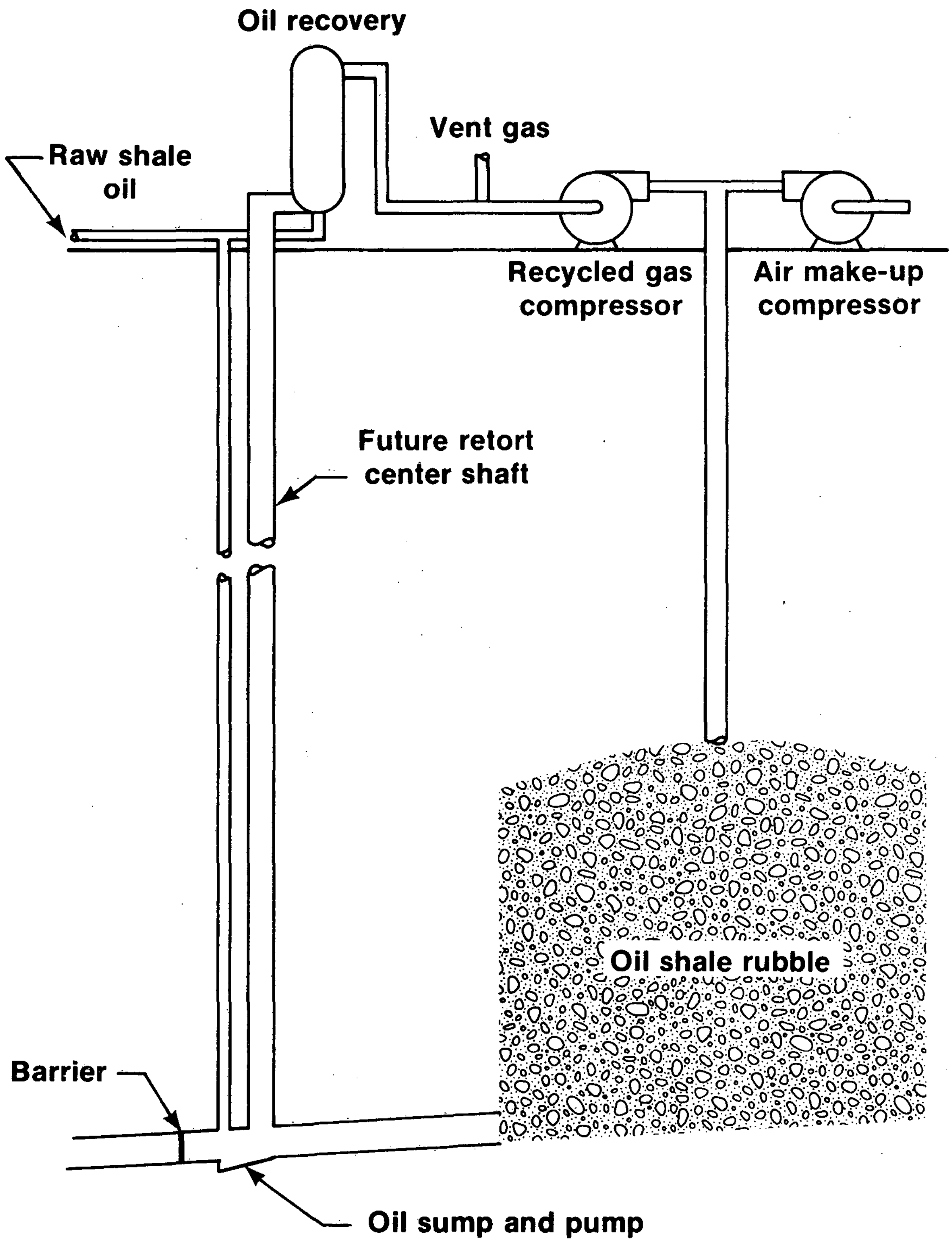


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Figure 3-12. Occidental oil shale process. Source: McCarthy, 1976b.

proceeds vertically downward. The carbon left on the shale, after oil and gas are driven off, becomes the fuel. Part of the offgas is recirculated to control the oxygen supply in the combustion air and, thereby, the rate of retorting. The oil and retort water drain to a bottom sump from where they may be pumped to storage.

Occidental began field tests in 1972 in Logan Wash near DeBeque, Colorado. The first retort, 30 feet square and 72 feet high, contained about 3000 to 4000 tons of broken shale at about 25 percent void volume. Two other similar retorts were constructed and ignited. Retorting of these three projects produced about 4500 barrels of oil, a yield of over 60 percent based on Fischer Assay. Retort 4, the first full-sized retort, 120 feet square by 250 feet high, was constructed and fired in 1975. Ignition was successful and a total of 27,500 barrels of oil were recovered. Retorts 5 and 6 have been completed, and Retorts 7 and 8 are now being prepared for operation.

In 1976, Occidental Oil Shale, Inc. and the Department of Energy entered into a two-phase cooperative agreement consisting of engineering development of the Occidental modified in-situ process as the first phase and a technical feasibility demonstration as the second phase. Retorts 5 and 6 were constructed and burned under this Cooperative Agreement. The purpose of Retort 5, which was fired April 1977, was to test the vertical free-face retort system. The mined void was removed from the retort in a vertical slot along the center of the room. This retort was 118 x 118 x 272 feet and contained 140,450 tons of rubblized rock with an average void volume of 17.3 percent and an average Fischer Assay of 15.7 gallons per ton. The retort produced 11,047 barrels of oil for a yield of 21 percent. Low oil recovery was attributed to nonuniform distribution of void across the center of the retort, and it was concluded that a single vertical slot did not provide adequate radial distribution of void and particle size (Occidental, 1979).

Retort 6 was fired in August 1978. The purpose of this retort was to test the horizontal free-face retort system. In this method, three horizontal levels are mined out and the oil shale above and below these levels is blasted into the horizontal rooms. Retort 6 was 164 x 164 x 334 feet and contained 362,000 tons of rubblized rock with an average void volume of 23.1 percent and an average Fischer Assay of 15.6 gallons per ton. The retort produced an estimated 54,000 barrels of oil for a yield of 40 percent. Some deterioration of the sill pillar, a 40- to 50-foot pillar at the top of the retort that contains the inlet-gas distribution system, occurred during this run, which limited control of retort input conditions. Retort performance was good considering the upset conditions experienced during ignition. It was concluded that the horizontal free-face system provided a more uniform vertical flow, and better particle size than the vertical system (Occidental, 1979).

The Logan Wash property contains relatively low-grade shale, 15 gallons per ton, and therefore may be marginal for commercial operation. Thus, Occidental extended their operation to richer shales, and in late 1976, when Shell Oil Company withdrew from the C-b Oil Shale Project, Occidental and Ashland announced a "letter of agreement" arrangement for Occidental to join Ashland. Subsequently, this participation was adjusted to 50 percent for Occidental Oil Shale, since Ashland withdrew and was replaced by Tenneco.

According to the revised Detailed Development Plan, Occidental plans to develop the tract on a commercial basis in a progressive fashion using Occidental's modified in-situ process.

Occidental proposes to develop Tract C-b using a staged approach. Two demonstration units, a 5000 barrel per day Commercial Feasibility Demonstration Unit and a 2500 barrel per day Technical Feasibility Demonstration Unit, will use retorts that are 405 ft x 150 feet in plan and 312 feet high to test retorting concepts. This will be followed by a 50,000 barrel per day commercial plant using retorts that are 310 ft x 155 feet in plan and 390 feet high (Occidental, 1979).

Development of Tract C-b was started in December 1977 following acquisition of the Prevention of Significant Deterioration permit from the EPA. They presently have completed construction of two concrete headframe towers, a 313-foot high production shaft, and a 178-foot high service shaft. Construction is in progress to erect a 147-foot high ventilation-escape shaft and to sink the 29-foot diameter production shaft, the 34-foot diameter service shaft, and the 15-foot diameter ventilation-escape shaft. Other construction work progressed concurrently with headframe and shaft sinking, including excavation for two 5-acre water collection and treatment ponds, completion of the permanent boiler building and control house, and partial construction of the ventilation-escape hoist house.

Rio Blanco Oil Shale Project

The Rio Blanco Oil Shale Project is a partnership representing 50 percent interest of Gulf Oil Corporation and Standard Oil Company of Indiana. This partnership proposes to develop federal lease tract C-a using a vertical modified in-situ technology. In the proposed process, 40 percent of the in-place shale would be mined and processed on the surface in a Lurgi retort. The balance of the in-place shale would be blasted into the mined-out void as shown in Figure 3-9.

The proposed program consists of the Modular Development Phase, beginning in 1977, and the Commercial Phase, projected for 1987 (Gulf, May 1977). The Modular Development phase will consist of five small underground retorts ranging in size from 30 x 30 x 140 feet to 100 x 150 x 400 feet. These retorts will be burned in sequence to gain operating experience, to improve process efficiency, to confirm capital and operating costs, and to provide engineering design data for commercial operation. The first retort is presently scheduled for ignition in the summer of 1980 and the last retort for completion in 1981.

The Commercial Phase is projected to start in 1981 with production occurring by 1987. Thirty-year operation using 150 x 300 x 750 feet retorts and a relatively rapid retorting rate, compared to the Occidental process, are projected. Rio Blanco indicates that it will demonstrate commercial feasibility and other objectives of the prototype oil shale program at an initial rate of 50,000 barrels a day in the late 1980s and that ultimate production might be as much as 76,000 barrels a day. This would occur sometime in the 1990s (EDC, 1979).

SURFACE RETORTING

Surface retorting of the shale excavated from the underground retort and brought to the surface is a possibility that must be considered. Both developers of modified in-situ processes, Occidental and the Rio Blanco Oil Shale Project, are presently planning to retort mined-out shale in a Lurgi retort. There are strong technical reasons why joint in-situ and surface retorting may be desirable. Rich shale rubble may lose permeability during retorting because the shale tends to become plastic at high temperatures and pressures, decreasing permeability and lowering oil yield because retorting fluids will not pass freely through the rubble. It has been suggested that the richer shales in a proposed retorting zone be brought to the surface during retort preparation. The shale most susceptible to permeability loss would thus be removed and the overall efficiency of in-situ retorting would be improved. In addition, surface retorting is 25 to 30 percent more efficient than in-situ retorting, and more oil would be recovered for a given operation. Detailed analysis of the practicality of this alternative, which is beyond the scope of this report, would involve economic, technical, and environmental considerations. These include the effect of shale richness on rubble permeability loss and retorting yield, economics of surface retorting versus raw shale disposal, and the environmental effects of surface retorting operations.

In general, there are three types of surface retorting technologies. These are described by Sladek (1975) and only the highlights are repeated here. In the first type, a combustion zone fed by carbon on the spent shale provides heat for the retorting. Examples of this process are the Paraho Direct and the Union Type A. A second type of surface retort uses externally heated gases to decompose the organic material. Union Type B and Paraho Indirect are examples of this class. A third type of retort uses externally heated solids to transfer heat to the raw shale as in the TOSCO II and the Lurgi retorts. Each technology uses different techniques for operation including charging shale to the retort, controlling retorting, and recovering the oil. TOSCO, Paraho, Lurgi, and Union have made large-scale field tests of their respective processes. Efficiencies of recovery range from 85 to 100 percent of Fischer Assay depending on the process. More detailed information on surface retorts are available in other publications of the Colorado School of Mines (Sladek, 1974-75; Colorado School of Mines, 1964-79).

PRODUCT UPGRADING

The recovered shale oil is similar in appearance to crude petroleum oil. There are, however, some significant differences in physical and chemical properties. Average values for selected parameters for shale and crude oils are shown in Table 3-5. The principal differences are:

1. Shale oil has a larger percentage of distillation products in the higher ranges and consequently its viscosity and pour point are higher.

2. Shale oil has a higher nitrogen content.

Table 3-5. Properties of shale oils.

Property	In-Situ Oils					Surface Oils					
	LETC 10-ton simulated in-situ Jensen et al. (1971)	LETC 150-ton simulated in-situ Jensen et al. (1971)	LETC in-situ Rock Springs Site 4 Jensen et al. (1971)	LETC in-situ Rock Springs Site 7 Jensen et al. (1971)	Occidental in-situ McCarthy et al. (1976b)	Paraho Albright and Poulson (1977), Atwood (1977)	TOSCO II Atwood (1977)	Union Type A Albright and Poulson (1976)	USBM gas combustion Jensen et al. (1971)	Fischer Assay Jackson et al. (1978)	Crude petroleum oil Bland and Davidson (1967)
Distillation, volume percent:											
Naptha (IBP-400°F)	6	7	15	11	5	6	18	-	6	1-16	30
Light distillate (400-600°F)	26	31	48	42	25	19[c]	24	-	19	21-25	22
Light gas oil (600-800°F)	33	36	24	30	45	50[a]	34[a]	-	25	26-31	28[a]
Heavy gas oil (800-1000°F)	26	20	6	12	20	25	24[b]	-	27	21-31	20[b]
Residuum (1000°F+)	9	7	7	5	5	-	-	-	23	9-17	-
Specific Gravity:											
60°/60°F	0.92	0.91	0.89	0.90	0.90	0.93	-	0.95	0.94	0.90-0.96	0.85
Pour point, °F	60	60	40	30	70	80	80	75	80	65-90	< 5
Nitrogen, weight percent	1.6	1.6	1.4	1.8	1.5	1.8	1.8	2.2	1.5	1.4-2.3	0.1
Sulfur, weight percent	0.8	0.9	0.7	0.8	0.7	0.7	0.8	0.8	0.8	0.5-1.9	0.6
Viscosity, SUS-100°F	112	98	78	52	70	263	106	695	370	82 - 228	47
Carbon/hydrogen ratio	7-8	7-8	7-8	7-8	7	-	7.5	-	7-8	7-8	6-7

[a] Distillation range 600° to 900°F for TOSCO and crude petroleum; 550-850°F for Paraho oil.

[b] Distillation range >900°F for TOSCO and crude petroleum; >850°F for Paraho oil.

[c] Distillation range 350°-500°F.

Other differences are that shale oil may contain finely divided inorganic solids and pyrolytic products. In comparison to crude oil, shale oil is deficient in hydrogen and sulfur and has higher concentrations of some trace elements, including Al, As, Ba, Cu, Fe, Mg, Na, Se, U, and Zn (Fox, 1980). High pour points and viscosities will significantly increase costs of conveying oil from the recovery site. The contained substances, that is, solids, trace elements, etc., are undesirable because they might interfere with refining operations and subsequent use. Shale oil must therefore be prerefined or upgraded to make it compatible with conventional feedstocks for which most refineries are designed. The upgraded shale oil is called synthetic crude or syncrude. For the purposes of this study, it is convenient to discuss upgrading in two steps: first, reduction of viscosity, and second, removal of harmful substances.

The viscosity of an oil will be reduced if the heavier hydrocarbons are removed from the oil. One process extensively used in the refinery industry is distillation, which involves the physical separation of the hydrocarbon components of the raw oil into fractions of specified boiling point ranges. The raw oil is heated, partially volatilized, and then passed to a fractionator tower. The lightest portions, called overheads, are removed from the top of the tower. Other fractions, or sidestreams, are withdrawn from the sides of the tower at different elevations. The sidestreams become progressively heavier toward the bottom of the tower. The heaviest, called bottoms, are found at the lowest elevation. As the sidestream fractions are withdrawn, they may be passed through a stripping process in which lighter hydrocarbons are removed by steam and returned to the fractionator feed for recycling through the tower.

A second common method of viscosity reduction is coking, a thermal cracking process in which heavy hydrocarbons, such as the fractionator bottoms, are broken down under high pressure and low temperature to form lighter hydrocarbons. A residue, called coke, remains. Coke has a high carbon content which makes it suitable for manufacture into such items as electrodes. The light fractions derived from the bottoms may be returned for blending with the sidestreams and overheads from the fractionator. Delayed coking has recently been successfully used by Chevron's Salt Lake City refinery on about 3,400 barrels of oil from Occidental's Retort 5. The shale oil was fed to the delayed coker for two days at 13 percent concentration and for a day one 19 percent (Sullivan et al., 1978; Occidental, 1979).

The resulting blend will have considerably less viscosity than the raw shale oil since the heavy hydrocarbons have either been removed in the coke or have been cracked into lighter fractions. Inorganic solids and some trace metals tend to become concentrated in the coke and therefore are extracted from the oil. Some undesirable substances, however, may not be removed in coking and distillation. Nitrogen, sulfur, some oxygen compounds, and arsenic are examples. Nitrogen and arsenic are particularly poisonous to refinery catalysts, and sulfur and oxygen compounds in the finished product may contribute to air pollution and gum formation, respectively. Selection of methods to remove these materials depends on the amount and kind of harmful substances present. Nitrogen and sulfur concentrations can be reduced by hydrotreating or hydrogenation. The overhead streams from the fractionator and the coker are mixed with hydrogen in a high pressure and temperature reactor. The nitrogen and sulfur react with the hydrogen to form ammonia and hydrogen sulfide. These two compounds can be removed in a sulfur and ammonia recovery stage. Hydrotreating was also successfully used in the Chevron refinery run, and it was concluded that acceptable products can be produced by delayed coking and hydrotreating (Sullivan et al., 1978).

High arsenic concentrations in the oil (5 to 50 ppm) interfere with catalytic reactions in hydrotreating and subsequent refinery operations (Fox, 1980). Arsenic levels in conventional crude oils range from 0 to 0.3 ppm and therefore do not usually create problems. Burger et al. (1975) investigated the removal of arsenic from shale oil by caustic soda and was able to reduce arsenic content from 40 ppm to about 10 ppm. Union Oil Company has proposed a proprietary process using an absorbent to reduce arsenic content of shale oil from 50 ppm to 2 ppm (Shih et al., 1976). TOSCO plans to use a proprietary catalyst to remove arsenic in solid form (Shih et al., 1976). Recent work by Chevron indicates that arsenic may be readily removed on an alumina guard bed (Sullivan et al., 1978).

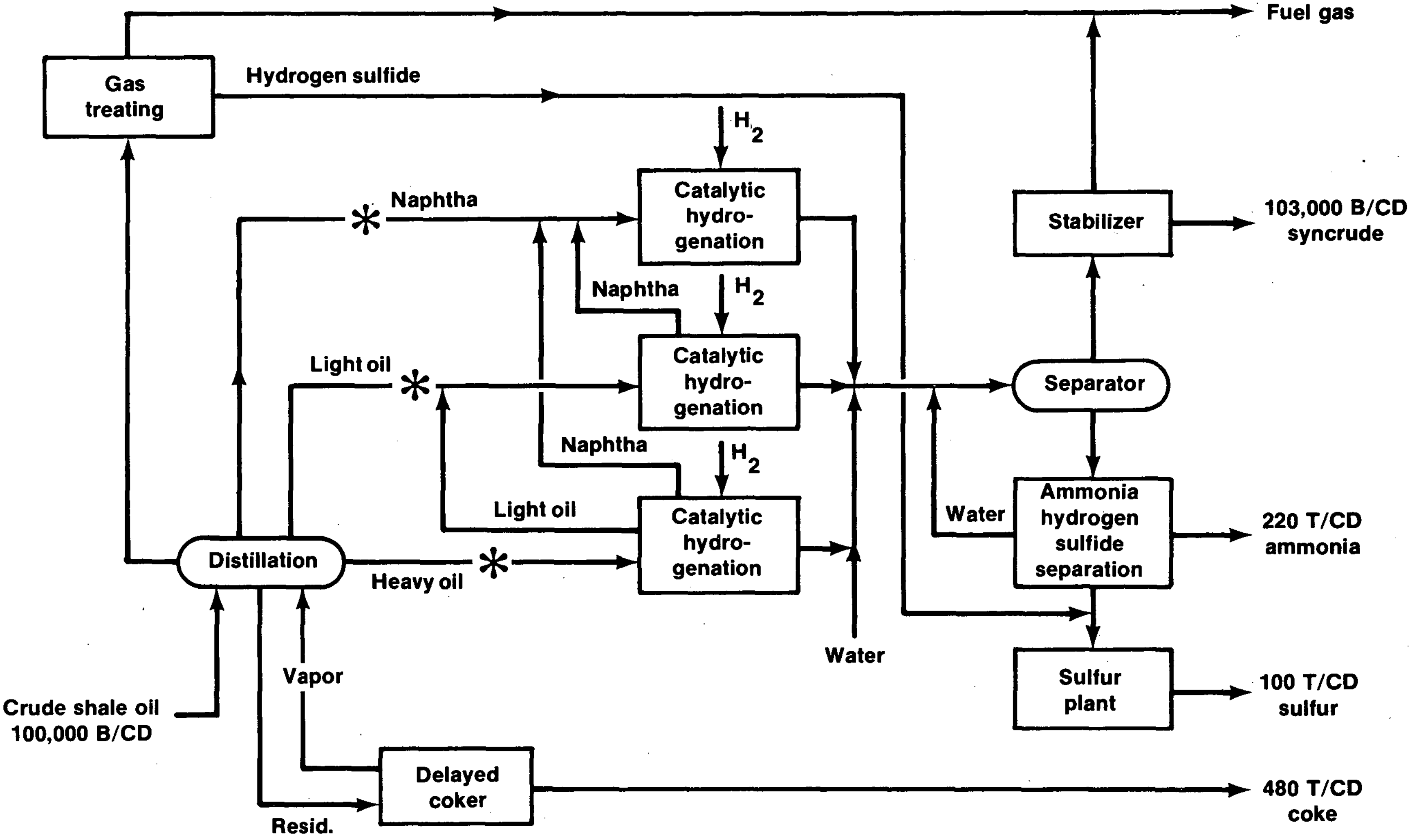
The hydrogenation stage is a large consumer of hydrogen; therefore this gas will most likely be manufactured at the site. One method is steam reforming in which light hydrocarbon gases are mixed with superheated steam and passed over catalysts to form hydrogen and carbon dioxide. The mixture is then cooled and the carbon dioxide removed. The gases produced in the upgrading operation may be a source of the hydrogen gas.

In addition to the basic differences between shale and crude petroleum oils, there are also differences in shale oils produced by alternative processing methods (Table 3-5). In-situ produced oils, in general, have lower viscosities and pour points than surface-retorted oils. It has been postulated that some thermal cracking or coking of oil takes place in the retort and, therefore, some heavy ends are converted to lighter oils. If this is the case, then it may not be necessary to upgrade the raw oil shale at the recovery site. It might be possible to economically transport the oil to a less environmentally sensitive area for pre-refining. Several upgrading processes have been discussed in the literature (Sladek, 1974-75; Shih et al., 1976; Frost et al., 1976). A flow diagram for a process investigated by Frost et al. is illustrated by Figure 3-13. Inputs are crude shale oil, hydrogen, and water. Outputs are fuel gas, synthetic crude oil, coke, sulfur, and ammonia.

TECHNICAL FRAMEWORK

The above review indicates that the only in-situ technologies that have been successfully tested are the modified in-situ process and the Geokinetics process. Since the former is suitable for a much larger part of the resource, 419 billion barrels of in-place oil (Smith et al., 1978a), subsequent analyses of the potential water resources effects of in-situ oil shale recovery will concentrate on the modified in-situ process. By implication, many of these analyses also apply to true in-situ processes.

Two variations of the vertical modified in-situ process have been proposed, the Occidental process and the Rio Blanco Oil Shale Project's process. These two processes, because of available information, will be



* *Arsenic removal-process not specified.*

Figure 3-13. Flow diagram of a shale oil upgrading process.
Source: Frost et al., 1976.

evaluated in this study. A 50,000 barrel per day facility including surface retorting by the Lurgi process will be evaluated for each process. These processes have been described in Occidental's Phase I Final Report (Occidental, 1979), Ashland's and Occidental's Modifications to Detailed Development Plan (Feb. 1977), and Rio Blanco Oil Shale Project's Revised Detailed Development Plans (Gulf, May 1977). Scenarios will be developed here based on these two processes. Modifications to the proposed plans will be made based on more current information, when available, and assumptions will be used in the absence of definitive industrial plans.

The basic features of the two modified in-situ processes to be considered here are very similar. They primarily differ in process details and projected plant location. The pertinent differences between these processes are summarized in Table 3-6. The overall processing concept involves three basic steps which were shown schematically on Figures 3-4 and 3-9. First, 20 to 40 percent of the in-place shale is mined out at several levels, and the remaining shale is blasted into the mined-out void. Boreholes are drilled into the shale, loaded with an explosive, and detonated with appropriate time delays to fill the void with broken shale. Connections are then made to the top and bottom of the retort and retorting is carried out. The top of the shale bed is ignited with a gas burner or equivalent, and steam and air are injected. Residual carbon left behind by the pyrolysis zone is combusted, supplying heat for pyrolysis. The hot vapors are swept out the reaction zone, condense on the cool shale ahead of the reaction zone, and are collected in a sump at the bottom of the retort. The gases, oil, and water are separated, the oil is pipelined out of the area and the water and gases are disposed of or reused in the process. This section will describe the retorting technology; water demands and effluents will be discussed in Chapters 5 and 8, respectively.

It is important to realize that the scenarios described here are highly tentative in nature. Both of these processes are presently under development and the configuration of the final, commercialized process is presently unknown. Significant changes must be expected in both processes as research and development solve some of the technical problems faced by modified in-situ retorting. These technical problems presently include development effective rubblization methods, process control, definition of adequate porosity, and improvement of process efficiency. The Occidental process has received considerably more research and development effort than the Rio Blanco process; laboratory work has been completed at Occidental's Bakersfield facility and six field retorts have been prepared, ignited, and retorted. The Rio Blanco process, on the other hand, has only been investigated in the laboratory by LLL and Rio Blanco Oil Shale Project; no field data are presently available.

In spite of these limitations, these two processes are illustrative of modified in-situ retorting and include sufficient differences to span the range of likely processes. The pertinent features of each assumed processing scenario are summarized in Table 3-6. The values not referenced on this table were assumed for the purposes of this report. A 50,000 barrel per day facility, in which the mined-out shale is retorted in a Lurgi retort, is assumed for each process. The two processes differ primarily in retort dimensions, retorting rate, and retort porosity. The Rio Blanco Process, to be located on Tract C-a, uses a rapid heating rate, 14 feet per day,

Table 3-6. Key assumptions for the Rio Blanco and Occidental vertical modified in-situ processes.

	Tract C-a Rio Blanco Process	Tract C-b Occidental Process
Commercial production (bbl/day)	50,000	50,000[a]
Retort size, length x width x height (ft)	300 x 150 x 750[b]	310 x 155 x 390[a]
Retort spacing (between sides x between ends) (ft)	95 x 95[b,c]	150 x 50[a]
Retort porosity (percent)	40	23[a]
Distance from ground surface to top of retort (ft)	450[c]	1400[c]
Retort efficiency		
In-Situ	65	65
Surface	90	90
Burn rate (ft/day)	14[b]	1[d]
Time to burn one retort (days)	54	390
Oil shale density (lb/ft^3)	137	137[a]
Shale grade (gal/ton)	25	25
Surface retort	Lurgi	Lurgi
Days of operation per year	350	350[a]

[a] Occidental, 1979

[b] Gulf, 1977

[c] Varies over tract; reported values are typical

[d] McCarthy et al., 1976a

and a high void volume, 40 percent, while the Occidental process, to be located on Tract C-b, uses a low heating rate, one foot per day, and a low porosity, 23 percent. The relative merits of these two approaches are presently under debate and study by industry and Department of Energy laboratories and additional field experience is required to identify the relative merits of each.

Estimates of oil recovery, number of retorts required per year to sustain production, and surface area covered by these retorts are presented in Table 3-7 for the processes outlined in Table 3-6. During full-scale operation, oil recovery will be a continuous process designed to maximize oil production with respect to labor and capital investment. Retorts will be prepared, fired, and abandoned. There will first be a buildup period to peak plant capacity, followed by an extended period of operation at full output, and then a tapering off of output as the resource is exhausted or the project is terminated. In order to sustain the assumed production rate of 50,000 barrels per day over an extended period, a large number of retorts is required. Estimates in Table 3-7 indicate that in a typical work year of 350 days, it will be necessary to place a new retort of the size shown in Table 3-6 in operation every 21 days on Tract C-a and every 11 days on Tract C-b. At any one time, three retorts will be in various stages of production on Tract C-a and 36 on Tract C-b. A larger number of retorts will be in production on Tract C-b at any one time because of the much lower retorting rate used by Occidental.

The relative production by the surface and in-situ retorts is shown in Table 3-7. In the Rio Blanco process, 48 percent of the oil is produced by Lurgi surface retorts; thus in a 50,000 barrel per day facility, Tract C-a would produce 24,000 barrels of oil per day at the surface and 26,00 barrels of oil per day in situ. Tract C-b, using the Occidental process, would produce 29 percent of the oil in Lurgi surface retorts. Thus, for a 50,000 barrel per day plant, 14,500 barrels of oil per day would be produced at the surface and 35,500 barrels per day would be produced in situ. The Rio Blanco process produces a larger fraction of its oil at the surface because 40 percent of the in-place shale is mined out to create in-situ voids while the Occidental process mines only 23 percent.

The areal extent of the two facilities is a function of the development plan, which in turn depends on the physical features of the site and the particular requirements of the technologies used. The portion of each site devoted to the retorts is by far the largest share. The surface areas occupied by the retorts, 21 acres on Tract C-a and 41 acres on Tract C-b, are estimated in Table 3-7. These areas are only the surface projections of the in-situ retorts and supporting pillars, and they are not "disturbed" surfaces as would be land on which surface retorts and other facilities are constructed. At this rate of development, the two tracts could sustain production of 50,000 barrels per day for over 100 years.

Table 3-7. Retort production, number of retorts, and areal extent of a 50,000 barrel per day vertical modified in-situ facility using the Rio Blanco and Occidental processes.

	Tract C-a Rio Blanco Process	Tract C-b Occidental Process
Weight of shale moved to surface,[a] 1000 ton/retort	925	295
Weight of shale retorted in-situ,[b] 1000 ton/retort	1387	988
Oil production,[c] 1000 bbl/retort		
In-Situ	537	382
Surface	495	158
Number of retorts		
Total retorts started per yr[d]	17	32
Retorts burning simultaneously[e]	3	36
Surface Area,[f] acres/yr	21	41

[a] length x width x height x density x porosity

[b] length x width x height x density x (1-porosity)

[c] weight of shale x retorting efficiency x shale grade

[d] days of operation x total daily in-situ production/in-situ oil production per retort

[e] $\frac{\text{time to burn one retort}}{\text{days of operation}}$ x total retorts started per year

[f] total retorts started per year x (retort surface area + pillar surface area)

CHAPTER 4

HYDROLOGY AND WATER RESOURCES

The Upper Colorado River Basin is comprised of three hydrologic subregions: the Green River Subregion, the Upper Main Stem Subregion, and the San Juan-Colorado Subregion. The basin, its hydrologic subregions, and the oil shale deposits within it are shown in Figure 4-1. As the figure indicates, nearly all of the basin's oil shale deposits are within the Green River Subregion, the richest deposits lying: (1) within the Parachute Creek drainage basin in Colorado, (2) near the confluence of the White River and the Green River in Utah, and (3) along a section of the Green River northwest of Rock Springs, Wyoming.

The first section of this chapter describes, in general terms, the water resources of the Upper Colorado River Basin and, where appropriate, the specific aspects of water resources within the Green River Hydrologic Subregion. In essence, this section represents a "macro-scale" assessment of water resources in the tri-state oil shale region of Colorado, Utah, and Wyoming. Subsequent to this assessment, the water resources of a specific lower order basin--the Piceance Creek Basin--situated within the Green River Subregion, is summarized. The Piceance Creek Basin is considered to be somewhat representative of the lower order basin within the Green River Subregion that may be developed by in-situ oil shale technologies in the future. The assessment of the water resources of the Piceance Creek Basin represents a "micro-scale" assessment of water resources in a specific lower order basin.

References used in writing this report include: (1) Upper Colorado Region Comprehensive Framework Study (UCR Group, 1971); (2) USGS Professional Paper 441 (Iorns et al., 1965); USGS Professional Paper 442 (Iorns et al., 1964); USGS Professsional Paper 813-C (Price and Arnow, 1974); USGS Professional Paper 908 (Weeks, 1974); Westside Study Report on Critical Water Problems Facing the Eleven Western States (USDI, 1975); and Colorado River Regional Assessment Study (USU, 1975). This report is essentially a summary of the above references with major emphasis placed on information that can be used as a basis for predicting water-related impacts.

The principal reference used, the Upper Colorado Region Comprehensive Framework Study (UCR Group, 1971), specified 1965 as its base year (i.e., 1965 was defined as being representative of "present conditions"), even though the report was published in 1971. To facilitate matters, we have frequently used 1965 data to describe "present conditions," since much of the data for 1965 adequately describe present conditions, particularly average annual precipitation, average annual evaporation, etc. However, some data for 1965 (e.g., on water use) are not accurately representative of present conditions. In those cases, more recent data are used when available; or general estimates, often interpolations or extrapolations, are made to describe present conditions.

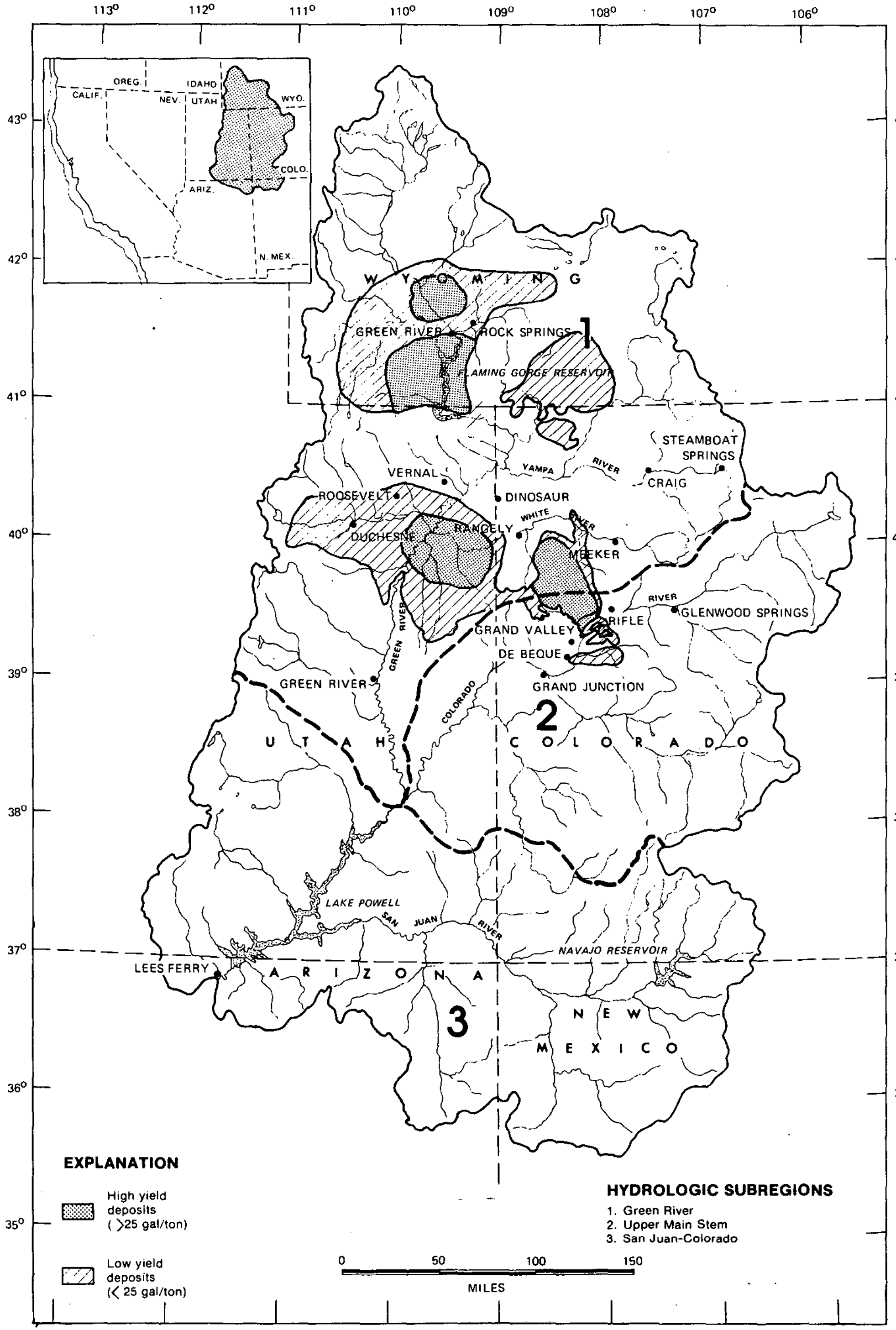


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Figure 4-1. The Upper Colorado River Basin and locations of major oil shale deposits. Source: UCR Group, 1971.

BASIN DESCRIPTION

The Upper Colorado River Basin consists of about 109,600 square miles of drainage area that contributes runoff to the mouth of the basin at Lees Ferry, Arizona, which separates the upper and lower basins of the entire Colorado River system. The basin extends for a latitudinal distance of about 550 miles and a longitudinal distance of about 350 miles. Its three hydrologic subregions are briefly described below. Within the basin, the principal tributaries to the Colorado River include the Green and San Juan rivers.

The Green River Subregion

The Green River Subregion drains an area of about 44,700 square miles (exclusive of about 4,000 square miles that comprise a closed basin) and is located in southwestern Wyoming, northwestern Colorado, and northeastern Utah. The major river within the subregion is the Green River, the largest tributary of the Colorado River. Major tributaries of the Green River include the Big Sandy Creek and the San Rafael, Prince, Duchesne, White, Yampa, Henrys Fork, Blacks Fork, and New Fork rivers.

Elevations throughout the subregion range from 3880 to over 14,000 feet. The subregion contains many diverse topographical features, including mountains, hills, plateaus, plains, valleys, canyons, and narrow gorges (Iorns et al., 1965).

The Upper Main Stem Subregion

The Upper Main Stem Subregion, an area of about 26,200 square miles, includes the Colorado River and all of its tributaries above the junction of the Colorado and Green rivers. The principal river within the subregion is the upper reach of the Colorado. Within the subregion, major tributaries to the Colorado River include the Roaring Fork, Eagle, Gunnison, and Dolores rivers.

Throughout the subregion, the elevation ranges from 3880 to more than 13,000 feet. The western portion of the subregion is essentially a dissected plateau, whereas the eastern portion consists of a series of uplifted mountain masses, weathered and eroded by water and glaciers (Iorns et al., 1965).

The San Juan-Colorado Subregion

The San Juan-Colorado Subregion includes about 38,600 square miles of drainage area. The major river within the subregion is the Colorado. Its principal tributary here is the San Juan River, the second largest tributary in the entire Upper Colorado River Basin. Other rivers tributary to the Colorado River include the Dirty Devil, the Escalante, and the Paria.

The subregion contains many diverse topographical features, including deserts, mountain meadows, high mountains, deep canyons, and broad alluvial valleys (Iorns et al., 1965).

PRECIPITATION, RUNOFF, AND EVAPORATION

The Upper Colorado River Basin is characterized by highly variable climatic conditions that produce significant seasonal and annual differences in precipitation, runoff, and evaporation affecting the amount, quality, and use of water.

Precipitation

Annual precipitation within the basin runs from less than six inches in desert areas to over 40 inches at higher elevations, as shown in Figure 4-2.

The intensity of precipitation is highly variable. For most of the basin, precipitation in amounts over 0.1 inches per day occurs on an average of about 10 to 50 days per year. Precipitation is generally heaviest during the winter and spring months.

During the period from late October through mid-April, most precipitation throughout the basin occurs in the form of snow. Annual snowfall ranges from 300 inches in the higher elevations to about five inches in the lower elevations. Maximum snow accumulation occasionally exceeds 100 inches in the higher elevations and does not completely melt until late summer.

Within the Green River Subregion, annual precipitation runs from less than six to more than 40 inches, 6 to 20 inches being average throughout most of the subregion. Precipitation is heaviest near headwaters at higher elevations; lighter precipitation occurs on lower elevation plains and valleys.

Runoff

The runoff-producing areas of the Upper Colorado River Basin are described in Figure 4-3. Greater runoff occurs near the headwaters at higher elevations. Most streamflow in the basin is derived from snow melting in the mountainous areas; the result is high flow conditions in May and June, medium flow conditions in April and July, and low flow conditions during the remainder of the year.

The average annual discharge of the Colorado River at the mouth of the Upper Colorado River Basin is about 12.4 million acre-feet (based on 1965 conditions). However, significant variations in annual runoff occur as a consequence of both annual variations in precipitation and long-term climatic trends. During the period 1914-1965, the average annual discharge varied from a low of 4.4 million acre-feet to a high of 21.9 million acre-feet. (It should be noted that, in addition to precipitation and climatic variations, human activities also significantly influence the average annual discharge.)

The Green River Subregion, representing about 41 percent of the total basin area, contributes about 38 percent of the total discharge at Lees Ferry. The average annual unit discharge of the subregion is about 0.15 cfs/mi^2, although the average annual unit discharge of higher-order tributaries ranges up to 2.7 cfs/mi^2. Within this subregion, greater runoff

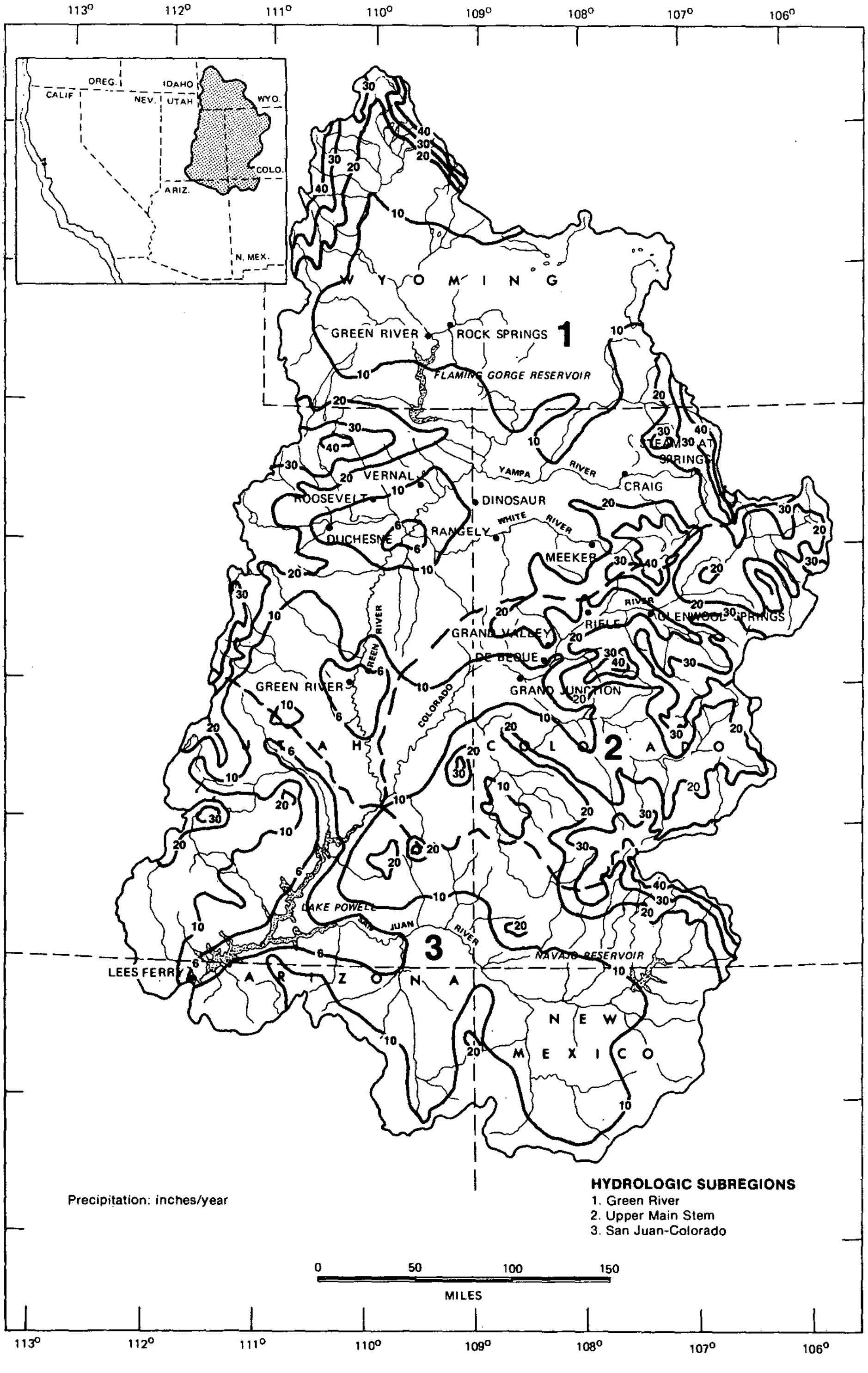

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Figure 4-2. Annual precipitation of the Upper Colorado River Basin. Source: UCR Group, 1971.

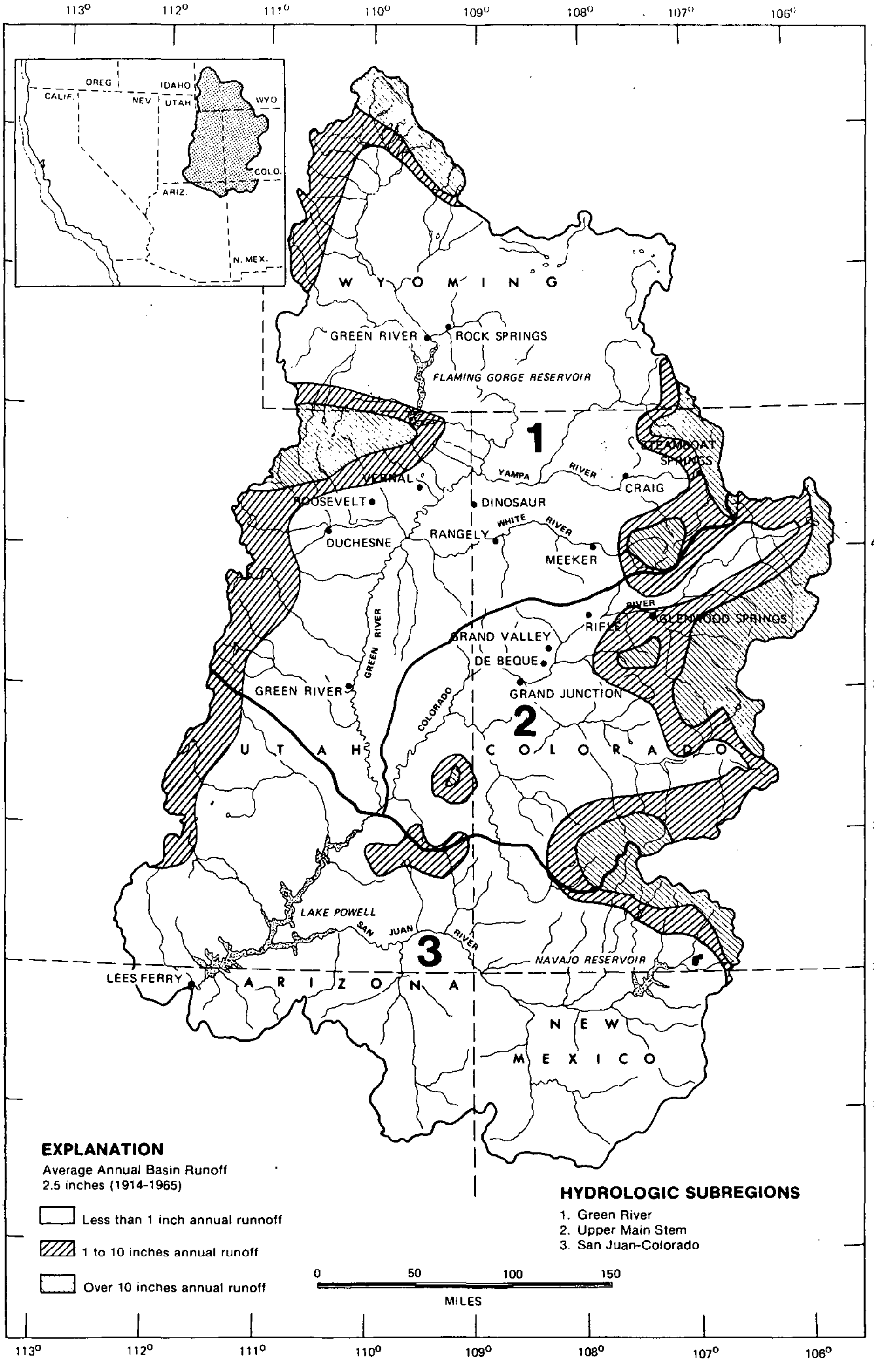

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Figure 4-3. Annual runoff in the Upper Colorado River Basin. Source: UCR Group, 1971.

occurs near the headwaters at higher elevations while lesser runoff occurs at lower elevations, as shown in Figure 4-3.

Evaporation

Figure 4-4 shows the average annual evaporation within the Upper Colorado River Basin (as derived from pan evaporation data). Annual evaporation rates for lakes and reservoirs throughout most of the basin vary from less than 30 inches at higher elevations to more than 60 inches in lower valleys. Evaporation rates throughout the basin vary both seasonally and annually, and are affected by wind conditions, temperature, solar radiation, and relative humidity.

SURFACE WATER RESOURCES

Surface water resources, in conjunction with groundwater resources, comprise a common water resource pool which has a variety of beneficial uses. This section of the report discusses surface water resources, and a subsequent section is devoted to groundwater resources. However, it is important to note that surface water and groundwater resources are not entirely independent of each other and that considerable interaction occurs.

Surface water resources in the Upper Colorado River Basin consist of both natural and developed components. Natural components include streams, rivers, and lakes; developed components include canals, pipelines, and reservoirs. Streams, rivers, canals, and pipelines serve as vehicles for water transport, and lakes and reservoirs serve as water storage facilities.

Streams and Rivers

Natural transport of surface water throughout the basin is accomplished by streams and rivers. The transport of surface water by developed structures such as pipelines and canals is much less significant and, therefore, will be subsequently ignored.

There are more than 300 flow-gaging stations located in the basin, monitoring everything from small, first-order streams to the Colorado River. These flow-gaging stations include 13 main stations that are located on the Colorado River or on principal tributaries. The locations of these major gaging stations and their annual average discharge are shown in Figure 4-5.

Seasonal and annual variations in streamflow exist throughout the basin as a consequence of both climatic variations and water withdrawals. An example of seasonal variation in streamflow is presented in Figure 4-6, which describes the monthly discharge of the Colorado River at Lees Ferry. As the figure shows, the period of greatest flow occurs during May and June when snowmelt from higher elevations begins to appear at Lees Ferry. After June, the average monthly flow begins to decrease due to irrigation water requirements and lesser snowmelt.

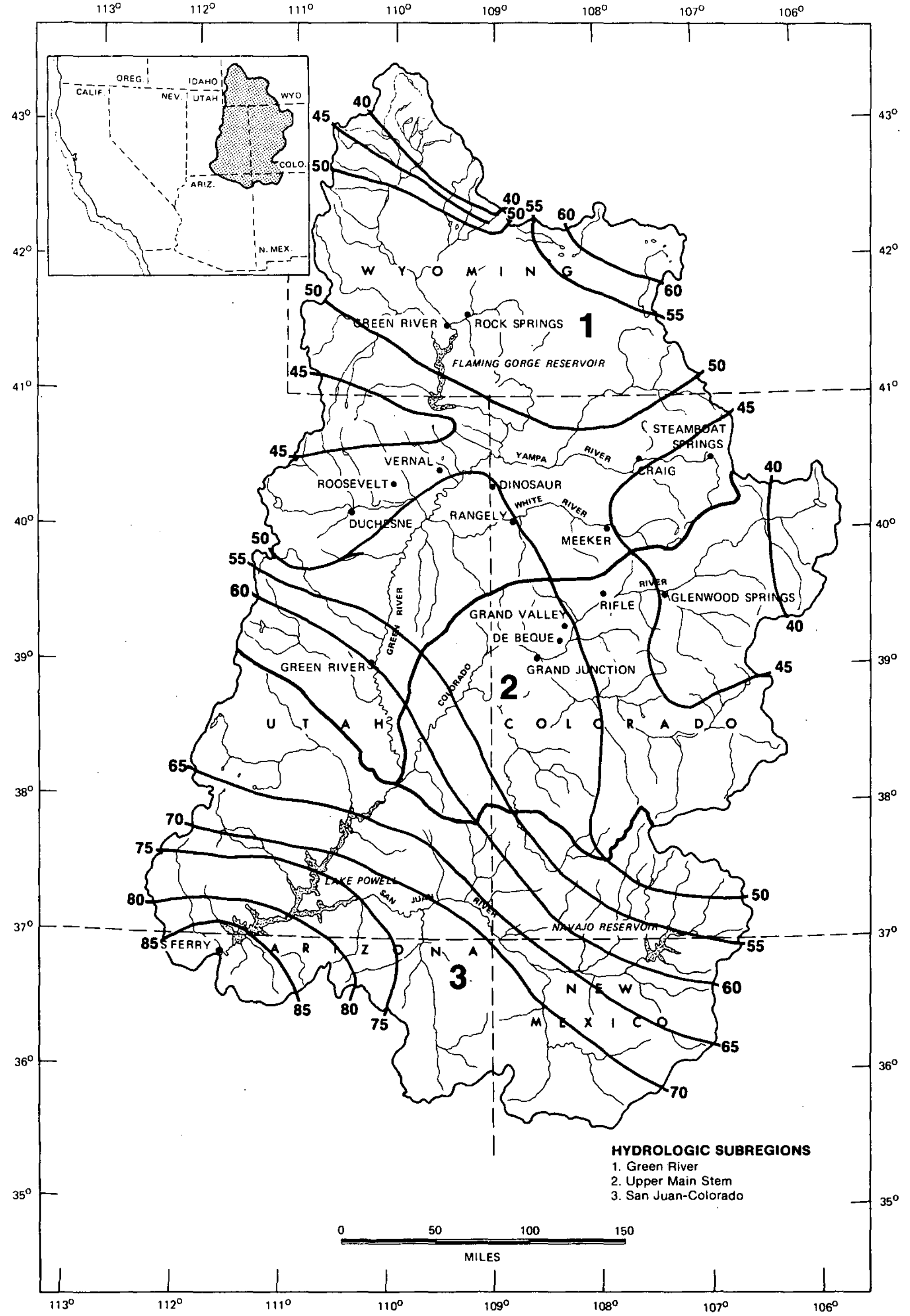

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Figure 4-4. Annual evaporation within the Upper Colorado River Basin. Source: Price and Arnow, 1974.

Gaging Station	Drainage Area (mi^2)	Average Annual Discharge (acre-ft)
GREEN RIVER SUBREGION		
1. Green River near Fontenelle, Wyo.	3,970	1,166,000
2. Fontenelle Creek at Fontenelle, Wyo.	224	49,480
3. Big Sandy Creek below Eden, Wyo.	1,610	35,350
4. Blacks Fork near Green River, Wyo.	3,670	249,900
5. Green River near Greendale, Utah	15,100	1,575,000
6. Little Snake River near Lilly, Colo.	3,730	432,050
7. Yampa River near Maybell, Colo.	3,410	1,131,000
8. Green River at Jensen, Utah	26,100	3,338,000
9. Duchesne River near Randlett, Utah	3,920	555,700
10. Strawberry River at Duchesne, Utah	1,040	113,700
11. Yellow Creek near White River, Colo.	258	1,010
12. Piceance Creek at White River, Colo.	629	12,310
13. White River near Meeker, Colo.	762	462,200
14. White River near Watson, Utah	4,020	532,460
15. Willow Creek near Ouray, Utah	967	24,690
16. Minnie Maud Creek near Myton, Utah	231	14,700
17. Price River at Woodside, Utah	1,500	84,040
18. Green River at Green River, Utah	40,600	4,427,300
19. San Rafael River near Green River, Utah	1,670	112,330
UPPER MAIN STEM SUBREGION		
20. Gunnison River near Grand Junction, Colo.	7,870	1,898,200
21. Colorado River near Colorado-Utah State Line	17,900	5,066,400
22. Colorado River near Cisco, Utah	24,100	5,662,000
SAN JUAN-COLORADO SUBREGION		
23. San Juan River at Shiprock, N. Mex.	12,900	1,876,300
24. San Juan River near Bluff, Utah	23,000	1,955,000
25. Colorado River at Lees Ferry, Ariz.	108,170	12,403,700
26. Paria River at Lees Ferry, Ariz.	1,410	22,670
27. Colorado River at Lees Ferry, Ariz.	109,580	12,426,370

Gaging stations shown in Figure 4-5.

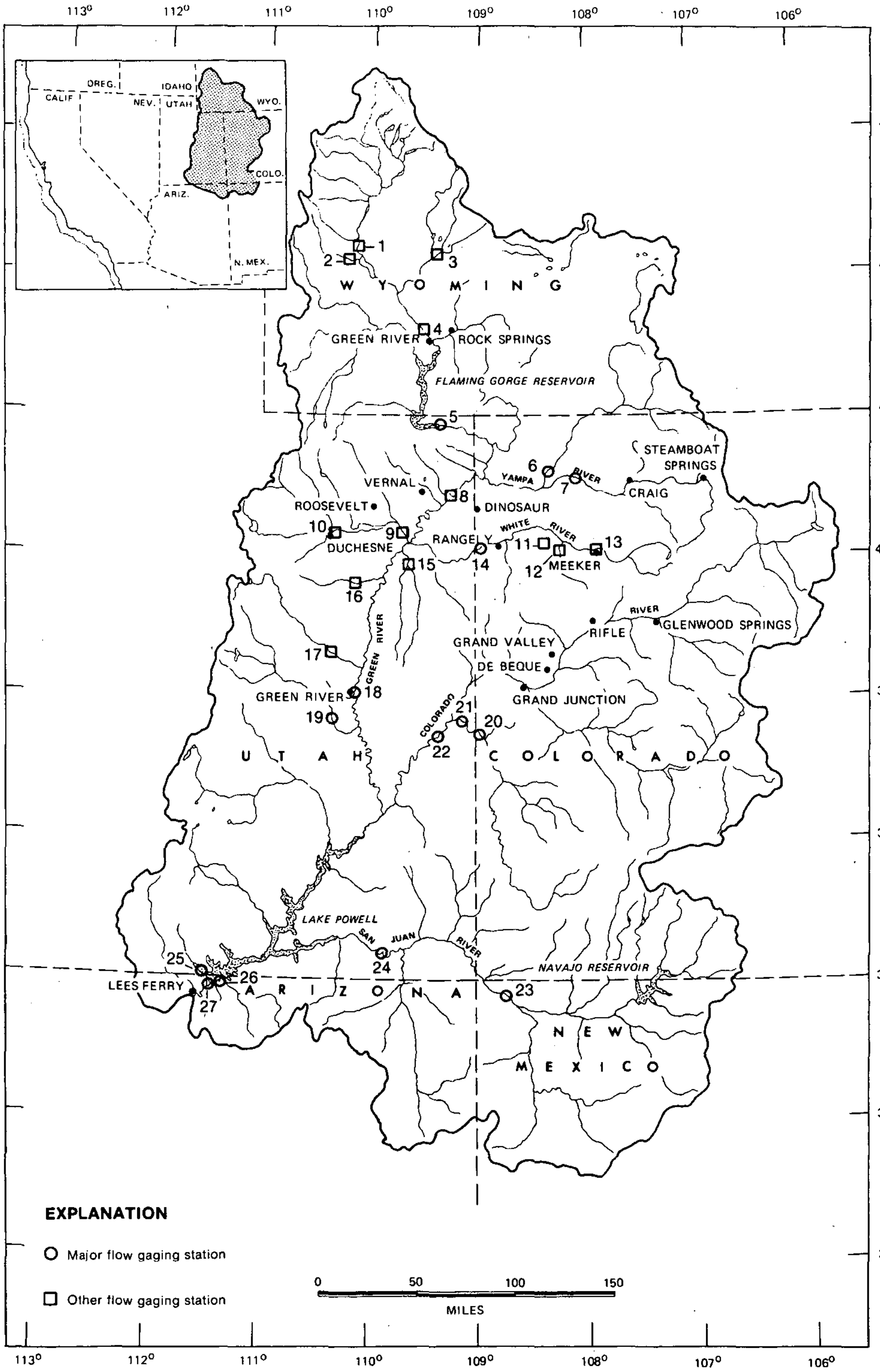

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Figure 4-5. Flow-gaging stations, drainage areas, and average annual discharges of the Upper Colorado River Basins. Source: UCR Group, 1971; Iorns et al., 1964 and 1965.

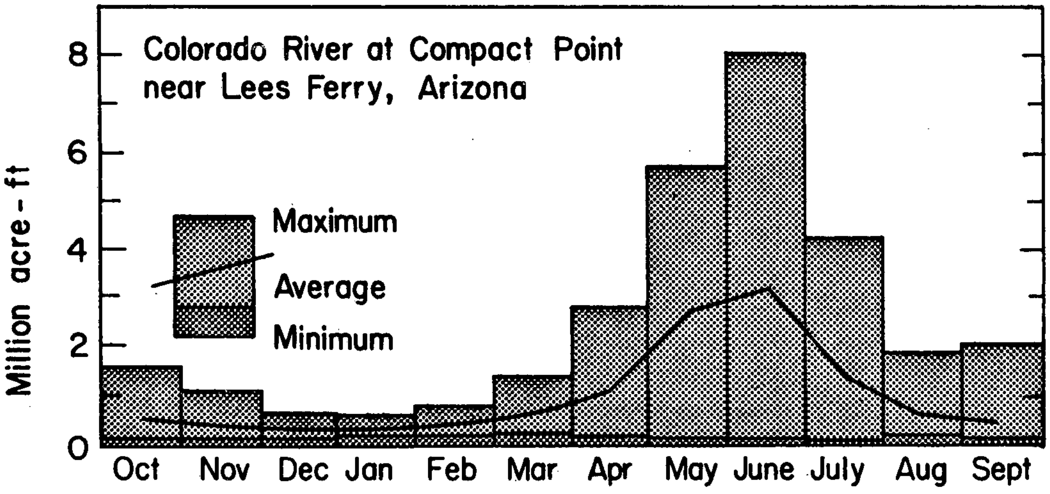

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Figure 4-6. Seasonal variation in discharge for the Colorado River at Lees Ferry, Arizona. Source: UCR Group, 1971.

A further indication of streamflow variation is provided by Figure 4-7, a flow duration curve for the Colorado River at Lees Ferry. The figure indicates that the mean discharge (i.e., 50th percentile on the flow duration curve) for the Colorado River at Lees Ferry is about 8000 cfs.

The Colorado River is the eventual recipient of streamflow contributed by all tributaries in its basin. Many tributary streams and rivers also have gaging stations, and their discharge records are available from the USGS.

There are no gaging stations on the Green River at the mouth of the subregion. The nearest gaging station on the Green River is at Green River, Utah, about 60 miles upstream from the mouth of the subregion (Figure 4-5). Variations in Green River flow are illustrated in Figures 4-8 and 4-9. The mean discharge of the river at Green River, Utah, is about 3500 cfs.

Gaging stations are situated on many Green River tributaries that traverse major oil shale deposits. Discharge records for these stations are available from the USGS. The location of flow-gaging stations on several of these streams and their average annual discharge are listed in Figure 4-5.

Lakes and Reservoirs

For the purposes of this discussion, lakes are defined as quiescent bodies of water, while reservoirs are defined as artificial lakes. Most of the natural lakes in the basin are small and are used primarily for recreation. Therefore, from a water resources standpoint, they are insignificant compared to reservoirs and are subsequently ignored. Some major lakes and reservoirs in the study area are shown in Figure 4-10.

As of 1965, a total of 581 reservoirs, each with a capacity of more than 50 acre-feet, had been developed within the Upper Colorado River Basin. These reservoirs, with a total capacity of 29.7 million acre-feet (excluding fish and wildlife and municipal and industrial reservoirs), are described in Table 4-1.

Table 4-1. Reservoirs in the Upper Colorado River Basin as of 1965.

Type of reservoir	Number	Active capacity, acre-ft
Irrigation	309	2,800,000
Fish and wildlife	232	-
Municipal and industrial	30	-
Main Stem regulation	2	25,700,000
Export regulation	8	1,200,000
Total	581	29,700,000

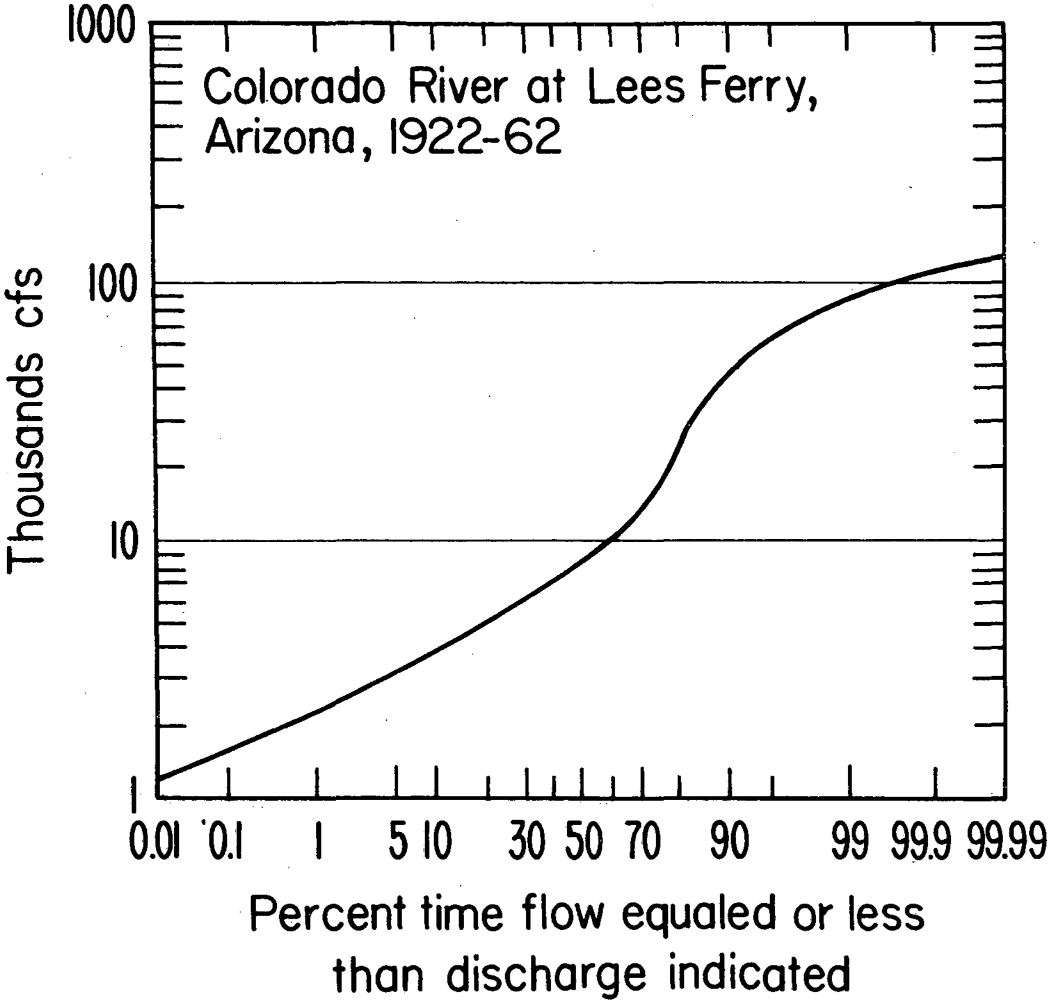

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Figure 4-7. Flow duration curve for the Colorado River at Lees Ferry, Arizona. Source: UCR Group, 1971.

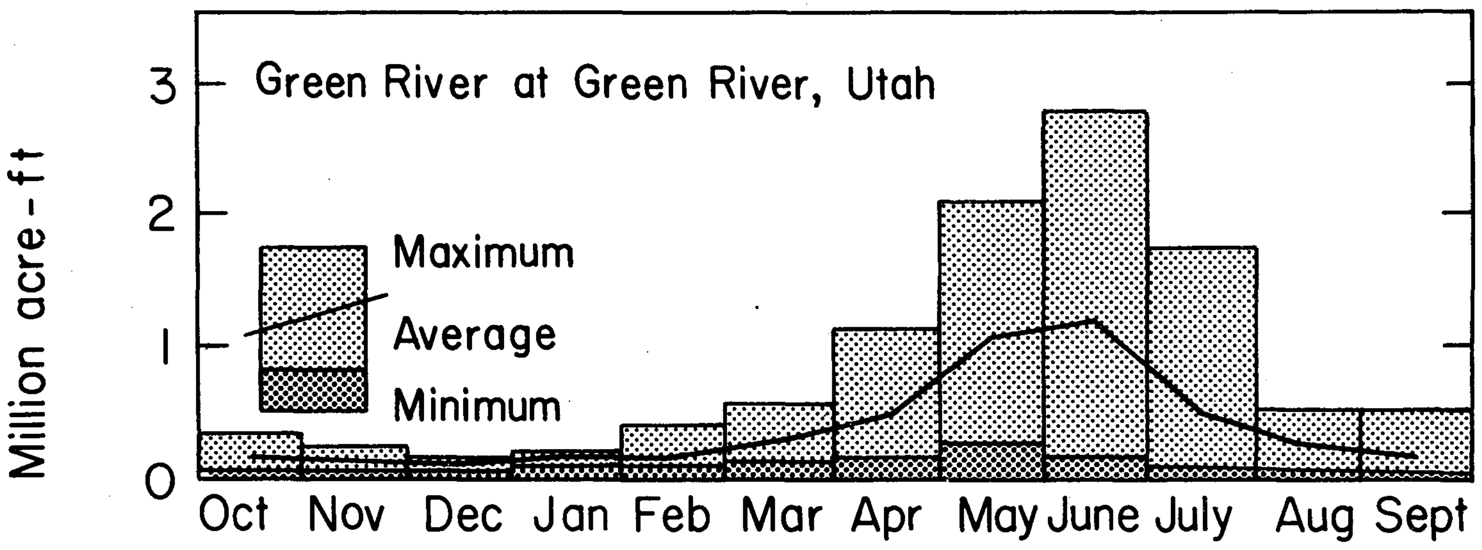

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Figure 4-8. Seasonal variation in discharge for the Green River at Green River, Utah. Source: UCR Group, 1971.

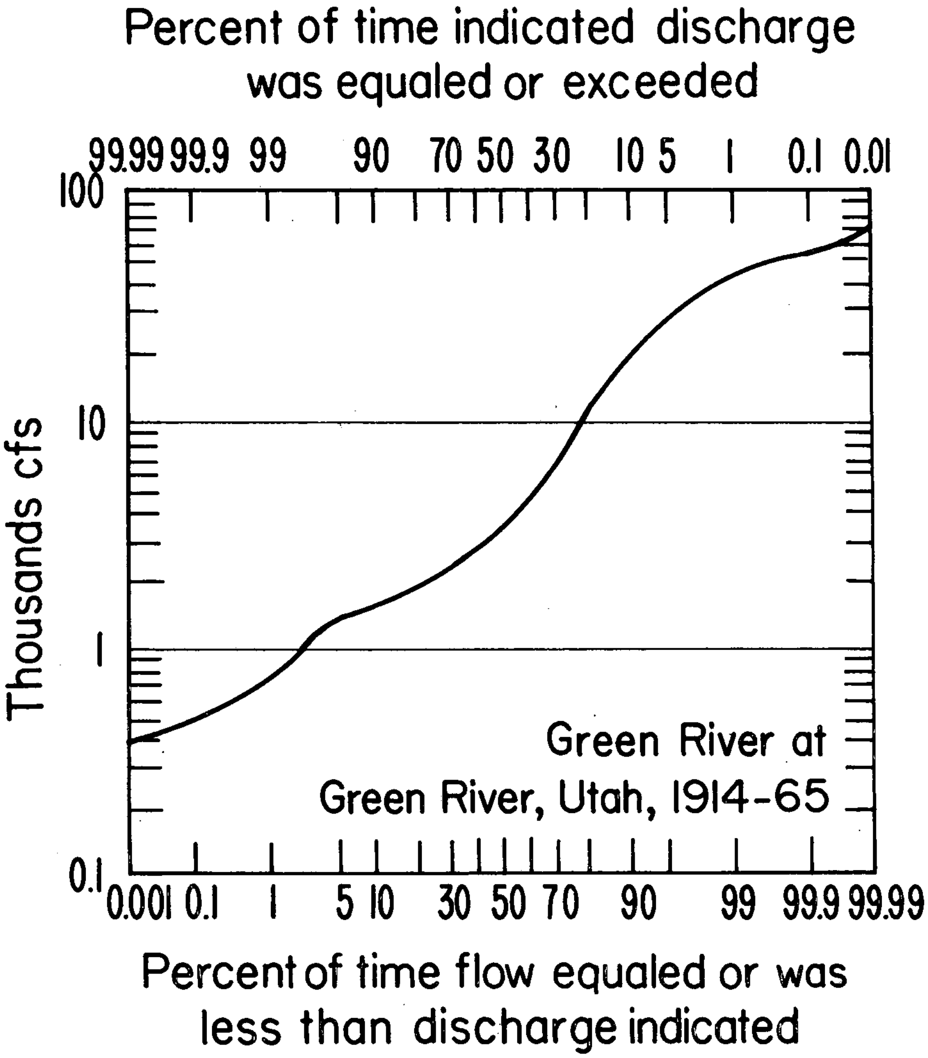

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Figure 4-9. Flow-duration curve for the Green River at Green River, Utah. Source: UCR Group, 1971.

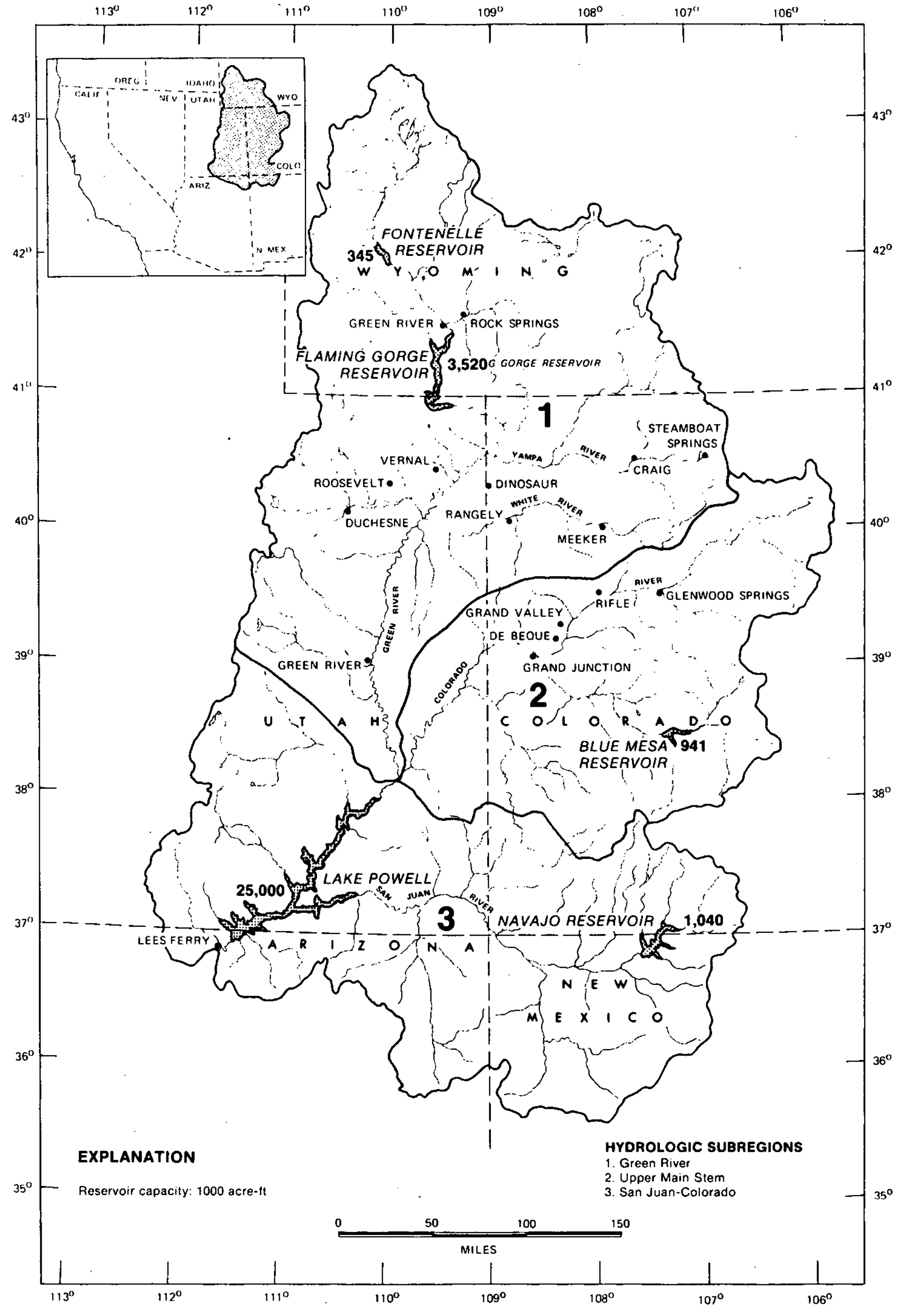

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Figure 4-10. Major reservoirs within the Upper Colorado River Basin. Source: UCR Group, 1971.

The most important reservoirs in the basin include Lake Powell, Flaming Gorge Reservoir, Navajo Reservoir, Blue Mesa Reservoir, and Fontenelle Reservoir. Their locations are shown in Figure 4-10. Most of these reservoirs were constructed as part of the Colorado River Storage Project, a federally sponsored program to regulate flow of the Colorado River and its principal tributaries.

Reservoirs in the basin are normally filled during the snowmelt runoff period and during the non-irrigating season when available water exceeds demand. As streamflows diminish in late summer, water stored in reservoirs is released to supplement natural flows in order to meet municipal, industrial, and irrigation water requirements. For irrigation, water is released from reservoirs primarily from July to October; reservoir releases for municipal and industrial requirements are made at those times of the year when natural streamflows cannot meet demands.

In the Green River Subregion prior to 1960, there were 41 major storage reservoirs, each with a capacity of at least 1000 acre-feet and with a total usable capacity of 576,000 acre-feet. Since 1960, the following major reservoirs have been developed in the subregion:

Reservoir	Capacity, acre-ft
Flaming Gorge Reservoir	3,520,000
Fontenelle Reservoir	345,000
Steinaker Reservoir	33,300
Joes Valley Reservoir	54,600

SURFACE WATER QUALITY

Generally, surface water is of relatively good quality throughout the Upper Colorado River Basin and its three hydrologic subregions. Surface waters are normally of excellent quality near headwaters at higher elevations, whereas, as streams progress downward, their quality deteriorates as a consequence of hydrologic, geologic, and human factors.

Water quality data for streams draining areas containing oil shale deposits in Colorado and Utah are shown in Table 4-2. This table shows that there is considerable variation in the water quality of streams draining major oil shale areas.

The White River, which receives flow from smaller streams draining the tracts directly, originates in Colorado in the mountains east of Meeker and is low in dissolved solids and high in suspended solids from erosion. From September through February, this pattern is reversed and dissolved solids are high and suspended solids are low. This pattern is caused by the flow switching from predominately surface snowmelt to predominately

Table 4-2. Chemical composition of surface waters draining oil shale regions in Colorado and Utah.

		White River, near Watson[a]	Evacuation Creek, near mouth[b]	Piceance Creek[c]	Yellow Creek, near White River[d]	White River, near Meeker[e]	Colorado River, near Cameo[f]	Parachute Creek, below Grand Valley[g]
Alkalinity	min.	172	351	268[h]	894	80	87	-
	max.	236	444	765[h]	1510	148	148	-
	avg.	199	404	489[h]	1303	94	111	-
Aluminum	min.	0.00	.00	-	-	-	-	-
	max.	0.050	.09	-	-	-	-	-
	avg.	0.018	.011	-	-	-	-	-
Ammonia (NH_3)	min.	0.01	0.01	-	-	-	-	-
	max.	0.19	0.11	-	-	-	-	-
	avg.	0.06	0.06	-	-	-	-	-
Arsenic	min.	0	0.002	0.000	0.002	-	-	-
	max.	0.004	<0.006	0.005	0.009	-	-	-
	avg.	0.002	0.003	0.002	0.005	0.0030[i]	-	-
Barium	min.	-	-	0.000	<0.1	-	-	-
	max.	<0.1	<0.1	0.2	0.4	-	-	-
	avg.	<0.1	<0.1	<0.087	0.2	-	-	-
Bicarbonate	min.	132[j]	428	258[h]	843	97	97	-
	max.	314[j]	541	933[h]	1620	180	181	-
	avg.	195[j]	493	558[h]	1353	113	129	363
Boron	min.	10[j]	1.9	0.11	0.41	-	0.000	-
	max.	190[j]	2.5	0.33	0.73	-	0.090	-
	avg.	64[j]	2.2	0.22	0.61	-	0.035	-
Chemical oxygen demand	min.	0	6	-	-	8[i]	-	-
	max.	38	35	-	-	150[i]	-	-
	avg.	10	24	-	-	83[i]	-	-
Cadmium	min.	<	-	0.00	<0.001	-	-	-
	max.	<0.001	0	<.015	0.001	-	-	-
	avg.	<0.001	0	<.001	0.001	-	-	-
Calcium	min.	28[j]	140	41[h]	15	29	30	
	max.	100[j]	200	100[d]	130	73	80	
	avg.	56[j]	172	77	38	40	52	86.
Carbonate (CO_3)	min.	0	0	0[h]	0	0	0	-
	max.	3	0	0[h]	313	9	0	-
	avg.	0.2	0	0[h]	115	1	0	-
Chloride	min.	8.2[j]	49	9.1[h]	93	3.2	16	-
	max.	140[j]	60	25[h]	130	33	205	-
	avg.	30[j]	54	13.8[h]	118	9.5	83	18
Chromium	min.	-	-	0.00	-	-	-	-
	max.	<0.01	0.03	0.09	-	-	-	-
	avg.	<0.01	<0.01	<.006	-	-	-	-
Conductivity, µmhos/cm	min.	328[j]	1300	600[h]	2410	207	275	-
	max.	1160[j]	5500	2240[h]	3724	577	1270	-
	avg.	631[j]	4666	1380[h]	3425	297	657	-

Table 4-2. Chemical composition of surface waters draining oil shale regions in Colorado and Utah. (continued).

		White River, near Watson[a]	Evacuation Creek, near mouth[b]	Piceance Creek[c]	Yellow Creek, near White River[d]	White River, near Meeker[e]	Colorado River, near Cameo[f]	Parachute Creek, below Grand Valley[g]
Copper	min.	0.001	0.001	0.00	0.002	-	-	-
	max.	0.006	0.004	0.012	0.009	-	-	-
	avg.	0.003	0.002	0.003	0.004	0.005[i]	-	-
Cyanide	min.	0.00	0.00	0.00	-	-	-	-
	max.	0.01	0.00	0.02	-	-	-	-
	avg.	0.00	0.00	0.00	-	-	-	-
Dissolved oxygen	min.	-	-	9.0[h]	6.9	11.6	-	-
	max.	-	-	12.4[h]	11.2	12.2	-	-
	avg.	-	-	10.6[h]	8.9	11.8	-	-
Fluoride	min.	0.2[j]	0.6	0.4[h]	1.3	0.1	0.1	-
	max.	0.7[j]	0.9	1.2[h]	2.6	0.5	0.6	-
	avg.	0.3[j]	0.8	0.7	2.1	0.2	0.3	-
Hardness ($CaCO_3$)	min.	110[j]	1000	190[h]	420	98	100	-
	max.	340[j]	1200	700[h]	670	250	280	-
	avg.	221[j]	1120	489	551	134	180	-
Iron	min.	0.010	0.02	0.01[h]	0.02	0.02	0.010	-
	max.	0.270	0.05	0.16[h]	0.40	0.21	0.060	-
	avg.	0.023	0.03	0.07[h]	0.07	0.06	0.047	-
Lead	min.	0.000	0.000	0.00	0.001	-	-	-
	max.	0.002	0.003	<0.016	0.013	-	-	-
	avg.	0.001	0.002	<0.003	0.004	0.001[i]	-	-
Lithium	min.	-	0.00	0.00	0.08	-	-	-
	max.	0.03	0.15	0.02	0.18	-	-	-
	avg.	<0.015	0.13	0.007	0.14	-	-	-
Magnesium	min.	11[j]	150	21[h]	50	6.3	6.5	-
	max.	34[j]	180	110[h]	140	17	21	-
	avg.	20[j]	164	72	111	8.5	12.3	60
Manganese	min.	0.000	0.03	0[h]	0.00	0.00	0.000	-
	max.	0.030	0.19	0.25[h]	0.25	0.03	0.090	-
	avg.	0.009	0.08	0.05[h]	0.04	0.02	0.012	-
Mercury	min.	0.0000	-	0.00	0	-	-	-
	max.	0.0002	0.0003	0.0008	0	-	-	-
	avg.	0.00003	<0.0001	<.0001	0	0.0[i]	-	-
Molybdenum	min.	0.001	0.037	-	-	-	-	-
	max.	0.004	.067	-	-	-	-	-
	avg.	0.003	0.052	-	-	-	-	-
Nickel	min.	0.000	0.002	-	-	-	-	-
	max.	0.012	0.009	-	-	-	-	-
	avg.	0.003	0.006	-	-	-	-	-
Nitrate	min.	0.00	0.00	0.22	-	-	-	-
	max.	0.39	0.32	3.7	-	-	-	-
	avg.	0.13	0.07	1.4	-	-	-	1.39
Nitrite	min.	0.00	0.00	0.00	-	-	-	-
	max.	0.01	0.03	0.13	-	-	-	-
	avg.	0.00	0.01	0.03	-	-	-	-
Phosphorus	min.	0.00	0.01	0.00[h]	0.00	0.01	-	-
	max.	0.74	0.05	0.14[h]	1.80	0.03	-	-
	avg.	0.12	0.03	0.04[h]	0.17	0.03	-	-

Table 4-2. Chemical composition of surface waters draining oil shale regions in Colorado and Utah (continued).

		White River, near Watson[a]	Evacuation Creek, near mouth[b]	Piceance Creek[c]	Yellow Creek, near White River[d]	White River, near Meeker[e]	Colorado River, near Cameo[f]	Parachute Creek, below Grand Valley[g]
pH	min.	7.1[j]	7.8	7.5[h]	8.0	7.9	7.1	-
	max.	8.3[j]	8.7	8.4[h]	8.8	8.8	8.5	-
	avg.	7.8[j]	8.2	8.0[h]	8.5	8.0	7.8	8.0
Potassium (K)	min.	1.1[j]	1.8	2.4[h]	3.9	1.1	1.4	-
	max.	4.5[j]	12	4.9[h]	6	2	5.7	-
	avg.	2.1[j]	7.8	3.3[h]	4.5	1.2	2.9	-
Selenium (Se)	min.	0.001	0.000	0.00	0.000	-	-	-
	max.	0.002	0.002	0.002	0.003	-	-	-
	avg.	<0.001	0.0008	0.001	0.002	0.004[i]	-	-
Silica (SiO_2)	min.	9.8[j]	7.6	1.4[h]	6.9	4.4	3.9	-
	max.	19[j]	10	21[h]	13	16	12	-
	avg.	13.4[j]	8.8	16.3[h]	9.5	10.4	8.7	-
Silver	min.	-	-	-	-	-	-	-
	max.	<0.001	<0.002	-	-	-	-	-
	avg.	<0.001	<0.002	-	-	-	-	-
Sodium	min.	14[j]	680	66[h]	630	3.8	18	-
	max.	150[j]	780	380[h]	800	25	150	-
	avg.	51[j]	728	155[h]	717	8.6	65	143
Solids, dissolved	min.	203[j]	3290	392[h]	1740	124	172	-
	max.	713[j]	4070	1630[h]	2590	353	743	-
	avg.	415[j]	3826	949[h]	2369	181	388	701
Solids, suspended	min.	-	-	-	-	23[i]	-	-
	max.	-	-	-	-	95[i]	-	-
	avg.	-	-	-	-	71[i]	-	-
Sulfate	min.	51[j]	2000	110[h]	400	22	36	
	max.	320[j]	2400	570[h]	750	120	190	
	avg.	130[j]	2160	334[h]	587	45	93	394.
Sulfide	min.	0.0	0.0	0.0	-	-	-	-
	max.	0.3	0.3	0.9	-	-	-	-
	avg.	0.1	0.06	0.2	-	-	-	-
Zinc	min.	0.010	-	0.00	0.00	-	-	-
	max.	0.110	0.06	0.06	0.02	-	-	-
	avg.	<0.025	<0.027	0.019	0.01	0.06[i]	-	-

[a] Data from Ashland (1975); period of record is Aug. 1974-May 1975; averages are arithmetic.

[b] Data from U.S. Dept. of the Interior (1970-1974); period of record is Aug. 1974-Feb. 1975; averages are arithmetic.

[c] Data from Ashland (1977) for Piceance Creek below Rio Blanco; period of record is Oct. 1974-Sept. 1975; averages are arithmetic.

[d] Data from U.S. Dept. of the Interior (1974); period of record is May-Sept. 1974; averages are flow-weighted.

[e] Data from U.S. Dept. of the Interior (1974); for White River near Meeker, Oct. 1973-Sept. 1974; averages are flow-weighted.

[f] Data from U.S. Dept. of the Interior (1970-1974); period of record is Oct. 1970-Sept. 1974; averages are flow-weighted.

[g] Data from ARCO (1974).

[h] Data from U.S. Dept. of the Interior (1970-1974) for Piceance Creek below Ryan Gulch; period of record is Dec. 1970-Sept. 1974; averages are flow-weighted.

[i] Data from U.S. Dept. of the Interior (1974) for White River below Meeker; period of record is April-Sept. 1974; averages are flow-weighted.

[j] Data from U.S. Dept. of the Interior (1970-1974); period of record is Oct. 1970-Sept. 1974; averages are flow-weighted.

groundwater. The principal ions in the White River near Watson are calcium, sodium, magnesium, potassium, bicarbonate, chloride, and sulfate.

The quality of Evacuation Creek, which drains into the White River near Watson, Utah, is considerably different from that of the White River. This stream is sustained by groundwater seepage for all but a few days of the year (Ashland, Aug. 1975). However, the quality of the sustaining aquifer is much different from the aquifer feeding the White River. Alkalinity, conductivity, dissolved solids, sulfate, sodium, magnesium, and hardness are much higher in Evacuation Creek than in White River.

Piceance Creek, Parachute Creek, and Yellow Creek drain Colorado oil shale areas. The quality in all three is affected significantly by irrigation practices, and the concentration of dissolved solids, fluoride, sodium, etc., increases in the downstream direction. In all three cases, the major river receiving the flow from these streams is of much higher quality than the streams themselves.

The quality in each of the three streams is distinctly different. Alkalinity, conductivity, fluoride, hardness, magnesium, sodium, and sulfate are high in Yellow Creek while alkalinity, conductivity, magnesium, sodium, and sulfates are lower in Piceance Creek than in Yellow Creek. Parachute Creek concentrations typically fall between those two.

The Colorado River, like the White River, receives flow from smaller streams which drain oil shale tracts directly. The quality of the Colorado River in areas of oil shale activity is similar to that of the White River; dissolved solids and alkalinity are low compared to streams draining into the river. The predominate ions are calcium, chloride, sodium, and sulfate.

On a regional, basin-wide scale, the most significant water quality parameters within the basin are TDS (total dissolved solids) and suspended sediment. In addition, there are less significant water quality parameters that are important in areas of municipal, industrial, and agricultural activities. These occur as a consequence of wastewater discharges and runoff from developed areas. However, problems associated with these less significant water quality parameters are highly localized in nature, and their severity normally diminishes outside of their area of origin.

Mineral Quality of Surface Waters

The principal water quality problem within the basin is high concentrations of TDS. Major factors responsible for high TDS levels include leaching processes acting on geologic formations and evapotranspiration associated with irrigation activities.

TDS concentrations vary considerably throughout the basin (Fig. 4-11). Near headwaters at higher elevations, TDS levels of many streams are less than 20 mg/l, whereas at lower elevations several streams have TDS levels approaching 3000 mg/l. TDS concentrations generally increase as a stream progresses from its headwaters to lower elevations, primarily due to the types of rocks underlying a stream's drainage basin. Near headwaters, rocks are mainly igneous and metamorphic (relatively insoluble), while

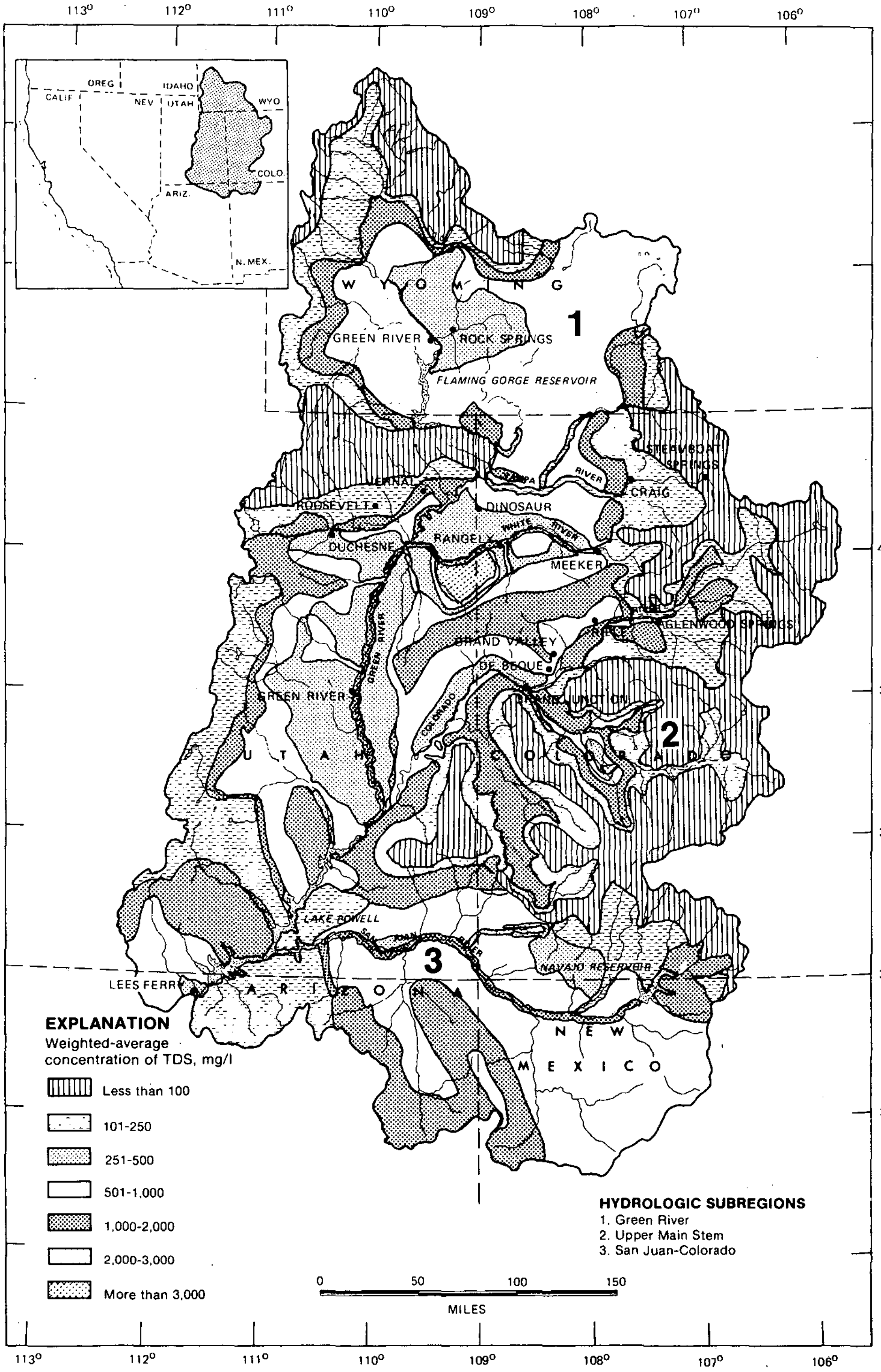

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Figure 4-11. Concentrations of TDS in streams within the Upper Colorado River Basin. Source: UCR Group, 1971.

at lower reaches the drainage basin is often overlain by sedimentary rocks containing minerals that are considerably more soluble.

In addition to TDS increases, the ionic composition of water changes as streams progress from headwaters to lower elevations. The headwaters mainly contain calcium and bicarbonate, whereas, as streams progress downward, their TDS reflects greater proportions of sodium, magnesium, sulfate, and chloride, primarily as a consequence of leaching processes.

It is estimated that the Upper Colorado River Basin contributes about 8.7 million tons of TDS to Lees Ferry each year, based on 1965 conditions. Of this total, approximately 33 percent is contributed by the Green River Subregion, 48 percent by the Upper Main Stem Subregion, and 19 percent by the San Juan Subregion. The TDS concentration of the Colorado River at Lees Ferry is estimated to be about 580 mg/l. A more definitive portrayal of geographic variations in TDS throughout the basin is presented in Figure 4-11.

In addition to geographic variations in TDS, there also exist significant seasonal variations in TDS concentrations throughout the basin. Generally, for unregulated streams, TDS levels are low during high streamflow conditions in the spring, and high during low streamflow conditions in the late summer.

Similar to the entire Upper Colorado River Basin, the quality of surface water within the Green River Subregion is generally good, the major quality problem being relatively high TDS levels. The TDS concentration at various points along the Green River is shown in Table 4-3. As shown in the table, TDS levels increase by about 50 percent as the Green River progresses downstream from Wyoming to Utah.

Table 4-3. Average TDS concentration at various points along the Green River.

Station location	TDS concentration, mg/l
Green River at Green River, Wyoming	316
Green River near Greendale, Utah	419
Green River near Ouray, Utah	397
Green River at Green River, Utah	465

Other major rivers within the subregion also have TDS problems. Big Sandy Creek has a TDS concentration ranging from 1000 to 2000 mg/l and Price River has a TDS of 3000 mg/l at its mouth.

The ionic composition of surface waters varies throughout the Upper Colorado River Basin. Generally, the major cation is either calcium or sodium, while the major anion is either sulfate, chloride, or bicarbonate. The quality of surface water at selected gaging stations within the Upper Colorado River Basin is shown in Figure 4-12.

Normally a strong relationship exists between streamflow and chemical composition. The TDS concentration of a particular stream is usually greater during periods of low flow. Figure 4-13 shows the relationship between streamflow and chemical composition at four gaging stations near the lower ends of the basin's three subregions. At these locations, calcium and bicarbonate are the predominant cations and anions during high flows, except in the Colorado River near Cisco, Utah, where sulfate is slightly greater than bicarbonate. At median and low flows, sodium and sulfate become the predominant cations and anions, except in the San Juan River near Bluff, Utah, where calcium is greater than sodium.

Suspended Sediment in Surface Waters

Suspended sediment in streams and rivers represents a significant water quality problem in parts of the Upper Colorado River Basin. Suspended sediment concentrations at selected gaging stations throughout the basin are presented in Table 4-4.

As shown in Table 4-4, significant concentrations of suspended sediment occur in the Colorado River and its principal tributaries. High concentrations of suspended sediment in streams and rivers are detrimental to lotic aquatic communities for the following reasons:

1. Suspended sediment adversely affects primary productivity by inhibiting light transmission required for photosynthesis.

2. It smothers benthic organisms after settling.

3. It clogs the gills of fish.

Furthermore, high concentrations of suspended sediment decrease the useful lifespan of reservoirs (by settling and slowly filling them) and impair the utilization of surface water as municipal, industrial, and irrigation water supply.

Sources of Pollution and Degradation of Surface Water Quality

Degradation of water quality can occur through natural processes (e.g., leaching processes acting upon geologic formations) or as a consequence of human activities. Water quality degradation associated with human activities is normally defined as "pollution." The following discussion will focus on both human and natural sources of water quality degradation within the Upper Colorado River Basin.

Major point sources of surface water pollution in the basin include municipal and industrial wastewater effluents. These effluents contribute a variety of pollutants to surface receiving waters, the most significant being TDS on a basin-wide scale. (Most treatment plants are only about

	Gaging Station	Ca + Kg	Na + K	SO_4 + Cl + NO_3	Alkalinity
1.	Green River near Fontenelle, Wyo.	3	1	1	3
2.	Green River near Greendale, Utah	6	4	6	4
3.	Green River at Jensen, Utah	7	6	12	1
4.	Duchesne River near Randlett, Utah	1	2	3	0
5.	Piceance Creek at White River, Colo.	1	6	2	5
6.	Evacuation Creek near White River, Utah	2	2	3	1
7.	White River near Watson, Utah	8	6	7	7
8.	Green River at Green River, Utah	9	5	10	4
9.	Gunnison River near Grand Junction, Colo.	6	2	7	1
10.	Colorado River near Cisco, Utah	5	3	5	3
11.	San Juan River at Shiprock, New Mex.	7	4	8	3
12.	San Juan River near Bluff, Utah	9	8	14	3
13.	Colorado River at Lees Ferry, Ariz.	12	9	18	3

Gaging stations shown in Figure 4-12
(Units: equivalents per million).

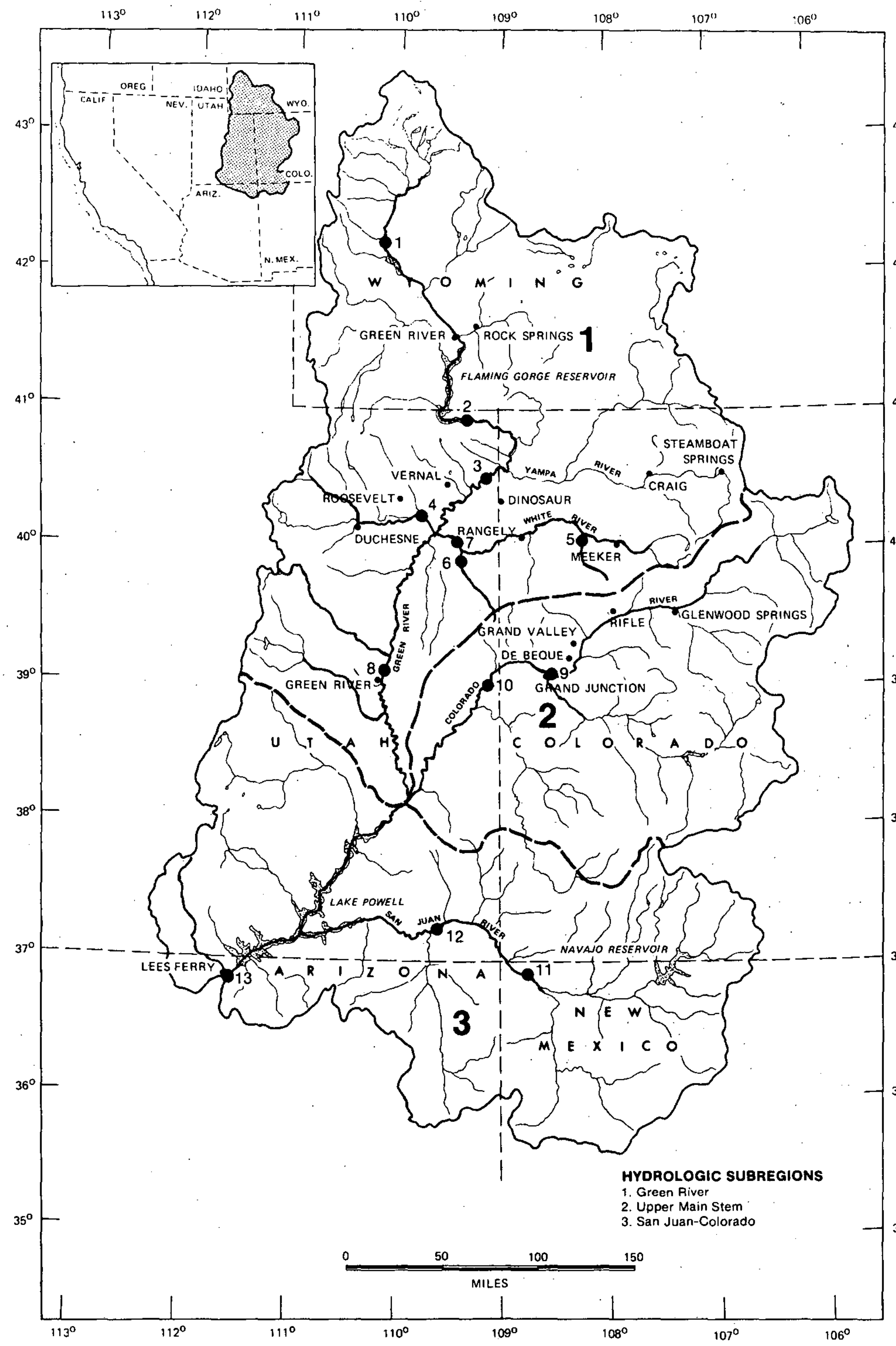

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Figure 4-12. Quality of surface water at selected gaging stations in the Upper Colorado River Basin. Source: Iorns et al., 1965.

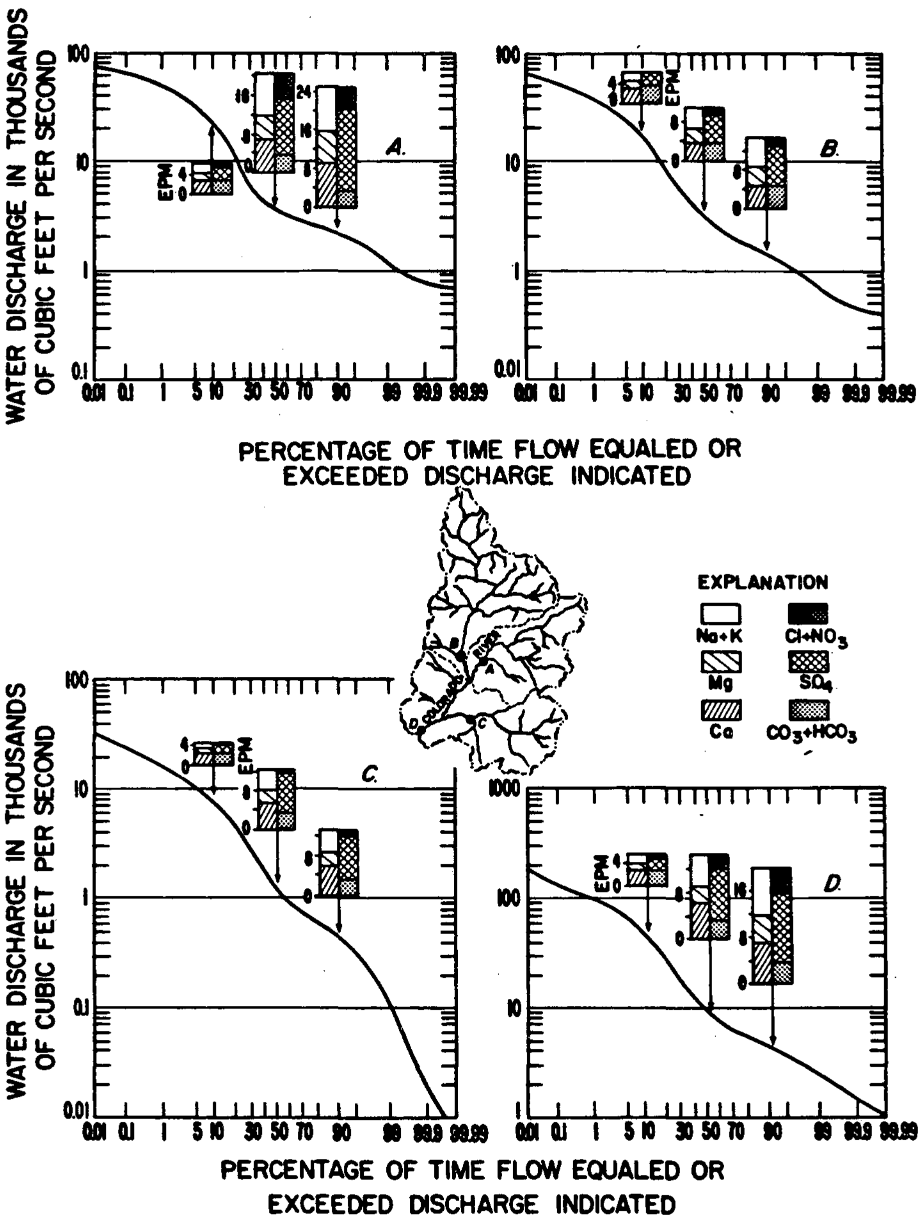

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Figure 4-13. Relation of the chemical composition and concentration of dissolved solids to water discharge at stations on the three main streams in the Upper Colorado River Basin: (A) Colorado River near Cisco, Utah; (B) Green River at Green River, Utah; (C) San Juan River near Bluff, Utah; (D) Colorado River at Lees Ferry, Arizona. The concentration of specific ions, in equivalents per million, epm, is shown for the 10th, 50th, and 90th percentiles of the flow-duration curve for each location. The flow-duration curves are for the water years 1914-57 adjusted to 1957 conditions (from Iorns et al., 1965).

Table 4-4. Suspended sediment concentrations of the Upper Colorado River Basin (long-term averages: 1914-1957).

Gaging station[a]	Weighted average suspended sediment concentration, ppm
7. Yampa River near Maybell, Colorado	196
18. Green River at Green River, Utah	3,760
20. Gunnison River near Grand Junction, Colorado	806
22. Colorado River near Cisco, Utah	2,050
24. San Juan River near Bluff, Utah	13,500
27. Colorado River at Lees Ferry, Arizona	5,800

[a] Locations of gaging stations are given in Figure 4-5.

Source: UCR Group, 1971.

five percent effective in removing TDS.) Less significant sources of surface water pollution include mine drainage, effluents from minerals processing, and disposal of saline water from oil fields.

Irrigation return flows represent the major nonpoint source of surface water pollution in the basin, contributing substantial amounts of TDS to surface waters as a consequence of leaching. Another nonpoint source of lesser significance is runoff from animal feedlots.

Contributions of TDS by major sources of surface water pollution in the basin in 1965 are summarized in Table 4-5. As the table shows, irrigation activities are by far the most significant source of surface water pollution, contributing substantial amounts of TDS to surface waters. In comparison, other sources of surface water pollution are insignificant. However, it is important to note that of the 8.7 million tons of TDS generated each year in the basin (based on 1965 conditions), most is attributed to natural sources.

Table 4-5. Contributions of TDS by sources of water pollution in the Upper Colorado River Basin in 1965.

Subregion	TDS, tons/yr Municipal wastewater effluent	 Effluent from manufacturing activities	 Irrigation return flow
Green River	4,610	2,000	925,000 to 1,425,000
Upper Main Stem	4,750	4,200	866,000 to 1,546,000
San Juan-Colorado	6,300	2,300	204,000 to 349,000
Total	15,660	8,500	1,995,000 to 3,320,000

Natural sources of TDS (i.e., geologic sources not related to human activities) include both point and nonpoint (diffuse) sources. Point sources are springs and seeps that discharge into streams; nonpoint sources are surface runoffs from natural watersheds. The total estimated TDS inflow from natural (geologic) point and nonpoint sources is shown in Table 4-6. Geographic variations in diffuse (nonpoint) TDS pickup are illustrated in Figure 4-14.

Table 4-6. Total estimated TDS inflow from natural (geologic) sources.

Subregion	TDS, tons/yr Point sources	 Nonpoint sources
Green River	145,400	1,139,000 to 1,639,000
Upper Main Stem	568,800	2,060,000 to 2,740,000
San Juan-Colorado	11,500	825,000 to 970,000
Total	725,700	4,024,000 to 5,349,000

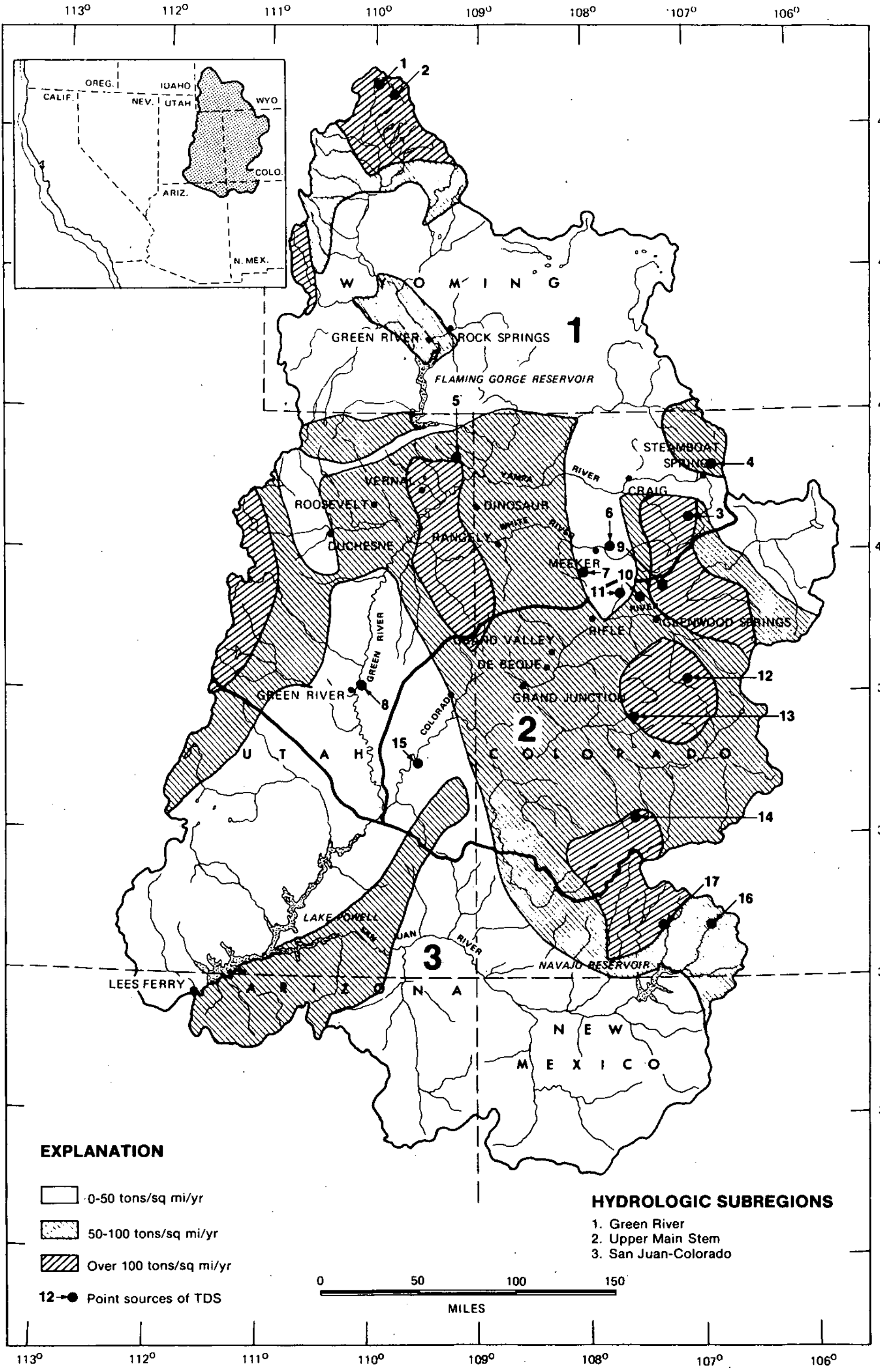

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Figure 4-14. Areas of diffuse (nonpoint) TDS pickup.
Source: UCR Group, 1971.

It is anticipated that the amount of TDS generated in the basin will increase in the future due to increased human activities (i.e., increased urbanization, industrialization, and irrigation activities). Estimates of TDS production in the year 2020 are presented in Table 4-7.

Table 4-7. TDS production in the Upper Colorado River Basin in the year 2020.

	TDS, tons/yr		
Subregion	Municipal wastewater effluent	Effluent from manufacturing activities	Irrigation return flow
Green River	7,200	6,600	1,083,000 to 1,666,000
Upper Main Stem	10,100	17,600	1,071,000 to 1,913,000
San Juan-Colorado	19,100	11,900	367,000 to 628,000
Total	36,400	36,100	2,521,000 to 4,207,000

Source: UCR Group, 1971.

As indicated in the table, it is anticipated that a substantial increase in the TDS produced in the Upper Colorado River Basin will occur by the year 2020. However, it is important to note that considerable effort, at both federal and regional levels, has been and will continue to be devoted to mitigation of TDS problems in the basin. These efforts, if successful, may significantly alter the above projections.

Estimates of TDS production in 1965 are considered to be fairly representative of present conditions (1976). In support of this assertion, estimates of TDS production in 1970, made by the Utah Water Research Laboratory, are presented in Table 4-8.

The 1970 estimate of 8.6 million tons per year (made by the Utah Water Research Laboratory) is almost identical to the 1965 estimate of 8.7 million tons per year (made in UCR Group, 1971). These two estimates suggest that the estimated annual TDS production in the Upper Colorado River Basin in 1965 and 1970 did not differ significantly.

The Utah Water Research Laboratory also estimated TDS loadings for selected gaging stations within the basin, based on 1970 levels of basin development. These estimates, presented in Table 4-9, were derived by averaging long-term estimates made by the Utah Water Research Laboratory and the U.S. Bureau of Reclamation. (The locations of the gaging stations identified in Table 4-9 are shown in Fig. 4-5).

Table 4-8. Estimates of TDS production in the Upper Colorado River Basin in 1970.

Subregion	TDS, tons/yr	Average TDS concentration mg/l
Green River	2,700,000	475
Upper Main Stem	4,700,000	640
San Juan-Colorado	1,200,000	390
Total	8,600,000	579

Source: USU, 1975.

Table 4-9. Estimated TDS loading at selected gaging stations within the Upper Colorado River Basin (based on 1970 level of Basin development).

Gaging Station[a]	Estimated TDS loading, tons/yr	Estimated TDS concentration, mg/l
18. Green River at Green River, Utah	2,530,000	418
22. Colorado River near Cisco, Utah	4,430,000	572
24. San Juan River near Bluff, Utah	1,000,000	374
27. Colorado River at Lees Ferry, Arizona	8,570,000	504

[a] Locations of gaging stations are given in Figure 4-5.

Source: USU, 1975.

Problems of pollution and degradation of surface waters in the Green River Subregion are similar to those of the Upper Colorado River Basin as a whole. About 30 percent of the population of the Upper Colorado River Basin resides in the Green River Subregion, the largest town being Rock Springs, Wyoming, with a population of slightly over 10,000. Due to the subregion's relatively low population and low intensity of industrial development, the TDS contribution of municipal and industrial effluents is not particularly significant. In contrast, however, irrigation activities within the subregion contribute a substantial amount of TDS. Irrigated land in the subregion yields from two to six tons of TDS per acre per year. Within the subregion, the areas with the highest TDS yield include the lower Duchesne River, the lower Price River, and the San Rafael River basins.

Natural sources account for the influx of most suspended sediment in streams and rivers, primarily as a consequence of natural erosion processes. However, sediment discharge from industrial activities, such as gravel-washing operations and irrigation flows, occasionally contribute to localized high concentrations of suspended sediment.

GROUNDWATER RESOURCES

Groundwater resources can be used alone or in conjunction with surface water resources for a variety of beneficial uses. The purpose of this section is to describe the vertical and areal extent of groundwater throughout the Upper Colorado River Basin, as well as its availability and quality.

Quantity and Availability of Groundwater

Geology is the principal factor controlling the quantity and availability of groundwater. The rocks underlying the basin consist mainly of consolidated and semiconsolidated strata. Igneous and metamorphic rocks underlie parts of the mountains, and unconsolidated alluvial deposits underlie reaches of major stream valleys.

An aquifer is defined as a rock formation that will yield (i.e., transmit) significant quantities of water. The capacity of an aquifer for transmitting water depends on the rock material comprising it. Unconsolidated alluvium represents the best aquifer material; other categories of rocks have lesser or no capacity for transmitting water.

Stratigraphic conditions (i.e., vertical variations in geology) differ throughout the Upper Colorado River Basin. In areas where rich deposits of oil shale are situated, stratigraphic conditions often resemble those of the Piceance Creek Basin (a lower order basin located within the Green River Subregion). A vertical cross section of the Piceance Creek Basin is presented in Figure 4-15. The "Mahogany Zone" and the "Parachute Creek Member," shown in the figure, are composed almost entirely of oil shale. The Mahogany Zone is bounded by an unconfined aquifer above and a confined aquifer below.

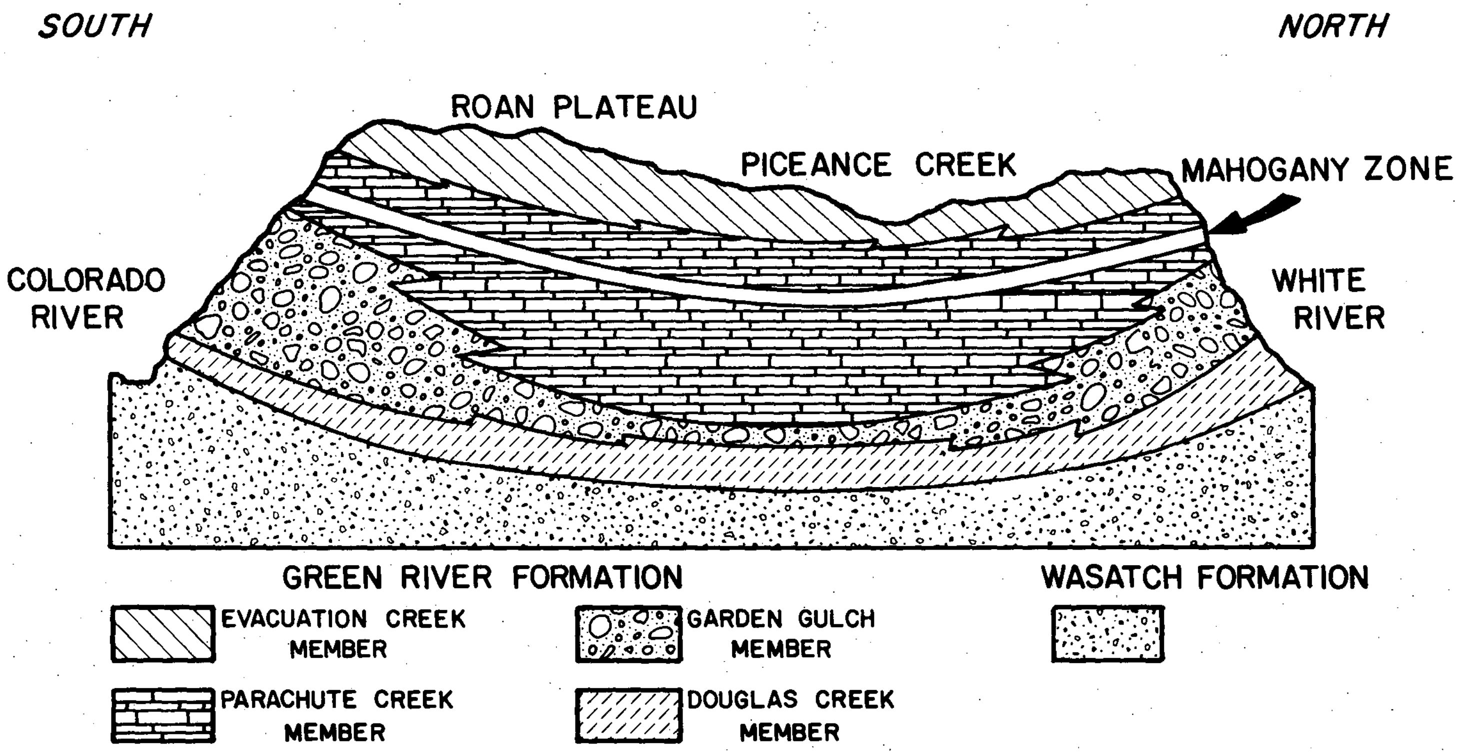

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Figure 4-15. Vertical cross section of Piceance Creek Basin.
Source: Sladek, 1974.

Groundwater Storage

Throughout the Upper Colorado River Basin, various types of rocks outcrop, as shown in Figure 4-16. These outcrops include unconsolidated alluvium, as well as volcanic, sedimentary, igneous, and metamorphic rocks. Some of these outcrops function as aquifers due to their high permeability. The estimated volume of recoverable groundwater associated with the various rock categories within the upper 100 feet of saturated thickness and the area they encompass are shown in Table 4-10. As shown in the table, the storage capacity is estimated to be between 50 million and 116 million acre-feet.

The largest volume of recoverable groundwater is contained in sedimentary, igneous, and metamorphic rock outcrops. However, this water is not generally available to individual wells because these rocks, as a whole, are characterized by a low permeability and a low specific yield. In contrast, the water contained in unconsolidated alluvium and volcanic rock outcrops is readily available to individual wells because of the higher permeability and higher specific yield. From Table 4-10, it is apparent that about 6.6 million to 17.4 million acre-feet (unconsolidated alluvium plus volcanic) is readily available to individual wells from these outcrops.

Table 4-10. Estimated storage of recoverable groundwater in the Upper Colorado River Basin.

	Storage				
	Area of outcrop mi^2	Specific yield, %	Saturated thickness, ft	Water, 1000 acre-ft	
Category of rock				Min	Max
Unconsolidated alluvium	1,300	5-15	50[a]	2,100	6,200
Volcanic	3,500	2-5	100	4,480	11,200
Sedimentary, igneous, and metamorphic	107,700	2	100	43,800	98,100
Total	112,500			50,380	115,500

[a] Saturated thickness less than 100 ft in most parts of the basin for this category of rock.

Source: Price and Arnow, 1974.

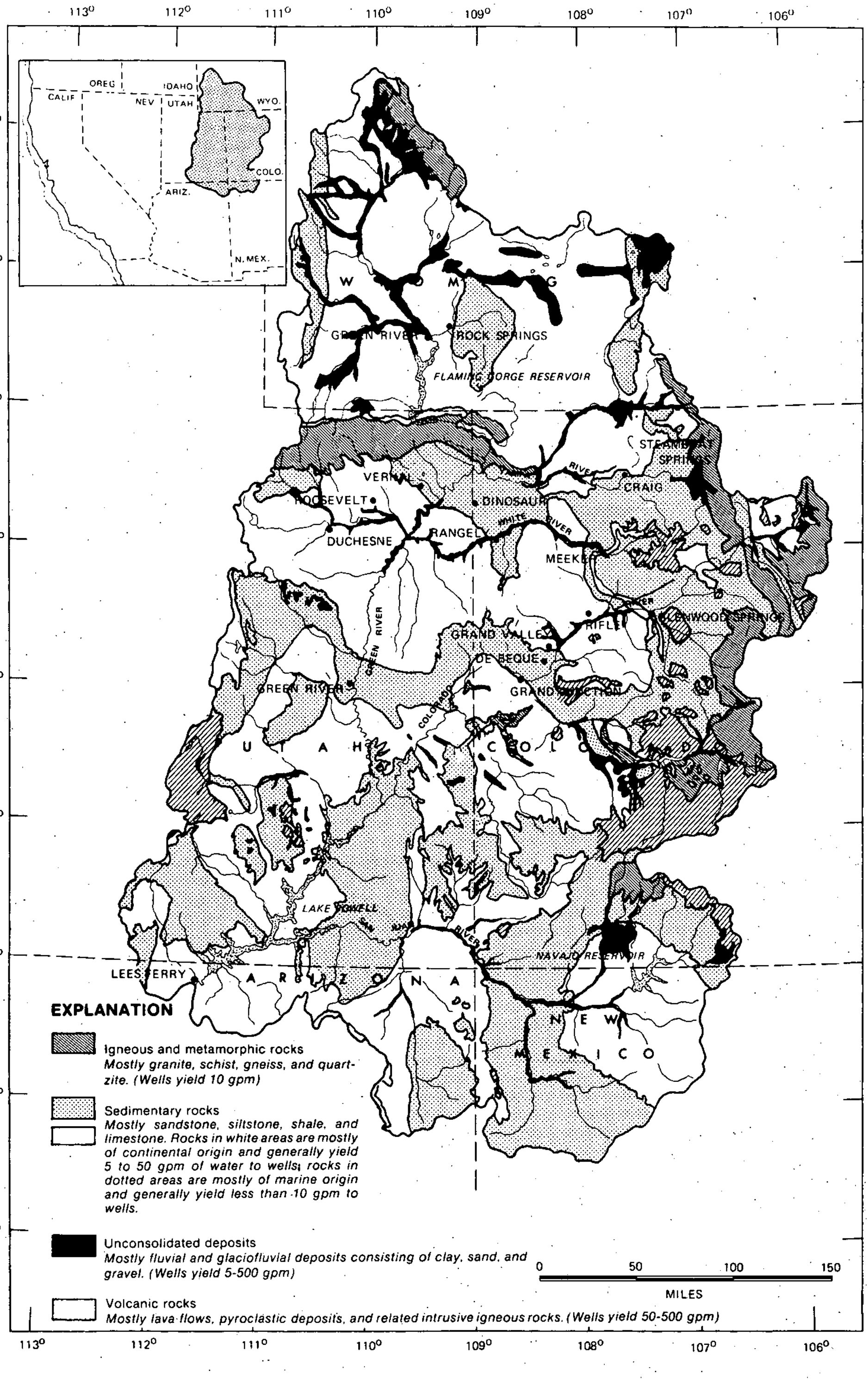

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Figure 4-16. Areal extent of rock formation outcrops at surface. Source: Price and Arnow, 1974.

Figure 4-17 shows the volume of recoverable groundwater contained within the upper 100 feet of saturated thickness in aquifers throughout the basin. Most of the basin area is underlain by rock formations with an estimated volume of recoverable groundwater, in the upper 100 feet of saturated thickness, ranging from 600 to 1300 acre-feet per square mile. However, at least 30 percent of the basin area is underlain by rock formations with a lesser volume of recoverable groundwater.

It should be noted that the total recoverable groundwater in storage throughout the basin (i.e., in the complete vertical section of saturated rocks) is far greater than the amount stored in the upper 100 feet of saturated rocks. The estimate of recoverable groundwater storage was limited to the upper 100 feet of saturated thickness because of its ready accessibility. Much of the groundwater below the upper 100 feet of saturated rocks is not readily accessible because of high drilling and pumping costs.

The northern part of the Green River Subregion contains the largest areal extent of unconsolidated alluvium outcrop in the basin. A comparison of Figures 4-1 and 4-16 indicates that limited outcrops exist in the areas of high-yield oil shale, as shown in Figure 4-16.

Safe Yield

Precipitation is the source of virtually all groundwater in storage throughout the Upper Colorado River Basin. Most of the water derived from precipitation is consumed by evapotranspiration or becomes overland flow; the remainder becomes groundwater recharge. Principal areas of natural recharge are in the higher mountains and plateaus, which receive the largest amount of precipitation. Groundwater migrates from areas of natural recharge to areas of natural discharge that include springs and gaining reaches of streams. While migrating between areas of recharge and discharge, groundwater is considered to be in "transient" storage.

Within the basin, total annual precipitation averages about 95 million acre-feet. Of this amount only about four percent, or about four million acre-feet, becomes groundwater recharge.

Safe yield is defined as the maximum amount of water that can be withdrawn from storage each year for an indefinite time without depleting the storage. Safe yield cannot exceed average annual groundwater recharge. Any withdrawal in excess of safe yield is defined as "overdraft" or "mining."

Safe yield for the Upper Colorado River Basin is estimated to be about 4 million acre-feet (based on the estimated average annual groundwater recharge in the basin). The estimated total annual withdrawal of groundwater from the basin in 1970 was only about 120,000 acre-feet. Since this total represents only three percent of the estimated safe yield, it is apparent that mining of groundwater does not presently occur on a basin-wide level. Although it is possible that localized mining of individual aquifers may take place, this is unlikely, since there are few areas of concentrated groundwater withdrawals from wells within the basin.

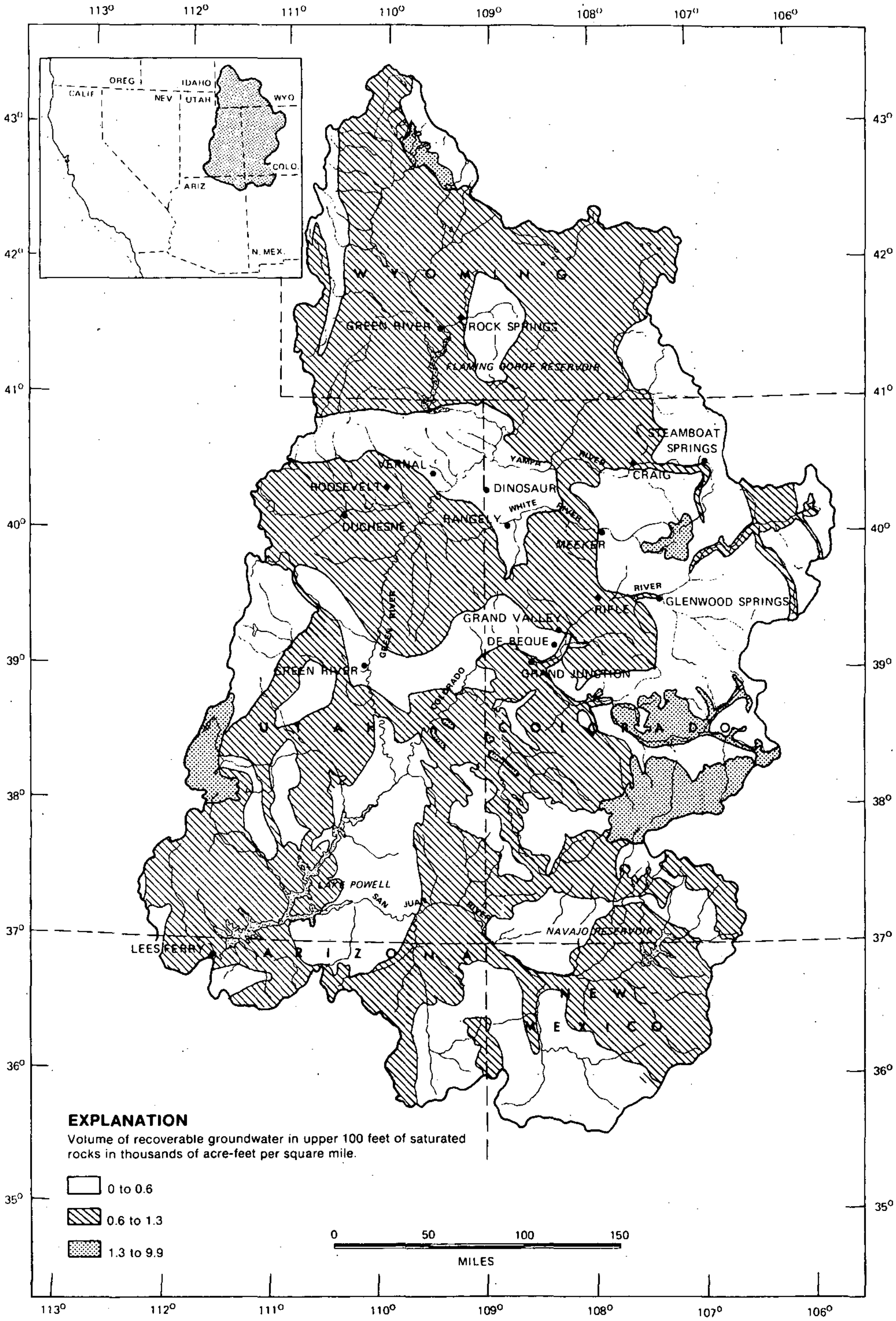

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Figure 4-17. Areas of recoverable groundwater. Source: Price and Arnow, 1974.

Depths to Groundwater and Fluctuations in Groundwater Levels

Figure 4-18 illustrates depths to groundwater throughout the Upper Colorado River Basin. The depth to groundwater from the surface affects the accessibility of groundwater to wells, since drilling and pumping costs increase with depth. Generally, depths to groundwater are least along the alluvial plain of main streams; they are greatest (generally more than 500 feet below the surface) along portions of the Colorado Plateau adjacent to particular stretches of the Colorado and San Juan rivers that have carved deep canyons.

It should be noted that both unconfined and confined (artesian) aquifers exist throughout the basin. Unconfined conditions commonly exist in shallow alluvial aquifers, in prinicipal recharge areas, and in the relatively flat-lying rocks that prevail in the southern portion of the basin. Artesian conditions occur locally throughout the basin and occasionally produce wells that flow freely at the surface. However, several hundred feet of drilling through unsaturated rocks is normally required before artesian aquifers are reached.

Most of the northern portion of the Green River Subregion is underlain by groundwater that exists at a depth of less than 100 feet, while most of the southern portion is underlain by groundwater existing at unknown depths.

Fluctuations in groundwater levels are caused by variations in natural recharge, natural discharge, and pumping. These variations are primarily seasonal in nature. As a result, changes in groundwater storage correspond to changes in groundwater levels. Rising groundwater levels normally indicate increases in groundwater storage, while declining levels usually indicate decreases in groundwater storage. Other than in highly localized situations, fluctuations in groundwater levels are normally less than ±10 feet throughout the basin. The most dramatic fluctuations occur in the vicinity of "new" reservoirs, such as Lake Powell, where groundwater levels may rise more than 50 feet due to increased bank storage around the reservoirs.

Availability of Groundwater

The general availability of groundwater, as indicated by the potential yield of individual wells, is shown in Figure 4-19. The potential yield from a well is a function of geologic conditions, aquifer characteristics, depth to groundwater, well diameter, etc. Throughout most of the Upper Colorado River Basin, yields from wells generally range from 5 to 50 gal/min. However, wells that tap alluvium on major streams are normally capable of higher yields, ranging from 50 to 500 gal/min. Yields from wells within the Green River Subregion generally range from 5 to 50 gal/min.

There are numerous springs located throughout the basin. Although most springs yield only a few gallons per minute, a few yield in excess of 100 gal/min. High-yield springs are generally found near the headwaters of larger streams.

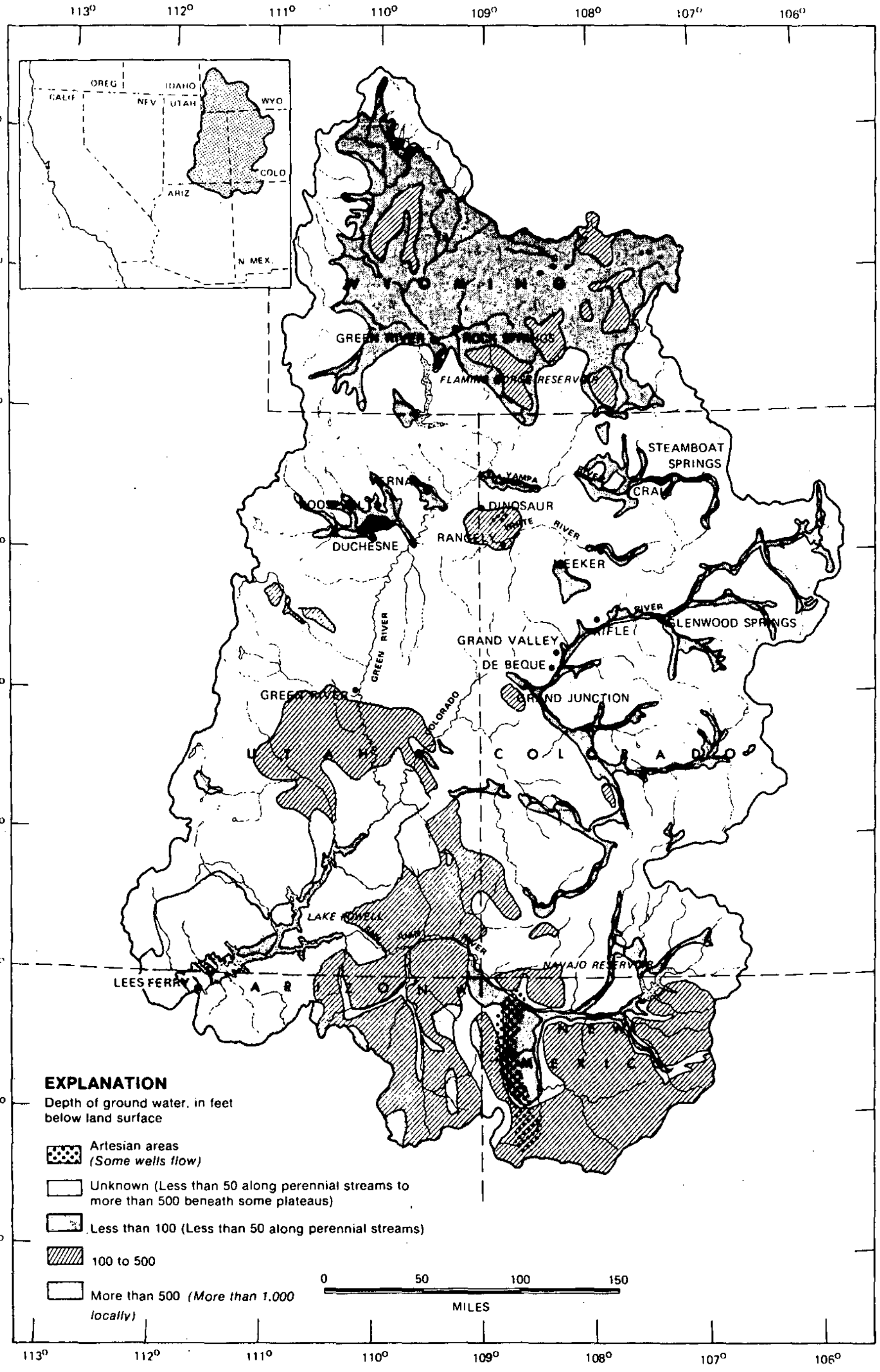

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Figure 4-18. Depths to groundwater. Source: Price and Arnow, 1974.

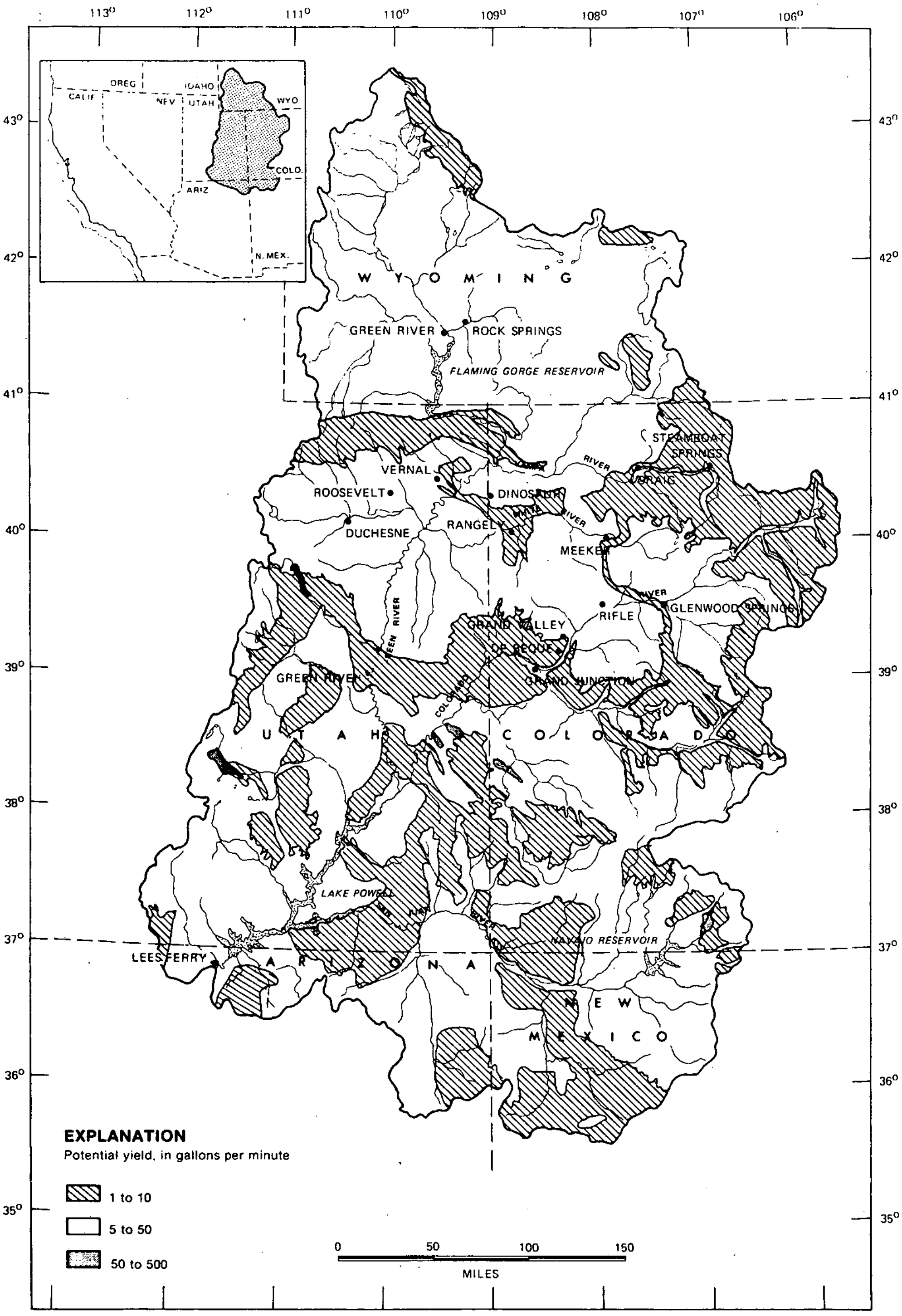

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Figure 4-19. Potential yields to properly located, properly constructed wells. Source: Price and Arnow, 1974.

Areas of Groundwater Recharge and Groundwater Discharge

Groundwater recharge occurs in areas where water enters into storage in an aquifer, whereas groundwater discharge occurs in areas where water exits from storage. Water can enter into storage along losing reaches of a stream by percolation through the unsaturated zone above an aquifer, etc. Water can exit from storage along gaining reaches of a stream via springs, etc.

Areas of groundwater recharge and discharge within the Upper Colorado River Basin are identified in Figure 4-20. As the figure shows, principal areas of natural groundwater recharge are at higher elevations where the average annual precipitation exceeds 12 inches. In addition to natural groundwater recharge, a significant degree of artificial groundwater recharge occurs in major irrigated areas. Principal areas of groundwater discharge are along the gaining reaches of streams.

Groundwater Quality

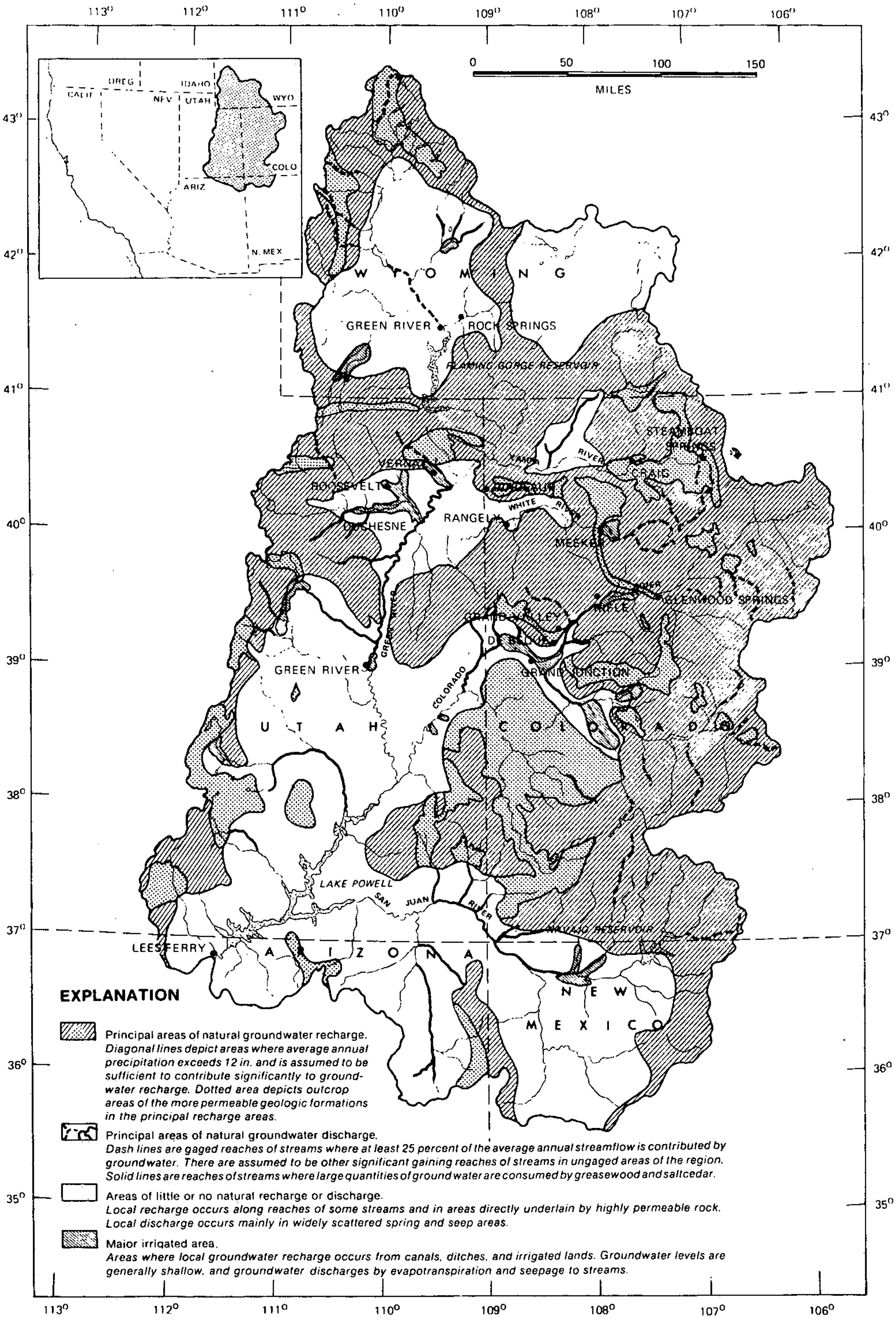
Geological conditions greatly influence the quality of groundwater underlying the Upper Colorado River Basin. As a general rule, alluvium normally yields water of the highest quality; low-permeability rock formations that have their origin in brackish or marine environments (i.e., shale, siltstone, sandstone, and some limestone) usually yield water of the poorest quality.

At higher elevations throughout the basin, good quality water is generally found in shallow aquifers in most rock formations. At lower elevations, good quality water most commonly occurs in relatively permeable sandstone formations. In contrast, poor quality water most commonly occurs in shale and siltstone strata.

Overall, groundwater is more highly mineralized than surface water within the basin. Although TDS concentrations in groundwater are generally higher than those in surface waters, the quality of much of the groundwater underlying the basin is relatively good.

The major groundwater quality problem within the basin is localized occurrences of high TDS concentrations. Groundwater with the lowest TDS concentrations is normally found in higher elevation mountain areas where rocks are relatively insoluble and groundwater freely circulates. TDS concentrations in these areas are usually less than 500 mg/l. In contrast, groundwater with the highest TDS concentrations is usually found in areas underlain by marine shale and siltstone formations. These formations are widely exposed in the northeast, central, and southeast portions of the basin. Typical TDS concentrations in these areas vary from 1000 to 3000 mg/l, or more.

Figure 4-21, which is based on data derived from chemical analysis of water from springs and wells, illustrates TDS variations in groundwater occurring throughout the basin. As shown in the figure, there are significant basin-wide variations in TDS concentrations, the highest generally being found in the Green River Subregion.



EXPLANATION

▨ Principal areas of natural groundwater recharge.
Diagonal lines depict areas where average annual precipitation exceeds 12 in. and is assumed to be sufficient to contribute significantly to groundwater recharge. Dotted area depicts outcrop areas of the more permeable geologic formations in the principal recharge areas.

Principal areas of natural groundwater discharge.
Dash lines are gaged reaches of streams where at least 25 percent of the average annual streamflow is contributed by groundwater. There are assumed to be other significant gaining reaches of streams in ungaged areas of the region. Solid lines are reaches of streams where large quantities of ground water are consumed by greasewood and saltcedar.

☐ Areas of little or no natural recharge or discharge.
Local recharge occurs along reaches of some streams and in areas directly underlain by highly permeable rock. Local discharge occurs mainly in widely scattered spring and seep areas.

▨ Major irrigated area.
Areas where local groundwater recharge occurs from canals, ditches, and irrigated lands. Groundwater levels are generally shallow, and groundwater discharges by evapotranspiration and seepage to streams.

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Figure 4-20. Areas of groundwater recharge and groundwater discharge. Source: Price and Arnow, 1974.

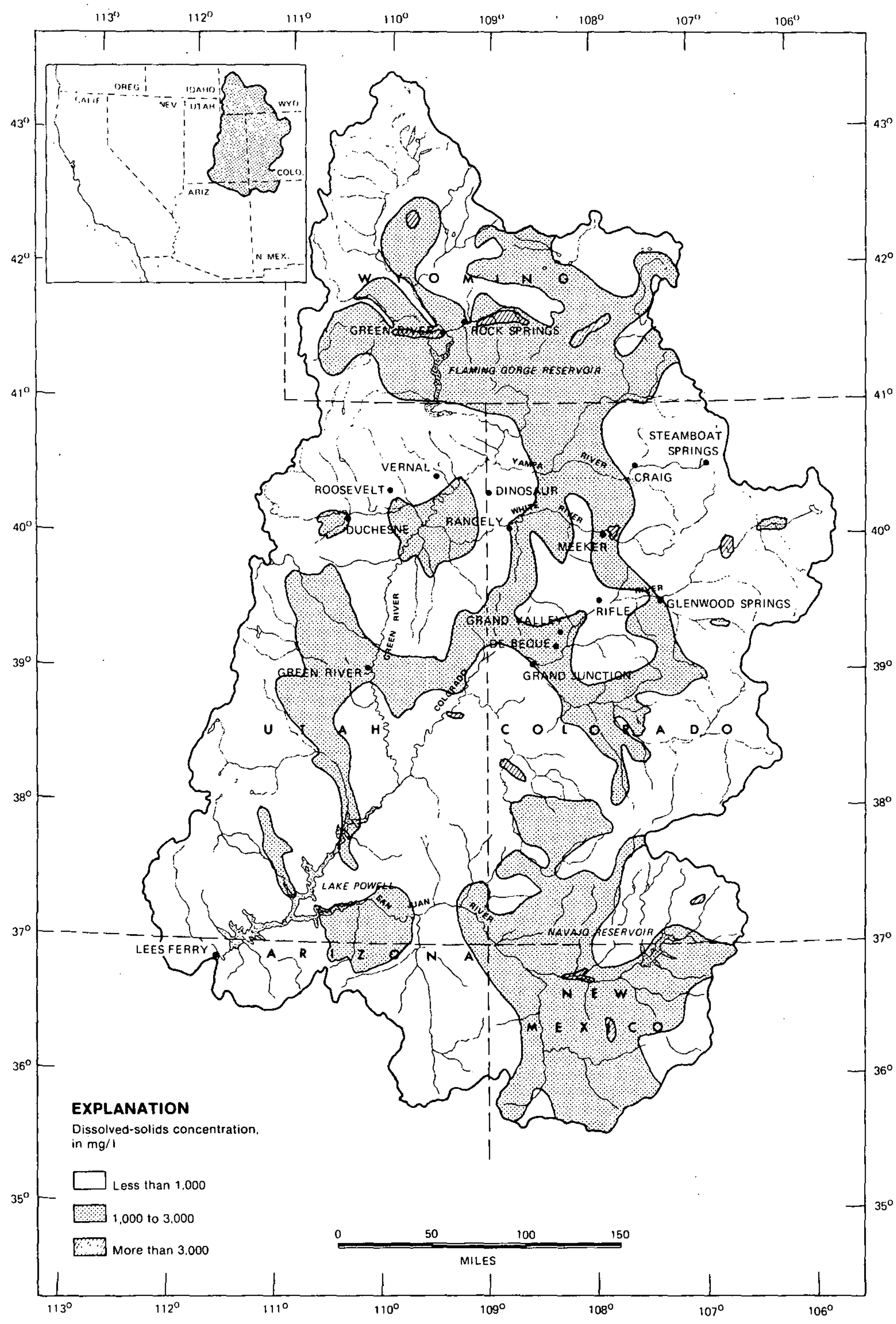

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Figure 4-21. Concentrations of dissolved solids in groundwater. Source: Price and Arnow, 1974.

QUALITY OF GROUNDWATER FROM REPRESENTATIVE WELLS AND SPRINGS PRINCIPALLY IN RIVER ALLUVIUM

(Units = equivalents per million)

Well or Spring	Ca	Mg	Na + K	Cl	SO_4	Alkalinity
359-G	14	16	30	5	42	13
148-G	8	4	12	2	15	7
650-G	10	8	18	3	21	12
648-G	5	2	6	2	6	5
674-G	4	3	3	2	3	5
239-G	2	2	4	1	1	6
455-G	42	29	29	9	81	10
456-G	11	7	16	3	14	17
1021-G	23	19	43	17	56	12
110-G	17	9	11	5	21	11
14-G	24	13	18	3	42	12
44-G	6	5	18	3	9	17
624-G	18	6	27	5	37	9
1005-G	12	0	58	3	55	12
848-G	32	8	1	1	32	8

Wells and springs listed in column 1 are located on the map in Figure 4-22.

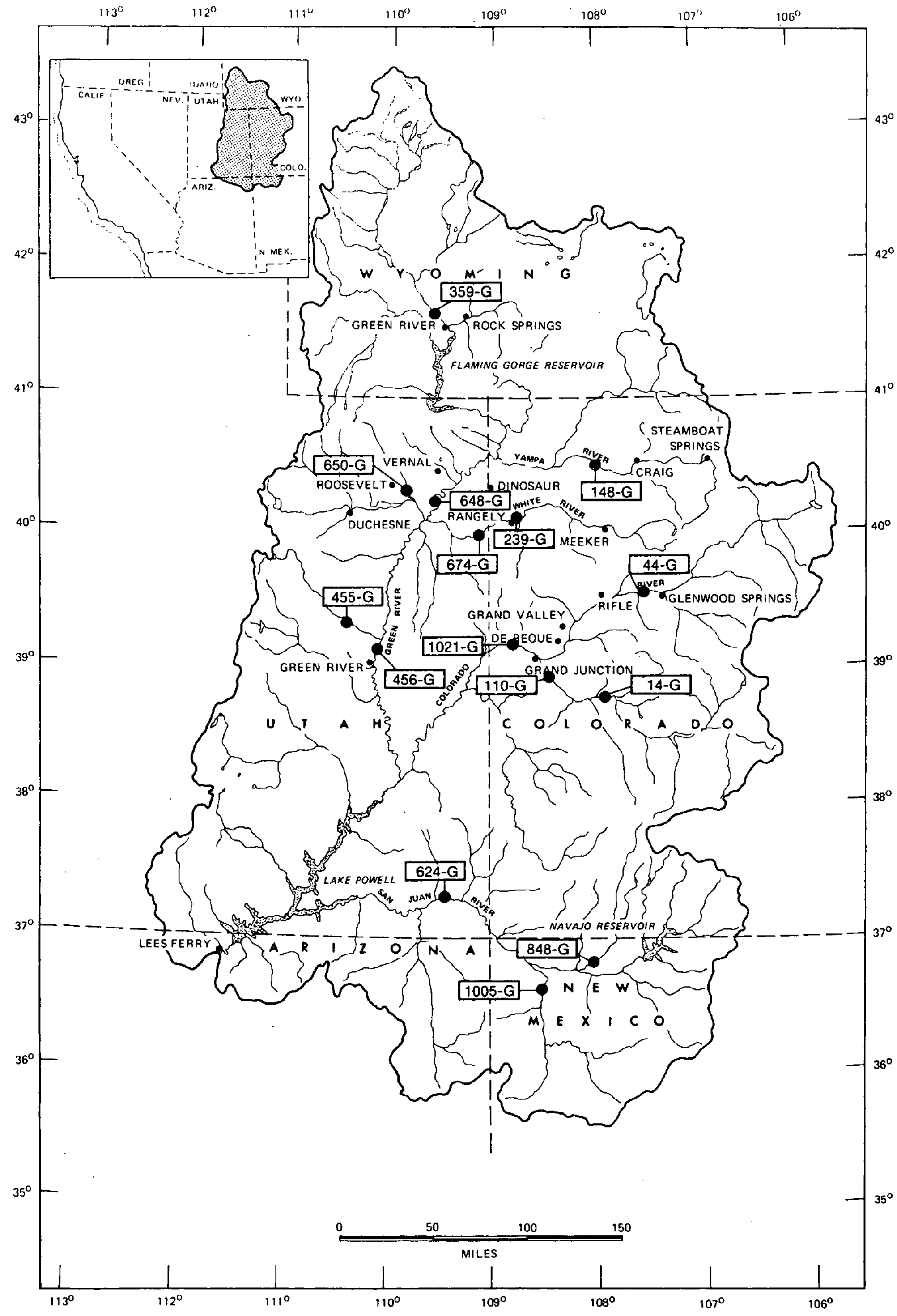

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Figure 4-22. Quality of groundwater from selected wells and springs throughout the Upper Colorado River Basin. Source: Iorns et al., 1965.

Usually, water containing less than 1000 mg/l is considered to be potable. As shown in Figure 4-21, most of the Upper Colorado River Basin (approximately 70 percent) is underlain by potable groundwater. In contrast, about 30 percent of the basin is underlain by nonpotable groundwater (i.e., groundwater with a TDS concentration greater than 1000 mg/l). Much of the Green River Subregion is underlain by poor quality groundwater with a TDS concentration ranging from 1000 to 3000 mg/l. In isolated areas within the subregion, TDS concentrations exceed 3000 mg/l. The concentration of various ions found in groundwater from representative wells and springs throughout the Upper Colorado River Basin is illustrated in Figure 4-22. As the figure shows, the quality of groundwater varies significantly throughout the basin.

WATER USE

Within a regional planning basin, there is a fixed volume of water available each year for water supply, this volume being defined as "undepleted water supply" or "virgin water supply." Undepleted water supply is equivalent to the total annual volume of water that would discharge at the mouth of a basin, as derived from surface runoff and groundwater baseflow, if the basin were in a completely undeveloped state without human activities. It represents the maximum volume of water available for water supply during an average year from both surface water and groundwater resources and implicitly includes the safe yield of groundwater from aquifers underlying the basin.

A "withdrawal" is defined as a volume of water extracted from the undepleted water supply for a particular use. A portion of the withdrawal is returned after use, while the remaining portion is lost, the lost portion being defined as a "depletion" or "consumptive use." The term "water depletion" is synonymous with the term "consumptive use."

Current Water Supply and Water Depletion Patterns

The total undepleted water supply available in the Upper Colorado River Basin is estimated to be about 14.9 million acre-feet per year, based on the period of record 1914-1965. The total undepleted water supply within each of the hydrologic subregions is shown in Table 4-11.

Water depletions occur throughout the Upper Colorado River Basin as a consequence of various activities, including:

- Irrigation
- Municipal and industrial water use
- Minerals processing
- Electric power generation
- Fish and wildlife
- Recreation
- Reservoir evaporation

Table 4-11. Annual average (1914-65) undepleted water supply in the Upper Colorado River Basin and its hydrologic subregions.

Subregion	Undepleted water supply, 1000 acre-ft
Green River	5,460
Upper Main Stem	6,810
San Juan-Colorado	2,610
Total	14,880

Source: UCR Group, 1971.

Water depletions associated with each of the above activities in 1975 are summarized in Table 4-14. As seen in the table, the most significant water depletion in the basin is that associated with irrigation activities. Main stem reservoir evaporation is another major cause of water depletion.

It should be noted that the basin exports a net 716,000 acre-feet of water each year (net export = total export - total import). Although technically not considered to be a water depletion, exports decrease the available water supply and are classified as a water depletion in Table 4-12.

Most withdrawals and depletions within the basin are related to surface water. In fact, groundwater depletions represent only about one percent of the total basin-wide water depletions. In 1970, about 122,000 acre-feet of groundwater were withdrawn, resulting in a depletion of about 63,000 acre-feet (Price and Arnow, 1974). The largest withdrawal of groundwater is for industrial purposes, and irrigation results in the greatest depletion of groundwater.

Future Water Use

Entire Upper Colorado River Basin. In Table 4-13, present water use is compared with projected water needs in the Upper Colorado River Basin for the year 2020. The estimates presented in the table describe the water supply "theoretically" available within the basin. However, these estimates ignore the legal framework that will govern the future use of water that is theoretically available. The future disposition of available water (including the use of water by in-situ oil shale development) is discussed in more detail in Chapter 5 (Statutory Framework for Water Availability and Water Quality for In-Situ Oil Shale Development).

Table 4-12. Estimated 1975 water depletions in the Upper Colorado River Basin.

	Water depletions by subregion, 1000 acre-ft			
Use	Green River	Upper Main Stem	San Juan-Colorado	Total
Irrigation	810	795	326	1,931
Municipal and industrial	10	15	14	39
Minerals	33	9	7	49
Electric power	20	4	51	75
Recreation/fish and wildlife	25	8	29	62
Reservoir evaporation	52	60	39	151
Main stem reservoir evaporation	73	19	428	520
Consumptive conveyance losses	22	175	12	209
Import	0	0	(133)	(133)
Export	122	614	113	849
Other	123	11	11	145
Total	1,290	1,710	897	3,897

Source: USID, 1975.

Table 4-13. Water depletion and available water supply for the Upper Colorado River Basin: 1975-2020.

Subregion	Undepleted water supply, 1000 acre-ft		Water depletions, 1000 acre-ft		Available supply, 1000 acre-ft	
	1975	2020	1975	2020	1975	2020
Green River	5,460	5,460	1,290	2,390	4,170	3,070
Upper Main Stem	6,810	6,810	1,710	2,230	5,100	4,580
San Juan-Colorado	2,610	2,610	897	1,930	1,713	680
Total	14,880	14,880	3,897	6,550	10,983	8,330

Sources: UCR Group, 1971; USID, 1975.

In Table 4-13, the estimated 11 million acre-feet of water supply presently available in the basin represents the residual flow of the Colorado River at Lees Ferry after water depletions have been subtracted from the undepleted water supply. It is anticipated that basin-wide water depletions in the future will increase as a consequence of increased water use associated with population growth, industrialization, and increased irrigation activities.

Projections for the year 2020 were developed by the Upper Colorado Region Comprehensive Framework Study (UCR Group, 1971), based on population and economic projections made by the Office of Business Economics-Economic Research Service (OBERS). These projections do not include future water use estimates for in-situ oil shale development. Projections for the year 2020 indicate that basin-wide water depletions will increase by about 70 percent. Irrigation depletions alone are expected to increase by about 600,000 acre-feet by the year 2020. It is anticipated that future increases in water depletions will result in serious water problems throughout the basin, including significant increases in TDS concentrations.

Green River Subregion. The undepleted water supply available in the Green River Subregion is about 5.5 million acre-feet per year. Water depletions in the subregion in 1975 were about 1.3 million acre-feet per year. The major water depletion in the subregion is associated with irrigation activities (810,000 acre-feet per year). Other significant water depletions include exported water (122,000 acre-feet per year) and evaporation at the Flaming Gorge Reservoir (73,000 acre-feet per year).

Projections for the year 2020 indicate that water depletions will increase substantially, primarily due to increased irrigation acitivites within the subregion. A summary of present (1975) and future (2020) water depletions in the Green River Subregion is presented in Table 4-14.

Table 4-14. Present and future water depletions in the Green River Subregion: 1975 and 2020.

	1975	2020	Change, %
Undepleted water supply, 1000 acre-ft	5,460	5,460	0%
Water depletions, 1000 acre-ft	1,290	2,390	+85%
Available water supply, 1000 acre-ft	4,170	3,070	-36%

Sources: UCR Group, 1971; USDI, 1975.

WATER RESOURCES OF THE PICEANCE CREEK BASIN

The Piceance Creek Basin is a lower order basin situated within the Green River Hydrologic Subregion of the Upper Colorado River Basin. The basin is a likely candidate for future oil shale development and therefore will be discussed in various sections of this report as an example of a typical basin suitable for in-situ oil shale development. Federal lease tracts C-a and C-b, the sites for development of the Rio Blanco and Occidental VMIS technology, are located within this basin.

Much of the following information describing the water resources of the Piceance Creek Basin was derived from Weeks et al. (1974). In other sections of the report, additional information on the water resources of the basin are presented in order to facilitate the various assessments being made.

The location of the Piceance Creek Basin and federal lease tracts C-a and C-b are described in Figure 4-23. The basin is situated in northwestern Colorado and drains an area of about 900 square miles. It includes both the Piceance Creek and Yellow Creek drainage areas. The composite of these two drainage areas has been designated as the Piceance Creek Basin.

Surface Water in the Piceance Creek Basin

Major surface waters within the Piceance Creek Basin include the Piceance Creek and Yellow Creek, both of which are perennial streams. A few of the tributaries to these streams are also perennial. However, most streams within the basin are intermittent. Most of the following discussion will focus specifically on the Piceance Creek, the most important surface water within the basin.

The major sources of stream flow in the Piceance Creek Basin include groundwater base flow and snowmelt from higher elevations along the perimeter of the basin. Snowmelt produces a period of high stream flow that starts in the spring and continues until mid-summer. Stream flow for the remainder of the year is maintained almost entirely by groundwater base flow. About 80 percent of the flow measured at the mouth of the basin is derived from groundwater base flow.

The average annual discharge of the Piceance Creek at White River is about 12,300 acre-feet per year, as measured by a gaging station. However, this does not include water that is diverted from the Piceance Creek, immediately before the gaging station, for irrigation outside the basin. The USGS has estimated the adjusted annual discharge to be 14,520 acre-feet per year, including the flow measured at the gaging station and the estimated diverted flow. The only significant activity resulting in depletion of streamflow through the Piceance Creek Basin is depletions associated with irrigation.

A flow duration curve for the Piceance Creek is presented in Figure 4-24. As shown in Figure 4-24, there are significant variations in stream flow in the Piceance Creek. It should be noted that the shape of this flow duration curve is influenced by irrigation practices.

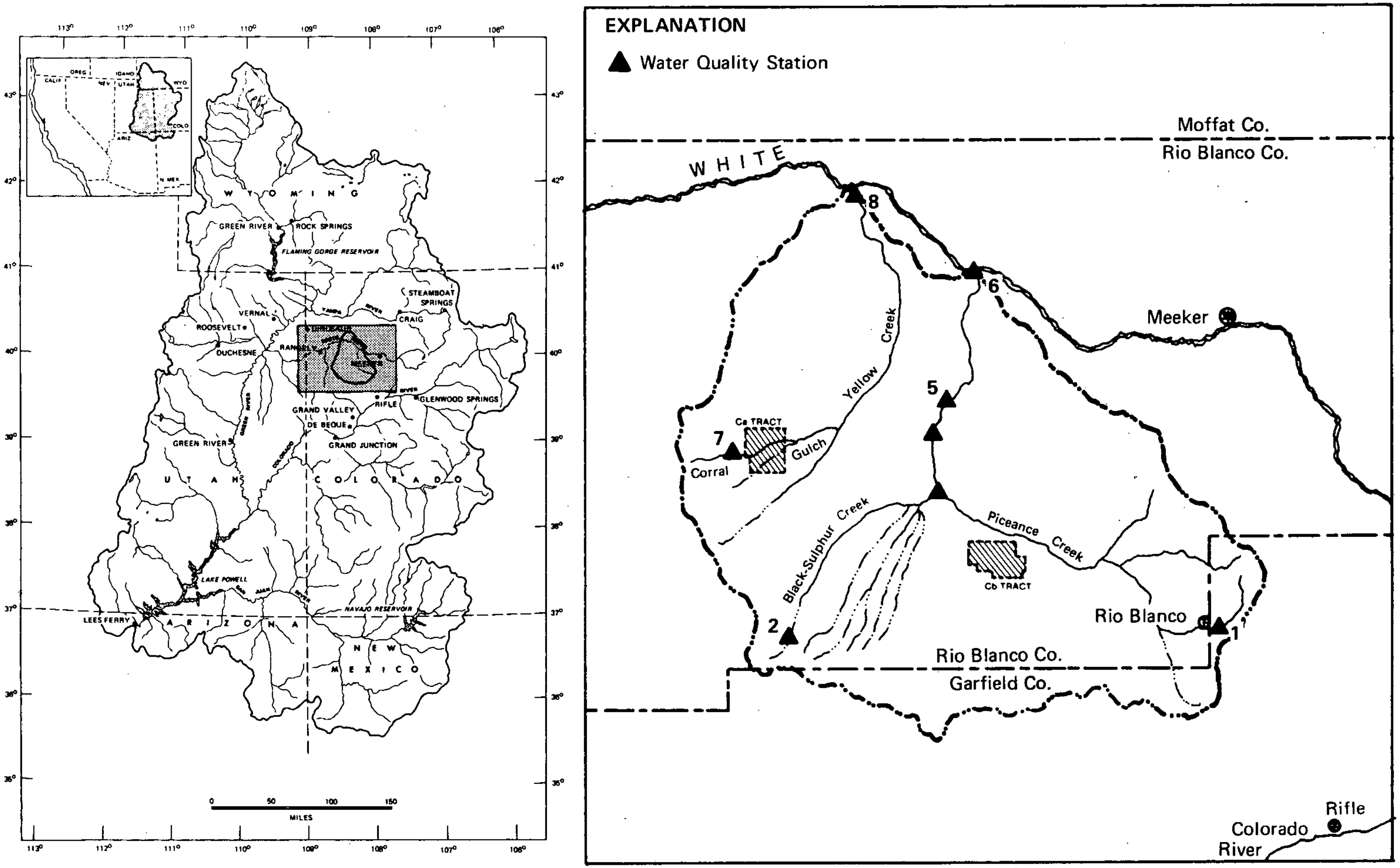

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Figure 4-23. The Piceance Creek Basin and the location of water-quality sampling sites on streams. Adapted from Weeks et al., 1974.

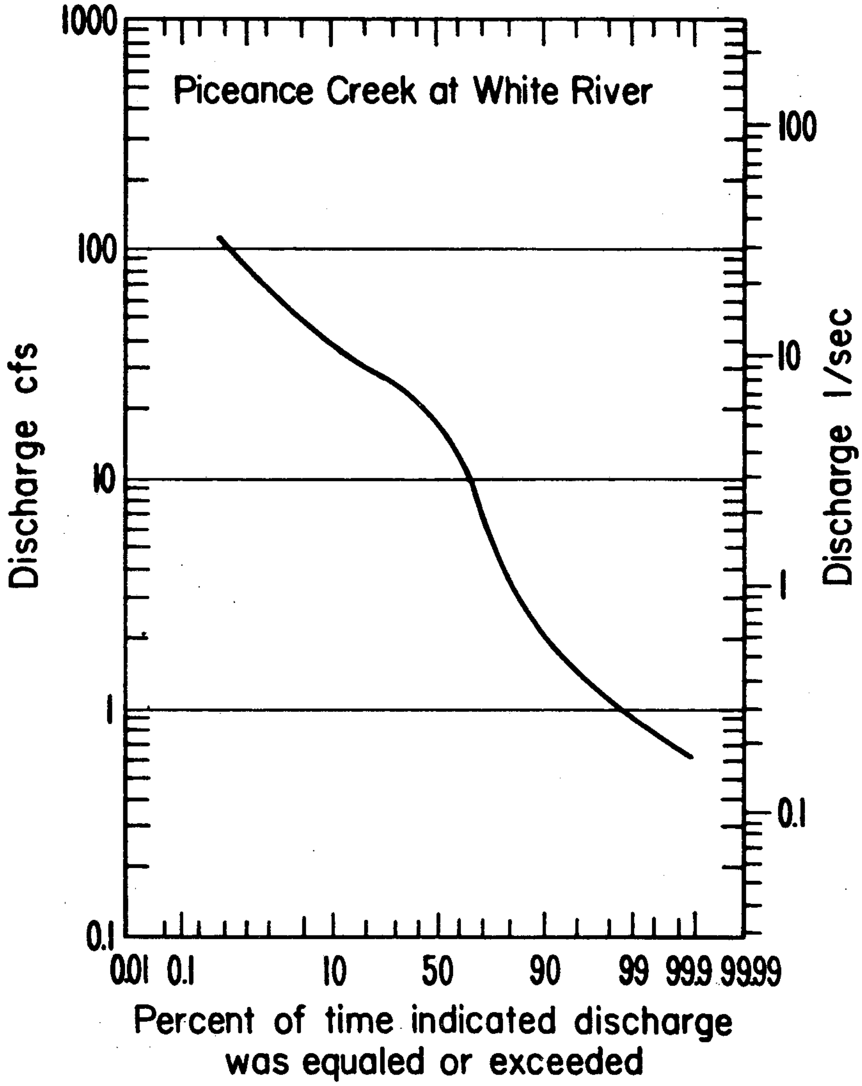

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Figure 4-24. Flow-duration curve for Piceance Creek at White River, Colorado. Source: Weeks et al., 1974.

Water quality in surface waters varies throughout the Piceance Creek Basin. The chemical composition of surface waters of the Piceance and Yellow creeks was presented in Table 4-2. The streams of the basin are classified as a mixed bicarbonate type in the upper reaches, gradually changing into a sodium bicarbonate type in the lower reaches. Concentrations of TDS, sodium, and chlorine all increase from the headwaters to the lower elevations. Changes in chemical quality of the Piceance Creek in the downstream direction are shown in Figure 4-25. Samples for these analyses were collected over a 30-day period between July and August, 1973. As shown in Figure 4-25, the TDS increases and the chemical composition changes as streamflow progresses from the headwaters to lower elevations. Overall, the TDS in the Piceance Creek ranges from 500 mg/l in the upper reaches to 5,000 mg/l in the lower reaches.

Groundwater in the Piceance Creek Basin

Groundwater occurs throughout the Piceance Creek Basin. The principal aquifer system consists of an upper and lower aquifer separated by a confining layer known as the Mahogany Zone, a thick continuous layer of rich oil shale. The Mahogany Zone, which ranges in thickness from 100 to 200 feet, persists throughout the basin and effectively separates the upper and lower aquifers both chemically and hydraulically, except in the recharge and discharge areas. These two aquifers extend throughout the basin; occasional fractures in the Mahogany Zone permit limited interaction between the aquifers. A geohydrological section through the Piceance Creek Basin is presented in Figure 4-26. In addition to these two principal aquifers, there are alluvial aquifers; they are limited to valley bottoms along creeks, however, and are not considered important relative to the principal aquifers.

The transmissivity of the upper aquifer ranges up to 7500 gpd/ft and averages 1000 gpd/ft. The average depth of the saturated zone is about 300 feet. The hydraulic gradient averages about 60 ft/mi and the average storage coefficient is 0.001. The transmissivity of the lower aquifer averages 2,000 gpd/ft but ranges up to 15,000 gpd/ft. The average depth of the unsaturated zone is about 600 feet; the storage coefficient averages 0.0001 while the average hydraulic gradient is about 60 feet per mile. As noted above, occasional fractures in the Mahogany Zone permit limited exchange between the two principal aquifers. Throughout most of the basin, the lower aquifer is characterized by a greater head with the greatest head difference normally existing near the center of the basin. The difference in hydraulic head between the upper and lower aquifers is less than 100 feet in almost all areas and differences of less than 50 feet are typical. Both aquifers discharge into the Piceance Creek and the Yellow Creek, the lower aquifer first discharging into the upper aquifer through occasional fractures in the Mahogany Zone.

The chemical quality of groundwater in the Piceance Creek Basin varies both within and between the aquifers. The quality of the alluvial, upper, and lower aquifers on lease tracts C-a and C-b is summarized in Tables 4-15 and 4-16 in terms of the minimum, maximum, and average observed values for the period 1974-1976. These tables indicate that the principal cations and ions in groundwaters in the vicinity of these lease tracts are CO_3, HCO_3, SO_4, Cl, Ca, Mg, K, Na, and Si. Most of the trace elements, with the exception of B, F, and Fe, occur at concentrations less than one ppm.

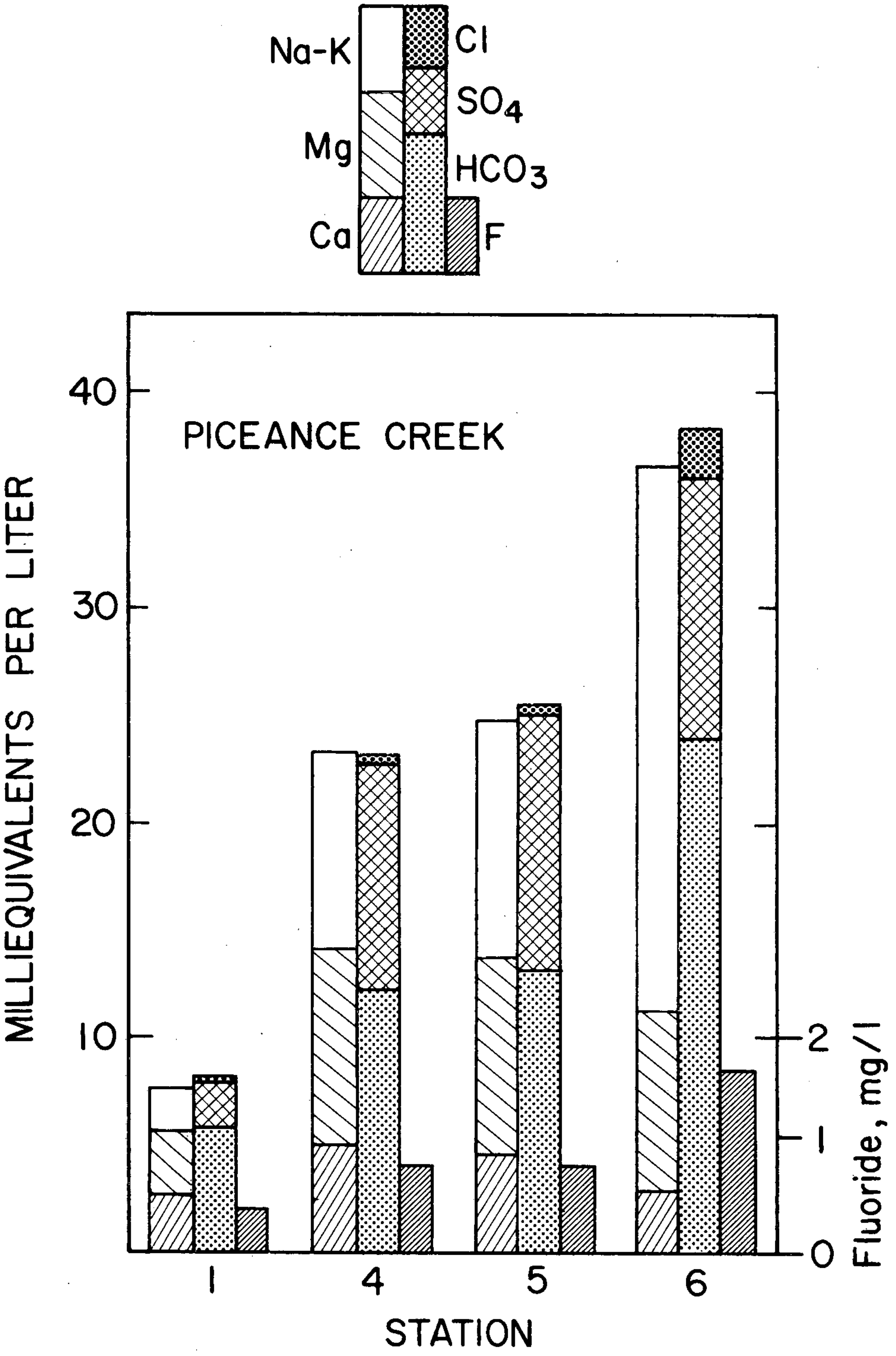

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Figure 4-25. Chemical composition of surface water in the Piceance Creek Basin (See Figure 4-23 for station locations). Source: Weeks et al., 1974.

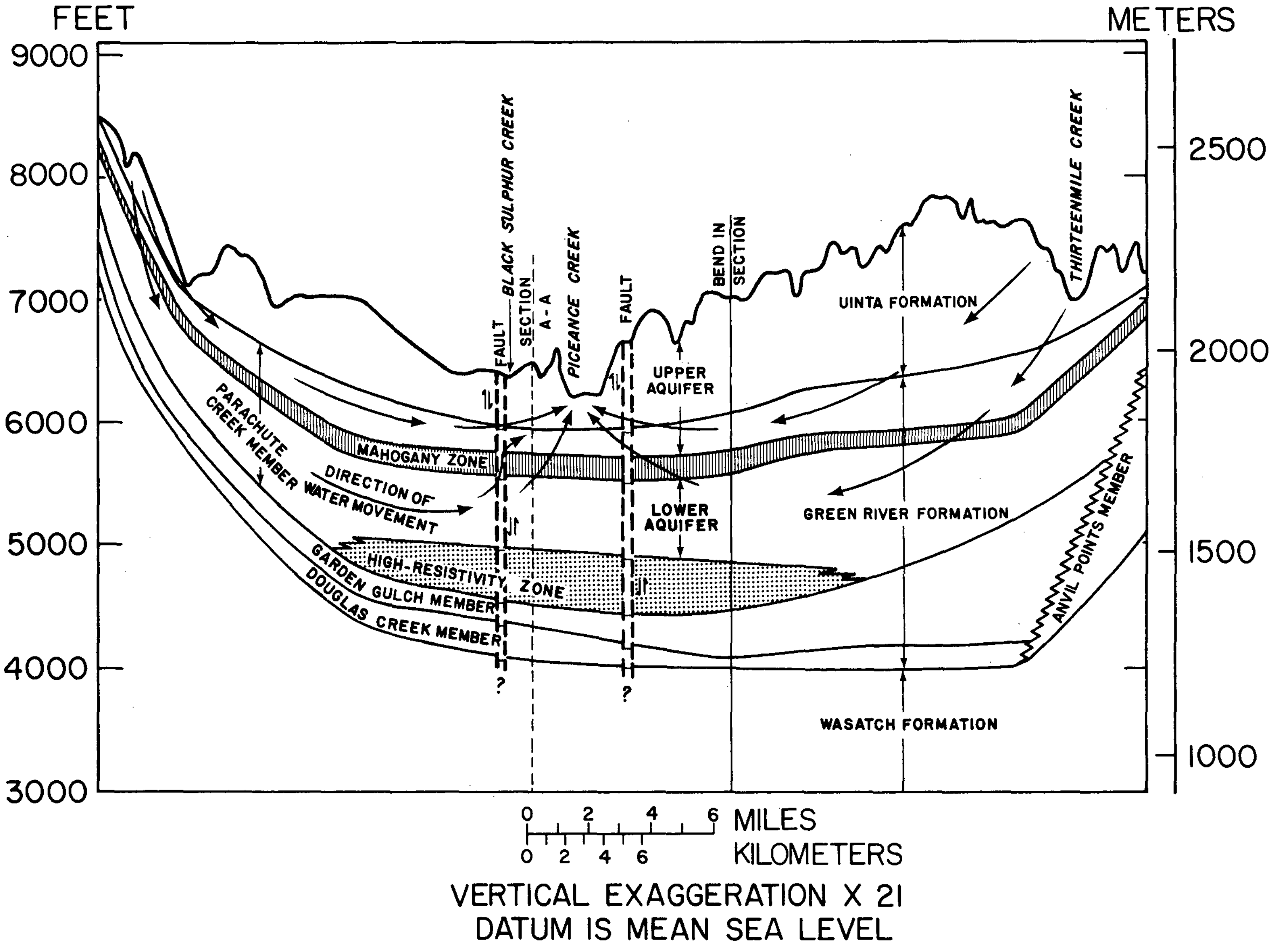

Figure 4-26. Geohydrologic section through Piceance Creek Basin. Adapted from Weeks et al., 1974.

Table 4-15. Groundwater quality of lease tract C-a.

Parameter (mg/l unless otherwise specified)	Alluvial Aquifer			Upper Aquifer			Lower Aquifer		
	Min.	Max.	Avg.[a]	Min.	Max.	Avg.[a]	Min.	Max.	Avg.[a]
Alkalinity	310	880	383	70	2390	408	52	4500	674
Aluminum	<0.1	1.2	0.14	<0.01	1.0	0.15	<0.01	1.0	0.24
Ammonia as NH_4	<0.1	6.4	0.36	<0.1	1.8	0.3	0.02	9.6	0.59
Arsenic	<0.01	<0.1	<0.011	<0.01	0.05	0.010	<0.01	0.03	0.01
Barium	<1	<1	<1	<0.1	<1	<0.98	<0.1	<1	<0.97
Beryllium	<0.02	0.6	0.11	<0.01	<0.01	<0.01	<0.1	<0.1	--
Bicarbonate	360	680	459	85	2760	482	260	3310	842
Biochemical oxygen demand	3.8	3.9	3.85	--	--	--	--	--	--
Boron	<0.01	27	0.19	0.01	4.8	0.33	0.01	5.7	0.84
Bromide	<0.01	0.9	0.15	<0.02	0.5	0.07	<0.02	<0.1	<0.05
Cadmium	<0.01	1.1	0.017	<0.001	0.1	0.0096	<0.001	0.03	0.0099
Calcium	39	210	96.4	4	260	34.8	0.80	98	8.8
Carbon, dissolved organic	2.0	292	18.7	1.0	50	8.5	3.0	73	10.5
Carbonate	<0.1	48.0	0.26	<0.1	335	0.88	<0.1	710	68.8
Chloride	1.3	41.0	12.8	<0.1	87	12.0	<0.1	160.0	21.7
Chromium	<0.01	0.2	0.011	<0.01	<0.05	<0.012	<0.01	<0.05	<0.011
Chemical oxygen demand	5	85	16.4	<0.1	400	17.7	<0.1	92	12.9
Coliform, fecal (col/100 ml)	<10	40	20	--	--	--	--	--	--
Coliform, total (col/100 ml)	20	250	71	--	--	--	--	--	--
Conductivity, µmho/cm	860	2252	1288	810	4200	1267	845	5180	1459
Copper	<0.01	2.4	0.012	<0.01	0.8	0.074	<0.01	0.3	0.088
Cyanide	<0.01	0.02	0.01	<0.01	0.1	0.01	<0.01	0.08	0.01
Fluoride	0.1	0.7	0.26	0.1	60	0.41	0.3	85	14.69
Hardness, as $CaCO_3$	280	810	448	32	1110	328	20	630	110
Iron	<0.05	28	1.03	<0.005	36	5.02	<0.05	16.2	0.78
Kjedahl Nitrogen	<0.10	8.8	1.78	--	--	--	--	--	--
Lead	0.01	1.0	0.14	0.002	3.8	0.17	0.003	26	0.21
Lithium	<0.1	<0.1	<0.1	0.1	1.0	0.13	0.1	0.6	0.13
Magnesium	3.7	145	57	3.5	200	52	1.9	105	20
Manganese	<0.05	15	0.58	<0.01	1.7	0.13	0.05	0.8	0.075
Methylene blue active substances	<0.01	<0.01	<0.01	--	--	--	--	--	--
Mercury	<0.001	<0.01	<0.0026	<0.001	0.045	0.0036	<0.001	<0.01	0.0024
Molybdenum	<0.1	<0.1	<0.1	<0.05	1.8	0.13	<0.05	0.2	0.1
Nickel	0.01	0.2	0.054	<0.001	0.2	0.019	<0.001	<0.1	<0.023
Nitrate as NO_3	0.1	165	3.9	<0.01	7	0.21	<0.1	2	0.1

Table 4-15. Groundwater quality of lease tract C-a (continued).

Parameter (mg/l unless otherwise specified)	Alluvial Aquifer			Upper Aquifer			Lower Aquifer		
	Min.	Max.	Avg.[a]	Min.	Max.	Avg.[a]	Min.	Max.	Avg.[a]
Nitrite as N	0.01	150	0.22	<0.02	0.6	0.07	<0.20	0.60	0.07
Nitrogen, Ammonia	0.10	5.3	0.36	0.20	1.8	0.51	0.40	3.2	1.18
pH (units)	6.0	7.2	6.32	6.0	8.8	6.78	6.0	8.9	7.16
Phenols	<0.001	0.013	0.0021	<0.001	0.17	0.0025	<0.001	1.0	0.0024
Phosphate, dissolved as PO_4	0.10	0.10	0.10	--	--	--	--	--	--
Phosphate, ortho	<0.01	0.30	0.10	0.09	1.0	0.10	<0.10	1.0	0.11
Potassium	<1.0	14.0	3.66	<1.0	11.0	2.19	<1.0	15.0	2.64
Radioactivity, (pc/l)									
Gross alpha	0.2	31.0	7.34	0.1	29.0	3.48	0.1	30.0	3.31
Radium 226	0.1	1.0	0.26	0.1	0.8	0.17	0.09	0.9	0.31
Gross beta	1.0	35.0	9.5	2.0	73.0	12.7	2.0	830.0	21.4
Selenium	<0.01	<0.1	≤0.010	<0.001	<0.01	<0.0098	<0.01	<0.1	<0.010
Silica as SiO_2	16	41	29.2	<0.1	58	25.6	<0.1	60.0	10.1
Silver	<0.01	<0.1	<0.013	0.001	0.1	0.012	<0.001	0.1	0.0089
Sodium	66	350	151.1	92	1170	212.0	155	1560	397
Solids, dissolved	640	1650	777	530	2850	905	540	3640	1075
Strontium	1.4	5.0	2.50	0.1	10.5	2.89	0.2	3.5	0.68
Sulfate	150	720	297	<4	900	325	<4	580	112
Sulfide	<0.10	1.60	0.16	0.03	49	0.63	<0.01	6.50	0.56
Temperature (°F)	42.0	57.7	48.8	46.4	68.9	54.0	46.9	75.2	58.5
Vanadium	--	--	--	<0.05	<0.05	--	<0.05	<0.05	--
Zinc	0.01	3.2	0.29	0.01	15.0	0.26	0.02	68.0	0.24

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[a] Arithmetic mean for pH and temperature, geometric mean for all other parameters

-- Not reported

Source: Gulf, 1977

Table 4-16. Groundwater quality of lease tract C-b.

Parameter (mg/l unless otherwise specified)	Alluvial Aquifer			Upper Aquifer			Lower Aquifer		
	Min.	Max.	Avg.	Min.	Max.	Avg.	Min.	Max.	Avg.
Aluminum	0.1	3	0.3	0.03	4	0.3	0.002	2	0.3
Ammonia	<0.01	15	0.5	0.1	7.9	1.2	0.1	200	17
Antimony	--	--	--	ND	0.02	--	ND	0.08	--
Arsenic	<0.001	0.05	0.006	<0.001	0.06	0.01	0.001	0.2	0.02
Barium	0.01	0.6	0.07	0.009	0.6	0.1	0.02	8	0.8
Beryllium	ND	<0.002	--	ND	0.003	--	ND	0.002	--
Bicarbonate	320	730	540	340	2100	790	100	25,000	4000
Boron	0.001	5	0.5	0.01	18	1.4	0.05	400	36
Bromide	0.006	0.1	0.04	0.003	0.2	0.03	0.003	10	0.7
Cadmium	ND	<0.03	--	ND	<0.02	--	ND	0.1	--
Calcium	16	102	67	3	120	32	2	220	14
Carbon, dissolved organic	2	11	6	--	--	--	2	175	23
Carbon, total organic	1	9	5	1	9	3	1	40	10
Carbonate	23	1	6.2	76	2	21	2000	1	220
Cesium	ND	0.03	0.006	<0.001	0.2	0.01	<0.001	4	0.2
Chloride	0.9	29	11	2	510	26	1	9800	1200
Chromium	0.002	<0.1	--	0.002	0.3	--	0.002	0.02	<0.009
Cobalt	<0.001	0.05	0.008	<0.001	0.01	0.003	<0.001	0.03	0.006
Conductivity, µmho/cm	950	1930	1380	800	4200	1670	630	45,000	7240
Copper	0.005	0.2	0.04	0.003	3	0.09	0.003	0.9	0.06
Fluoride	0.1	5	0.65	0.1	190	10	4	48	21
Gallium	ND	0.03	--	<0.001	0.004	--	<0.001	0.06	0.007
Germanium	ND	0.03	--	ND	0.002	--	ND	0.05	--
Iodide	0.001	0.03	0.007	<0.001	0.08	0.006	<0.001	3	0.3
Iron	<0.05	9	<0.3	<0.02	7	0.5	<0.05	8	0.8
Lead	<0.002	0.2	<0.02	<0.002	0.07	0.01	0.003	0.4	0.03
Lithium	--	<0.5	--	--	3.1	--	1.3	79	10
Magnesium	20	120	80	2.2	150	42	1.5	110	11
Manganese	0.003	2.3	0.2	0.002	0.6	0.1	0.002	0.6	0.1
Mercury	0.00002	0.048	0.003	<0.00003	0.0031	0.0004	<0.00003	0.0027	0.0004
Molybdenum	0.005	0.2	0.04	0.003	0.1	0.02	<0.004	0.02	0.04
Nickel	0.003	0.1	0.02	<0.001	0.2	0.02	<0.001	0.06	0.01
Nitrate	<0.02	9.1	1.6	<0.02	2.9	0.41	<0.02	3.4	0.46
pH (units)	7.3	8.7	8.2	8.1	9.1	8.6	8.1	9.3	8.7
Phosphate	<0.01	1.1	<0.09	<0.01	0.4	<0.09	0.01	0.7	<0.09

Table 4-16. Groundwater quality of lease tract C-b (continued).

Parameter (mg/l unless otherwise specified)	Alluvial Aquifer			Upper Aquifer			Lower Aquifer		
	Min.	Max.	Avg.	Min.	Max.	Avg.	Min.	Max.	Avg.
Potassium	0.7	5	1.5	0.3	11	2.2	1	120	21
Radioactivity, pc/l									
Gross alpha	0	18	5	0	21	6	0	460	28
Gross beta	0	13	2	0	33	3	0	390	16
Rubidium	0.002	0.06	0.01	<0.002	0.05	0.01	0.005	0.9	0.2
Scandium	<0.001	0.02	0.004	<0.001	0.009	0.003	<0.001	0.01	0.004
Selenium	ND	0.03	0.009	<0.001	0.03	0.006	<0.001	0.02	0.004
Silica	11	41	17	4	32	17	2	38	13
Silver	--	--	--	ND	0.05	--	ND	0.02	--
Sodium	93	730	175	44	1200	330	140	17,000	2500
Solids, dissolved	696	1300	996	520	3100	1100	356	42,000	6190
Sulfate	200	530	370	4	520	220	2	350	63
Thorium	--	--	--	ND	<0.001	--	ND	<0.001	--
Titanium	0.01	2	0.3	0.003	2	0.1	0.006	1	0.1
Tungsten	--	--	--	ND	0.02	--	ND	0.05	--
Uranium	--	--	--	ND	0.03	--	ND	0.02	--
Vanadium	<0.001	0.2	0.01	<0.001	0.006	0.002	<0.001	0.1	0.01
Yttrium	ND	0.007	--	ND	0.01	--	<0.001	0.03	--
Zinc	0.01	2	0.2	0.003	2	0.2	0.005	4	0.2
Zirconium	<0.001	0.04	0.007	<0.001	0.03	0.006	<0.001	0.9	0.08

ND not detected

-- Not reported

Source: Ashland, 1977

The alluvial and upper aquifers on both tracts and the lower aquifer on Tract C-a are of similar quality while the lower aquifer on Tract C-b differs significantly from the others. The Tract C-b lower aquifer has much higher total dissolved solids, Cl, CO_3, HCO_3, Na, and B than the other aquifers.

Within the Piceance Creek Basin, small amounts of groundwater are used for stock watering and domestic water supplies for some ranchers. It is estimated that about 80 percent of the flow in Piceance Creek and the Yellow Creek, as measured at the mouth of the basin, represents groundwater base flow.

CHAPTER 5

STATUTORY FRAMEWORK FOR WATER AVAILABILITY AND WATER QUALITY FOR IN-SITU OIL SHALE DEVELOPMENT

The purpose of this chapter is to put into perspective the statutory framework that governs the use of water and controls the discharge of waste effluents from an in-situ oil shale industry. The availability of water from an administrative and statutory standpoint is presented. Federal and state regulations applicable to those portions of Colorado, Utah, and Wyoming lying within the Upper Colorado Basin are discussed, and a foundation is developed for assessing the effect of discharges in terms of parameters for which regulations have not yet been set.

AVAILABILITY OF WATER

Water is essential for the development of an in-situ oil shale industry. It will be consumed in oil recovery, upgrading, and other operations and by the surrounding communities in which the labor force lives. The total demand will be a function of the size of the industry and the recovery technologies used. The quantity of water available to meet this demand depends both on the amount of groundwater and surface water physically present and on the legal and institutional situation in the three states of the oil shale region. The hydrology and water supply aspects of the Upper Colorado River Basin, the recovery technologies, and the size of industry are covered elsewhere in this report. The purpose of this section is to place water supply and demand for oil shale development in perspective with particular emphasis on the legal and institutional aspects.

Water Demand

The water demand depends on the size of the industry and the recovery technologies used. The ultimate size of the industry cannot be presently estimated; therefore, water demands herein are expressed as gallons of water consumed per barrel of shale oil produced. Proportional demands for any size industry can thus be determined if necessary.

Previous water consumption studies related to oil shale development have generally been oriented toward surface retorting. Although surface retorts are not directly within the scope of this report, practically speaking, it may be economically feasible in the future to combine surface and in-situ retorting. Twenty to forty percent of the in-place shale volume must be mined and brought to the surface for disposal. If this shale is rich enough in oil, a surface retort may be justified. Water demands for this operation would then be included in the overall project demand.

A general comparison of water use by categories for surface and in-situ technologies is shown in Table 5-1. Water consumption for associated growth, which is estimated to be 15 to 20 percent of the amount consumed by the technologies (CDNR, 1979b), is not included. This table indicates that the various surface retorting processes may consume from 207 to 224 gallons of water per barrel of oil while in-situ retorting may require relatively

Table 5-1. Comparison of net water consumption by surface and in-situ technologies. Excludes water demands for associated growth and includes water produced during retorting.

Process	Water consumption, gal/bbl	
	Surface[a]	Modified in-situ
Mining and crushing	23	12[b] to 19[a]
Retorting and upgrading	96 to 113	12[a] to 28[c]
Disposal of spent shale and revegetation	38	2[a] to 19[b]
Retort abandonment	0	10[d] to 150[d]
Power generation	25	26[c] to 46[a]
Miscellaneous	25	9 to 25[a]
TOTAL	207 to 224	71 to 278[e]

[a] Brown et al., 1977.

[b] Grew, 1977.

[c] Ashland, 1977 and Feb. 1977.

[d] Chapter 7, water consumption required to control in-situ leaching of spent shale. The lower value, 10 gal/bbl, is the amount of water required for intentional leaching with two pore volumes of water and 10 percent brine disposal. The higher value is the water required for grouting in-situ retorts with a slurry of raw or spent shale or other low-cost material. In this case, a credit of 50 percent may be taken for the water associated with the surface spent shale not disposed of and revegetated in the usual fashion, i.e., credit = 0.5 (19 gal/bbl) = 9.5 gal/bbl.

[e] Includes as a credit of 9.5 gal/bbl for spent shale used to grout in-situ retorts. See note d above.

less or more, about 71 to 278 gallons per barrel of oil. The amount of water required is strongly dependent on the type of technology used to control in-situ leaching of spent shale (Chapter 7). If no control technology is assumed for in-situ leaching, less total water is required for the in-situ processes because lesser quantities of raw and spent shale must be processed, handled, and disposed of. However, special control technologies may be required to mitigate leaching of in-situ retorts. Depending on the technology selected, up to 140 gal/bbl of additional water may be required (Chapter 7). In this case, in-situ technologies will require more water than surface technologies.

Surface technology is one in which shale is mined and brought to the surface for retorting. The spent shale is then sent to a surface disposal site. Surface retorting water demands shown in Table 5-1 are based on estimates made by Brown et al. (1977) in a recent report. The mining and crushing category includes water for site development, dust suppression, drilling, conveyance, crushing, and stockpiling operations. The retorting and upgrading category is the largest water consumer. Brown et al. considered three recovery technologies: Union, Paraho Indirect, and TOSCO II. Upgrading in each case is assumed to be visbreaking in which the shale oil is heated to reduce viscosity, thus making the oil suitable for pipe lining. In general, principal water losses occur from cooling towers and retorts. The consumption shown in the table has been adjusted to include retort water produced in the retort. Water used in disposal of spent shale and for revegetation includes that used for quenching and moisturizing the hot shale to control dust and to facilitate compaction in a disposal pile. Water is also consumed in leaching salts from upper layers in the piles and for irrigation of vegetation for two growing seasons (See Chapter 6). The miscellaneous category includes water lost by evaporation, unscheduled uses, and operating losses.

Water consumption estimates in Table 5-1 for in-situ retorting with no surface processing are based on three different sources: the Golder report (Brown et al., 1977), on material prepared by Ashland Oil, Inc. and Occidental Oil Shale, Inc. (Ashland, 1977 and Feb. 1977), and on material presented in Chapter 7 of this report. The mining and crushing category includes water lost as ventilation exhaust and by construction use, drilling, and dust control. Retorting and upgrading includes water used for steam injection and utilities, excluding power generation. This last category is net since retort water production has been deducted from gross consumption. Less water is lost in shale disposal and revegetation in in-situ processing than in surface retorting since only a portion of the shale in the retort is brought to the surface for disposal. However, large water consumption is required to return the in-situ spent shale to a condition of environmental acceptability. Control measures, which will eliminate or mitigate undesirable environmental impacts, must be instituted if spent retorts are to be safely abandoned after oil has been extracted. The control method that will be used by commercial operations is presently unknown; several options under study by industry and the research community are discussed in Chapter 7 of this report. The control technologies which appear the most viable from economic and technical standpoints are intentional leaching and the grouting of abandoned retorts. These technologies would consume water, as would other methods that might be used. Intentional leaching, which requires the lower water consumption noted for retort abandonment in Table 5-1, involves passing two pore volumes of water through an abandoned retort to flush out soluble materials, collecting and treating the leachate, and reusing the leachate following discharge or ten percent of the flow as brine. The larger water consumption for retort abandonment noted in Table 5-1, 150 gal/bbl, is the amount of water required to fill abandoned retorts with a grout based on raw or spent shale. The water is used to pre-wet the in-situ spent shale and to slurry the grout material.

A credit, amounting to about 50 percent, may be taken for water not consumed for surface disposal of raw or spent shale. The amount of water consumed in power generation depends primarily upon the type of cooling used. The value of 26 gal/bbl in Table 5-1 is based upon on an estimated 12 gpm per MW. The miscellaneous category includes evaporation, unscheduled uses, and losses.

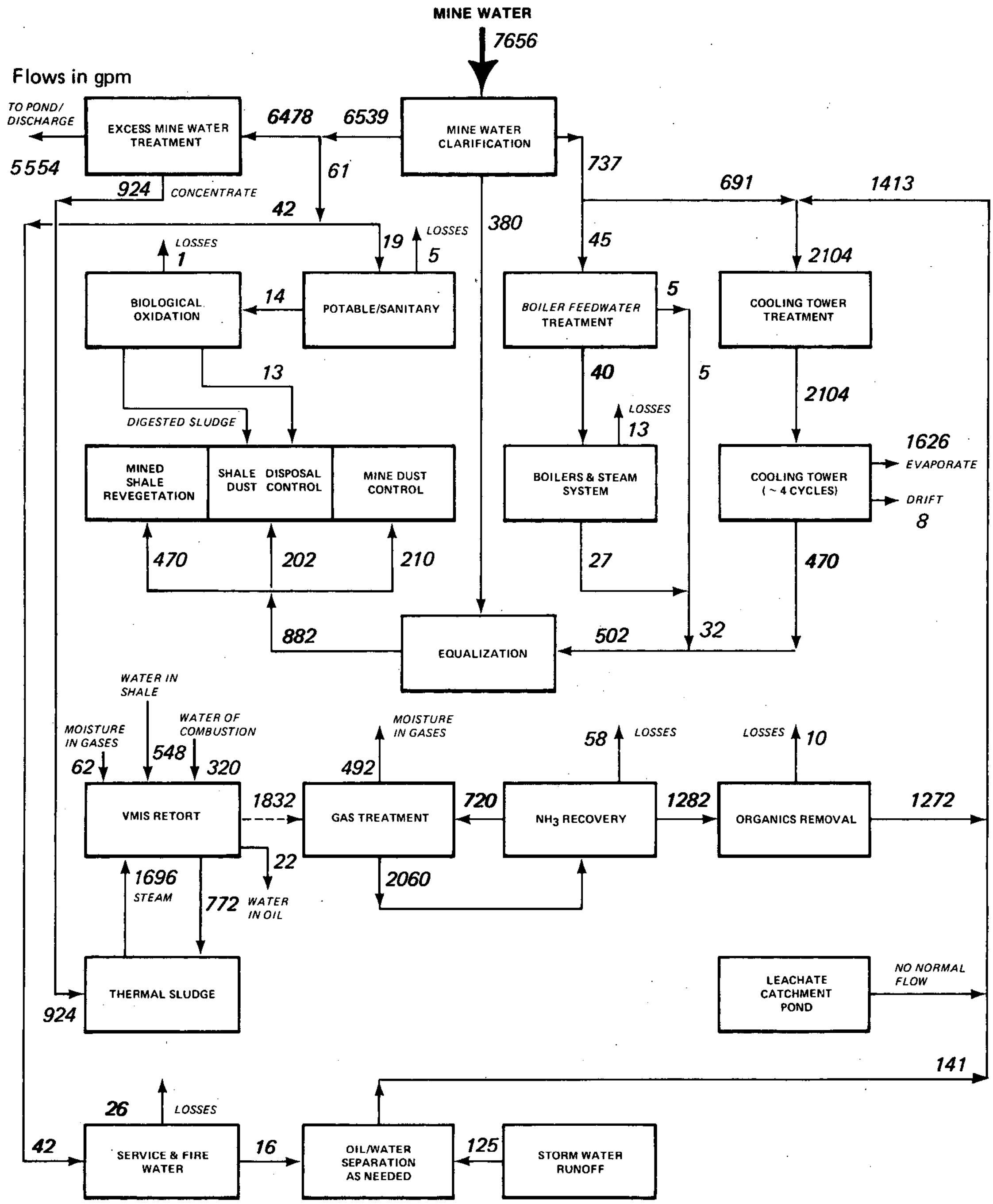
In-situ retorting may be done alone or in combination with a surface retorting process. Recent studies suggest that the latter approach is more economical (Grossman, 1977; Berry, 1978). The most likely water consumption for a combined surface/in-situ facility will probably be about midway between the two extremes given in Table 5-1. Note that this is about half of the consumption shown for the surface technologies.

Water Balances

Hypothetical water balances for an in-situ and a combined surface in-situ plant are shown in Figures 5-1 and 5-2 and summarized in Table 5-2. The two scenarios shown in Figures 5-1 and 5-2 are based on the Occidental vertical modified in-situ retorting technology (Chapter 3); the water balances were modified from a recent DOE study (Nevens et al., 1979). These scenarios assume that shale of 25 gal/ton will be retorted in place with steam and air injection for a yield of 57.2 percent of Fischer Assay. No on-site upgrading will occur. Low Btu gas produced by retorting will be used to generate steam and to produce electricity by gas turbine. Ammonia and sulfur will be recovered as byproducts. About 20 percent of the raw shale will be mined to produce void space. The site will be dewatered prior to and during retorting, and mine water not used in the process will be evaporated or reinjected.

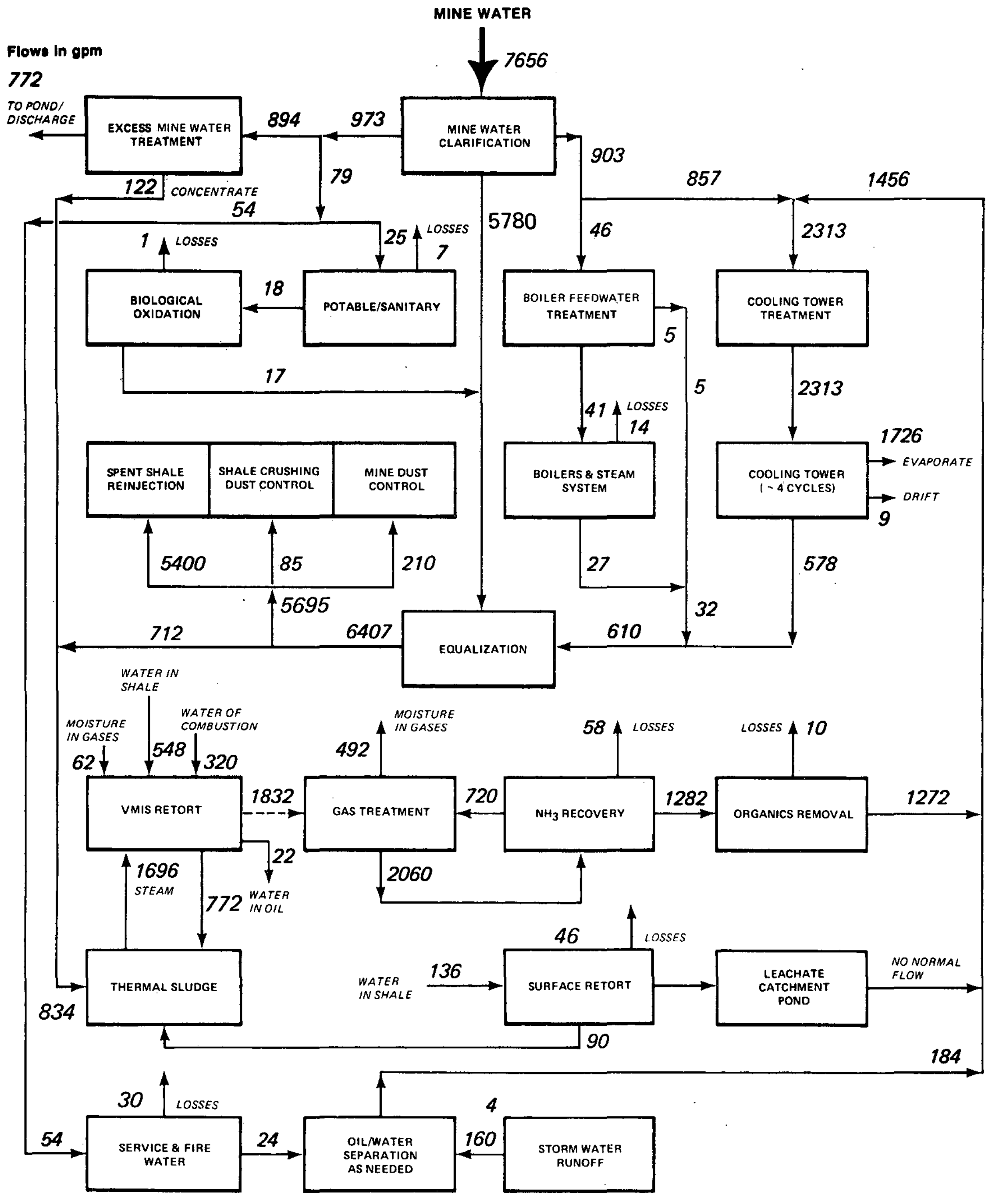
In the in-situ process, the mined-out raw shale is disposed of directly on the surface, and no controls are used to mitigate the leaching of in-situ spent shale (Chapter 7). In the other scenario, it is assumed that the mined out shale is retorted in a Lurgi-type retort and that the spent shale is returned to the abandoned retorts as a slurry. The in-situ spent shale is prewetted before slurry injection to improve flow and distribution of the slurry within the retort.

Table 5-2 suggests that the majority of the water demand of a shale plant can be met by mine water removed during site dewatering. However, dewatering flow rates will peak early in a project while demands may peak at a later time. This will require on-site storage and may result in the loss of a portion of the dewatering supply if adequate storage cannot be phased with dewatering operations. This area requires further study. Additional water is supplied to the VMIS and Lurgi retorts by moisture in the input gas, by moisture in the raw shale, by combustion of organics within the VMIS retort, and from storm water runoff. Since the major source of water for an in-situ industry will likely be mine water, state water laws governing groundwater will play a key role in the availability of water for an in-situ oil shale industry. The major consumptive uses of water in these scenarios are for cooling water, dust control, and retort abandonment. The higher water demands of the VMIS-Lurgi scenario are due to the underground disposal of spent shale. Table 5-2 indicates that this operation may require about 57 gallons of water



FXBL-807-1391

Figure 5-1. Major water streams for modified in-situ oil shale plant producing 57,000 bbl/day crude shale oil and 97 MW electricity.



FXBL-807-1392

Figure 5-2. Major water streams for modified in-situ Lurgi shale oil plant producing 81,000 bbl/day crude shale oil and 100 MW electricity.

Table 5-2. Water balance for modified in-situ retorting with and without surface retorting by the Lurgi process (gpm).

	VMIS with Lurgi surface retort (81,000 bpd)	VMIS with no surface retorting (57,000 bpd)
IN (Makeup to plant or produced in retorting)		
Mine water[a]	6,884	2,102
Moisture in shale, Lurgi-Ruhrgas retort	136	0
Moisture in input air and shale and water of combustion	930	930
Storm water runoff	160[c]	125
TOTAL	8,110	3,157
OUT (Consumed)		
Slurry water for Lurgi spent shale	3,220	0
Water to saturate spent shale in abadoned retort	2,180	0
Dust control	295[d]	425[d]
Revegetation	0	470
Cooling water, evaporation, and drift	1,735	1,634
Losses: potable, service, and fire water	37[b]	31[b]
Losses: water treatment, ammonia recovery, and steam cycle	83	82
Losses: Lurgi-Ruhrgas retort and product gas	46	0
Losses: MIS retort gas and oil	514	514
TOTAL	8,110	3,156

[a] Water required for plant use; excludes excess mine water ponded or discharged.

[b] The VMIS with surface retorting case includes 400 plant personnel in addition to 1600 mine and plant personnel for VMIS with no surface retorting.

[c] Estimated for surface area of 200 acres.

[d] Mine use dust control estimated at 32 lb water/10^3 lb mined-out shale. Spent shale disposal dust control estimated at 100 lb water/10^3 lb spent shale which is equal to 10 percent by weight of 40,000 tons/day of disposed shale.

Source: Nevens et al., 1979.

per barrel of oil to slurry the spent shale and an additional 39 gallons of water to pre-wet in-situ spent shale. This report estimates that water requirements for retort grouting are about 150 gal/bbl (80 gal/bbl to pre-wet the shale and 70 gal/bbl to slurry the shale), about 60 percent higher than Table 5-2 estimates (See Chapter 7). This high water demand (an additional 96 to 150 gallons per barrel) could preclude use of this method of underground disposal of spent shale.

Potential Water Supply

It was shown in Chapter 4 that only a relatively small amount of the runoff from the Upper Colorado River Basin is available for new uses such as oil shale. Most of the water in the basin has already been allocated for such beneficial uses as municipal, industrial, and agricultural purposes. Since the appropriation and transfer of water is part of the administrative and judicial system of the respective states, it is impossible to determine with any degree of precision how much of this water will be available for oil shale development.

There is little agreement on the amount of water available for oil shale development. A number of studies have been completed in the last decade that estimate surface water supplies available to a synfuel industry in the west producing from one million to seven million barrels of shale oil per day. One estimate of the amount of surface flow that could be made available for oil shale development is shown in Table 5-3. This does not include existing water rights currently held by potential developers. The total amount of water available to each of the oil shale states from the Colorado River is also indicated for comparative purposes. These estimates should be used with caution because they are based on 1974 data and judgements concerning the amounts of committed and uncommitted water. Although the data and judgements were valid at that time, they did not include groundwater. In all probability, estimates made under today's conditions would be quite different (UDWR, 1975).

However, Table 5-3 does serve to show the relative amounts of surface water available for oil shale development. If all of the 440,000 acre-feet per year of water estimated to be available for oil shale development in 1974 (see Table 5-3) is used for this purpose and if the unit water demands for in-situ retorting presented in Table 5-1 are accurate, the maximum capacity of an in-situ oil shale industry, based on surface water alone, would be 1,400,000 to 5,500,000 barrels per day. This is consistent with a recent study by the National Academy of Sciences (1980) which estimated that available surface water supplies could support a 2,600,000 to 7,000,000 barrel per day industry. This represents about 8 to 30 percent of the 1977 U.S. consumption of crude oil (cited as 18,400,000 barrels per day by Bupp et al., 1979). Unfortunately, most of the richer oil shale deposits are located in Colorado which may have only 20 percent of the available water. This would limit the maximum size of an industry in Colorado to producing 300,000 to 1,100,000 barrels per day or from two to six percent of the 1977 U.S. consumption. Additional water, amounting to 15 to 20 percent of the total consumption figures cited in Table 5-1, would be required to support the associated infrastructure. Thus, the maximum-sized industry would produce 1,200,000 to 4,800,000 barrels per day, and the Colorado maximum production would be 200,000 to 1,000,000 barrels per day. Rattien and Eaton (1976)

Table 5-3. Availability of surface water for oil shale development.

State	10⁶ acre-ft/yr Share of Colorado River water available to state	10⁶ acre-ft/yr Water available for oil shale
Colorado	2.98	0.09
Utah	1.32	0.13
Wyoming	0.81	0.22

Source: FEA, 1974.

have similarly noted that the Piceance Creek Basin, the most likely site for early shale oil commercialization, could not support a 1,000,000 barrel per day industry and that there appears to exist only 14,000 acre feet per year of assured water, not enough for a 50,000 barrel per day plant. If oil shale is to supply a major fraction of the U.S. demand for crude oil, particularly in Colorado, water may have to be made available from other sources.

Sparks (1974) has stated that 250,000 acre feet of water could be made available in Colorado each year to support an oil shale industry. He felt that, if the need arose, this amount could be increased to 400,000 acre-feet but that there would be a corresponding loss in water available for agricultural production. The Colorado Department of Natural Resources (CDNR, 1979a) recently estimated that 138,000 acre feet of water could be made available annually in Colorado (90,000 acre feet per year from the Green Mountain Reservoir and 48,000 acre feet per year from the Ruedi Reservoir) without competing with other uses. Another study (CDNR, 1979b) indicated that a 1.5 million barrel per day equivalent synfuel industry could be supported by existing water supplies without significant impacts on existing uses. On the other hand, the Utah Division of Water Resources (UDWR, 1975) has estimated that, if more than 50,000 acre-feet of water were used annually in Utah for oil shale, there would be a reduction of some other planned uses.

Groundwaters may also provide some of the required water. The previous section indicated that mine water removed during dewatering could be used to supply most of the on-site water requirements. However, it is presently uncertain, as will be discussed below, whether these waters can be used without violating existing water rights. The extensive dewatering required for in-situ retorting may dry up local wells, springs, and streams, thus affecting adjacent or downstream water rights. In that case, mine waters would have to be reinjected, discharged to surface streams, or exported from the site to replace affected water rights.

The maximum amount of groundwater that may be withdrawn basinwide without significantly affecting water levels is the annual recharge. Any water withdrawn in excess of this amount would lower the water table and lead to a conditions known in the West as "mining" groundwater. The estimated natural recharge in the Piceance Creek Basin and the Uinta Basin, locations most likely to support early commercialization of oil shale, are 26,100 acre-feet per year (Weeks et al., 1974) and 120,000 acre-feet per year, respectively (Price and Miller, 1975). If all of this water were used to support an in-situ oil shale industry with water demands similar to those summarized in Table 5-1, the maximum capacity of the industry would be 500,000 to 1,800,000 barrels per day. The maximum size of an in-situ industry in the Piceance Creek Basin using only groundwater would be 100,000 to 300,000 barrels per day. These amounts would be reduced even further if water consumption of the associated infrastructure were included. Thus, groundwater alone will not support a large-scale in-situ industry without significant mining of groundwater, and surface water will have to be made available.

There are many uncertainties surrounding the availability of water for oil shale development. A recent NAS report (1980) concluded that estimates of water supplies in the Colorado River Basin are subject to great uncertainties due to unpredictable climatic variations, unresolved rights, claims still to be adjudicated, inaccurate data, and shifting political climates and social goals. The reader is thus cautioned to independently assess the available information and to update and modify it for the particular case under study.

Before any water can be used, however, the oil shale industry must first obtain the right to divert and put water to use. This must be done within the legal framework defined by applicable state statutes. The right to use surface water of the Colorado River Basin is governed by the Colorado River Compact of 1922, by the Mexican Water Treaty of 1944, by the Upper Colorado River Basin Compact of 1948, and by the water laws of the states concerned.

Following is an outline of some of the difficulties that may be experienced if large quantities of water are needed to supply an oil shale industry. These potential difficulties are briefly discussed in the context of water law. If more detailed information is desired, reference may be made to Dewsnap and Jensen (1973), Holland (1975), Radosevich et al. (1976), and Vranesh and Cope (1977) and to the references quoted therein. Much of the following is taken from these authors. Unless a particular state is mentioned, it may be assumed that the information applies to all three states.

The Effect of Water Law Doctrines on Oil Shale Development

Holland (1975) summarizes the effect of prevailing water law doctrines on oil shale development. His analysis was based on a surface retorting operation in which each 1,000,000 barrel per day operation diverted not less than 150,000 acre-feet and consumed about 85,000 acre-feet. He did not estimate the ultimate size of the industry. His conclusions are summarized below:

- Oil shale production as a significant part of the national demand will require more water than will remain in the unappropriated supply by the time large-scale production can begin.

- Existing water law doctrines complicate the easy transfer of water rights. These could lower oil production by raising the cost of water or by barring transfer. Production would be delayed by court procedures necessary to resolve conflicts.

- The doctrine of federal reserve rights offers hope that water for oil shale development can be obtained on some land. On the other hand, it might cut off private water rights which might be used on other lands for oil shale development.

The two major classes of water rights in the oil shale states are appropriative rights and federal reserve rights. A discussion of each follows.

Appropriative Rights. The three oil shale states allocate water rights by the prior appropriation system. Under this system, the application of water to beneficial use gives the user a vested right to that amount of water. This right is subject only to conflicting rights which existed earlier. This has been expressed as "first in time, first in right."

In general, the necessary steps to acquire a right to appropriate water are:

- To express an intent to appropriate water

- To actually divert or capture water

- To apply the water to a beneficial use

These steps are specifically for the situation where there is unappropriated water in a surface water body. Unappropriated water is the excess in the water body over that for which existing rights are held to divert and use. Water rights may also come by transfer from others who hold valid rights.

The priority of rights is all important. Appropriators are considered to be either junior or senior to other users with respect to the time that the right has been held. Priority is determined by the date of the first action showing an intent to appropriate water, such as an application filed with the state engineer. In times of shortage, users, in descending order of seniority, may withdraw their full entitlement until there is no water remaining in the stream. There is no need to share with or consider the rights of those junior to the diverter. Rights given to the oil shale industry in the future will probably be junior to all others having earlier rights. Senior appropriators will fill their needs, and the juniors will go without if there is not enough to go around. It would be a serious matter for an industry with a heavy capital investment to sit idle for an extended period because of no water. This could happen either on an annual basis in dry years, when there is reduced runoff, or on a seasonal basis, as in the case of irrigation diversions which peak in summer months. In the latter case, there may be sufficient water in the stream on an annual basis, yet diversions could only be made for oil shale during off-seasons. Either would create a hardship since retorting and upgrading demand is relatively constant over the year. Assuming such conditions existed, the industry might have to provide offstream storage to ensure a firm annual supply.

The mere expression of an intent to appropriate is not enough to establish priority unless all of the necessary legal steps are carried through with due diligence to the actual application of water to the intended use. Some of those oil shale firms that have filed applications to use water in the past few years may be affected by being unable to prove due diligence. The original purpose behind the prior appropriation doctrine was to prevent reservation of water which could not be put to immediate use. Without such a concept, large amounts of water could have been reserved for future use, thus precluding more immediate and perhaps more beneficial use by others.

Diligence can be determined only through the judicial process since it is not determined specifically by statute. An applicant who has allowed several years to elapse after filing an application before diverting water must be prepared to show due diligence. This will become increasingly difficult as more and more applicants compete for diminishing supplies of unallocated water, and holders of conflicting rights present challenges in the courts against new applicants.

Groundwater is also subject to appropriation just as is surface water. Permits are required before appropriation can begin. A different interpretation of priority, however, applies to groundwater use. When surface water supplies are reduced by natural or other conditions, junior appropriators are shut off, beginning with the one with the most recent right. There are no juniors in groundwater use. New wells are allowed until basin withdrawal equals or exceeds recharge. Where overuse has occurred, as may be indicated by drastically lowered water tables, pumping by the more recent users may be limited by the courts to protect older users.

The groundwater laws of Colorado, Wyoming, and Utah, in detail, have little uniformity. Colorado recognizes tributary groundwater, non-tributary groundwater, and "designated" groundwater, and limits the annual use of non-tributary groundwater to one percent of the water in storage. Most of the groundwaters affected by in-situ oil shale retorting are non-tribuatory and therefore, an upper limit exists on the amount of these waters that may be drained and used on site. Utah, on the other hand, treats groundwater the same way as surface water; and the allocation of groundwaters in Wyoming is at the discretion of the State Engineer, subject to certain criteria.

In some parts of the oil shale region (e.g., in the Piceance Creek Basin) there are large volumes of groundwater. Many favorable retorting sites lie below the water table. In these cases, extensive dewatering will be required. Large quantities of groundwater must be withdrawn before retort preparation and retorting may take place. It has been proposed to use a portion of this water for oil shale retorting and upgrading. Water not so used would be discharged into the surface streams or reinjected into aquifers some distance away from the oil recovery activities. Undoubtedly, large-scale dewatering and the subsequent use and disposal of the groundwater would cause extreme changes in the groundwater flow patterns. Most surface streams receive a high percentage of their flow from groundwater inflow. Piceance Creek gets some 80 percent of its annual flow from groundwater. There are many wells and springs throughout the basin, some of which are being used for irrigation and domestic beneficial use. Before a permit could be granted by the state to dewater retort areas and use or otherwise dispose of the withdrawn water, an applicant would undoubtedly have to show that such activities would not harm existing water uses. The leasees of tracts C-a and C-b, for example, have a court-approved augmentation plan in which any water rights affected by dewatering would be restored. Such proof and assurances may be difficult and expensive to provide for a large-scale industry. It would probably include a regional groundwater model such as the one currently under development by the USGS, which in turn would require an extensive geohydrologic survey. Even if such a model were developed to show that little or no harm would result, it would not preclude the possibility of future law suits against a pumper for damages incurred by loss of a well or spring or by diminished surface flows.

Unappropriated water in the streams is conventionally considered to be the excess of water above that for which rights are on record. Beneficial use, the amount that is actually used in a historical sense, is the real measure of the right, not the amount shown on the record. For example, if a diverter has a paper right to use five cfs but has never used more than three cfs, he has an actual right to only three cfs and there are two cfs available for other use. Therefore, there might be unappropriated water available if records were adjusted to reflect the amounts actually used. Holland (1975) cites a Wyoming study which found that acreage under irrigation was only about 50 to 60 percent of that allowed under paper rights. The same study also showed that paper rights are already much larger than the available supply and the actual gain in supply might be small.

If unappropriated water cannot be found because of existing rights, water may be obtained by transfer of such rights from present holders. Transfers may be purchased, rented, leased, loaned, or exchanged, but in any case, the transfer is subject to legal and administrative procedures set by state statutes. The principal reason for this is the protection of the rights of other users, both junior and senior. The purchase of rights by the oil shale industry certainly implies a change of type and location of beneficial use, and it may involve a change in diversion points. Changes in beneficial use and diversion points may in some circumstances affect the right of others.

This is best illustrated by an example. Assume that there is an existing right to divert 100 cfs at point A for irrigation at point B. An oil shale developer wishes to purchase this right for use at point C. Since C is located some distance from B it would be desirable to divert at point D. There are several possible changes in stream flow that might affect other diverters. Few activities consume all of the water diverted and applied. Irrigation using the common field flooding method, for example, is relatively inefficient since typically 20 to 50 percent of diverted water is actually consumed. The remainder returns to surface streams either by direct runoff or by horizontal groundwater flow to the stream. Oil shale processing is much more consumptive than irrigation because over 90 percent may be consumed. Since returned water becomes part of the supply for diverters downstream of the return point, any reduction in flow may affect their rights. In the example above, irrigation use at B would return to the stream about 50 cfs of the water diverted at A. An oil shale development would return 10 cfs or less to the stream. This would be a loss of 40 cfs or more. In addition, if the new point of return at D is downstream from that of the original use at B, the users in the reach between the old and new points of return will be deprived of the use of the entire 50 cfs. The effect on a prospective purchaser could be that a purchase of the right to divert 100 cfs at point A would yield only 50 cfs or less. Similar complications exist if the purchaser wishes to divert upstream from the original point of diversion at A. The users in the reach between the new diversion point and the old would be deprived of the use of up to the full amount diverted, depending on the amount and point of return.

In reality the transfer of rights is even more complex than this example indicates. The intended purchaser must show that no rights anywhere else on the stream, either junior or senior, are detrimentally affected by the intended diversion and use scheme. This is particularly true if transfers are to take place between watersheds, as may well be the case in the oil shale region. Where possible, sites are located in relatively dry areas. The only way that this can be done is through the judicial system, within which the purchaser proves beyond reasonable doubt that rights of all existing users will be protected.

Federal Reserve Rights. The other major class of water rights which may affect oil shale development is the federal reserve rights to water on lands which have been withdrawn from the public domain. A large percentage of the land on which oil shale is found is owned by the federal government. When public lands were set aside for use as forests, parks, etc., water was reserved to satisfy whatever purpose the lands were intended to serve. In most cases a specific amount of water was not reserved, and it has been left to the courts to determine the exact amount when a question arises. Indian reservations, for example, have been given rights by the courts to withdraw water to satisfy the present and future needs of the reservation. Enough water has been reserved to irrigate all of the practically irrigable acreage on the reservation.

The courts must determine the original purpose for reserving the land before they can grant rights to withdraw water from federal reserve rights. If it should be found that oil shale development is within the purpose or intent of the reservation, water may then become available to the oil shale industry from federal reserve rights. One apparent difficulty is that few lands have been reserved specifically for oil shale development. There are many kinds of reserved lands including military reservations, wildlife refuges, national forests, grazing districts, reclamation districts, and public water holes. If water has been reserved for water holes or grazing lands, for example, its use in oil shale production might be difficult to justify. On the other hand, some lands, such as the Naval Oil Shale Reserves in Colorado, were withdrawn specifically for shale oil. These lands would certainly receive more favorable consideration from the courts for the use of reserved water for oil shale development than others. The doctrine of federal reserve rights therefore offers some promise that water might be available for use on some land for shale oil production, but this option can only be determined through the judicial system. One difficulty may occur in areas where water is fully appropriated: a finding that federal reserve rights are superior to existing rights would mean that present users lose their right to use water, with consequent hardship. Heavy compensation may have to be paid to those affected by the loss of water that the oil shale industry would gain.

WATER QUALITY ASPECTS OF IN-SITU OIL SHALE DEVELOPMENT

Unlike surface retorting of oil shale, where many effluents may be consumed on site, in-situ retorting produces a number of waste streams that may require off-site disposal. These waste streams include retort water, dewatering effluents, sanitary effluents, and refinery effluents. Disposal options encompass three broad classes: (1) treatment and discharge to surface waters or groundwaters, (2) treatment and reuse, and (3) evaporation. The selection of a specific option or combination of options depends on a variety of factors including economics, land availability, and water availability, as well as the state and federal laws governing the discharge of effluents. Additionally, if a disposal option is selected that includes treatment and discharge, the degree and type of treatment required will depend on applicable state and federal laws.

In the following sections the types of regulations that may be imposed are discussed, existing regulations are identified, and a basis for evaluating effects is developed where no regulations presently exist.

Water Quality Regulations - General

Water quality regulations are enforceable federal or state laws that are designed to protect the quality of surface waters and groundwaters. Typically, two types of regulations are used. These are effluent limitations and water quality standards. The effluent limitation is a restriction on the amount of a particular constituent that may be present in a waste stream prior to its dilution or introduction into a receiving water. It is usually expressed at a maximum allowable rate of dischage, concentration, or mass of a constituent that may be released from a point source. A water quality standard, on the other hand, is a limitation on the concentration of a constituent that may be present in a surface water or a groundwater. The primary difference between the two types of regulations is that the effluent limitation is placed on the waste stream itself while the water quality standard is placed on the body of water receiving the waste.

Each type of regulation is discussed below with reference to in-situ oil shale development and those waters of Colorado, Utah, and Wyoming that are within the Upper Colorado River Basin.

Existing Federal and State Regulations

There are a number of federal and state regulations which may apply to an in-situ oil shale industry. However, many uncertainties surround these regulations because specific standards for an oil shale industry have not been promulgated. For example, PL 95-87, as presently drafted, applies only to coal. However, this Act commissions a study that will form the basis of similar regulations for oil shale. Similar uncertainties exist in most of the federal acts and, thus, regulatory uncertainty is a factor that impedes the development of an oil shale industry.

The applicable acts and standards are:

- Federal Water Pollution Control Act (PL 92-500)
- Surface Mining Control and Reclamation Act (PL 95-87)
- Resource Conservation and Recovery Act (PL 94-580)
- Safe Drinking Water Act (PL 93-523)
- Colorado River Basin Salinity Control Forum Standards
- Water quality criteria and effluent limitations set by the states of Colorado, Utah, and Wyoming

Federal Water Pollution Control Act. This Act originated in 1948 and was modified in 1956, 1965, 1966, 1970, and 1972. The 1972 revision, Public Law 92-500, is a most significant piece of water quality legislation. The primary goal of the Act is to "retore and maintain the chemical, physical, and biological integrity of the Nation's navigable waters" (Izaac Walton League, 1973). This is to be accomplished through uniform nationwide standards, enforceable regulations, a permit program based on effluent limitations, and a continuing planning process.

The provisions of the Act are jointly administered by the Environmental Protection Agency (EPA) and the states. The EPA sets procedures and regulations to be followed by states, defines the degree of pollutant control that must be achieved by municipalities and industries, determines the best technology available for achieving the standards, and approves and revises state programs. The states must develop water quality standards, establish pollutant loadings to protect the propagation of fish and wildlife, develop continuing planning processes, operate a permit program, review federal grant applications for municipal sewerage treatment plants, and enforce regulations. If the states fail in any area, the EPA has the authority to step in.

This Act is significant to oil shale development for three reasons. First, it requires states in the oil shale area to set water quality standards. Colorado, Wyoming, and Utah have complied with the Act and their standards are discussed below. In addition, it requires the adoption of salinity standards for interstate waters. These are discussed in a subsequent section. Second, the Act establishes the framework for setting effluent limitations for an in-situ oil shale industry. This has not been done to date (March 1980) but it may be anticipated that there will be limitations before any plant goes into commercial operation. Existing effluent limitations on refineries (U.S. Federal Register, August 1973) may apply to oil shale prerefining wastes. Third, the Act has established effluent limitations for municipal effluents. These are summarized in Table 5-4. Any sanitary sewerage produced by an oil shale plant must conform to these limitations. Historically, EPA has set standards for pH, BOD_5, and suspended solids for industry that are equivalent to, or more stringent than, those for municipal discharges. Therefore, the limitations on BOD_5, suspended solids, and pH which EPA may establish for an in-situ oil shale industry probably will be at least as restrictive as those shown in Table 5-4.

Table 5-4. Effluent limitations that apply to all municipal discharges (PL 92-500).

Parameter	Parameter limitations 7 consecutive days average	 30 consecutive days average
BOD_5, mg/l	45	30[a]
Suspended solids, mg/l	45	30[a]
pH	6-9	6-9
Fecal coliform bacteria	400/100 ml	200/100 ml

[a] In no case should the percentage removal of BOD_5 and suspended solids in a 30-day period be less than 85 percent.

Source: U.S. Federal Register, 1973.

Surface Mining Control and Reclamation Act. This Act (PL 95-87) requires the protection of the hydrologic system, safe disposal of solid and liquid wastes, and site rehabilitation for coal mines. Section 709 of this Act directed the Council on Environmental Quality (CEQ) to commission an "...in-depth study of current and developing technology for surface and open pit mining and reclamation for minerals other than coal designed to assist in the establishment of effective and reasonable regulation of surface and open pit mining and reclamation for minerals other than coal." The National Academy of Sciences has recently completed this study (NAS, 1980), and regulations similar to those published for coal mining will be developed in the future.

The permanent regulatory program for implementing this Act was promulgated on March 13, 1979, and states have until March 1980 to submit programs for federal approval. The existing Act establishes performance standards for surface and underground coal mining. It may be anticipated that similar standards will be set for oil shale. The Act calls for maximizing resource recovery and minimizing waste, restoring lands in an environmentally sound manner and to the approximate original contour, and stabilizing surface areas and spoil piles. Disturbance of the hydrologic balance must be minimized, subsidence prevented, mining operation wastes returned underground as feasible, regraded areas must be revegetated, and mine drainage prevented.

The most significant of these requirements for in-situ oil shale processing will be the equivalent of minimizing disturbances to the hydrologic system and elimination of mine drainage (in-situ leachates in the case of oil shale). In-situ retorting will significantly alter groundwater hydrology by extensive site dewatering. The aquifer media will be desaturated, i.e., water removed from the pore space will be replaced by air, and unsaturated flow will result, establishing a very different hydrologic regime after site abandonment. In-situ leachate control, as discussed in Chapter 7, is likely to be technologically difficult and costly.

Resource Conservation and Recovery Act. This Act establishes a permitting program for the generation, transport, and disposal of all wastes not regulated under existing programs and defines three categories of wastes. "Hazardous" wastes are certain specific industrial wastes and all others designated by test criteria. "Special" wastes are certain large-volume, low-hazardous wastes; and "all other wastes" are non-hazardous materials. Hazardous waste is subject to extensive record-keeping and must be disposed of in a permitted facility that meets stringent standards. A waste may be designated as hazardous if certain standards are exceeded in a standard leaching test. Regulations have not yet been defined for special wastes.

This Act could have far-reaching consequences for the oil shale industry, depending on the designation of oil shale wastes and the standards established for "special" wastes. If spent shale were declared to be a "hazardous", the costs of meeting the tenets of this Act may be prohibitive and limit retorting options that require large-scale surface disposal of spent shale. However, there is presently no indication that spent shale would be so classified and a recent test (DOE, 1979) indicates that Paraho spent shale is not a hazardous waste. This Act also sets groundwater standards under landfills. These standards apply to alluvial aquifers below a spent shale disposal facility. The application of this Act to in-situ spent shale is uncertain and should be investigated.

Safe Drinking Water Act. This Act sets standards for drinking water and establishes the Underground Injection Control Program. Utah and Wyoming have adopted the 1972 Federal Drinking Water Standards as water quality standards for waters used for public water supply (EPA, 1974; WDEQ, 1974). These will be discussed in subsequent sections. In addition to this, the Act has been interpreted as applying to well injection of wastes into aquifers that serve or might serve as sources for public drinking water. Any disposal of oil-shale related effluents by means of underground injection will be regulated under the State Underground Injection Control Program, whose establishment is mandated by the Public Health Services Act as amended by the Safe Drinking Water Act, PL 93-523. The intent of the program is to prevent underground injection practices that endanger underground sources of drinking water. The final formulation of this program had not been promulgated as yet (March 1980).

Preliminary versions of the State Underground Injection Control Program indicate that groundwaters to be protected as underground sources of drinking waters are those having less than 10,000 mg/l total dissolved solids. Certain underground waters having less than 10,000 mg/l total dissolved solids may be excluded from protection under the program where extenuating circumstances exist. These include: occurrence of extensive injection practices in the area; availability of otherwise adequate water supplies to meet projected needs for the foreseeable future; the aquifer is mineral or oil producing; recovery of water from the aquifer is economically or technically impracticable; or the water is so contaminated with substances other than total dissolved solids that its use as a drinking water supply would be economically or technically impracticable.

The program will be implemented at the state level where the state has established regulations and enforcement procedures to the satisfaction of the EPA Administrator. In states where such EPA approval has not been obtained, EPA retains primary enforcement responsibility.

The precise implication of the State Underground Injection Control Program to the development of an oil shale industry cannot be defined until the final form has been promulgated. It seems likely, however, that no new effluent disposal stipulations will pertain to the oil shale industry beyond those embodied in existing legislation, particularly the state antidegradation policies. It seems likely, however, that it could affect reinjection of mine waters, hydraulic fracturing for true in-situ processes, prewetting of in-situ spent shale prior to grouting (Chapter 7), intentional leaching of in-situ spent shale (Chapter 7), and perhaps steam retorting. It may be possible to obtain exceptions in certain instances. For example, it may be possible to locally reinject dewatering effluents into the lower aquifer. Saline pockets of groundwater which probably could not economically or technically be developed as a drinking water source are known to exist in some areas (Weeks et al., 1974). The oil shale zones which are aquifers could be declared oil or mineral producing to prevent the application of Underground Injection Control Program for hydraulic fracturing or steam retorting. These issues may well be resolved in the courts and will require a case-by-case solution during the early commercialization of oil shale.

Colorado River Basin Salinity Control Forum Standards. Section 303 of PL 92-500 called for the adoption of salinity water quality standards for interstate waters (USDI, 1977; CRB, June 1975 and August 1975). In response to this, the EPA in December 1974 issued a regulation requiring the states of the Colorado River Basin to adopt salinity water quality standards (U.S. Federal Register, Dec. 1974). This regulation required that the flow-weighted average annual salinity in the lower main stem of the Colorado River be maintained at or below the average value for 1972. To implement this regulation, the seven states involved formed the "Colorado River Basin Salinity Control Forum" which established both salinity standards and a plan of implementation for the Colorado River. The Forum prepared a report called "Proposed Water Quality Standards for Salinity Including Numeric Criteria and Plan of Implementation for Salinity Control, Colorado River System" (CRB, June 1975). Following public meetings, the Forum developed a "Supplement" (CRB, Aug. 1975) containing modifications to the original report. Formal public hearings, as required by PL 92-500, were held and the states subsequently adopted the report and its supplement. The standards were adopted officially by EPA during 1976. Together, these two documents constitute the water quality standards as required by Section 303 of PL 92-500 and by the 1974 regulation promulgated by the EPA. Since Colorado, Utah, and Wyoming were included in the Forum, the resulting standards and implementation plan apply to these three states.

The water quality standards set by the Forum are:

Location	Salinity (mg/l)
Below Hoover Dam	723
Below Parker Dam	747
Imperial Dam	879

The Forum recognized that there are two ways in which these standards can be met: (1) by reducing the salt loading or (2) by increasing the supply of better quality water. The control process selected by the Forum is to reduce the salt loading to the River.

The implementation plan consists of a number of federal and nonfederal projects and measures to maintain the flow-weighted average annual salinity in the lower main stem at or below the recommended levels through 1990. The principal components of the plan are:

- Construction and operation of 16 salinity control units authorized by Title II of PL 93-320.
- Placing effluent limitations on industrial discharges, as authorized in Section 402 of PL 92-500.
- Reformulation of authorized but unconstructed federal water projects to reduce the salt loading effect.
- Use of saline water for industrial purposes wherever practical.

Several aspects of the resulting implementation plan are significant for in-situ oil shale development. These are:

- A no-salt return policy, wherever practicable, will be adopted for industrial dischargers.
- Cooling tower blowdown waters are to be eliminated from the Colorado River.
- Measures will be implemented to prevent the return of salt from oil shale plants to the Colorado River.

The reference to no-salt return from oil shale plants was directed at surface retorting processes where virtually 100 percent of the effluents can be reused in the disposal of the spent shales. In that case, a no-salt return policy is reasonable. However, in the case of in-situ processes, the volume of effluent produced is larger, and the opportunity for reuse of the effluents is considerably diminished. The only way a no-salt return policy could be implemented would be by ponding and evaporation of effluents. This would require a substantial amount of land.

An alternative to evaporation would be treatment to remove salinity to an acceptable level and subsequent discharge. No such level is specified in the implementation policy. It is obvious that there would be effluent salinity levels which would not cause an increase in the salinity anywhere in the Colorado River Basin, and the standards could be met. The omission of this possibility from the implementation plan suggests that a future decision will have to be made to resolve this issue.

Colorado Water Quality Regulations. The State of Colorado has adopted water quality standards and effluent limitations that are applicable to an in-situ oil shale industry (CDH, 1974 and 1975). The water quality standards include "basic standards" that apply to all state waters, including both surface waters and groundwaters, and other standards that apply to specific water bodies based on their use.

Colorado's waters are subdivided into four classes--A_1, A_2, B_1, B_2--according to the uses of the water. Water quality standards are set for each class. The distinction between class A and class B waters involves their use for water contact recreation such as swimming and water skiing. The class A waters are suitable for all uses including contact recreation; class B waters are suitable for all uses except contact recreation. Figure 5-3 shows Colorado's classification of state waters within the Upper Colorado River Basin (CDH, 1974). This figure indicates that all surface waters in Colorado that would be affected by an in-situ oil shale industry are class B waters. Groundwaters, although unclassified at this time, would probably be class B waters as they are not usually used for contact recreation. Therefore, class B water is the only type of water of concern to an in-situ oil shale industry. Water quality standards that apply to water classes B_1 and B_2 are summarized in Table 5-5.

Supplemental to the standards summarized in Table 5-5, Colorado has an "Antidegradation Policy" which applies to both surface waters and groundwaters. This policy requires that state waters, whose quality is better than the limits indicated in Table 5-5, be maintained at existing quality unless it can be demonstrated that a change is justified.

In addition to basic and specific water quality standards, Colorado adopted general effluent limitations in March 1975 which are applicable to all discharges into Colorado waters including those from an in-situ oil shale industry except storm water runoff (CDH, 1975). These regulations, which are summarized in Table 5-6, apply to discharges into both surface waters and groundwaters. The BOD_5, suspended solids, and pH limitations shown in Table 5-6 are the same as EPA requirements for municipal discharges shown in Table 5-4. These limitations apply only until the State of Colorado or EPA sets specific guidelines for an in-situ oil shale industry. Additionally, the state reserves the right to supersede the general effluent limitations with stricter ones, as required. These limitations are significant for two reasons. First, they apply to discharges to groundwaters. This would make the alternative of groundwater disposal of effluents less attractive than it might otherwise be, due to the high degree of treatment that would be required prior to disposal. Second, as written, they seem to apply to in-situ leachate or groundwater that has migrated through abandoned in-situ retorts. Obviously, the problem of treating a diffuse source that is underground is enormous.

WYOMING

I	Waters that support or could support, game fish.
II	Waters that support or could support nongame fish.
III	Waters that do not or could not support fish.

COLORADO

B1	Suitable for all uses except contact recreation. Standards on these streams require a minimum dissolved oxygen of 6 mg/l and a maximum temperature of 68°F.
B2	Suitable for all uses except contact recreation. Standards on these streams require a minimum dissolved oxygen of 5 mg/l and a maximum temperature of 90°F.

UTAH

C	Suitable for all uses except contact recreation without treatment but with coagulation, sedimentation, filtration, and disinfection prior to use as a domestic supply.
CC	Same as **C** plus requires a minimum dissolved oxygen of 6 mg/l and a maximum temperature of 63°F.
CW	Same as **C** plus requires a maximum temperature of 68°F.

Water classifications for various locations shown in Figure 5-3.

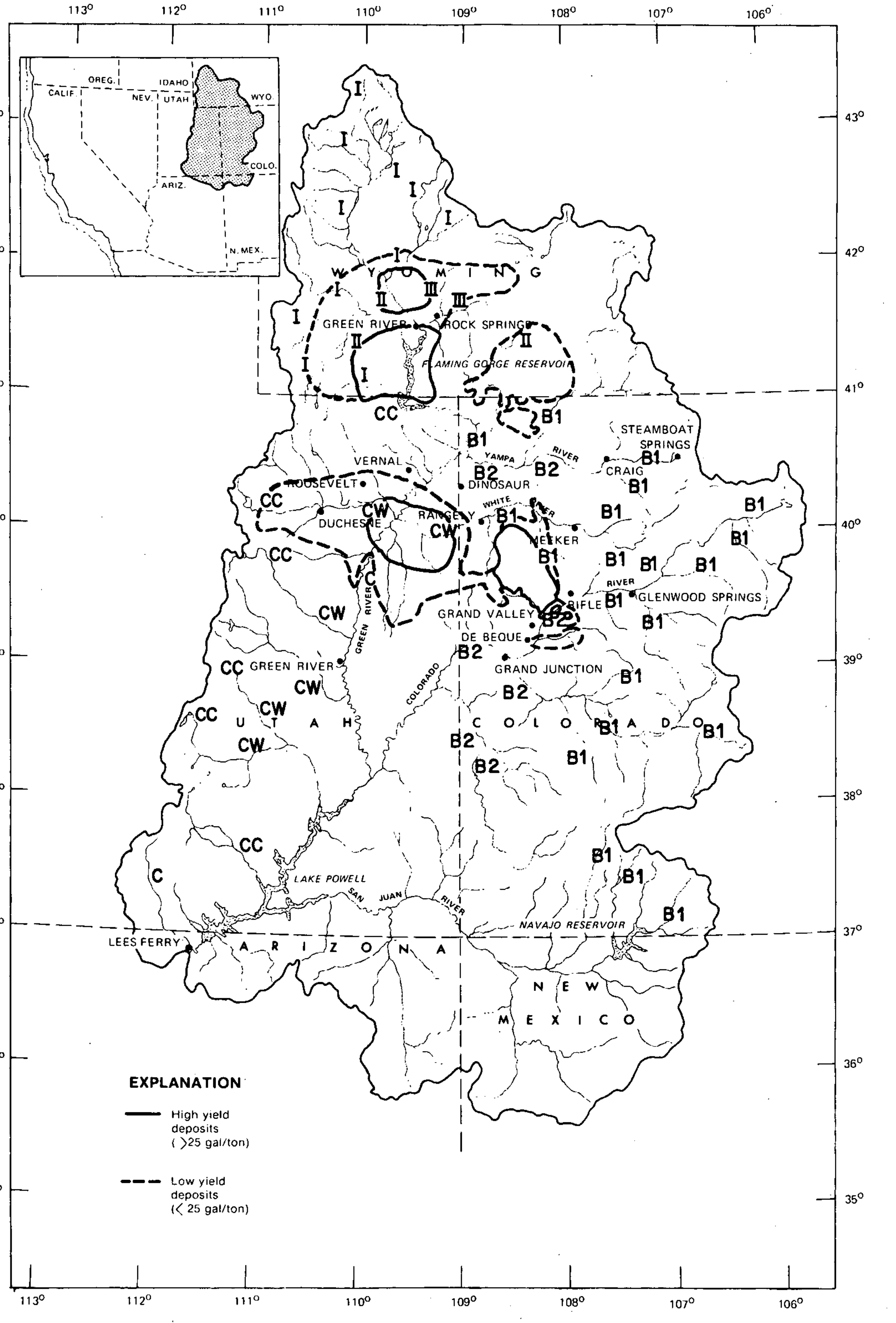


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Figure 5-3. Water classification, according to use, of the Upper Colorado River Basin in Colorado, Utah, and Wyoming (Outlined areas indicate oil shale deposits).

Table 5-5. Colorado water quality standards applicable to an in-situ oil shale industry.

Standard	Class	
	B_1	B_2
Settleable solids[a]	Free from	Free from
Floating solids[a]	Free from	Free from
Taste, odor, color[a]	Free from	Free from
Toxic materials[a]	Free from	Free from
Oil and grease[a]	Cause a film or other discoloration	Cause a film or other discoloration
Radioactive material[a]	Drinking water standards	Drinking water standards
Fecal coliform bacteria[b]	Geometric mean of <1000/100ml from five samples in 30-day period	Geometric mean of <1000/100ml from five samples in 30-day period
Total coliform bacteria[b]	Geometric mean of <10,000/100 ml from five samples in 30-day period	Geometric mean of <10,000/100 ml from five samples in 30-day period
Turbidity[b]	No increase of more than 10 JTU	No increase of more than 10 JTU
Dissolved oxygen[b]	6 mg/1 minimum	5 mg/1 minimum
pH[b]	6.0 - 9.0	6.0 - 9.0
Temperature[b]	Maximum 68°F Maximum change 2°F	Maximum 90°F Maximum change: Streams - 5°F Lakes - 3°F

[a] Applies to both surface waters and groundwaters.

[b] Applies to surface waters only.

Source: CDH, 1974

Table 5-6. Colorado general effluent limitations.

Parameters	Parameter limitations 7-day average	 30-day average
BOD_5	45 mg/1	30 mg/1[a]
Suspended solids	45 mg/1	30 mg/1[a]
Fecal coliform	As determined by the Division of Administration of the State Health Department to protect public health in the stream classification to which the discharge is made	
Residual chlorine	Less than 0.5 mg/1	
pH	6.0 - 9.0	
Oil and grease	10 mg/1 and there shall be no visible sheen	

[a] In no case shall the arithmetic mean of the BOD_5 and suspended solids for effluent samples collected in a period of 30 consecutive days exceed 15 percent of the arithmetic mean of the values for influent samples collected at approximately the same time during the same period (85 percent removal).

Source: CDH, 1975

Utah Water Quality Regulations. The State of Utah has adopted water quality standards that are applicable to both surface waters and groundwaters (EPA, 1974; USU, 1975). Utah's standards are based on the use of the water. Six use classifictions are provided:

1. Class A. Waters suitable for all raw water uses, including contact recreation, without treatment.
2. Class B. Waters suitable for all raw water uses, including contact recreation without treatment, but with disinfection prior to use as domestic water supply.
3. Class C. Waters suitable for all raw water uses, except contact recreation, without treatment but with coagulation, sedimentation, filtration, and disinfection prior to use as a domestic supply.
4. Class D. Waters suitable for limited irrigation and industrial water supply.
5. Class E. Waters that are to be protected from controllable pollution that may result in a health hazard or nuisance.
6. Class S. Waters that will be protected as class A waters except as permitted by the state.

In addition to these six broad classes, class C waters are subdivided into five classes as follows:

1. Class CC. Class C plus temperature and dissolved oxygen limitations.
2. Class CW. Class C plus temperature limitations.
3. Class CR. Class C plus coliform limitations.
4. Class CCR. Class C plus limitations of class CC and class CR.
5. Class CWR. Class C plus limitations of class CW and class CR.

The classification of all Utah waters in the Upper Colorado River Basin is shown in Figure 5-3 (USU, 1975). This figure shows that all of these waters are classed as C waters or as some variation of C waters. No classification is presently available on groundwaters. Since some groundwaters may fall under a classification other than C, water quality standards for all classes are shown in Table 5-7.

In addition to these specific standards, Utah has a nondegradation policy and specific requirements for interstate waters. The nondegradation policy (EPA, 1974) states that "Waters whose existing quality is better than established standards will be maintained at high quality unless it has been affirmatively demonstrated to the state that a change is justifiable as a result of necessary economic or social development and will not preclude present and anticipated use of such waters."

Table 5-7. Summary of Utah water quality standards.

Parameter	Applicable water class[a] and standards
Physical and bacteriological	A, B, S: drinking water standards
Radioactive and chemical	All classes except E: drinking water standards
Settleable solids, floating solids, oil, scum, color, odor, taste, turbidity, toxic materials, etc.	C, CC, CW, CR, CCR, CWR: free from
Total coliform bacteria	B, C: < 50/100 ml CC,CW: < 5000/100 ml CR, CCR, CWR: < 1000/100 ml D: < 5000/100 ml
Fecal coliform bacteria	C, CC, CW: < 2000/ml CR, CCR, CWR: < 200/100 ml
pH	A, B, S: 6.5 - 8.5 C, CC, CW, CR, CCR, CWR: 6.5 - 8.5, no increase > 0.5 D: 6.5 - 9.0
Biochemical oxygen demand, BOD_5	A, B, S: nil C, CC, CW, CR, CCR, CWR: < 5 mg/1 D: < 25 mg/1
Dissolved oxygen, DO	C, CW, CR, CCR, CWR: > 5.5 mg/1 CC: > 6.0 mg/1
Temperature	CC: maximum 68°F, increase 2°F CW, CR, CCR, CWR: maximum 80°F, increase 4°F

[a] Water classes are defined in text.

Source: EPA, 1974

Utah state waters that are also interstate water have the following additional requirements:

- No wastes containing As, Ba, B, Cd, Cr, CN, F, Pb, Se, Ag, Cu, and Zn that are reasonably amenable to treatment or control will be discharged untreated or uncontrolled into the Colorado River System.
- The dissolved oxygen content and pH value of the waters of the Colorado River System shall be maintained at levels necessary to support the natural and developed fisheries.

Wyoming Water Quality Regulations. Wyoming has adopted water quality standards on 14 parameters which would be applicable to an in-situ oil shale industry (WDEQ, 1974). These standards are based on the use of the water and apply only to surface waters. The basis of the Wyoming standards is the preservation and protection of fish and aquatic life in all surface waters. To this end, three classes of water were designated as follows (WDEQ, 1976):

> Class I. Waters which presently support or could potentially support, game fish.
>
> Class II. Waters which presently support or could potentially support, nongame fish.
>
> Class III. Waters which do not have the potential to support fish.

The classification of the waters of Wyoming that lie within the Upper Colorado River Basin are shown in Figure 5-3 (WDEQ, 1976). This figure indicates the major water bodies in the Upper Colorado River Basin are Class I or II. Smaller streams not shown on this figure are Class III.

In addition, Wyoming recognizes public water supply and recreation as specific uses. The standards set by Wyoming for each class and use are summarized in Table 5-8.

Water Quality Criteria

The information presented in previous sections of this chapter focused on existing water quality regulations. These regulations represent the minimum compliance that would be required of an in-situ oil shale industry seeking permission in 1980 to discharge its effluents. In addition to these regulations, certain additional regulations may be established to cover those parameters specific to an in-situ oil shale industry's effluent if that effluent can result in a water quality problem on discharge of the waste.

One method of anticipating what these additional regulations might be is to examine each effluent, its impact on the receiving water if discharged, and the level of treatment required to meet existing regulations. In some instances, the discharge will degrade some parameters not currently regulated in such a way that the existing uses of the water are compromised. The water quality levels that should not be violated are called water quality criteria,

Table 5-8. Wyoming water quality standards applicable in the Upper Colorado River Basin.

Parameter	Class I[a]	Class II[a]	Class III[a]	Full body contact[a] (reservoirs and lakes below 7000 ft above sea level)	Exceptions
Settleable solids	Free from	Free from	Free from	--	
Floating solids	Free from	Free from	Free from	--	
Taste, odor, color	Free from	Free from	Free from	--	
Toxic materials	Free from	Free from	Free from	--	Fish toxicants used for management purposes
Radioactive material	3 pCi/l Ra 226, 10 pCi/l Sr 90, or federal drinking water standards; all available controls must be applied	3pCi/l Ra 226, 10 pCi/l Sr 90, or federal drinking water standards; all available controls must be applied	3 pCi/l Ra 226, 10 pCi/l Sr 90, or federal drinking water standards; all available controls must be applied	--	
Turbidity	No increase of more than 10 JTU	No increase of more than 10 JTU	--	Secchi disc must be visible at 1 m	
Dissolved oxygen	No death or injury to aquatic life or 6 mg/l minimum	No death or injury to aquatic life or 5 mg/l minimum	--	--	In spawning areas, no reduction in natural dissolved oxygen is permitted unless it is due to an allowed thermal discharge
Temperature	No change harmful to aquatic life; Maximum change 2°F for (1) natural water temperatures under 68°F, (2) any stream with cold water fisheries, or (3) in any impoundment; maximum change 4°F for natural water temperatures exceeding 68°F which support a warm water fishery	No change harmful to aquatic life; Maximum change 2°F for (1) natural water temperatures under 68°F, (2) any stream with cold water fisheries, or (3) in any impoundment; maximum change 4°F for natural water temperatures exceeding 68°F which support a warm water fishery	--	--	Variances allowed for experimental purposes for periods of less than 5 yr

(continued)

Table 5-8. Wyoming water quality standards applicable in the Upper Colorado River Basin (continued).

Parameter	Class I[a]	Class II[a]	Class III[a]	Full body contact[a] (reservoirs and lakes below 7000 ft above sea level)	Exceptions
Temperature (cont.)	Maximum is 78°F for cold water fish; Maximum is 90°F for warm water fish No changes in spawning beds	Maximum is 78°F for cold water fish; Maximum is 90°F for warm water fish; No changes in spawning beds	--		
pH	6.5 - 8.5	6.5 - 8.5	6.5 - 8.5		
Fecal coliform	From 1 May - 30 Sept., geometric mean of 1000/100 ml from 5 samples separated by 24 hr in 30 days and 10% < 2000/100 ml in 30 days	From 1 May - 30 Sept., geometric mean of 1000/100 ml from 5 samples separated by 24 hr in 30 days and 10% < 2000/100 ml in 30 days	From 1 May-30 Sept., geometric mean of 1000/100 ml from 5 samples separated by 24 hr in 30 days and 10% < 2000/100 ml in 30 days	From 1 May-30 Sept., geometric mean of 200/100 ml from 5 samples separated by 24 hr in 30 days and 10% < 400/100 ml in 30 days[b]	
Undesirable aquatic life	Free from	Free from	Free from		
Oil and grease	Shall not cause a film, globules, or discoloration on the surface or visible deposits on the bottom or shoreline; Shall not exceed 10 mg/l	Shall not cause a film, globules, or discoloration on the surface or visible deposits on the bottom or shoreline; Shall not exceed 10 mg/l	Shall not cause a film, globules, or discoloration on the surface or visible deposits on the bottom or shoreline; Shall not exceed 10 mg/l		
Total gas pressure	Shall not exceed 110% of existing atmospheric pressure in water supporting cold water aquatic life	Shall not exceed 110% of existing atmospheric pressure in water supporting cold water aquatic life	Shall not exceed 110% of existing atmospheric pressure in water supporting cold water aquatic life		
Salinity	Such that the salinity of the Colorado River system be maintained at or below the average in the lower main stem during 1972	Such that the salinity of the Colorado River system be maintained at or below the average in the lower main stem during 1972	Such that the salinity of the Colorado River system be maintained at or below the average in the lower main stem during 1972		

[a] When the designated use is public water supply, the most recent federal drinking water standards apply to the treated water.

[b] This also applies to: (1) the North Platte River from the Colorado-Wyoming state line to the outlet of Alcova Reservoir including the Encampment River and Big Creek; (2) the Tongue River from the intake of the Ranchester Municipal water treatment plant upstream to the headwaters; and (3) the Green River from Flaming Gorge Reservoir at the Wyoming-Utah state line upstream to its headwaters.

Source: WDEQ, 1974

which are recommended limitations on the concentration of a constituent that may be present in a water body. Unlike standards, which are the law, criteria are recommendations. They are limitations set to protect prescribed uses of water. The uses of the water are referred to as beneficial uses and typically include domestic water supply, irrigation, aquatic life, and recreation. The process of establishing beneficial uses and water quality criteria precedes establishing standards.

Water quality criteria for some parameters not covered by existing state or federal regulations which may be significant for an oil shale industry are summarized in Table 5-9. This table presents criteria for inorganic and organic constituents for the beneficial uses of domestic water supply, freshwater aquatic life, livestock watering, and irrigation. Beneficial uses of interstate streams of the Colorado Basin are shown in Figure 5-4. The information in Table 5-9 and Figure 5-4 will be used in Chapters 7 and 8 to assess the effect of waste discharges containing minor inorganic and organic constituents on waters of the basin.

No.	Stream	Reach	Public Water Supply	Industrial Water Supply	Irrigation	Livestock Watering	Fish & Wildlife (cold)	Fish & Wildlife (warm)	Waste Assimilation	Aesthetic	Recreation (body contact)	Recreation (limited)
	GREEN RIVER SUBREGION											
1.	Green River	Source to Flaming Gorge Reservoir	●	●			●	●	●	●		●
2.	Green River	Flaming Gorge Reservoir to Wyoming-Utah state line	●	●			●	●	●	●	●	
3.	Green River	Wyoming-Utah state line to Flaming Gorge Dam	●	●	●	●	●				●	
4.	Green River	Flaming Gorge Dam to Utah-Colorado state line	●	●	●	●	●					●
5.	Green River	All reaches in Colorado					●					
6.	Green River	Colorado-Utah state line to mouth	●	●	●	●		●			●	
7.	Little Snake River	Source to Wyoming-Colorado state line	●	●	●		●	●				●
8.	Little Snake River	Wyoming-Colorado state line to Powder Wash	●				●					
9.	Little Snake River	Powder Wash to mouth										
10.	Yampa River	Source to Williams Fork	●				●					
11.	Yampa River	Williams Fork to mouth		●				●				
12.	White River	Source to Piceance Creek	●				●					
13.	White River	Piceance Creek to Rangely water intake	●					●				
14.	White River	Rangely water intake to Colorado-Utah state line		●				●				
15.	White River	Colorado-Utah state line to mouth	●	●	●			●				
	UPPER MAIN STEM SUBREGION											
21.	Colorado River	Source to Williams Fork River	●				●					
22.	Colorado River	Williams Fork River to Parachute Creek			●		●					
23.	Colorado River	Parachute Creek to Colorado-Utah state line		●				●				
24.	Colorado River	Colorado-Utah state line to mouth (to Lake Powell(?))	●	●	●	●		●			●	
	SAN JUAN SUBREGION											
31.	Colorado River	Green River to Lake Powell	●	●	●	●		●			●	
32.	Colorado River	Lake Powell to Utah-Arizona state line	●	●			●	●	●	●	●	
33.	Colorado River	Utah-Arizona state line to Lees Ferry										

Segments of rivers and streams shown in Figure 5-4.

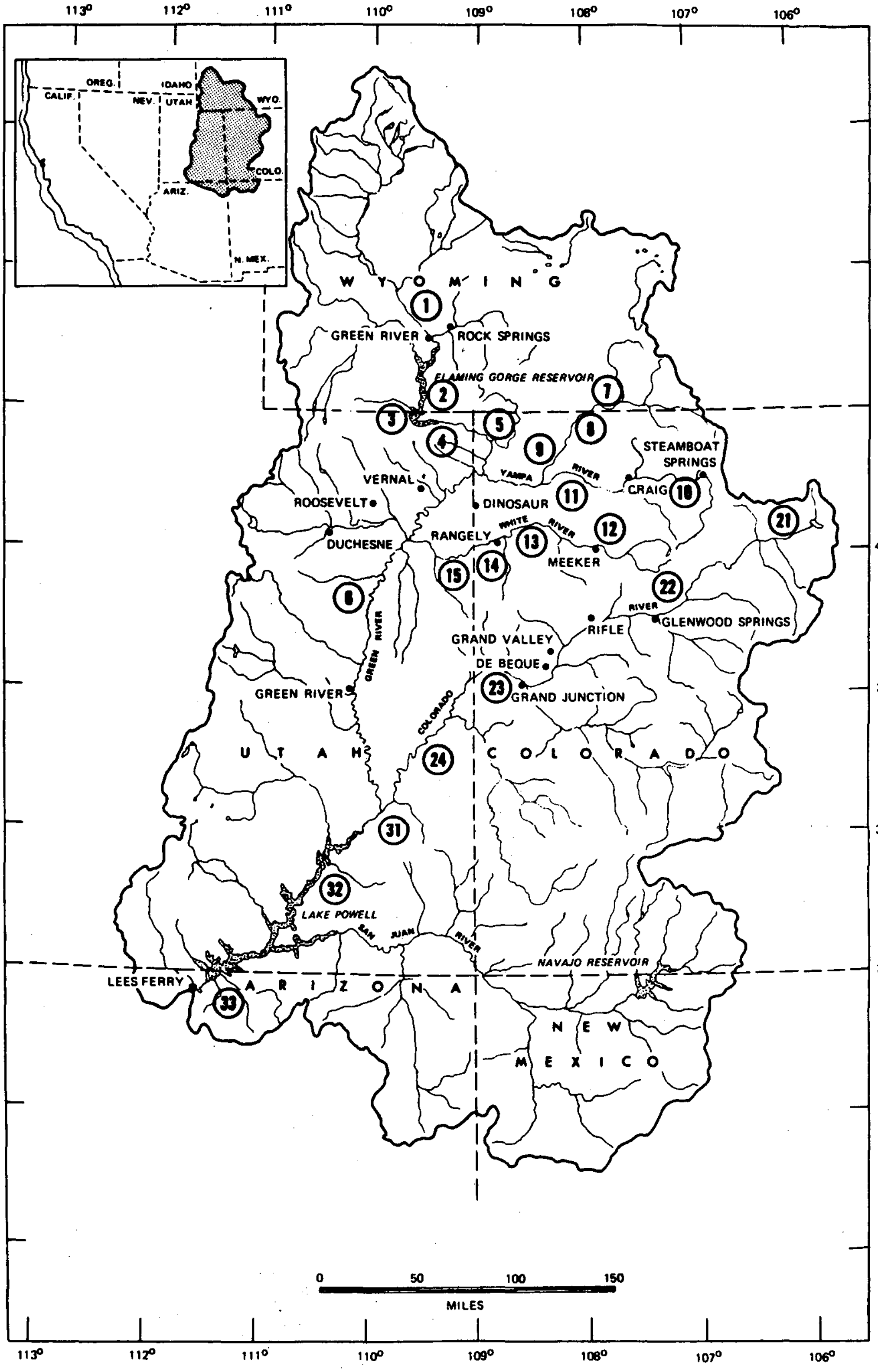

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Figure 5-4. Present water uses--interstate steams. Source: UCR, 1971.

Table 5-9. Water quality criteria levels not to be exceeded in the main water mass.

Parameters	Domestic water supplies, mg/l	Livestock watering, mg/l	Irrigation, mg/l	Freshwater aquatic life, mg/l
Inorganics				
Aluminum		5	5-20	(a)
Ammonia	0.5			0.02
Arsenic	0.1	0.2	0.1-2.0	
Barium	1			
Beryllium			0.1-0.5	
Boron	(a)	5.0	0.75-2.0	
Cadmium	0.010	0.050	0.010-0.050	0.003-0.0004
Chloride	250		(b)	0.003[c]
Chromium	0.05	1.0	0.1-1.0	0.05
Cobalt		1.0	0.05-5.0	
Copper	1	0.5	0.20-5.0	(b)
Cyanide	0.2			0.005
Fluoride	1.4-2.4	2.0	1-15	
Iron	0.3	None	5-20	
Lead	0.05	0.1	5-10	0.03
Lithium			0.075-2.5	
Manganese	0.05	None	0.20-10	
Mercury	0.002	0.010		0.00005
Inorganics (cont.)				
Molybdenum		(a)	0.010-0.050	
Nickel			0.20-2.0	(b)
Nitrate-nitrogen	10	100[d]	None	
Nitrite-nitrogen	1	10		
Phosphate	(a)			
Selenium	0.01	0.05	0.02	
Sodium	None		(a)	
Sulfate	250			
Sulfides				0.002
Vanadium		0.1	0.10-1.0	
Zinc	5	25	2.0-10	(b)
Organics				
Foaming agents (MBAS)	0.5			
Nitrilotriacetate (NTA)	(a)			
Carbon-chloroform extract	0.3			
Carbon-alcohol extract	1.5			
Phenolics	0.001			
Polychlorinated biphenyls	(a)			0.000002

[a] Inadequate data available to set criterion.

[b] Variable, depends on soil conditions, bioassay test, etc.

[c] Chlorine residual.

[d] $NO_3 + NO_2$.

Source: NAS, 1973

CHAPTER 6

WATER QUALITY EFFECTS OF LEACHATES FROM AN IN-SITU OIL SHALE INDUSTRY

Since most of the oil shale deposits are located in or adjacent to aquifers, in-situ processing may result in groundwater disruption by leaching of abandoned retorts. Additionally, if modified in-situ retorting is used, in which 20 to 40 percent of the in-place shale is mined and is either stockpiled or retorted at the surface, disposal piles of raw or spent shale may be leached by snowmelt or precipitation, and the leachate transported into aquifers or surface waters (see Figure 6-9).

The purpose of this chapter is to evaluate the magnitude and significance of leachate discharges from an in-situ oil shale industry so that environmental control requirements can be identified. The report focuses on a hypothetical 50,000 barrel per day facility located on lease tracts C-a and C-b (see Chapter 3, Table 3-6).

LEACHATE FROM IN-SITU RETORTS

In-situ leachates are produced by the interaction of local groundwaters with in-place spent shales and other retorting products, including gases, waters, oils, and tars. They originate when groundwater flows through an abandoned in-situ retort and from gas leakage during retorting.

Retort construction and operation may permit retorting gases to mix with groundwaters. Rubblization may create cracks and fissures through which gases may move or, where retorts intersect aquifers, the natural aquifer permeability may permit gas to escape directly into aquifers. If these possibilities exist, and if the retorts are <u>not</u> operated at negative pressure, gases produced during retorting could come in contact with groundwaters. Virtually no data exist on this phenomenon and thus it cannot be discussed in detail. However, it should be realized that the potential for gas interaction exists and that it may increase the level of certain organic and inorganic compounds in affected groundwaters.

This section will primarily review and assess available data on the leaching of organics and inorganics from in-situ spent shales. Most of these data were derived using spent shales from laboratory or pilot-scale retorts. These spent shales are referred to as "simulated" to distinguish them from field spent shales. The geohydrology of leachate formation, the mechanics of leaching, and factors that affect leachate composition will be discussed. Available experimental data will be assessed and used to estimate the leachate composition for a field in-situ retort. A method of estimating leachate transport will be presented.

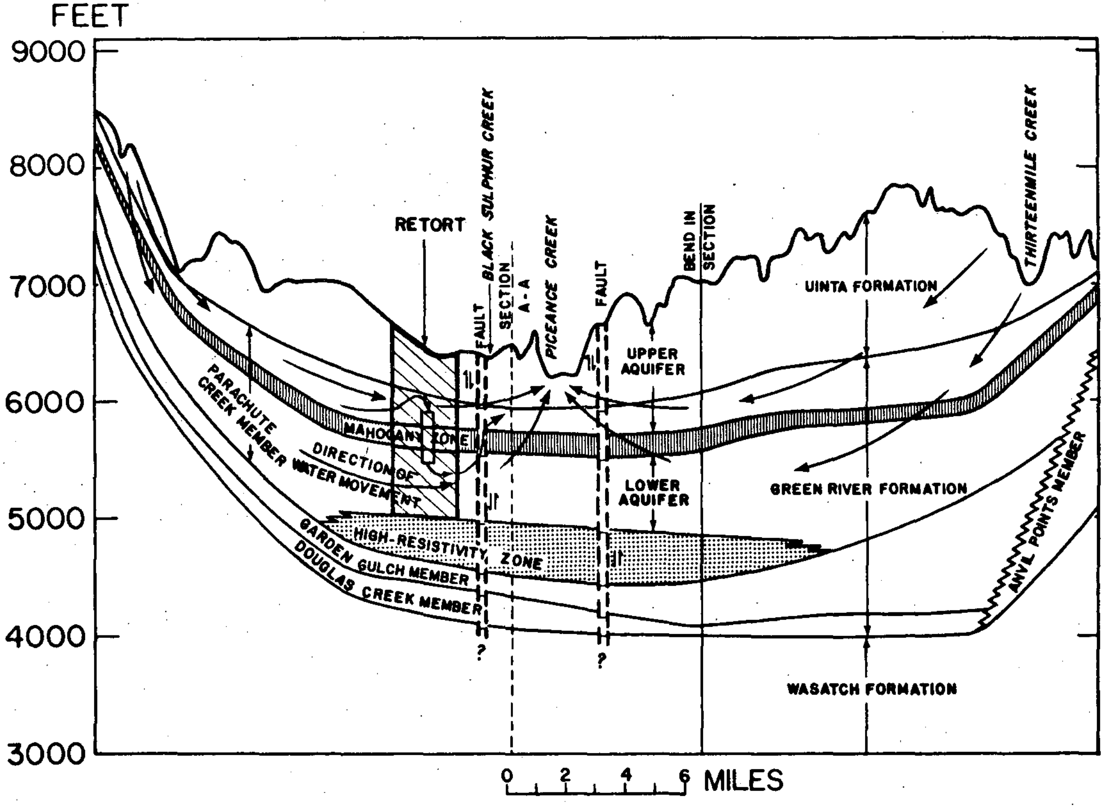
In these discussions, the reader should bear in mind that research on the in-situ leaching of spent shales is in its infancy and that the data are incomplete. Because none of the information to be presented has been published in the technical literature, it has not been subjected to peer review. Wide variations in experimental technique, analytical methods, and spent-shale sources have been prevalent. Therefore, comparisons are difficult to make. This material should be considered an attempt to present a consistent data base to define control technology requirements and as a framework for defining additional research needs. It should not be considered as the final word on the leaching of in-situ spent shales.

Geohydrology of Leachate Formation

Modified in-situ retorting requires partial mining and fracturing of the retort block to create adequate porosity for effective retorting. This introduces permeability into an otherwise largely impermeable strata. The stratigraphy described in Figure 6-1 is typical of that found in the Piceance Creek Basin where the richer oil shale deposits occur. Recent work by Occidental Oil Shale, Inc. (1978) indicates that the aquifer system in the vicinity of lease tract C-b is considerably more complex than previously believed (Weeks et al., 1974). Preliminary work indicates that instead of an upper and a lower aquifer, as previously believed, there are 15 aquifers separated, in part, by aquitards. This considerably complicates the question of leachate transport. This report will refer to an "upper" and a "lower" aquifer. However, the reader should bear in mind that the system is substantially more complex.

The lower aquifer is normally confined and the upper aquifer acts as an unconfined aquifer although confined conditions exist (Weeks et al., 1974). A head difference of from 10 to 55 feet exists in most parts of the basin. Thus, permeability produced by partial mining, fracturing, and retorting could create a possibility for groundwater to migrate into an abandoned in-situ retort after completion of retorting.

The extent and nature of leachate migration will depend on dewatering management and on how the retorts are located relative to the aquifers. Four likely configurations for retort/aquifer location are shown schematically in Figure 6-2. The first three configurations are typical of conditions in the center of the Piceance Creek Basin, Colorado, where most of the rich oil shale deposits occur. In this area, the Mahogany Zone is sandwiched between several tiers of aquifers and aquitards. Retort location within this tiered structure depends on resource characterization, and retorts will be located to maximize resource recovery. The retorts may be located so that they penetrate the entire depth of the Mahogany Zone and intersect aquifers on both sides or so that they largely intersect only a lower or an upper aquifer. These two cases are very different from the standpoint of leaching characteristics. If a retort connects two aquifers, the retort will act as a conduit transporting leachates from one aquifer to the other. Flow will be either upward or downward, depending on the head differential between the aquifers. When only one aquifer is intersected, flow will be lateral through the retorts. The two-aquifer case may be represented by flow through parallel conduits, and leachate release may be described as a "line" source. The single aquifer case may be represented by flow through a series of retorts, and leachate release may be described as a "point" source. The total flow delivered by the parallel case will be considerably larger than the series case. An additional difference is that leachate will pass through several abandoned retorts in the series case; this may result in constituent removal by adsorption or ion exchange.



VERTICAL EXAGGERATION X 21
DATUM IS MEAN SEA LEVEL

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Figure 6-1. Geohydrologic section through the Piceance Creek Basin. Adapted from Weeks et al., 1974.

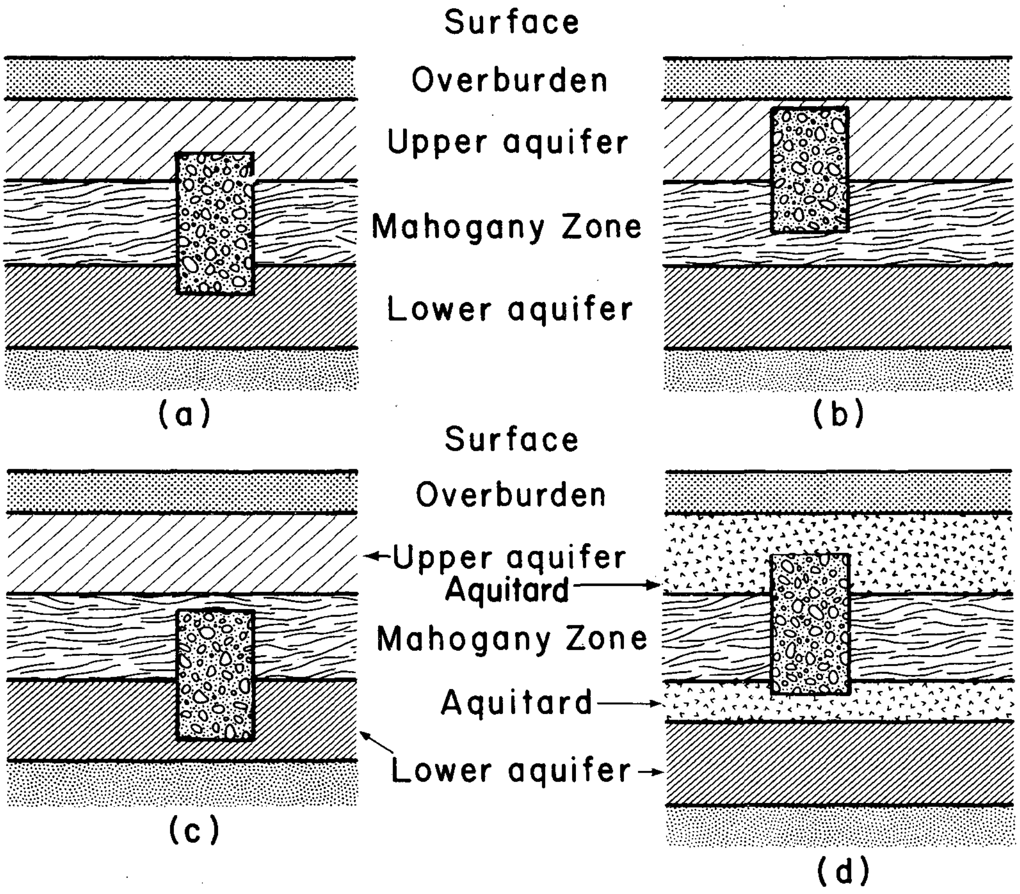

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Figure 6-2. Retort/aquifer configuration.

The retorts may also be located so that they do not directly intersect either aquifer. This is shown in the final schematic in Figure 6-2. This configuration is unlikely for retorts located in the Piceance Creek Basin but may occur in Utah or Wyoming oil shale deposits. This would represent the ideal configuration as there would be little interaction between the spent shale and groundwater. This situation exists in Utah where the oil-shale zone may exist either above or below a groundwater table.

Mechanics of Leaching

The following description (slightly modified) of the mechanics of in-situ leaching is from Parker et al. (1977).

The mechanics of the leaching of spent oil shale can be divided into chemical and physical aspects. The physical aspects will be considered first. Obviously, the spent shale must be cooled to below the boiling point of water to permit leaching. If no liquid water enters the hot in-situ retort, cooling may take years. The accidental or intentional injection of liquid water into the hot spent retort could quickly cool the spent shale.

Soluble material may be removed either from the surface of spent shale or from its complex internal pore system by diffusion. When liquid water contacts the spent oil shale, it will be drawn into the shale by capillary forces. Suddenly immersing a fragment of spent oil shale in water will result in capillary forces drawing water into the oil shale from all external surfaces while displacing gases through a few of the larger pores. The influx of water from the surface toward the central portion of the shale fragment will displace soluble salts from areas near the surface of the oil shale fragment into the central portion of the shale fragment. In contrast, if only the lower surface of the spent oil shale fragment is wet with water, as might occur if there was a slowly rising water level in an in-situ retort, water will be imbibed into the shale fragment from the bottom only and result in a miscible displacement of soluble salts to the upper surface of the spent shale fragment where the soluble salts will be more quickly leached into the bulk of the water. After the pore space of the retorted oil shale has been largely filled with water by capillary forces, only a small percentage of the residual gas saturation will remain within the shale. At this time, molecular diffusion will serve to transfer soluble material both to and from the spent shale fragment and the groundwater in which it is immersed.

Important chemical reactions associated with oil shale leaching occur at temperatures above 600°C where some shale minerals are changed from their natural state into different species. The major reactions are the decomposition of carbonates above 600°C, principally those of magnesium and calcium, and the formation of silicates (Campbell, 1978) above 800°C. Metal oxides formed between 600°C and 800°C are hydrated to strongly alkaline hydroxides. Retorting processes that use in-situ oxidation to generate the energy required for the process will normally reach these temperatures although the pyrolysis of oil shale can be accomplished easily at lower temperatures. Temperatures reached during the retorting process may also dehydrate various minerals, particularly clays. The temperatures necessary to produce calcium aluminosilicates, as in portland cement manufacture (1400°C), are not normally reached in oil shale processing. Slow retorting rates and the low thermal conductivity of oil shale may permit slow mineralogical reactions to occur within a field retort, reactions that might not be observed in laboratory studies using shorter heating times and operating under nonadiabatic conditions. Opportunities will exist during cooling for gas-phase reactions, such as hydration in the presence of steam and recarbonation in the presence of carbon dioxide.

When the spent oil shale is sufficiently cool to permit liquid water to exist, ionic reactions may begin. If the water is the result of condensing steam, only the ions available from the spent shale will participate in the reactions. If groundwater contacts the oil shale, ions supplied by the groundwater will also participate in the reactions. Major anticipated reactions are those of lime (produced by decomposition of calcite and dolomite) with clay, feldspars, and quartz. The precipitation of divalent cations by carbonates present in the groundwater will also be a major reaction. Changes in pH during the leaching process will also alter the solubilities of some ions. It should be stressed that the chemical environment inside the pores of the retorted oil shale may be very different from that observed in the external water. For example, the pH of the groundwater may be 8 to 9, whereas the pH inside the spent shale may be above 12. In addition to supplying additional soluble materials to the groundwater, the spent shale may serve to remove various ions from the groundwater. An obvious example is precipitation of carbonate ions in groundwater by calcium and magnesium in the spent shale.

Factors Affecting Leachate Quality

The leaching of inorganic and organic materials from in-situ spent shale will be influenced by (1) chemical-mineralogical characteristics of raw oil shale, (2) retorting conditions, (3) particle size distribution of the spent shale, (4) quality and temperature of groundwater, and (5) the flow regime of groundwater migrating through an abandoned retort. The first two, mineralogy of oil shales and retorting conditions, are believed to be the most significant. There is evidence that retorting conditions can be varied to control the amount of leachable material present. These first two items also apply equally to both surface and in-situ spent shales. Therefore, when they are discussed, operating conditions peculiar to surface retorting, such as indirect heating or inert-gas runs, will be considered. Each of these items is discussed below.

In addition to these recognized and quantifiable factors, there are two other factors specific to field retorts about which little is known. In field retorts, material at the bottom of the retort may be incompletely retorted, wet with oil, and have accumulated condensed metal species, such as mercury (Fox et al., 1979). The effect of this bottom plug on leachate quality is unknown and research on it is needed. In addition, gases produced during retorting may migrate out of the burn area and into groundwater aquifers. The magnitude of this would depend, among other things, on the fracture system present, gas holdup, and retorting pressure. This is poorly understood, and laboratory and theoretical investigations are required.

The amount of inorganic material available for leaching depends, ultimately, on the amount present in the original oil shale and the form in which it occurs. The amount of organic material available for leaching, on the other hand, is likely not affected by levels in the parent rock due to volatility considerations; retort operating conditions are believed to largely control leachable organics. The mineral residence determines the effect of retort operating conditions on the chemical composition and leachability of the spent shale. For instance, calcium and magnesium occur primarily as carbonates. If the shale is heated to about 600°C, these carbonates are converted into corresponding oxides which are readily solubilized. If temperatures exceed about 800°C, the metal oxides would react with silicon to form silicates which are relatively insoluble.

The chemical composition of the organic fraction of oil shale, kerogen, is relatively uniform throughout the Green River Formation (Smith, 1961). However, the chemical composition of the inorganic fraction of oil shale has been shown to be highly variable (Desborough et al., 1976; Poulson et al., 1977). Both mineralogical composition and elemental abundances vary widely. Tenfold to thousandfold variations in some elemental levels in oil shale from different depths in the same formation have been reported (Poulson et al., 1977). Significant variations both horizontally and vertically have also been recorded (Desborough et al., 1976; Poulson et al., 1977).

The quality of leachate derived from in-situ spent shale will be influenced by the retorting conditions employed. The most important conditions are retorting temperature and input gas composition, which determine the composition of the spent shale. Temperature is important because it is a measure of the amount of energy that is supplied to the raw oil shale. This controls the chemical reactions that occur, including decomposition of carbonate minerals, pyrolysis and combustion of kerogen, and volatilization of chemical species. The input gas is important because it provides the atmosphere in which chemical reactions take place. Four types of atmospheres are typically used: inert gas, air, air and recycle gas, air and steam, or a combination thereof. All four of these atmospheres are used in various surface retorting processes. Inert gas and air and recycle gas are used exclusively in surface retorting processes; for example, TOSCO, Paraho. Air and air-and-steam atmospheres are used in various in-situ processes. When air is used, the atmosphere is oxidizing and certain chemical reactions may occur between the shale and the oxygen in the input gas, thus affecting the organic and inorganic composition of the spent shale. When recycle gas is used as diluent, additional interactions may occur between the spent shale and recycle gas. For example, adsorption of components from the recycle gas onto the spent shale may occur. These adsorbed species are more readily leached than other chemically bound constituents. In an inert gas run, nitrogen is externally heated to provide heat of pyrolysis. Under these conditions, the atmosphere is reducing and a different set of interactions may occur.

The highest concentration of organic constituents may be found in leachate derived from spent shale produced during an externally heated inert-gas run or during a combustion run in which recycle gas is used as a diluent (Amy and Thomas, 1977). These conditions are more typical of various surface-retorting processes--such as USBM gas combustion retort, Paraho indirect, or TOSCO--than in-situ processes. Spent shale produced during an inert-gas run may result in a leachate of significant organic content since no combustion of residual organic material occurs. Spent shale produced during a combustion run employing recycle gas may result in a leachate with significant levels of organic constituents since recycle gas contains various volatile organic compounds that may adsorb onto the spent shale as input gas is supplied behind the reaction front in the retort. These adsorbed constituents may be readily removed by leaching. In contrast, the lowest concentration of organic contaminants may be found in leachate derived from spent shale produced during high-temperature combustion runs that do not utilize recycle gas. High-temperature combustion runs utilize residual carbon, which remains on the spent shale after oil extraction, as a fuel to provide an internal heat source for pyrolysis; the resultant spent shale thus contains very little organic carbon.

The highest concentration of most inorganic constituents may be found in leachate derived from spent shale produced at temperatures between 600°C and 800°C. This phenomenon is primarily attributable to carbonate decomposition which occurs at retorting temperatures above 600°C. Carbonate decomposition results in large amounts of calcium and magnesium oxides, both of which are very soluble and produce high pH leachates. Furthermore, spent shale resulting from retorting in the presence of air will normally produce leachate of a higher inorganic content than spent shale produced in the absence of air because air provides an oxidizing atmosphere for reaction with easily oxidized metals in the shale matrix, thus liberating these metals as ions. If sufficiently high temperatures, in excess of 800°C exist, mineralogical reactions may form insoluble minerals which could trap some otherwise leachable constituents (Campbell, 1978; Smith et al., 1978b; Campbell and Taylor, 1978).

The effect of oil-shale retorting on the decomposition of some carbonate minerals has been studied by Campbell (1978) and Campbell and Taylor (1978). They found that three principal carbonate/silicate reactions occur during oil-shale retorting. First, dolomite $Ca(Mg_xFe_{1-x})(CO_3)_2$ decomposes at about 600°C to produce iron and magnesium oxides and calcite ($CaCO_3$). Between 700°C and 800°C, calcite decomposes to calcium oxide and carbon dioxide. The calcium oxide may react with silica to produce calcium silicate compounds ($3CaO{\cdot}SiO_2$, $2CaO{\cdot}SiO_2$) and other compounds that are nonreactive (gehlenites and akermanites). Above 800°C, nonreactive silicates, such as mellites and diopside, form. Campbell (1978) summarized these reactions as:

$$Ca(Mg_x,Fe_{1-x})(CO_3)_2 \overset{\Delta}{\rightarrow} (1-x)FeO + xMgO + CaCO_3 + CO_2 \tag{1}$$

$$CaCO_3 \overset{\Delta}{\rightarrow} CaO + CO_2 \tag{2}$$

$$nCaO + mSiO_2 \overset{\Delta}{\rightarrow} Ca_nSi_mO_{(n+2m)} \tag{3}$$

$$xCaCO_3 + ySiO_2 \overset{\Delta}{\rightarrow} Ca_xSi_yO_{(x+2y)} + xCO_2 \tag{4}$$

These reactions are greatly accelerated in the presence of steam (Campbell and Taylor, 1978), suggesting that silicate formation in in-situ retorts employing steam/combustion will be enhanced.

Silicate formation at high temperatures may have a significant influence on the leaching potential of spent shales. Silicates are relatively insoluble, suggesting that the leaching potential of spent shales will be significantly reduced if they are produced at temperatures greater than 800°C (likely for in-situ retorts). This effect, which has been discussed by Smith et al. (1978), may be a significant deterrent to solubilization of many constituents.

However, it is important to note that the data of Campbell and Taylor are based on laboratory studies. Some leaching results, to be presented later for simulated spent shales generated at temperatures in excess of 800°C, are not significantly different from those generated at lower temperatures. This is likely because the laboratory studies were conducted under ideal conditions. Small quantities of finely powdered shale were used in the studies of Campbell and Taylor to avoid heat- and mass-transfer limitations. Silicate formation in simulated or field in-situ retorts would be limited by large particle size and nonuniform heating rates. Thus, it is likely that only a fraction of the carbonate minerals will be converted to insoluble silicates.

Some constituents--including Cd, Hg, S, N, and H--will probably occur at lower levels in leachate derived from spent shale produced during high-temperature runs. This is due primarily to the volatility of these constituents. During retorting, they are released from the shale and form gaseous or condensed species which may leave the retort with the offgases (Fox et al., 1978; Fox, 1980). Because they are removed from the shale, the quantity available for leaching and, therefore, the levels in the leachate would be lower than in low-temperature retort runs for the same oil shale. However, there is some evidence that suggests that volatilized mercury may accumulate in the lower portions of in-situ retorts where it may be readily leached (Fox et al., 1978).

Inert atmospheres may also enhance the removal of certain inorganic constituents from the spent shale, resulting in lower levels of those constituents in the leachates from inert atmospheres than in leachates from air atmospheres. This is because H, C, CO, and H_2S produced during retorting may reduce metal oxides, forming gaseous metal species (Fox, 1980) which would be removed from the retort. Experimental data on these reactions are not available, and they should be investigated.

The spent-shale surface area will significantly affect the rate at which material is leached. This area comprises the external surface area and the internal surface area associated with pores created by kerogen conversion. Therefore, leaching rate may not be a simple function of particle size. Generally, leachate derived from spent shale of a smaller particle size range will contain higher concentrations of inorganic and organic constituents during initial periods of leaching because it has a greater surface area per given volume available for leaching. Leaching of larger particles will result in lower initial concentrations. This is in accordance with mass-transfer theory.

The ambient quality of groundwater contacting in-situ spent shale may significantly affect the quality of leachate. Groundwater with a high TDS and alkalinity may influence the types and quantities of materials leached as a consequence of (1) high buffering capacity, (2) precipitation reactions involving ions originally present in the groundwater and ions leached from the spent shale, (3) counter-diffusion of ions originally present in the groundwater back into the shale matrix, and (4) ion exhange reactions. The solubility of a constituent in contact with groundwater is a very important property that will affect its leachability. The pH of spent shale leachate typically ranges from 7-13 (see Tables 6-9 and 6-14). Thus, constituents that are soluble in this pH range are likely to be found in leachate. Constituents that are soluble at alkaline pH's include As, Al, Se, Mo, B, F, Li, Na, K, Cl, and Zn. Those that are less soluble include Cr, Fe, Ca, and Mg. The presence or absence of such constituents in leachate would be mediated by the mineralogical residence of the element in the spent shale and the presence or absence of other anions or cations. For example, even though As and Se are soluble in alkaline waters, if they occur in the spent shale in pyrites, which are not readily leached by alkaline waters, they would not be found at high levels in the leachate. Likewise, the removal of Ca from solution would be greatly enhanced if CO_3 were present.

Groundwater temperature may influence the type and amount of materials leached from in-situ spent shale. Groundwater contacting spent shale shortly after retorting will undergo an increase in temperature ranging from ambient temperature to temperatures of boiling/vaporization. Some substances are more soluble in hot water than in cold, and vice versa. Thus, high-temperature groundwater may enhance the solubilization of some materials and inhibit solubilization of other materials from spent shale (Amy and Thomas, 1977).

The flow regime (i.e., flow direction, flow velocity, etc.) of groundwater passing through an abandoned retort will influence the leaching of inorganic and organic material from in-situ spent shale. For example, the flow regime will influence contact time between groundwater and spent shale, surface renewal of groundwater at the groundwater/spent shale interface, and the manner in which groundwater initially contacts the spent shale.

Leaching of Organic Constituents

The leaching of organics from simulated in-situ spent shale has been investigated by Amy (1978), Amy and Thomas (1977), and Hall et al. (1978). Review and analysis of these data indicate that in 30 days, from 1.0 to 38 milligrams of total organic carbon (TOC) may be leached for every 100 grams of in-situ spent shale at water temperatures of 20°C to 80°C. Most of this organic carbon is solubilized after the passage of the first few pore volumes of water through leaching columns. This is significant as it suggests that leaching of in-situ retorts may be a feasible control strategy. Only limited data are available on the organic characterization of leachates. This information indicates that about equal quantities of acidic, basic, and neutral materials are present in leachates, and that organic nitrogen and phenols are present at concentrations greater than 0.1 ppm.

The most extensive work completed to date is that of Amy (1978). He found that in continuous-flow experiments, most of the leachable organics are solubilized with the passage of the first few pore volumes of water. Thereafter, the TOC concentration rapidly drops and levels off to a low value, typically between 1 and 5 ppm. An example of this behavior for a combustion-run spent shale is shown in Figure 6-3. Hall et al. (1978) and Wildung (1977) report similar results for, respectively, a simulated in-situ spent shale from a steam-combustion run of LETC's 10-ton retort and a Paraho spent shale.

Amy hypothesized that this behavior is due to two principal mechanisms: leaching from the exterior shale surface and macropores and leaching from internal micropores. When water first passes through a column of spent shale, the organics on the surface of the particles and in the macropores are readily removed. The amount of time required to remove them likely depends on the surface area of the particle. This accounts for the pulse of organic carbon during early leaching times. Thereafter, molecular diffusion controls the release of organics from the micropores. This accounts for the low TOC tail that persists for long periods after the initial pulse has passed.

The above described mechanism is shown schematically in Figure 6-4. There are three aspects of this mechanism that are very important in predicting the effect of in-situ spent shale leachate on groundwater quality (this discussion also applies to inorganics). These factors are the concentration of TOC in the tail (A in Fig. 6-4), the maximum pulse concentration (B), and the length of time the pulse persists (C). It is likely that the duration time of the pulse and maximum pulse concentration depend on the particle surface area. Thus, it would take longer to remove the organics from large particles than from small particles. This is shown schematically in Figure 6-4 by the dashed line. Although there is no conclusive evidence to support this, a comparison of Amy's work (he found that about 3 pore volumes were required to pass the pulse when using a particle size range of 0.06 to 0.3 inch) and Hall's work (he found that 6 pore volumes were required to pass the pulse when 0.1- to 0.5-inch particles were used) and consideration of mass-transfer theory suggest that this is likely. The length of time it takes the pulse to pass, or equivalently, the number of pore volumes required to pass the pulse, will determine the initial effect of leachate on groundwater and the utility of intentional leaching and subsequent collection and treatment as a control strategy. The TOC concentration of the tail will determine the long-term effect of the leachate on local groundwaters. If the tail concentration is sufficiently low and if the organics present in it are not toxic, the long-term effects may not be severe.

There is not enough information available from which to determine the maximum pulse concentration, pulse duration, and tail concentration for a field retort because the relationship between particle size and these variables is undefined. In all laboratory work, small particle size ranges were used; field retorts will have much larger particles. Similarly, there are no data on the composition of the organics in the tail.

Even though definitive predictions cannot be made, an estimate of the probable effect of leachates on the organic composition of groundwater can be made using estimates of the mass of TOC leached per unit mass of

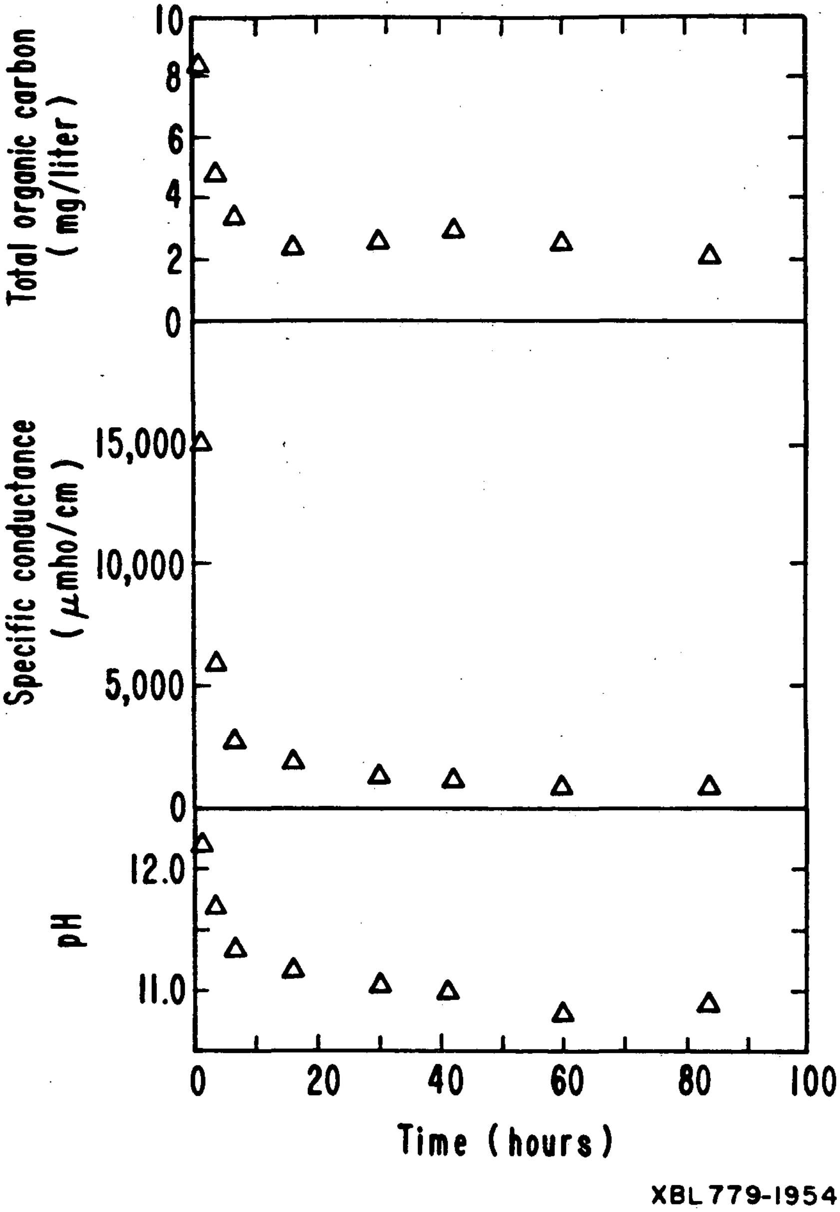

Figure 6-3. Continuous flow column experiment; column 12 in. long, 1 in. diameter; distilled water, flow rate 0.6 ml/min (Amy, 1978).

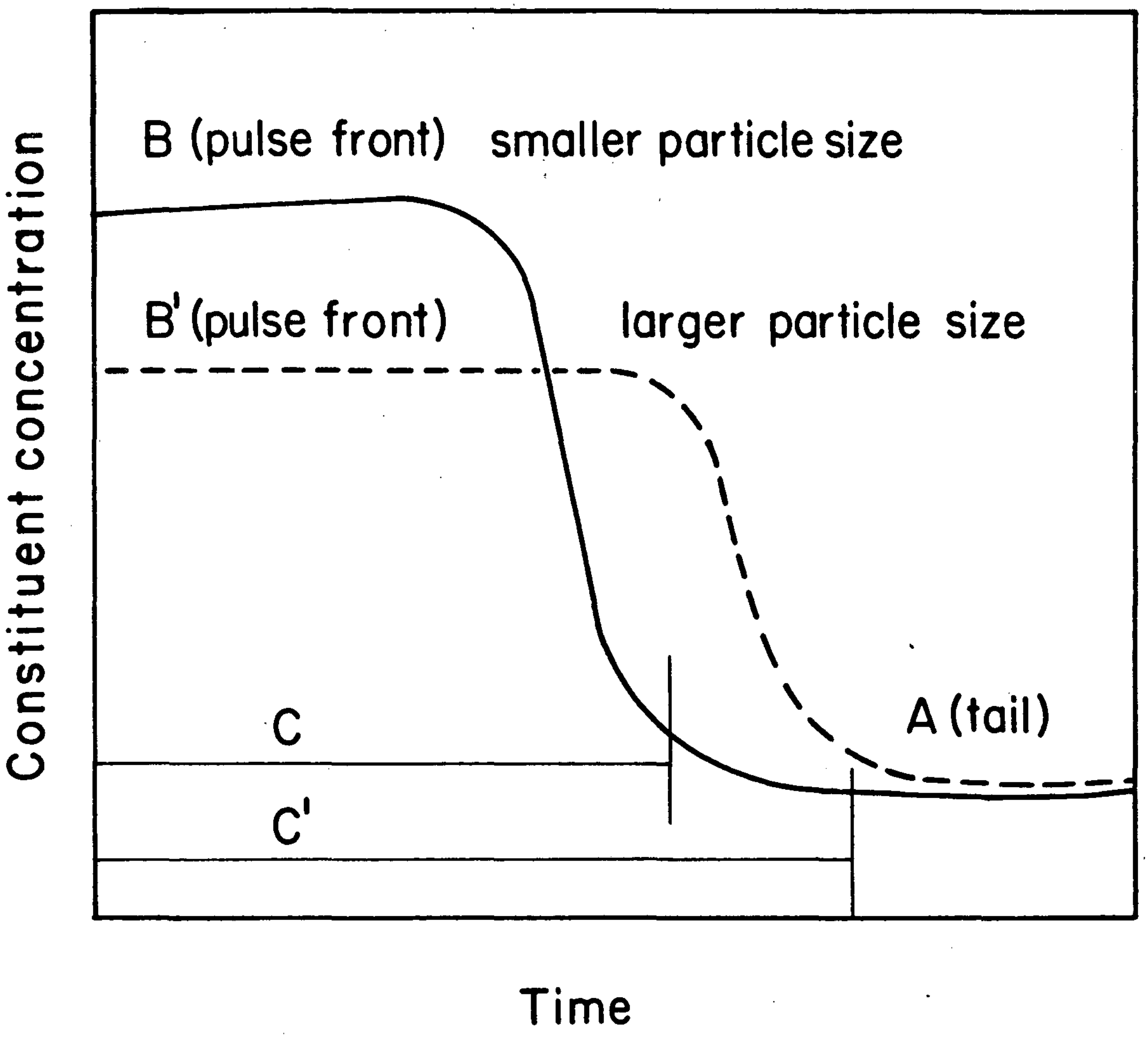

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Figure 6-4. Schematic of effluent from an in-situ retort.

shale and the number of pore volumes required to pass the front. Some of these data are presented and discussed below; they will be used later to determine the concentration of TOC in leachates from an in-situ retort.

Estimated quantities of TOC leached from simulated in-situ spent shale for various conditions are presented in Table 6-1. TOC is an indicator of the total organic material present in leachate. Some analytical problems have been noted (Hall et al., 1978) with the measurement of this parameter and therefore the values in Table 6-1 may be either high or low. However, the variablility due to analytical problems is probably small compared to the variability due to different retorting conditions and to different retorts.

Amy's batch data, summarized in Table 6-1, were obtained by bringing 50 grams of spent shale into contact with varying amounts of water, for time periods up to 30 days, and then analyzing the individual leachates for TOC. Results from a typical batch experiment for a combustion run are shown in Figure 6-5. Pertinent experimental conditions for the other experiments are summarized in Table 6-1.

The data summarized in Table 6-1 show that the mass of TOC leached from spent shales, produced in the simulated in-situ retorts at the Lawrence Livermore Laboratory (LLL), ranges from 1.5 to 6.9 milligrams per 100 grams of spent shale for inert gas runs; from 1.0 to 4.4 milligrams per 100 grams of spent shale for combustion runs; and from 2.9 to 11.8 milligrams per 100 grams of spent shale for a combustion run using recycle gas. Overall, for all of the retorting conditions investigated, the range was 1.0 to 11.8 milligrams of TOC per 100 grams of spent shale. The differences between the run types is likely realistic as the same analytical methods and retort were employed.

In contrast, the data obtained using spent shales from the simulated in-situ retorts at the Laramie Energy Technology Center (LETC) range from 10.0 to 38 milligrams of TOC per 100 grams of shale for a combustion run and a steam-combustion run. The difference between the LLL and LETC spent shales is probably related to differences in the simulated in-situ retorts and in the retort operating conditions; the LLL retort was operated at a higher temperature than the LETC retort. We do not believe that the high TOC values for steam combustion, relative to other run conditions, are due to the steam-combustion mode. The cause for the difference may be related to lower temperatures or nonuniform combustion in the LETC retort. The LETC retorting experiments used a very large particle size ranges (fines to 24-in blocks). This may have resulted in nonuniform combustion which could leave behind leachable organic carbon. The data reported in Table 6-1 from the LLL retort, on the other hand, were produced in runs in which a small particle size range was used (0.5 to 1 inches).

This summary indicates that the lowest amount of organic material was leached from combustion spent shales and that significantly higher amounts of organic material were leached from inert and combustion-recyle spent shales. The high levels of organic material removed from combustion-recycle spent shale is due to the adsorption of organics from the recycle gas onto the spent shale as the gas is supplied behind the reaction front. There is no statistically significant difference between the amount of organic

Table 6-1. Quantities of TOC leached from simulated in-situ spent shale.

Experiment	Particle size range, cm	Retort	Water	Leaching time	Inert gas retorting[a]	Combustion retorting[b]	Combustion and recycle gas retorting[c]	Combustion retorting with steam
30-day batch, 20°C (Amy, 1978)	0.06-0.3	LLL	Distilled	30 days	1.5-2.2	1.0-1.6	3.5	-
30-day batch, 80°C (Amy, 1978)	0.06-0.3	LLL	Distilled	30 days	2.2-6.0	1.0-2.0	2.9	-
30-day batch, 20°C (Amy, 1978)	0.06-0.3	LLL	Synthetic ground[d]	30 days	1.5-2.7	1.0-1.4	3.8	-
30-day batch, 80°C (Amy, 1978)	0.06-0.3	LLL	Synthetic ground[d]	30 days	4.0-6.8	1.0-1.8	3.4	-
Continuous flow column (Amy, 1978)	0.06-0.03	LLL	Distilled	80 hr	4.1-6.9[e]	3.8,4.4[e]	9.7,11.8[e]	-
2-day batch, 25°C (Jackson et al., 1975)	1-12	LETC	N/A	5 min	-	34-38	-	-
Continuous flow column (Hall et al., 1978)	0.1-0.5	LETC	Tap	144 hr	-	-	-	10.0-32.6[f]

[a] Range corresponds to four solid:water ratios ranging from 50 g shale/30 ml water to 50 g shale/200 ml water for one sample and 50 g of shale/50 ml water for a second, inert-run spent shale sample.

[b] Range corresponds to four solid:water ratios ranging from 50 g shale/30 ml water to 50 g shale/200 ml water for a single combustion run spent shale.

[c] Sample value for one combustion-recycle spent shale leached using 50 ml water per 50 g of shale.

[d] Synthetic groundwater had a conductivity of 12,000 μmho/cm and a pH of 9.

[e] TOC leached after 80 hr in, respectively, a 12-in-long and a 6-in-long column. Two unique samples were tested in each column for the inert run and one sample was used for the combustion and combustion-recycle runs.

[f] Based on a single column experiment and masses leached per each 6 in. of column length.

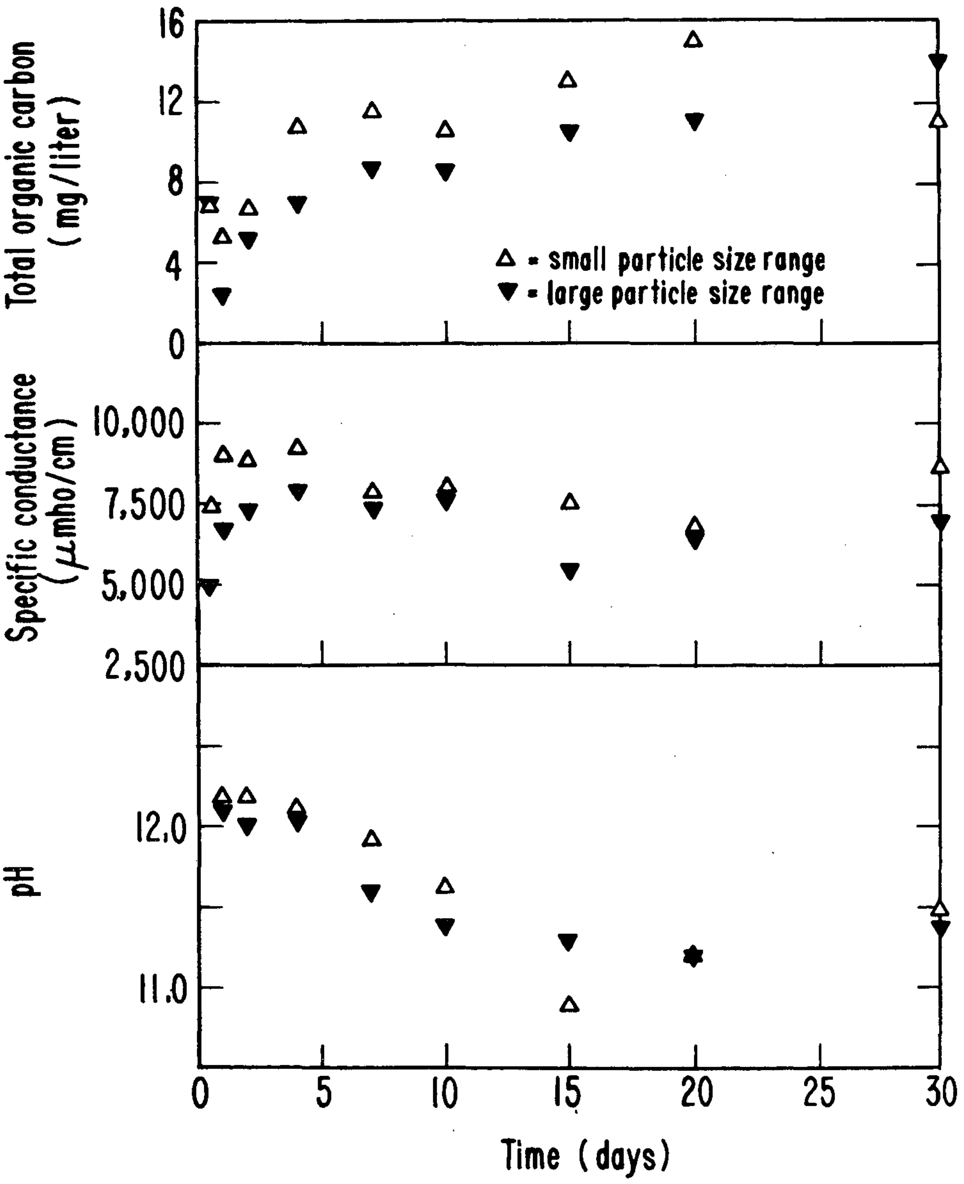

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Figure 6-5. Batch experiments conducted at 80°C: Type 1 spent shale; distilled water; △ = small particle size range; ▲ = large particle size range (Amy, 1978).

material leached when distilled water and artificial groundwater were used. This lends credence to laboratory data obtained with distilled water. It is significant to note that considerably higher amounts of organic material were leached during the continuous-flow column experiments than during the batch experiments. Similar results were obtained by Hall et al. (1978). This may be due to the precipitation or adsorption of organics during the batch studies, solubility limitations during the batch studies, or accelerated leaching of surface organics in the continuous-flow experiments. Elevated water temperatures had little effect on the amount of organic material leached from spent shale produced during ordinary combustion runs, enhanced the leaching of organic material from spent shale produced during inert gas runs, and inhibited the leaching of organic material from spent shale produced during combustion runs using recycle gas when distilled water was used.

The number of pore volumes required to pass the pulse, the mass of organics per unit mass of spent shale in the pulse, and the tail TOC concentration should be known to estimate the effect of leachates on groundwater quality. These data are summarized in Table 6-2 for inert, combustion, and steam/combustion retorting. The combustion-recycle run is not included because it is not now of commercial interest for in-situ retorting. These data will be used later to predict field leachate TOC concentrations. Since the mass data for the pulse are not significantly different from 30-day equilibrium leaching values presented in Table 6-1, estimates of the milligrams of leached constituent per 100 grams of shale presented in Table 6-1 and in Table 6-9 will be used later to predict field leachate concentrations.

The major limitation with the use of TOC as an indicator of organic constituents is that it provides only an estimate of the total amount of organic material present in leachate but provides no indication of the types of organic compounds present. Table 6-3 presents a summary of data which describe general categories of organic constituents--acidic, basic, and neutral fractions--present in leachate. The acid fraction may contain such organic compounds as carboxylic acids and phenols; the basic fraction may contain organic compounds like amines; and the neutral fraction may contain hydrocarbons. These data indicate that retorting conditions influence the types of organic compounds that are present in leachate. The presence of significant amounts of acidic, basic, and neutral material suggests that a variety of organic compounds is present in the leachates. The neutral fraction is the most predominant fraction associated with leachate derived from spent shale produced during inert gas runs.

The concentrations of organic nitrogen and phenol in Amy's leachates (1978) are summarized in Table 6-4. This table indicates that organic nitrogen and phenol concentrations are significantly higher in leachates produced from inert-run spent shales than from combustion-run spent shales. This is consistent with the TOC data discussed previously. The lowest level of these constituents occurs in leachates from combustion runs. Lower water temperatures appear to enhance the solubilization of both organic nitrogen and phenols. A comparison of Tables 6-3 and 6-4 indicates that about 20 percent of the base fraction is organic nitrogen.

Table 6-2. Summary of pulse and tail concentrations and number of pore volumes required to pass pulse for simulated in-situ spent shale for 50-g shale contacted with 50 ml water.

	Run Type		
	Steam/combustion (Hall et al., 1978)	Combustion (Amy, 1978)	Inert (Amy, 1978)
Particle size	0.1-0.5	0.06-0.3	0.06-0.3
Water	Tap	Distilled and synthetic ground	Distilled and synthetic ground
mg TOC/100 g spent shale in pulse	10.0-32.6	1.4-4.4	2.2-6.8
Pore volumes to pass pulse	6	1.5-4.7	1.7-3.9
Tail TOC concentration, ppm	1	1	1-2

Table 6-3. Quantities of organic fractions leached from spent shale after 30 days.

Water	Experiment[a]	Organic fraction	Leached organic fractions, μg/100g		
			Inert gas retorting[b]	Combustion retorting	Combustion and recycle gas retorting
Distilled	Batch, 20°C	Acid	370, 880	680	360
		Base	510, 540	460	290
		Neutral	880, 1050	860	280
		Total	1760, 2470	2000	930
	Batch, 80°C	Acid	450, 720	500	330
		Base	330, 360	610	470
		Neutral	350, 890	180	520
		Total	1130, 1970	1290	1320
Synthetic groundwater[c]	Batch, 20°C	Acid	920	420	-
		Base	440	370	-
		Neutral	1600	660	-
		Total	2960	1450	-
	Batch, 80°C	Acid	1100	500	-
		Base	590	330	-
		Neutral	2300	360	-
		Total	3990	1190	-

[a] All experiments conducted with particle size range of 0.06-0.3 in. See notes on Table 6-1 for description of other experimental conditions.

[b] The two values correspond to two separate inert-run spent shales.

[c] Synthetic groundwater had a conductivity of 12,000 μmho/cm and a pH of 9.

Source: Amy, 1978

Table 6-4. Quantities of organic nitrogen and phenols leached from spent shale.

Water[a]	Experiment[a]	Constituent	Mass leached per unit mass, μg/100g		
			Inert gas retorting	Combustion retorting	Combustion and recycle gas retorting
Distilled	Batch, 20°C	Organic nitrogen	70-100	70	90
		Phenols	41-43	25	22
	Batch, 80°C	Organic nitrogen	70-140	40	130
		Phenols	30-35	23	15
Synthetic groundwater	Batch, 20°C	Organic nitrogen	90	90	70
	Batch, 80°C	Organic nitrogen	90-120	70	60

[a] All experiments conducted with particle size range of 0.14 cm - 0.64 cm. See notes on Table 6-1 for description of other experimental conditions.

Source: Amy, 1978

Leaching of Inorganic Constituents

The leaching of inorganics from in-situ spent shale has been investigated by Amy (1978), Jackson et al. (1975), Shafer (1976), Parker et al. (1976, 1977, June 1978, Sept. 1978), and Kuo et al. (1979). Amy, Parker et al., and Shafer used simulated in-situ spent shales, while Kuo's and Jackson's work focused on field cores and measurements of backflood waters, respectively. These studies indicate that the principal ions in the leachate are SO_4, Na, HCO_3, and OH. Other constituents, such as Cl, F, Li, Mo, Pb, and Zn, occur at lower levels. The leachates typically have a high electrical conductivity and a high pH. Most of these constituents are solubilized after the passage of the first few pore volumes of water. This type of behavior is identical to that described previously for organics. The number of pore volumes required to remove most inorganic leachables is similar to that for TOC data (Table 6-2).

The quantity of various inorganics leached from in-situ spent shale is difficult to assess on a general basis. This is due primarily to the extreme variability of inorganics in oil shales, the wide range in groundwater quality encountered in areas of oil shale deposits, and the fact that most available data on leaching were obtained using distilled water (Margheim, 1975; Parker et al., 1977; Jackson et al., 1975; Stollenwerk and Runnells, 1977).

Available data indicate that there are major differences between the chemical composition of leachates obtained with groundwater and distilled water (Parker et al., 1977; Stollenwerk and Runnells, 1977). This is primarily because, with distilled water, ions are being removed from the spent shale by desorption or chemical reactions. When groundwater is used, the chemical components in it may enter into reactions with components in the spent shale or in the leachate itself. Available leaching data obtained using actual groundwater used a water with high total dissolved solids (TDS) and alkalinity. However, in some areas, good quality groundwater with low TDS and alkalinity is found. In these cases, leaching experiments using distilled water may be more representative than those using poorer quality groundwaters. Nevertheless, distilled-water data should be used with caution when evaluating the leaching of inorganics from in-situ spent shales.

Two general cases will be considered here for estimating the effect of the leaching of inorganic constituents from in-situ spent shale: leaching with groundwater of high TDS and alkalinity, and leaching with distilled or de-ionized water. Alkalinity is considered to be an important parameter because high alkalinity levels may lead to carbonate precipitates involving certain cations leached from the spent shale. TDS is considered to be an important parameter because various inorganic ions (whose potential presence is indicated by TDS measurements) present in groundwater may react with ions leached from spent shale or may displace ions associated with the spent shale by ion exchange processes. (In Chapter 4 of this report, Fig. 4-22 and Tables 4-15 and 4-16 describe the high degree of variability in groundwater TDS levels throughout the Upper Colorado River Basin.)

High TDS/Alkalinity Groundwaters. Only four studies have reported leaching data that were obtained for groundwaters: Jackson et al. (1975) and Parker et al. (1976, June 1978, Sept. 1978). These investigators used a composite groundwater from Rock Springs, Wyoming, where lean deep deposits of oil shale suitable for true in-situ development are located, and two groundwaters from Utah. The data derived from these studies are summarized in Tables 6-5 through 6-7.

Table 6-5 summarizes data obtained from LETC's Rock Springs Site 6 true in-situ field experiment (Jackson et al., 1975). The data presented in columns (1) and (5) of Table 6-5 provide an approximation of the composition of the groundwater before combustion was started. These data are for observation wells, located 90 feet to 200 feet from the burn area, six months after the burn started. Assuming that groundwater from the burn area would not reach the observation wells in this time, the reported quality would probably be similar to that in the burn area prior to start of the burn.

Column (2) of Table 6-5 gives the average quality of water obtained from a series of wells at which underground combustion (pattern wells) was started and from which products were recovered. The water samples were taken during the burn. These values represent leachate composition during passage of the first few pore volumes of water. All investigators conducting leaching experiments have found that the highest rate of release of inorganics occurs during this period. The high levels in column (2) are probably due to (1) interaction of groundwaters with retorting products, including retort waters, gases, and oil; (2) high chemical reaction rates due to high temperatures within the retort; and (3) reactions of steam with spent shale. A comparison of column (2) with columns (1) and (5) provides an estimate of the effect of in-situ retorting at Site 6 on local groundwater quality. This comparison shows that all reported parameters, with the exception of pH, increase (typically fourfold or more); pH decreases slightly. The pH decrease may be due to carbonic acid produced from CO_2 in the product gas.

Column (3) in Table 6-5 gives data for a series of wells drilled in the retorted area four years after the burn. These values represent leachate composition at the burn site four years after the burn. With two exceptions--K and pH, which increase--the values in column (3) are less, by a factor of 2 or more, than those in column (2). The increase in pH may be due to leaching of metal oxides and formation of hydroxides. The decrease in most parameters may be due to a decrease in available leachable materials, dispersion, diffusion, ion exchange, and precipitation. Most parameters decrease by a factor of 2 to 3 except Ca, Mg, and Cl, which decrease by factors of 7 or greater. The decrease in Ca and Mg is probably due to the precipitation of slightly soluble compounds of these cations, such as $CaCO_3$ and $Mg(OH)_2$.

An estimate of the effect of the burn on the original groundwater quality in the retorted area after a long period of time is obtained by comparing columns (1) and (3). This comparison shows that, while most parameters are high relative to original levels, Ca, Cl, and pH decrease. These changes are probably due primarily to continued leaching (recall that groundwater velocities are low and that several pore volumes must pass through a retort to remove most leachables), but may also be influenced

Table 6-5. Water quality analysis of wells near LETC's Site 6, true in-situ field experiment.

Constituent	Concentration, mg/liter				
	Observation wells 6 mo after combustion; analysis date: 11/71 - 8/72 (1)	Pattern wells during combustion; analysis date: 12/70 - 7/71 (2)	Pattern wells 4 hr after combustion; analysis date: 8/75 (3)	Observation well Q 4 yr after combustion; analysis date: 8/75 (4)	Observation well Q 6 mo after combustion; analysis date: 11/71 - 8/72 (5)
B	11	-	40	78	5.5
Ca	11	58	2.7	3.7	8.1
Cl	931	4250	592	2700	241
F	9.1	53	25	50	4.2
K	6.9	34	101	30	4.8
Mg	4.7	230	6.1	5.0	4.9
Na	1830	8900	3460	8400	723
NO_3	1.2	4.5	-	-	1.1
Si	-	-	16	12	-
CO_3	671	1940	1032	5300	465
HCO_3	1300	9750	3046	6000	361
SO_4	254	4810	2400	25	119
TDS[a]	5029	30,030	10,721	22,604	1938
pH	9.7	8.6	9.3	9.6	9.6

[a] Computed as sums of ions shown.

Source: Jackson et al., 1975

by differences in original groundwater composition in the pattern wells and observation wells.

The data presented in columns (4) and (5) of Table 6-5 describe the quality of groundwater in the same observation well six months and four years, respectively, after the burn. The difference between these two columns is due to groundwater transport from the retorted area to the observation well. Most values in column (4) are similar (within 25 percent) to those in column (2), suggesting that the leachate front has reached this well (see, for example, F, K, Na, HCO_3+CO_3). However, Ca, Mg, Cl, and SO_4 decrease. The decrease in both Cl and SO_4 may be due to ion exchange reactions; the decrease in Ca and Mg is probably due to precipitation.

It is interesting to note that large decreases in Ca and Mg were obtained relative to levels present in the initial leachate (column 2, Table 6-5) after four years had passed (columns 3 and 4). This is probably due to precipitation of the slightly soluble compounds $CaCO_3$ and $Mg(OH)_2$. The CO_3 and OH necessary to precipitate Ca and Mg are obtained from CO_2 in the product gas, from CO_3 leached from the spent shale, and from OH formed during the leaching of metal oxides.

Relevant chemical equations and corresponding solubility products at 25°C are:

$$CaCO_3 \rightleftharpoons Ca^{++} + CO_3^{=} \quad pK_{S_o} = -8.35 \tag{5}$$

$$Mg(OH)_2 \rightleftharpoons Mg^{++} + 2OH^- \quad pK_{S_o} = -10.65 \tag{6}$$

Using the above equilibria, the solubility-limited concentration of Ca and Mg and corresponding concentrations in field leachate measured by Jackson et al. (1975) are:

	Solubility-limited concentration, mg/l	Concentration in field leachate, mg/l (from Table 6-5)
Ca	2.7	2.7 - 3.7
Mg	4.3	5.0 - 6.1

This supports the hypothesis that Ca and Mg concentrations in the leachates are controlled by solubility of $CaCO_3$ and $Mg(OH)_2$. Similar calculations suggest that SO_4 is not controlled by the solubility of $CaSO_4$ (the equilibrium concentration of SO_4 is 480 mg/l).

The reduction of Ca and Mg during transport of the leachate is important when considering leachate disposition and effects. Even though Ca and Mg may be high in initial leachates, these levels may be reduced by natural processes to those close to original groundwater concentrations. Precipitation of $CaCO_3$ and $Mg(OH)_2$ may also reduce the primary porosity in the aquifer media, retarding leachate transport.

Several important conclusions can be drawn from Jackson's field measurements on Site 6 backflood waters. Elevated concentrations of many constituents persist in the burn area for several years after completion of retorting. The major components of the leachate (which occur at greater than 1000 mg/l) are Na, Cl, SO_4, HCO_3, and CO_3; Ca, Mg, K, and F occur at moderate levels. This agrees qualitatively with the laboratory data of Parker et al. (1976) and with results obtained with surface spent shales (Margheim, 1975; Wildung, 1977; Stollenwerk and Runnells, 1977; Culbertson et al., 1970). Some constituents decrease as the leachate is transported through the groundwater aquifer. These constituents are Ca, Mg, Cl, and SO_4. The Ca and Mg are probably reduced by precipitation, and the Cl and SO_4, by ion exchange.

Table 6-6 is a summary of laboratory-scale batch leaching studies by Parker et al. (1976) in which Rock Springs groundwater and Colorado oil shale were used. Column (1) presents the composition of the groundwater used for the leaching experiments. This water is similar in composition to that reported by Jackson et al. (1975) and discussed previously. Columns (2) and (3) summarize the composition of the leachate after 450 hours of contact. These data show that retorting conditions significantly affect the levels of ions in the leachate and that some constituents decrease and some increase. For the low-temperature inert run, Ca decreased significantly; Mg and Na decreased slightly; Zn, CO_3, and Fe remained about the same; and Cu, K, Li, and pH increased. In contrast, for the high-temperature run, CO_3, Fe, and Mg decreased significantly; Na decreased slightly; Ca, F, and Zn remained the same; and B, Cu, K, Li, and pH increased. The latter two conclusions suggest, as noted above, that some ions will be removed from groundwaters, thus improving their quality, and that other ions will be added. Those ions removed in significant quantities are probably controlled by carbonate or hydroxide precipitation reactions (Ca, Mg, CO_3, Fe) or ion exchange (Na).

There are significant differences between laboratory and field experiments. Gases, oils, and liquids produced in the field during retorting may contact the groundwater and increase a number of inorganic and organic constituents, including CO_3, HCO_3, NH_3, and sulfur compounds. This is evident in the data of Jackson et al. (1975) and of Parker et al. (1976). Parker's data indicate that CO_3 decreases and Jackson's data indicate that it increases. Additionally, the data of Parker et al. indicate that the levels of Ca and Mg decrease during initial leaching periods, and the data of Jackson et al. indicate they increase. The increase in CO_2 during field studies may be due to the production of CO_2 during retorting. This CO_2 may go into solution, increasing the concentration of CO_3 and HCO_3. An additional source of CO_3 in the field is nahcolite, $NaHCO_3$. The additional CO_3 available in the field enhances the long-term removal of Ca and Mg from solution by precipitation. Additionally, the elevated temperatures and longer contact times present in the field would initially enhance the solubilization of Ca and Mg.

It is interesting to observe that the TDS of the leachate in the experiments of Parker et al. (1976) decreased relative to the original groundwater while, in the experiments of Jackson et al. (1975) it increased significantly. Examination of the data suggest that this is due principally to the Na and CO_3 ions which increase according to the Jackson study and decrease according to that of Parker. The elevated CO_3 and Na levels in

Table 6-6. Material extracted from spent shale after 450 hr of leaching with Rock Springs groundwater.

Constituent	Leachate composition (mg/l)[a] Original groundwater, mg/l (1)	High temp. inert gas (2)	Low temp. inert gas (3)
B	8.5	41.2	-
Ca	6.25	6.25	0.21
Cu	trace	0.26	0.15
CO_3	3,300	1,053	3,050
F	26.5	26.5	-
Fe	0.77	0.38	0.70
K	38.5	75.8	45.5
Li	0.19	4.17	0.28
Mg	11.75	1.8	9.0
Na	5,065	4,538	4,450
Zn	0.19	0.20	0.19
pH	9.3	12.6	9.55
Sum of constituents	8,458	5,748	7,556

[a] Cylindrical cores of Anvil Points oil shale, 3.65 cm in diameter and 5.0 cm long, were retorted and leached in 200 ml groundwater in a continuously stirred, batch-leaching cell. Over increasingly long periods, 20 ml samples were taken for analysis and replaced by equal volumes of groundwater.

Source: Parker et al., 1976.

the Jackson study and decrease according to that of Parker. The elevated CO_3 and Na levels in the Jackson study are probably due to the solubilization of CO_2 and the leaching of nahcolite ($NaHCO_3$). The Na difference may be due to differences in oil shale composition or in ion exchange properties of the spent shales. Beds of nahcolite are known to exist in the Wyoming oil shales. These types of interactions further complicate the problem of estimating leachate quality from laboratory data. Gas-liquid equilibria, particle size distribution, the fraction of the retort fully combusted, mineral composition of the deposit, and other factors significantly affect leachate quality. Field measurement programs are required to assess the leaching of in-situ spent shales.

Table 6-7 is a summary of other laboratory-scale, batch-leaching studies, by Parker et al. (June 1978, Sept. 1978), in which two separate Utah groundwaters and Utah oil shale were used. The purpose of this study was to investigate the effect of temperature on leachate quality. Four hundred and fifty grams of crushed Utah shale were retorted in a laboratory retort at the temperatures and under the atmospheres shown in Table 6-7. The retort vessel was brought to temperature over a 12-hour period, maintained at that temperature for 48 hours, and cooled for 24 hours. Small samples (67 to 86 g) were leached at 35°C and 90°C with 200 ml of Douglas Creek or Birds Nest Creek groundwater for 21 days. The samples were agitated daily. The data summarized in Table 6-7 indicate that conductivity, pH, and alkalinity are significantly reduced in leachates derived from spent shales retorted at 1000°C relative to those retorted at 780°C. This is due to the formation of insoluble silicates at the higher temperatures as predicted by Smith (1978b). However, even though the levels of these constituents are reduced, they are still high enough, (e.g., pH = 11) to cause significant degradation of the local groundwaters. This occurs because there is not enough alkalinity to consume all of the calcium and magnesium (Parker et al., June 1978). The higher temperature (1000°C) has little effect on selenium, arsenic, or fluorine, and tends to enhance the leachability of boron. Hydration of unconverted metal oxides produces the high pH (~11), conductivity (7,000-15,000 μmho/cm), and alkalinity reported for 1000°C leachates.

Distilled Water. This section will address those studies that used distilled or de-ionized water as the leach water. As noted previously, the distilled or de-ionized water used in many studies is likely more similar to low-TDS/low-alkalinity groundwaters than to the high-TDS/high-alkalinity groundwaters discussed previously. Nevertheless, these data should be used with caution if extrapolated to field conditions.

Several investigations have been concerned with the leaching of inorganics by distilled water (Parker et al., 1977; Amy, 1978; Jackson et al., 1975; Shafer, 1976; Kuo et al. 1979). The results of these investigations may be used as approximations of what may occur if in-situ spent shale is leached by groundwater with a TDS of less than 1000 mg/l and an alkalinity of less than 50 mg/l as $CaCO_3$. These data are summarized in Tables 6-8 and 6-9.

Table 6-7. Effects of retorting and leaching-water temperatures on various characteristics and constituents of Utah spent-shale leachates.

Retort temperature, °C	Leaching temperature, °C	Material leached, g	pH	Conductivity, µmho/cm	Acid required to titrate leachate, meq/l		Boron, µg/ml	Fluorine, µg/ml	Selenium, µg/ml	Arsenic, µg/ml
					to pH 8.3	to pH 4.5				
(Leached in Douglas Creek water – air only)										
430	35	86	8.55	4300	0.08	6.88	1.75	26	–	–
430	90	86	8.21	4050	0	6.56	1.70	26.2	–	–
780	35	67	12.00	23000	89.82	4.09	1.75	38.7	<0.1	1
780	90	67	12.30	41400	139.15	11.47	2.88	41	–	1
1000	35	68	11.48	10980	12.82	6.52	6.1	33.7	<0.1	1
1000	90	68	11.44	12580	12.70	7.21	8.3	33.7	<0.1	1
(Leached in Birds Nest Creek water – air only)										
430	35	86	8.67	8480	0.08	5.74	1.75	23.8	–	–
430	90	86	8.22	7580	0	5.74	1.8	24.5	–	–
780	35	67	12.15	33000	127.51	9.01	2.15	37.8	–	–
1000	35	68	11.28	13600	6.97	6.15	9.2	25.5	<0.1	1
1000	90	68	11.03	14840	3.44	4.51	6.7	23.1	<0.1	1
(Leached in Douglas Creek water – air + 15% CO_2)										
430(Run 1)	35	86	8.30	5610	0	0.41	2.3	23.6	<0.1	–
430(Run 1)	90	86	7.73	6210	0	0.82	1.75	24.2	–	0
430(Run 2)	35	85	9.39	5250	0.25	0.57	1.95	25.6	<0.1	–
430(Run 2)	90	85	8.29	5700	0	1.88	1.9	26.2	<0.1	–
780	35	67	11.84	12580	39.42	4.67	3.5	37.5	<0.1	1
1000	35	65	11.47	8770	10.00	4.18	2.1	35.7	–	–
1000	90	65	11.39	7310	7.87	4.10	2.15	35	<0.1	1
(Leached in Birds Nest Creek water – air + 15% CO_2)										
430(Run 1)	35	86	8.63	8930	0.16	0.74	1.6	24.3	–	0
430(Run 1)	90	86	7.36	11000	0	1.15	1.8	25.6	–	–
430(Run 2)	35	85	9.52	8700	0.41	0.49	1.94	23	–	–
430(Run 2)	90	85	8.28	9270	–	1.64	1.35	22.4	–	–
780	35	67	12.35	26800	92.77	6.06	2.55	35.7	–	–
780	90	67	12.49	43800	83.75	12.05	3.1	36.5	<0.1	–
1000	35	65	11.23	12770	5.82	3.93	2.2	25	<0.1	–
1000	90	65	10.61	9580	1.48	2.60	2.1	24.5	<0.1	0

Source: Parker et al., 1978

Table 6-8. Summary of quantities of TDS leached from simulated in-situ spent shale by distilled water.

Source	Experiment[a]	Water[a]	Quantity of leached TDS, mg/100g Inert gas retorting	 Combustion retorting	 Combustion with recycle retorting
Simulated in-situ spent shale					
UCB (Amy, 1978)	30-day batch, 20°C	Distilled	110-160[b]	510[c]	1000[c]
UCB (Amy, 1978)	30-day batch, 80°C	Distilled	230-360[b]	470[c]	850[c]
UCB (Amy, 1978)	30-day batch, 20°C	Synth. grnd.[d]	0, 140[b]	420[c]	600[c]
UCB (Amy, 1978)	30-day batch, 80°C	Synth. grnd.[d]	0, 70[b]	250[c]	520[c]
UCB (Amy, 1978)	Continuous flow	Distilled	230-440[b,e]	2000, 2700[e]	2100, 2800[e]
Texas Tech. (Parker et al., 1977)	15-hr batch	Distilled	80->1120	405-944	-
LETC (Jackson et al., 1975)	5-min batch, 25°C	Distilled	-	250-760	-

[a] See Table 6-1 for description of other experimental conditions.

[b] Determined for two unique samples of inert-run shale.

[c] Single value for one each combustion and combustion-recycle spent shales.

[d] Synthetic groundwater had a conductivity of 12,000 μmho/cm and a pH of 9.

[e] TDS leached after 80 hr in, respectively, a 12-in-long and a 6-in-long column. Two unique samples were tested in each column for the inert run and one sample was used for the combustion and combustion-recycle run.

Table 6-9. Leachate composition of simulated in-situ spent shale.

	Experimenter										
	Amy (1978)			Jackson et al. (1975)	Hall et al. (1978)	Parker (1977)				Kuo et al. (1979)		
	LLL 125-Kg retort			LETC 10-ton	LETC 10-ton	Laboratory-scale retort				Laboratory-scale retort[d]	Field Retort 3E	
	Low temp. inert	High temp. combustion	High temp. comb.-recycle	High temp comb.	High temp. Steam-comb.	Low temp. inert	High temp. inert	Low temp. comb.	High temp. comb.	High temp steam	High temp. steam	
Experiment type[a]	B,C	B,C	B,C	B	C	B	B	B	B	B	B	
Particle size range, in.	0.06-0.3	0.06-0.3	0.06-0.3	1-12	0.1-0.5	2x1.5 cores	2x1.5 cores	2x1.5 cores	2x1.5 cores	--	--	
Contact time, batch	30 days	30 days	30 days	5 min	--	15 hr	15 hr	15 hr	15 hr	--	Soxhlet extraction	
Pore values for continuous-flow columns	31	31	31	--	12	--	--	--	--	--	--	
Constituent	Constituent concentration, mg/100 g											Data summary, simulated in situ retorts
Al	--	--	--	--	--	0.38-1.4	1.6-2.8	0.095-1.4	--			0.095-2.8
B	--	--	--	0.075-0.14	--	--	--	--	--	0.01-0.03	0.001-0.010	0.001-0.14
Ca	--	--	--	3.67-67	--	6.1-14	44-89	97-160	68-210	0.4 -2.5	0.03-0.21	0.03-210
Cl	--	--	--	5.5	--	--	--	--	--	--	--	5.5
CO_3	--	--	--	30-215	--	--	--	--	--	--	--	30-215
Cr	--	--	--	--	--	--	0.002-0.004	0.020-0.13	T[b]-1.8	--	--	0.002-1.8
F	--	--	--	1.2-4.2	--	--	--	--	--	--	--	1.2-4.2
Fe	--	--	--	--	--	0.0004-0.0005	0.0005-0.0006	0.003-0.042	0.004-0.04	--	--	0.0004-0.042
HCO_3	--	--	--	22-40	--	--	--	--	--	--	--	22-40
K	--	--	--	6-7.5	--	0.76-0.94	1.2-2.9	2.1-3.4	5.2-18	0.1-0.25	0.07-1.2	0.07-18
Li	--	--	--	--	--	0.020-0.10	0.33-0.81	0.092-0.18	0.098-0.42			0.020-0.42
Mg	--	--	--	0.28-4.0	--	0.072-0.88	0.034-0.040	0.013-8.0	0.002-0.008		0.006-0.02	0.002-8.0
Mo	--	--	--	--	--	T[b]	T[b]	T[b]	T[b]	-		T[b]
Na	--	--	--	12-235	--	12-21	8.8-43	22-35	11-77	0.2-0.55	0.05-0.21	0.05-235
NO_3	--	--	--	0.2-2.6	--	--	--	--	--	--	--	0.2-2.6
OH	--	--	--	22-40	--	--	--	--	--	--	--	22-40
Pb	--	--	--	--	--	--	0.014-0.017	--	--	--	--	0.014-0.017
Si	--	--	--	25-88	--	--	--	--	--			25-88
SO_4	--	--	--	50-130	--	--	--	--	--	0.8-2.8	0.28-0.60	0.28-130
Sr	--	--	--	--	--	0.004-0.01	0.60-2.8	1.4-2.4	1.5-8.7	--	--	0.004-8.7
Zn	--	--	--	--	--	0.001-0.011	0.006-0.025	0.011-0.020	0.008-0.021	--	--	0.001-0.025
TDS	0-440[c]	250-2700[c]	520-2800[c]	251-762	--	80-108	610- 1120	405-558	615-944	--	--	0-2800
TOC	1.5-6.9[c]	1.0-4.4[c]	2.9-11.8[c]	34-38	10.0-32.6	--	--	--	--	--	--	1.0-38
Organic N	0.07-0.14	0.07-0.09	0.06-0.13	--	--	--	--	--	--	--	--	0.06-0.14
Phenols	0.03-0.04	0.02-0.03	0.015-0.022	--	--	--	--	--	--	--	--	0.02-0.04
pH	7-10	11-12	11-12	10.4-11.2	--	8.88-10.6	11.6-12.0	7.76-12.0	12.0-12.7	--	--	7.76-12.7

[a] B = batch; C = continuous flow.

[b] T indicates a trace detected.

[c] Upper limit derived with 80-hr continuous flow columns; see Tables 6-1 and 6-7.

[d] Water-to-shale ratio varied from 7 to 75 ml/g.

Table 6-8 summarizes data for TDS, a general indicator of the overall inorganic quality of a water, leached under the retorting conditions specified. The data presented in Table 6-8 reveal that, depending on the particular retorting conditions employed, quantities of TDS ranging from 0 to 2800 milligrams per 100 grams spent shale may be leached from in-situ spent shale.

Quantities of specific inorganic constituents leached from simulated in-situ spent shales with distilled water are summarized in Table 6-9. There are significant differences between the data of the various investigators. The differences may reflect variations in analytical methods, retorting conditions, or oil shale composition and point to the need to identify and investigate variables affecting leachate composition.

The data of Parker et al. (1977) indicate that temperature and retorting atmosphere have the following effects on leachate composition:

1. The concentrations of Ca, Fe, K, Na, and Sr are higher in leachates from combustion runs than from inert-gas runs.

2. The levels of Li, Sr, and Cr in leachates derived from high-temperature combustion and inert runs are much higher than from low-temperature runs.

3. Ca is higher in high-temperature inert leachates and K is higher in high-temperature combustion leachates.

4. The levels of Mg are higher in leachates derived from low-temperature runs.

Kuo et al. (1979) conducted batch and continuous-flow leaching studies of simulated and field in-situ spent shales from the Occidental modified in-situ process. In Kuo's work, a series of samples from Occidental Research's "mini-retort" (Mahajan et al., 1977) that covered temperatures from 540 to 900°C, shale grades from 10 to 37 gallons per ton, and particle sizes from 0.3 to 4 cm, were leached with de-ionized water at room temperature. Additionally, a core from Retort 3E at Logan Wash, Colorado, was leached in a Soxhlet apparatus. The principal conclusions of these investigators were as follows:

(1) The major ions in the leachates were Ca, Na, K, OH, and SO_4.

(2) Ca, Na, and K concentrations reached maxima between 750°C and 850°C.

(3) Spent shales from undiluted air runs were more leachable at all temperatures than spent shales from air-steam runs.

(4) The concentration of most ions except OH and Ca reached neglible levels in leachate in the first five pore volumes of water for shales retorted at temperatures greater than 650°C.

The data of Kuo et al. (1979) suggest that leachates from these spent shales have lower concentrations of TDS, many inorganic ions, and a lower pH than leachates from other in-situ spent shales. These investigators concluded that leachates from spent in-situ retorts may not be an environmental concern and pointed out that concentrations of all trace elements except F and Cr were below the EPA drinking water standards.

The present author is in disagreement with these conclusions. The work by Kuo et al. did not reliably simulate field conditions, and the authors did not report adequate information to evaluate discrepancies between their work and others. Under field conditions, elevated-temperature spent shales will be contacted by high TDS groundwater. Residual gases such as CO_2 and H_2S, trapped in fractures and pores, will participate in the leaching process. Thus, Kuo's work is not sufficient to conclude that there will be no environmental problem. Additional work, which must include field measurements, is required to definitively answer this question. These authors also did not report adequate information to substantiate their conclusions. Very little experimental data were reported, only conclusions from the data. No information was given on shale-water contact times, a critical variable in leaching; and no information was presented on analytical methods. This lack of adequate experimental data and a methods description, coupled with the disagreement between this work and all others completed to date, leads the present author to conclude that this work must be repeated in other laboratories and the detailed data results published in the open literature before a fair assessment can be made.

The last column in Table 6-9 presents a range for all of the available data on simulated in-situ spent shale leachates. The reported ranges are very large, varying by a factor of more than 200 in many cases. This large variation reflects the differences in the composition of oil shales used in the experiments, the contact time between the leach water and the shale, particle sizes, retorting conditions, and other experimental conditions and procedures. Therefore, it is not possible to present a single number.

If one considers only the maximum observed value for each constituent in Table 6-9, the constituents may be grouped according to how much is leached. This grouping is as follows:

1. Less than 10 mg/100 g: Al, B, Cl, Cr, F, Fe, Li, Mo Mg, NO_3, Pb, Sr, Zn
2. Between 10 and 100 mg/100 g: HCO_3, K, OH, Si
3. Greater than 100 mg/100 g: Ca, CO_3, Na, SO_4

This grouping shows that the major inorganic constituents in the leachate are K, Ca, Na, SO_4, Si, OH, HCO_3, and CO_3.

Leachate Composition

An estimate of the average maximum composition of leach waters exiting from an in-situ retort may be made by using the values in the last column of Table 6-9, and some simplifying assumptions. The average maximum concentration is the average concentration of the pulse front described on Figure 6-4. The concentration of the tail is neglected in these calculations. The necessary assumptions are:

1. Most leachable constituents are removed with the passage of the first two to six pore volumes of leach water.

2. The mass of material leached per unit mass of spent shale using distilled water and contact times of up to 30 days is similar to what would be leached using local groundwaters and contact times greater than one year. In other words, the values summarized in the last column of Table 6-9 are reasonable approximations of the mass of material leached per unit mass of spent shale.

3. The leachate concentration exiting from the retort is constant.

4. The spent retort intersects a groundwater aquifer and groundwater migrates vertically through the retort.

It is important to understand the effect of each of these assumptions on leachate composition. The number of pore volumes required to remove the leachable constituents is the most critical assumption because it is directly related to leachate concentration. Available data suggest that from two to six pore volumes are required to pass the front (i.e., remove most of the leachables). The number of pore volumes may increase as the surface area decreases (i.e., as particle size increases). Thus, it is likely that a larger number of pore volumes would be required in a field retort to pass the front. Thus, the leachate concentration estimates to be presented here are high relative to field values.

The range of values presented in Table 6-9 was derived principally from laboratory data. There are significant differences between laboratory conditions and those that will be encountered in the field, as was noted previously in comparing the data of Jackson et al. (1975) and Parker et al. (1976). The primary differences are the short contact times between shale and water, the lower initial leach water temperatures, the small particle size ranges, the use of distilled water, and the limited size of the leached sample relative to the field case. Under actual field conditions, the contact time between shale and leach water may be of the order of one to ten years; the temperature of the spent shale may range from ambient to nearly 1000°C; the particles will range from fines to boulders; groundwater temperature of varying composition will contact the spent shale; and a very large segment, from several hundred to nearly 800 feet in depth, of the oil shale zone will be contacted. Additionally, temperatures reached in in-situ retorts may be higher than those used in laboratory retorts. If they exceed 800°C, it is possible that silicates will form. Because silicates are relatively insoluble, leachate concentrations may be lower than those predicted from laboratory data. These factors could result in significant differences between laboratory unit mass values as summarized in Table 6-9 and those that will be observed in the field. However, until field retorts are leached with local groundwater, the values in Table 6-9 may be considered the best available.

The front concentration will likely be uniform until the front passes. The concentration in the transition between the front and the tail will decrease. However, because many years may be required to reach this transition and because new retorts will be continually available for leaching, the concentration from a large collection of retorts over a long time period will be essentially uniform. This is a reasonable conclusion because the estimation procedure used here is for the average concentration.

The way in which the retort intersects an aquifer will affect leachate composition. Some likely configurations were shown in Figure 6-2. When both aquifers are intersected, the retort acts as a conduit. When flow is horizontal through the retort, leachate from one retort will pass through all upstream retorts. This may result in adsorption, ion exchange, or other interactions between the leachate from the downstream retort and spent shale in the upstream retort. Such interactions would likely be different from leachate passing through aquifer material (raw oil shale). These calculations do not apply to leachate exiting from a long series of retorts receiving horizontal flow.

Given the above assumptions, an estimate of the average maximum composition of leachate exiting from a spent in-situ retort may be computed as follows:

$$\bar{C}_i = \frac{10M_i m + (C_g)_i nV}{nV} \qquad (7)$$

where M_i = mass in milligrams of ith constituent per 100 grams of spent shale (Table 6-9)

m = mass of spent shale in a single retort = (1.1×10^9 kg for tract C-a and 7.5×10^8 for tract C-b; see Chapter 3)

$(C_g)_i$ = concentration of ith constituent in groundwater in mg/l

V = volume of water within a single retort (5.0×10^8 liters for tract C-a and 2.0×10^8 liters for tract C-b; see Chapter 3)

$\bar{C}_i$ = average maximum concentration of ith constituent exiting the retort

n = number of pore volumes (2 to 6) required to remove most of the leachables

Equation (7) may be used to estimate the average maximum composition of leachate due to the passage of the first few pore volumes of water. The first term in this equation, $10M_i m$, is the mass of material that can be potentially leached from a single in-situ retort. The second term, $(C_g)_i nV$, is the mass of the ith constituent present in the groundwater that fills the spent retort. The denominator, nV, is the total volume of water required to remove most of the leachables. The accuracy of

Eq. (7) is limited by how well M_i is known and by the actual number of pore volumes of water required to pass the front. Some experimental estimates of M_i are summarized in the last column of Table 6-9. However, these values are based on leaching times and leach-water compositions much different from those that will be encountered in practice. Thus, these values may be high or low due to adsorption, ion exchange, solubility, or kinetic considerations.

The estimated average composition of leachate discharging from spent in-situ retorts located on lease tracts C-a and C-b in the Piceance Creek Basin is presented in columns (6) and (7) of Table 6-10. These estimates were derived using Eq. (7), the leachable constituent summary for simulated in-situ spent shales presented in Table 6-9, and groundwater composition data from the vicinity of lease tracts C-a and C-b summarized in columns (2) through (5) of Table 6-10. Columns (6) and (7) present a range for the average composition of leachate discharging from spent in-situ retorts. The range corresponds to different retorting conditions (see Table 6-9) and a pore volume of from two to six. For example, the lower value in these columns is computed from the lower value for M_i and a number of pore volumes n equal to six. The larger value in columns (6) and (7) corresponds to the larger value for M_i and n equal to two.

Column (1) of Table 6-10 summarizes the mass of each constituent leached from simulated in-situ spent shale per 100 grams of spent shale (M_i) when the leaching is carried out with distilled or de-ionized water. Distilled-water data rather than Rock Springs groundwater data are used to determine leachate composition for the Piceance Creek Basin because Rock Springs groundwater contains significantly higher concentrations of HCO_3, CO_3, and TDS than do native groundwaters of the Piceance Creek Basin. These parameters--HCO_3, CO_3, and TDS--may play a significant role in controlling the composition of leach waters. (Clearly, experimental data derived using spent shales and groundwater from these areas are desirable; however, the data are presently unavailable.)

Columns (2) through (5) of Table 6-10 present predevelopment groundwater quality on the two tracts. The leach water will initially have a composition similar to that shown in these columns, depending on whether it is from the upper or lower aquifer. The work of Weeks et al. (1974) indicates that flow will be down on Tract C-a and up on Tract C-b. Therefore, retorts on C-a will be leached with upper aquifer water, and on C-b, with lower aquifer water.

This compilation indicates that the average concentration in the leachate for tabulated constituents may greatly exceed levels in native groundwaters. The significance of this will be discussed in a later section on assessment. On Tract C-a, flow is projected to be downward, and leachate with a composition similar to column (6) will mix with and be transported in the lower aquifer, which has an average quality as indicated by column (3). A comparison of the lower values in column (6) with column (3) indicates that Al, Cl, CO_3, Fe, Li, NO_3, Si, SO_4, and phenols will increase, that TDS, B, F, HCO_3, and Na decrease; and that K, Pb, Zn, and TOC remain about the same in lower aquifer waters. Major increases in all of the tabulated parameters will occur if the upper values in column (6) are considered.

Table 6-10. Estimated composition of leachate exiting an in-situ retort located on lease tracts C-a and C-b.

Constituent	Distilled water leachate composition (Table 6-9) mg/100g (1)	Predevelopment Groundwater Quality,[a] mg/l Tract C-a Upper aquifer (2)	 Lower aquifer (3)	 Tract C-b Upper aquifer (4)	 Lower aquifer (5)	Leachate Composition, mg/l Tract[b] C-a (6)	 Tract[c] C-b (7)
Al	0.095-2.8	0.14	0.24	0.3	0.3	0.49 - 31	0.89 - 53
B	0.001-0.14	0.33	0.84	1.4	36	0.33 - 1.9	36 - 39
Ca	0.03-210	35	8.8	32	14	35 - 2350[d]	14 - 3950[d]
Cl	5.5	12	22	26	1200	32 - 73	1234 - 1300
CO_3	30-215	0.88	69	21	220	110 - 2400	408 - 4250
Cr	0.002-1.8	<0.01	<0.01	0.002-0.3	<0.009	<0.02 -<20	0.01 - 34
F	1.2-4.2	0.41	15	10	21	4.8 - 47	29 - 100
Fe	0.0004-0.042	5.0	0.78	0.5	0.8	5.0 - 5.5	0.8 - 1.6
HCO_3	22-40	482	842	790	4000	560 - 920	4140 - 4750
K	0.07-18	2.2	2.6	2.2	21	2.5 - 200	21 - 360
Li	0.020-0.42	0.13	0.13	<3.1	10	0.20 - 4.8	10 - 18
Mg	0.002-8.0	52	20	42	11	52 - 140[d]	11 - 160[d]
Na	0.05-235	212	397	330	2500	212 - 2800	2500 - 6900
NO_3	0.2-2.6	0.21	0.1	0.41	0.46	0.94 - 30	1.7 - 49
Pb	0.014-0.017	0.17	0.21	0.01	0.03	0.22 - 0.36	0.12 - 0.35
Si	25-88	26	10	17	13	120 - 990	170 - 1660
SO_4	0.28-130	325	112	220	63	326 - 1800[d]	65 - 2500[d]
Zn	0.001-0.025	0.26	0.24	0.2	0.2	0.26 - 0.54	0.2 - 0.7
TDS	0-2800	905	1075	1100	6190	905 - 31,700	6190 - 58,700
TOC	1.0-38	8.5	11	3	10	12 - 430	16 - 720
Phenols	0.02-0.04	0.003	0.002	-	-	0.04 - 0.44	0.06 - 0.8

[a] Summarized from Tables 4-15 and 4-16.

[b] Assumes the retort is leached with upper aquifer water, that the mass of spent shale in the retort is 1.1×10^9 g, and that the volume of water contained by the retort is 5.0×10^8 liters. Computed using Eq. (7). For example, the lower value for TOC shown in column (6) is given by:

$$\frac{(10)(1.0)(1.1 \times 10^9) + (8.5)(5.0 \times 10^8)(6)}{(6)(5.0 \times 10^8)} = 12 \text{ mg/l}$$

[c] Assumes the retort is leached with lower aquifer water, that the mass of spent shale in the retort is 7.5×10^8kg, and that the volume of water contained by the retort is 2.0×10^8 liters. Computed using Eq. (7). For example, the lower value for TOC shown in column (7) is given by:

$$\frac{(10)(1.0)(7.5 \times 10^8) + (10)(2.0 \times 10^8)(6)}{(6)(2.0 \times 10^8)} = 16 \text{ mg/l}$$

[d] These constituents may be reduced on passage through the groundwater aquifer.

On Tract C-b, flow is projected to be upward, and leachate with a composition similar to column (7) will mix with and be transported in the upper aquifer which has an average quality as indicated by column (4). A comparison of the lower values in column (7) with column (4) indicates that Al, B, Cl, Cr, CO_3, F, Fe, HCO_3, K, Li, Na, NO_3, Pb, Si, TDS, and TOC will increase in the upper aquifer while SO_4 will decrease and Zn will remain about the same. Major increases in all of the tabulated parameters in Table 6-10 will occur if the upper values in column (7) are considered.

These comparisons illustrate the effect of two separate impacts on water quality, leaching, and mixing. Both may either increase or decrease the concentration of various constituents. In-situ retorts located in the Mahogany Zone form a permeable zone or a conduit which may transport water from one aquifer to the other. Thus, water quality may be affected by the mixing of two dissimilar waters. If flow is from the better quality aquifer, such as the upper aquifer, to the lesser quality aquifer, the lower aquifer in this case, the quality of the latter aquifer will be improved by mixing with higher quality water. Thus, the concentration of many constituents may actually be lowered, in the absence of significant leaching, when flow is downward in the Piceance Creek Basin system. On the other hand, if flow is from the lesser quality aquifer to the better quality aquifer, the latter will be degraded as a consequence of mixing with a poorer quality water. Thus, when flow is upward in the Piceance Creek Basin, the upper aquifer will be degraded due to mixing with a lower quality water. In addition to mixing, flow through abandoned retorts may remove soluble constituents from the contained spent shale. This material will be transported into the receiving aquifer where it will usually increase the concentration of various constituents. In certain cases, some of the leached constituents may react chemically with compounds present in the groundwaters and thereby remove them. An example of this would be the precipitation of $CaCO_3$ and $Mg(OH)_2$ as shown in Eqs. (5) and (6).

The consequences of leaching on Tract C-a may not be as significant as on Tract C-b if predevelopment flow conditions are re-established on site abandonment. On Tract C-a, leachate is discharged into the lower aquifer which does not directly recharge surface streams and is not used locally due to its poorer quality and the significant pumping heads that would be required to raise it. However, significant changes in the quality of the lower aquifer would eventually occur, over millennia, leading to the degradation of the upper aquifer by slow leakage through vertical cracks in the Mahogany Zone. The significance of these long time periods in evaluating environmental impacts is unknown and should be considered in other studies. The water quality impacts on Tract C-b would be more immediate because the leachate discharges into the upper aquifer which recharges local surface streams and is used for stock watering and irrigation.

Leachate Transport

A detailed quantitative assessment of leachate transport is beyond the scope of this study. Such an assessment would require the development of a sophisticated groundwater flow model for saturated-unsaturated flow in fractured media and an extensive field and laboratory measurement program to determine appropriate hydraulic and transport variables. Instead, leachate transport will be assessed using parameters estimated from recent work on the lease tracts and simple Darcian flow equations. Recommendations will be made for future work to provide more definitive estimates.

The local assessment will focus on lease tracts C-a and C-b in the Piceance Creek Basin where a thick layer of oil shale known as the Mahogany Zone (ranging in thickness from 100 to 200 feet) is situated between an upper and lower aquifer. The quality of water in these two aquifers in the vicinity of lease tracts C-a and C-b was summarized in Table 6-10. The upper aquifer has a transmissivity ranging up to 7500 gal/day/ft and an average storage coefficient of 0.001; the lower aquifer has a transmissivity ranging up to 15,000 gal/day/ft and an average storage coefficient of 0.0001 (Weeks et al., 1974). Occasional fractures in the Mahogany Zone permit limited exchange between the two aquifers.

The difference in hydraulic head between the upper and lower aquifer is less than 100 feet in almost all areas and differences of less than 50 feet are typical. Throughout most of the basin, the lower aquifer is characterized by a greater head, although in some parts of the basin this is not the case. Generally, the greatest head difference exists near the center of the basin where the head of the lower aquifer is normally greater than the head of the upper aquifer.

Recharge to both aquifers occurs near the perimeter of the basin at high elevations, primarily as a consequence of snowmelt during the spring. Discharge from the lower aquifer occurs as water moves upward from the lower aquifer through fractures in the Mahogany Zone into the upper aquifer. The upper aquifer discharges into Piceance Creek and Yellow Creek which are perennial streams (Weeks et al., 1974).

A diagram of the Piceance Creek Basin, describing the locations of the two prototype oil shale lease tracts and groundwater flow directions, is presented in Figure 6-6. A cross section of the basin was shown in Figure 6-1. This cross section describes the stratigraphy and direction of groundwater movement that are characteristic of much of the basin.

Prediction of leachate transport requires a suitable mathematical framework and field measurements of necessary hydraulic parameters. Neither of these is available for aquifers in the Piceance Creek Basin. Permeability in both the lower and upper aquifer is due mainly to fracture porosity; precipitation of secondary minerals in sandstones has largely filled the primary voids. Fractured aquifers are not isotropic and thus flow equations based on Darcy's law do not rigorously apply. Special equations based on flow through a series of fractures must be used in conjunction with data on the size and density of cracks. Theoretical modeling of flow in fracture systems and model application are in their infancy. However, available work (Lynch, 1964) suggests that movement of water in a fracture system is more rapid than in intergranular systems. Retardation caused by sorption may be less, due to the reduced surface area exposed to the flowing fluid. Under certain conditions, dispersion may cause significant concentrations to appear well ahead of the average. Therefore, the effect of leachate may be more severe than predictions based on isotropic conditions would indicate (transport times would be shorter).

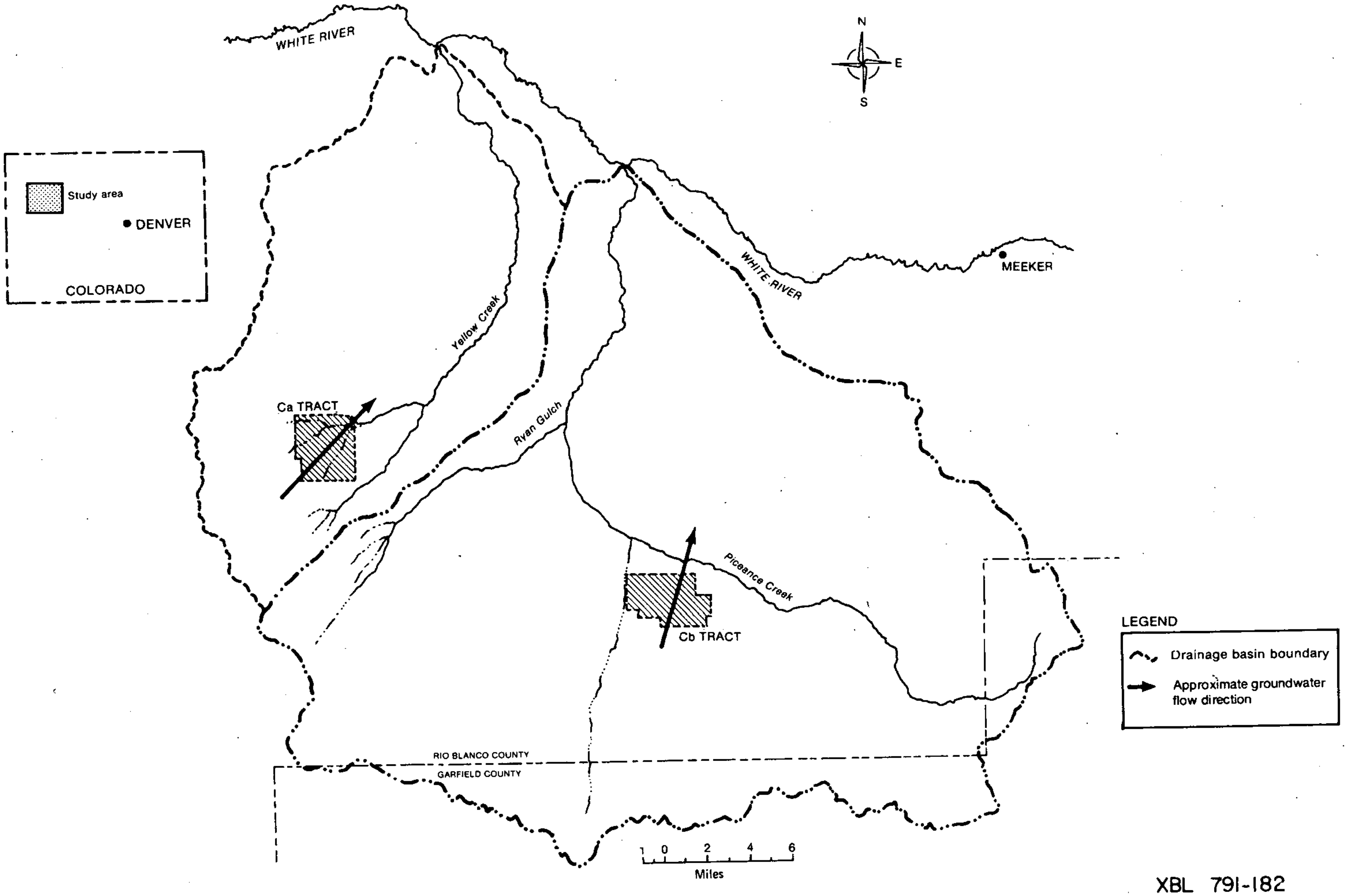

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Figure 6-6. Location of Piceance Creek Basin and prototype oil shale lease tracts C-a and C-b (Tipton, 1977).

This section will discuss the movement of leachate through the retort into the groundwater aquifers and ultimately into local stream channels. The discussion will assume saturated flow and that after an area is completely retorted, the dewatering wells will be shut off and groundwater will return to predevelopment conditions. However, large-scale dewatering will result in unsaturated flow conditions when groundwaters reinvade the site. Additionally, if there are other in-situ facilities still under production, predevelopment conditions may not be established. Thus, hydraulic gradients and groundwater flow directions may be different from those assumed here.

The dispersion of leachate constituents in the groundwater system will be presented and factors likely to retard transport identified. This will be developed using Darcy's law. However, the reader should bear in mind that Darcy's law does not rigorously apply to fractured aquifers. Points of departure will be discussed as pertinent.

Table 6-11 summarizes pertinent hydraulic variables, water velocities in aquifers and abandoned retorts, and travel times through the retorts and from the retorts to local streams. Inadequate data are available on most hydraulic parameters, and aquifer geohydrology is poorly understood. There are no field measurements available on effective porosity which is required to compute groundwater velocities. Recent work in progress on the lease tracts indicates that the aquifer systems are considerably more complex than previously believed. Therefore, the velocities and residence times presented in Table 6-11 and discussed below must be considered preliminary and should be updated when adequate field data become available.

Retort Hydraulics. After a retort block is abandoned, the dewatering wells will be turned off and groundwater will slowly refill the abandoned retorts. The rate at which groundwater passes through the retorts will be governed by the permeability of the surrounding aquifers and by the head difference between the aquifers. The lowest permeability will control the velocity of groundwater in the retort. Although the permeability of an abandoned retort is unknown, it can be safely assumed that it is considerably greater than the permeability of surrounding aquifers. There are no estimates of average head difference between aquifers on the lease tracts. Work completed to date suggests that the formations are heterogeneous and head differences will vary widely from point to point; thus, caution should be exercised in predicting flow rates (Tipton, 1977). To facilitate comparison of conditions on the two tracts, it is assumed that an average head difference of 25 feet exists between the aquifers on both tracts. On Tract C-a, the direction of groundwater flow will likely be from the upper to the lower aquifer (Weeks et al., 1974). The permeability of the upper aquifer, 1.5 feet per day, will control the flow of leachate through the retort. If a head difference of 25 feet exists across a 200-foot-high segment of the Mahogany Zone located on this tract, water will invade a retort at a rate of 680 feet per year and the residence time of water within the 750-foot-high retort will be one year. It is estimated that two to six pore volumes of groundwater will have to pass through the retort to remove most of the leachables. Therefore, leachate with a concentration similar to that in Table 6-10 may be output for two to six years after initiation of the leaching process.

Table 6-11. Aquifer characteristics and leachate transport in the vicinity of lease tracts C-a and C-b.

	Tract C-a		Tract C-b	
	Upper	Lower	Upper	Lower
Aquifer characteristics				
Transmissibility (T), ft^2/day	330[a]	940[a]	200[b]	53[b]
Aquifer thickness (b), ft	220[a]	220[a]	250-400[c]	200-500[c]
Permeability (k), ft/day	1.5[d]	4.3[d]	0.5-0.8[d]	0.1-0.3[d]
Hydraulic gradient (dh/dL)	0.01[e]	0.01[e]	0.01[e]	0.01[e]
Effective porosity (ϕ)	0.1[f]	0.1[f]	0.1[f]	0.1[f]
Groundwater transport				
Groundwater velocity (v), ft/yr	55[g]	160[g]	20-30[g]	4-10[g]
Shortest distance from tract to closest discharging stream (d), mi	4[b]		1[b]	
Time for leachate to reach stream (t), yr	130-380[h]		180-1450[h]	
Retort transport				
Head difference between aquifers (dh), ft	25[f]		25[f]	
Direction of groundwater flow in retort	Down[e]		Up[e]	
Controlling permeability (k), ft/day	1.5[e]		0.1-0.3[e]	
Hydraulic gradient in retort, (dh/dl)	0.083		0.083	
Groundwater velocity in retort (v_R), ft/yr	680[g]		45-140[g]	
Residence time in retort (R), yr	1		3-10	

[a] Gulf, 1977

[b] Tipton, 1977

[c] Occidental, 1978

[d] $k = T/b$.

[e] Weeks et al., 1974

[f] Estimated; no conclusive field data available.

[g] $v = (k/\phi)(dh/dl)$.

[h] $t = (d)(5280)/v$.

On Tract C-b, the direction of groundwater flow will be from the lower to the upper aquifer (Weeks et al., 1974). The permeability of the lower aquifer, 0.1 to 0.3 feet per day, will control the flow of leachate through the retort. If a head difference of 25 feet exists across a 200-foot-high segment of the Mahogany Zone on Tract C-b, water will invade the retort at a rate of 45 to 140 feet per year and the residence time of water within a 390-foot-high retort will range from three to ten years. Therefore, leachate may be output for six to 60 years after initiation of the leaching process.

These calculations indicate that leachate may be released from abandoned retorts over very long periods of time. This means that the retorts would act as sources of contamination for long periods of time. Additionally, the contact time between the leach water and the spent shale is of the order of years. These times are considerably higher than contact times used in laboratory leaching studies and may enhance or inhibit certain chemical reactions relative to laboratory results.

These simple calculations for two nearby sites in the Piceance Creek Basin indicate that there is considerable variability in the hydrologic conditions that will control the release and transport of leachate in groundwater aquifers. Effects will be highly site-specific. At two sites separated by about 18 miles along a line connecting tract centers, wide variations are apparent in the residence time of leachate in the retorts, direction of leachate flow, and groundwater flow velocities. On Tract C-a, it is estimated that leachate will be released from a retort for about two to six years and that it will be transported in the lower aquifer at about 160 feet per year. On Tract C-b it is estimated that leachate will be released from a retort for six to 60 years and that it will be transported in the upper aquifer at about 20 to 30 feet per year.

Aquifer Hydraulics. Once the leachate has emerged from the abandoned retort, it will be transported in either the lower or upper aquifer and eventually be discharged in a local surface stream. If it is assumed that the aquifers are isotropic and that the hydraulic parameters summarized in Table 6-11 are reasonable, flow velocities and leachate transit times from tracts C-a and C-b will be similar to those shown in Table 6-11. However, it must be kept in mind that the aquifers are anisotropic. This means that velocities may be higher than those computed from Darcian theory and, thus, the length of time it will take leachate to reach streams may be shorter than summarized here.

Tract C-a is about four miles from the nearest discharging surface stream, Yellow Creek, along a line parallel to the groundwater flow direction. If leachate moves downward through the retort and is transported in the lower aquifer, its average flow velocity will be about 160 feet per year, and it will take a minimum of a century for the leachate to reach Yellow Creek. Since groundwater discharge into Yellow Creek is probably primarily from the upper aquifer (see Fig. 6-1), much of this leachate may not directly enter Yellow Creek. It will take even longer for the leachate to reach Yellow Creek if it is transported in the upper aquifer.

Tract C-b is about one mile from Piceance Creek along a line parallel to the flow direction. If leachate travels upward through the retort and is transported in the upper aquifer, the average groundwater flow velocity will be about 20 to 30 feet per year, and it will take a minimum of two centuries for the leachate to discharge in Piceance Creek. It would take even longer for the leachate to reach Piceance Creek if it were transported by the lower aquifer.

Dispersion. After the leachate enters an aquifer, its concentration will be reduced due to dispersion, adsorption, and other natural processes. This section will discuss longitudinal dispersion and other factors likely to retard leachate transport.

Lynch (1964) described leachate transport in isotropic aquifers as:

$$\frac{\delta C}{\delta t} - D \frac{\delta^2 C}{\delta x^2} + v \frac{\delta C}{\delta x} + \frac{1}{\alpha} \frac{\delta q}{\delta t} = 0 \qquad (8)$$

where

x = distance from source in direction of groundwater flow

C = concentration of solute in the source

D = effective dispersion coefficient

v = groundwater flow velocity

t = time

α = porosity

q = amount adsorbed per unit volume.

Equation (8) describes the one-dimensional transport of a solute in porous media. Retardation due to sorption, ion exchange, etc., is represented by the last term in Eq. (8). Initial conditions and simplifying assumptions are required to solve this equation. It is assumed that the output of leachate acts as a step function, that is, the leachate concentration from a retort is suddenly raised to some value C_o and held there while the retort leaches. This is likely a better approximation than a pulse input where the mass input is assumed to take place instantaneously at t = 0 as it may take two to 60 years for the first two to six pore volumes to be released, and new spent retorts will be periodically available for leaching as the groundwater levels rise following shutdown of the dewatering wells. In practice, the input function will likely fall somewhere between a step and a pulse function. Because the input function cannot be defined, given the present state of knowledge, it will be qualitatively evaluated.

For a step input in an unbounded system, the initial conditions are:

$C(x,0) = 0$ for $t = 0$ and $x < 0$

$C(x,0) = C_o$ for $t = 0$ and $x > 0$

$C(-\infty,t) = 0$

$C(+\infty,t) = C_o$

The general solution to Eq. (8) is:

$$\frac{C}{C_o} = \frac{1}{2}\left\{1 + \operatorname{erf}\left[\frac{vt - x - \frac{Kx}{\alpha}}{\sqrt{4Dt(1+\frac{K}{\alpha})}}\right] + e^{\frac{vx}{D}}\ \operatorname{erfc}\left[\frac{vt + x + \frac{Kx}{\alpha}}{\sqrt{4Dt(1+\frac{K}{\alpha})}}\right]\right\} \qquad (9)$$

where

$q = KC$ (linear isotherm)

K = experimentally determined constant

The solution (9) assumes that retardation is essentially instantaneous and linear. If it is not, other solutions are more suitable, as given in Lynch (1964).

Equation (9) may be simplified to include only easily measured variables by making the following substitutions (Lynch, 1964): $L = vt$; $x = \Delta L + L$ and for $vx/D > 40$, $D = 1.92dv$; $d = 40.8\sqrt{k}$; $L' = L/(1 + K/\alpha)$; and $\Delta L' = x - L'$. These substitutions yield:

$$\frac{C}{C_o} \simeq \frac{1}{2}\operatorname{erfc}\left[\frac{0.0564\Delta L'}{k^{1/4}(L')^{1/2}}\right] . \qquad (10)$$

where k is the permeability in square centimeters and L' is in centimeters. Equation (10) will be used to estimate the transport of leachate in aquifers of the Piceance Creek Basin.

Some qualitative effects that may be expected from longitudinal dispersion of leachate in an isotropic aquifer are:

1. For a given distance of travel from the source, the dispersion of a constituent increases as the fourth root of the permeability.

2. Dispersion increases as the square root of the travel distance; however, dispersion, relative to distance of travel, decreases as the square root of the travel distance.

In an anisotropic system, dispersion conditions approach those of the isotropic system if a sufficiently large system is considered (Lynch, 1964). For a fractured system with a normal distribution of crack sizes and no retardation, a concentration $0.1C_o$ will exist nine times farther downstream than the average flow distance, and estimated arrival times of significant contamination, made by using Eq. (10), could be in error by as much as a factor of ten or more (Lynch, 1964). Therefore, the analyses presented here may underestimate leachate transport.

The solutions to Eq. (8) for the retardation case ($K \neq 0$) and for the no-retardation case ($K=0$) are identical except that L is reduced by $1/(1+K/\ )$ in the retardation case. This means that the shape of the dispersion front is the same in both cases but that the retarded front moves more slowly for the retardation case.

Retardation. Generally, when water contacts a solid different from the one it previously contacted (leachate contacting aquifer media) and when unlike waters mix (leachate and upper aquifer water) chemical and physical interactions may occur. Equation (10) includes the effect of such attenuation during transport. This may be caused by ion exchange, adsorption, solubility limitations, biodegradation, and other factors. No estimates of retardation for the system under study are available. Therefore, a range of values for K will be assumed and a sensitivity analysis presented.

Retardation may result from solubility considerations including the dissolution or precipitation of constituents due to contact of water with a solid phase. Calculations presented previously suggest Ca and Mg may be reduced by precipitation during aquifer transport. This could reduce aquifer permeability K and retard leachate transport. The extent of dissolution or precipitation may be estimated from equilibrium constants if all participating reactions are known. Unfortunately, this is seldom the case, and in a system as complex as the aquifer-leachate system, predictions of solubility are not presently possible. Qualitatively, many of the minerals that the leachate will contact are oxides, hydroxides, carbonates, and hydroxide-carbonates. These same ligands are the principal constituents of both native groundwater and leachate. Thus, the solid and solute chemical reactions of interest belong to the ternary system $Me^{+n} - H_2O - CO_2$. Me^{+n} is an anionic metal specie of charge +n. This system is discussed by Stumm and Morgan (1970). The presence of organic matter in leachate may have an important effect on leachate transport. The organics may complex the metal ions, increasing their mobility. They may also deplete any O_2, lowering the pH of the groundwater. This would allow Fe, Mn, and other elements to become soluble as Fe^{+2} and Mn^{+2} due to dissolution of Fe- and Mn-bearing minerals.

Solubility may affect the composition of leachate within the retort and during aquifer transport. Since the residence time of leachate in the retort is of the order of one to ten years, many solubility reactions may reach equilibrium within the retort. Additional solubility effects could occur during transport due to contact with the aquifer media, native groundwater, and changes in leachate quality.

Dissolved constituents may be removed from solution by sorption on colloidal or suspended material in the water or by sorption on the aquifer media. If sorption involves chemical bonding, it is termed ion exchange; if it involves physical forces, it is termed adsorption. Both of these mechanisms may be reversible and sorbed constituents may be released if conditions change.

Adsorption typically is strongly pH-dependent and usually occurs over a narrow pH range. The location of the adsorption region on the pH scale is characteristic of the metal ion and its complexes and is relatively insensitive to the adsorbent. This mechanism will likely control the concentration of a number of leachate constituents, such as Zn and Cr, during aquifer transport.

Many solid substances, when placed in contact with a liquid, lose some constituents and retain others. The lost components are usually replaced with similar species from solution such that the basic structure of the original solid is retained. This phenomenon is called ion exchange. In the geologic setting most ion exchange reactions involve cations, and clay minerals are especially important because they often have a high exchange capacity. The ion exchange capacity and adsorption characteristics of aquifer media in oil shale regions need to be determined. The upper aquifer consists of fractured lean oil shale, siltstone, and sandstone; the lower aquifer consists of fractured oil shale and saline minerals.

Assessment of In-Situ Spent Shale Leachate

This section will use information developed in previous sections to assess the effect of in-situ spent shale leachate on the quality of groundwater and surface water. The assessment applies to the technology framework described in Chapter 3.

Effect on Groundwater Quality. Groundwater degradation is a key concern because it is typically irreversible and may have long-term consequences. Since groundwater flow velocities are low, it will take centuries for contaminated water to be discharged. If these waters are withdrawn at some point during these centuries of transport, they may still have significant effects. Thus, even though it may take centuries for contaminated water to move an appreciable distance from the retort, there is no guarantee that during these centuries a farm or home or even a city will not be built at the retorting site of the tract and that groundwaters will be withdrawn for use.

A simple quantitative assessment of the effect of in-situ spent shale leachate on groundwater quality can be made using Eq. (10), the average composition of in-situ leachate from Table 6-10, and the hydraulic information presented in Table 6-11.

The graphical solution of Eq. (10) for the transport of leachate from a single line of retorts on Tract C-a in the lower aquifer is shown in Figure 6-7. This figure compares dispersion with no retardation ($K = 0$) with dispersion at two different levels of retardation ($K = 0.1$ and $K = 1.0$). The three approximately vertical lines shown on each graph represent the dispersion front. Each successive line corresponds to the dispersion front at a different point in time. The three lines shown on each graph correspond to one year, five years, and ten years after the initial release of leachate from a retort.

Figure 6-7 shows that for a step input, the concentration of various constituents in the aquifer will be the same as in the leachate for some distance from the source. At a distance $L = vt$ for the no-retardation case, and $L = vt/(1 + K/\ )$ for the retardation case, the initial concentration in the leachate, C_o, is reduced to one-half its initial value. Since Eq. (10) is for an isotropic aquifer, these same concentrations may occur at distances greater than L in practice.

A comparison of the three graphs on Figure 6-7 indicates that the net effect of retardation is to slow propagation of the dispersion front. This means that irrespective of the magnitude of the retardation factors, the composition of the groundwater in the vicinity of an in-situ facility will have approximately the same composition as the leachate. The distance that the leachate travels beyond the source will largely be determined by retardation of the aquifer media through which it passes.

Some constituents may be attenuated and others may not be. Sodium tends to remain in solution once it has been released. Thus, the no-retardation case would apply to Na, and the propagation of the dispersion front shown in Figure 6-7a would apply. This figure indicates that five years after the initial release of leachate and about 800 feet from the in-situ facility, the Na levels may reach 3000 mg/l. At distances greater than about 900 feet from the center of the facility, the concentration of Na would be about 400 mg/l, the concentration of native groundwater in the lower aquifer. In contrast, other constituents may be retarded. The data of Jackson et al. (1975) indicate that Ca, Mg, Cl, and SO_4 may be reduced; still other constituents (including Fe, Si, and Mn) may be adsorbed by the aquifer media and still others (including Pb and Se) may be reduced by solubility reactions. Thus, the concentration of these constituents 800 feet from the in-situ facility five years after the initial release of leachate may not be affected and may remain at their ambient levels (Figs. 6-7b and 6-7c). However, in the vicinity of the retorts, say 10 to 20 feet from the center of the facility, the levels of these constituents could be elevated and approach the levels recorded in Table 6-10.

In summary, this analysis suggests that the composition of groundwaters in the vicinity of an in-situ facility will approach that of in-situ leachate (Table 6-10). However, because the velocity of groundwaters is low, centuries may pass before the leachate travels an appreciable distance from the facility, although water transport along the fractures may reduce this time estimate. The distance from the source that each constituent will travel will depend on the groundwater flow velocity and the amount of retardation experienced. After a sufficient period of time, ranging from several years to several

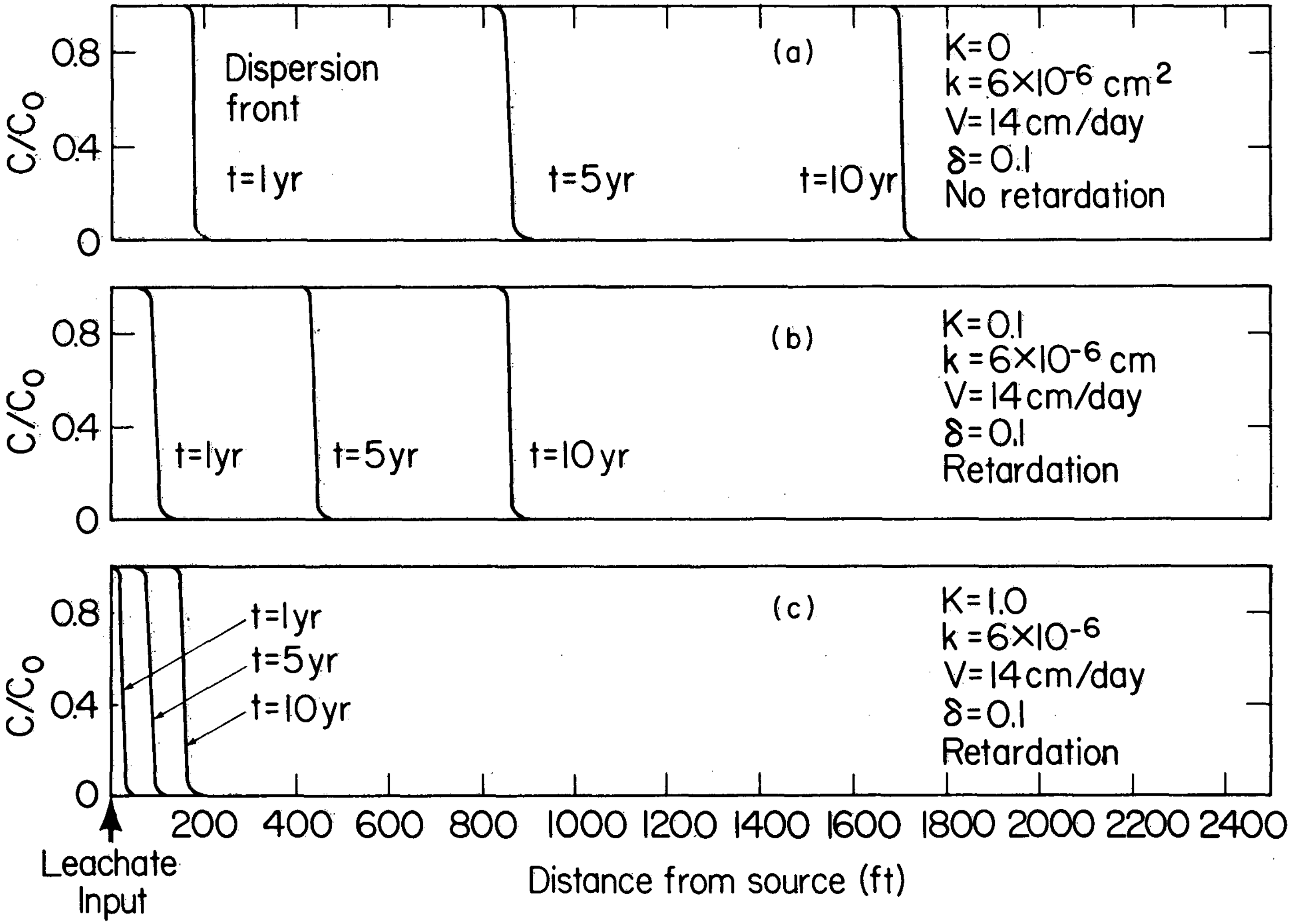

Figure 6-7. Transport of in-situ leachate in the lower aquifer in the vicinity of lease tract C-a.

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hundreds of years; and, depending on the specific site, the composition of local groundwaters may approach the leachate compositions shown in Table 6-10.

The significance of groundwater degradation may be determined by examining the present uses of the groundwater and by comparing the requisite quality to sustain these uses with estimated quality of the groundwater following leaching of in-situ spent shale. Groundwaters in the Piceance Creek Basin are primarily used for single-family domestic supply, stock watering, and irrigation. These uses rely primarily on alluvial aquifers rather than the upper and lower aquifers. Groundwaters in the immediate vicinity of the lease tracts are not known to be presently used although they are used along the White River. Therefore, immediate effects on local groundwater quality may not be a serious problem. However, this does not preclude their future use. If significant development were to occur in the Basin as a consequence of energy development, it is likely that groundwater would be a principal water supply. Therefore, the main concern is with long-term degradation.

The water quality criteria recommended by the EPA to sustain the uses of domestic water supply, stock watering, and irrigation are summarized in Table 6-12 and compared to predevelopment and postdevelopment groundwater quality. This tables shows that predevelopment groundwater in neither aquifer is ideally suited for use as a domestic supply or for livestock watering (unless treated) because of high levels of B, F, Fe, Pb, SO_4, or phenols. These waters may be locally suitable for irrigation of certain salinity-tolerant crops. However, locally high levels of B, F and Li will have to be evaluated on a case-by-case basis.

The quality of post-development groundwaters indicates that they may still be suitable for certain irrigation applications. High levels of Na and salinity, as indicated by Table 6-10, plus F and Li will have to be evaluated on a case-by-case basis. The post-development waters would not be suitable for either domestic supply or stock watering without extensive treatment due to high levels of certain trace inorganics, including Pb, Fe, F, and Cr, and certain trace organics, such as phenols. Additional study is required to identify other trace organics present in the leachates. Because some trace organics may be toxic at low concentrations, complete organic characterizations should be determined.

This comparison indicates that predevelopment groundwaters are acceptable for irrigation of some salt-resistant crops but would require limited treatment on a case-by-case basis for use as a domestic supply or for stock watering. If these waters were further degraded by in-situ spent-shale leachate, the level of treatment required to render them suitable for domestic supply or stock watering would be greater and the cost to supply the water accordingly higher. Since the area is sparsely settled and because most users are individuals or single farms or ranches, it is unlikely that treatment would be affordable or that knowledge of its requirement would be available. Because some constituents in post-development groundwaters may be toxic or carcinogenic, especially among the organics and trace metals, the use of these waters by unsuspecting parties may result in local or regional public health problems. In the long term, these waters may become largely unavailable for use if large-scale development of the area were to occur.

Table 6-12. Comparison of predevelopment and postdevelopment groundwater quality with water quality levels not to be exceeded in main water mass.

Parameters	Water quality criteria			Tract C-a			Tract C-b		
				Predevelopment groundwater quality			Predevelopment groundwater quality		
	Domestic water supplies,[a] mg/l	Livestock watering,[a] mg/l	Irrigation,[a] mg/l	Upper aquifer, mg/l	Lower aquifer, mg/l	Post-development groundwater quality, mg/l	Upper aquifer, mg/l	Lower aquifer, mg/l	Post-development groundwater quality, mg/l
Al	—	5.0	5 - 20	0.14	0.24	0.49 - 31	0.3	0.3	0.89 - 53
B	(b)	5.0	0.75 - 2.0	0.33	0.84	0.33 - 1.9	1.4	3.6	36 - 39
Cl	250	—	(c)	12	22	32 - 73	26	1200	1234 - 1300
Cr	0.05	1.0	0.1 - 1.0	<0.01	<0.01	<0.02 -<20	0.002-0.3	<0.009	0.01 - 34
F	1.4 -2.4	2.0	1 - 15	0.41	15	4.8 - 47	10	21	29 - 100
Fe	0.3	None	5 - 20	5.0	0.78	5.0 - 5.5	0.5	0.8	0.8 - 1.6
Li	—	—	0.075 - 2.5	0.13	0.13	0.20 - 4.8	<3.1	10	10 - 18
NO_3-N	10	100[d]	None	0.21	0.1	0.94 - 30	0.41	0.46	1.7 - 49
Pb	0.05	0.1	5 - 10	0.17	0.21	0.22 - 0.36	0.01	0.03	0.12 - 0.35
SO_4	250	—	—	325	112	326 - 1800	220	63	65 - 2500
Zn	5	25	2.0 - 10	0.26	0.24	0.26 - 0.54	0.2	0.2	0.2 - 0.7
Phenols	0.001	—	—	0.003	0.002	0.04 - 0.44	—	—	0.06 - 0.8

[a] Table 5-9

[b] Inadequate data available to set standard.

[c] Variable; depends on soil condition.

[d] $NO_3 + NO_2$.

It is important at this point to recall that the above analysis is based on a number of assumptions. Some of the key assumptions are reiterated here:

1. The input of leachate from an in-situ facility occurs as a step function.

2. Most leachable constituents are removed with the passage of the first two to six pore volumes of leach water.

3. The leachate concentration exiting from the retort is constant.

4. The data summarized in the last column of Table 6-9 are reasonable approximations of the true value for M_i, the mass of each material leached per 100 grams of spent shale.

5. The aquifers that transport the leachate are isotropic and saturated flow occurs.

6. Groundwaters return to predevelopment conditions on abandonment of the facility.

None of these assumptions will rigorously hold when applied to an actual in-situ facility. However, this is the best estimate that can be made, given the present state of knowledge. The output of leachate is likely neither a step nor a pulse function but rather something in between. This will tend to decrease leachate concentrations on transport in the aquifers and produce a gently sloping dispersion front as shown on Figure 6-8. It may take more than six pore volumes of water to remove most of the leachables due to the large particle sizes in field retorts. This will decrease the average leachate concentration. The data in Table 6-9 may not approximate what happens when a typical in-situ retort is leached with native groundwater. These values are all based on short-term (about 30 days or less) leaching experiments conducted with distilled water. In the field, the contact time will be years and the leach water will have a composition similar to the groundwater quality shown in Tables 4-15 and 4-16. The true values for M_i may be higher or lower. For example, Ca and Mg may be lower due to precipitation of slightly soluble compounds, and other constituents, such as Na, SO_4, and pH may be reduced by the formation of relatively insoluble silicates during retorting. Finally, the aquifers are anisotropic and may not return to predevelopment conditions. Other oil shale developments may alter predevelopment conditions, producing steeper hydraulic gradients and different flow directions, and unsaturated flow conditions, rather than saturated, will occur. Because of the anisotropic nature of the aquifers and the possibility of other developments, flow velocities may be higher than predicted here and transit times shorter. This would result in an earlier arrival of the leachate front at downstream points. The net effect of these items is unknown and, therefore, the type of analysis presented here should be periodically revised as new data are developed.

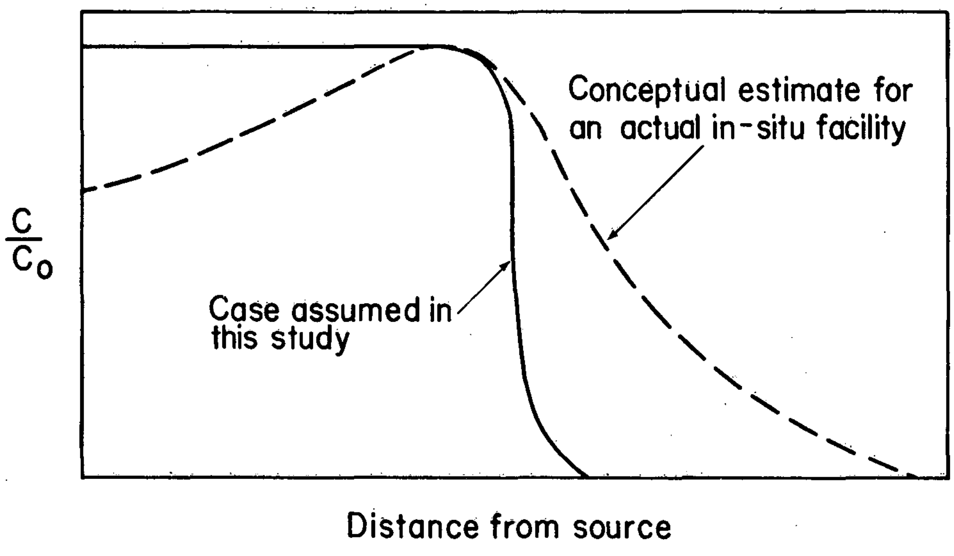

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Figure 6-8. Schematic representation of effect of study assumptions on leachate disposition in groundwater aquifers.

In conclusion, it is evident that measures to control the release of leachate from in-situ retorts may be required if the retorts are not wholly confined by aquitards. Potential control methods, which include reducing the permeability of the retorts by grouting or plugging, intentional leaching, and various hydrogeologic modifications are discussed in Chapter 7. However, it should be pointed out that before rational control decisions can be made, the nature and the magnitude of the leaching phenomenon and leachate transport in aquifers of the Piceance Creek Basin need to be investigated experimentally. Both laboratory and field studies are required to better define long-term leachate composition and retardation factors for the retort-aquifer system.

The effect of in-situ spent shale leachate from a facility located in the Piceance Creek Basin on groundwaters in other areas will be minimal. Since the velocity of groundwater is low, it will take many centuries for groundwaters originating from an industry located in the Piceance Creek Basin to reach groundwaters in areas outside of the Basin.

Effect on Surface Water Quality. In-situ spent-shale leachate will travel through aquifers of the Piceance Creek Basin for centuries. Eventually, assuming no change in the hydrologic system, it will discharge into either Piceance Creek or Yellow Creek. A schematic describing the flow of in-situ leachates and other leachates into the gaining reach of a stream is presented in Figure 6-9. This schematic is considered to be representative of actual conditions that exist throughout many parts of the Piceance Creek Basin.

An estimate of the impact of in-situ leachate on surface water quality can be made using the data in Table 6-10 and some simplifying assumptions. Equation (11), presented below, will be used to compute the increase in concentration of Na, TDS, and TOC in surface streams as a consequence of the discharge of in-situ leachates, given the following assumptions:

1. Leachate is discharged along the full length of the Piceance Creek and Yellow Creek from a single line source of retorts as a step function.

2. The leachate from both lease tracts arrives at Yellow Creek and Piceance Creek at about the same time, one to three centuries after site abandonment.

3. The base flow discharging into Yellow Creek and Piceance Creek will have the same composition as shown in columns (6) and (7) of Table 6-10, respectively. In other words, there significant retardation of TDS, Na, or TOC during aquifer transport.

4. About 80 percent of the flow of Piceance Creek and Yellow Creek is from the upper aquifer.

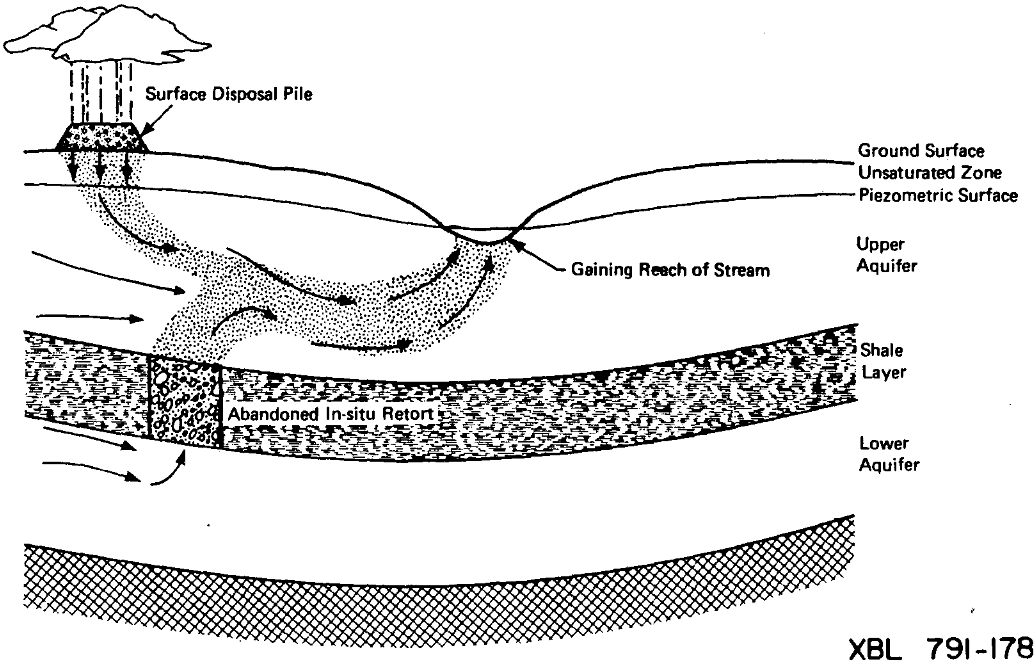

Figure 6-9. Flow of leachate into gaining reach of a stream.

5. The average annual discharge of groundwater into the Piceance Creek and Yellow Creek is 12,520 acre-feet. Approximately 11,600 acre-feet per year of this discharges annually into Piceance Creek and the balance into Yellow Creek (Weeks et al., 1974).

6. The increase in TDS, Na, and TOC in surface waters will be the same as the increase in these parameters in the groundwaters, attenuated by dilution from tributary streams.

Given the above assumptions, the increase in concentration of a constituent in surface waters is given by:

$$I = \frac{(C_l - C_u)_P \, B_P + (C_l - C_u)_Y \, B_Y}{Q} \tag{11}$$

where

I = increase in concentration, mg/l

C_u = concentration of upper aquifer, mg/l (Columns (2) or (4) of Table 6-10)

C_l = concentration of leachate, (Columns (6) or (7) of Table 6-10)

P = subscript designating Piceance Creek

Y = subscript designating Yellow Creek

B = average annual base flow, acre-feet/year

Q = Average annual stream flow, acre-feet/year (Column (1) of Table 6-13)

The first term in Eq. (11) is the increase in mass in the Piceance Creek and the second term is the increase in mass in the Yellow Creek due to the discharge of leachate into the streams from lease tracts C-b and C-a, respectively.

The potential effect of the discharge of in-situ leachate from a single line source of retorts into surface steams, calculated using the above-described procedure, is summarized in Table 6-13. This table presents the average annual discharge and estimated maximum possible increase in TDS, Na, and TOC at four points in the Upper Colorado River Basin due to the discharge of groundwater-borne, in-situ spent shale leachate into surface waters. If pulses from several line sources of retorts arrived at the streams simultaneously, the increases would be correspondingly larger. It would take centuries for the concentrations shown in this table to be reached (Table 6-11).

Table 6-13. Estimated increase in TDS, Na, and TOC in surface waters of the Upper Colorado River Basin due to the discharge of in-situ leachates from tracts C-a and C-b into Piceance Creek and Yellow Creek as the base flow.

Watercourse	Average annual discharge, acre-ft/yr	Maximum possible increase, mg/l		
		Na	TDS	TOC
	(1)	(2)	(3)	(4)
Piceance Creek at White River[a]	14,500	1740 - 5260	4100 - 46,100	10 - 570
Yellow Creek at White River[a]	1,150	0 - 2100	0 - 24,600	3 - 340
White River near Watson, Utah	532,000	50 - 150	110 - 1310	0.3 - 16
Green River near Green River, Utah	4,427,000	6 - 18	13 - 160	0.03 - 2
Colorado River at Lees Ferry, Arizona	12,426,000	2 - 6	5 - 56	0.01 - 0.7

[a] It is assumed that the leachate from Tract C-a discharges into Yellow Creek and from C-b into Piceance Creek.

The estimates summarized in Table 6-13 represent upper limits, or maximum possible increases in concentration for TDS, Na, and TOC. This is evident when the six assumptions on which the analysis is based are explored. Some of the more critical assumptions are discussed below.

In this analysis, it is assumed that leachate from both lease tracts arrives at Yellow Creek and Piceance Creek at about the same time. Thus, the effect of the mass input from both of these streams will affect all downstream reaches. It is possible that leachate from Tract C-a, as discussed previously, may not reach surface streams for millenia because groundwater flow may be downward through the retort into the lower aquifer which does not discharge into surface streams directly; slow leakage through the Mahogany Zone would have to occur before leaching of retorts on Tract C-a would affect surface water quality. This would occur long after retorts on C-b are completely leached. In this case, leachate from the two tracts would not be additive, and the impact on surface water quality would be lower. The impact of leachate discharges would be computed by alternatively setting B_Y and B_P equal to zero in Eq. (11). It is not possible to predict what the actual flow directions will be on abandonment; and, thus, the worst case is assumed here.

This work assumes that the upper aquifer discharges into Yellow Creek and Piceance Creek and that the change in concentration in that aquifer is equivalent to the change in concentration in the streams. It has recently been suggested that Piceance Creek and Yellow Creek may be fed by both the alluvial aquifer and the upper aquifer. The relative contribution from each is unknown, but it is certain that if a significant fraction of the base flow into these two streams originates from the alluvial aquifer, the impact of in-situ leachates on the upper aquifer would be less. While this issue cannot be resolved with the data available, a comparison of the quality of the upper and alluvial aquifers in Tables 4-15 and 4-16 with surface water quality in Table 4-2 suggests that the Piceance Creek may be fed by upper aquifer water.

This work also assumes that leachate exiting an in-situ retort reaches local streams unattenuated. It is likely that some constituents may be either reduced or increased during aquifer transport and certain others, such as Na, may be unaffected. Therefore, the values in columns (2) and (3) of Table 6-13 represent the likely range to be encountered for inorganic constituents. The Na column represents the lower limit because Na is usually not attenuated during aquifer transport. The TDS column, on the other hand, represents an upper limit because some of the constituents making up TDS will likely be attenuated during transport. The TOC values may be greatly reduced and the values in column (4) are probably maximum values. However, it is possible that organics present in the oil shale will be solubilized or exchanged for those in the leachate.

This tabulation indicates that the inorganic quality, and possibly the organic quality, of local, subregional, and regional waters may be significantly affected if in-situ leachate discharges into surface streams. The increase in salinity of surface waters may violate the salinity standards for the Colorado River, depending on interpretation of the law (see Chapter 5).

Similar calculations can be made for other constituents. These will indicate that surface streams near an in-situ facility that are largely fed by groundwater will eventually be degraded and that their quality will approach that of the in-situ leachate. Thus, the comparison shown in Table 6-12 applies, suggesting that these streams would not be suitable for drinking water or stock waters and would have limited use as an irrigation supply. However, at points farther downstream the degradation of surface waters would decrease due to dilution.

LEACHATE FROM SURFACE DISPOSAL PILES

In-situ processing will produce several different types of solid wastes that will likely be disposed of in surface piles. These may include spent shale, raw oil shale and other mine spoils, and solids from water and wastewater treatment facilities and air-pollution control facilities. Different processes will generate different types and quantities of solid waste. Disposal piles containing solid wastes will affect water quality as a consequence of runoff and percolation from the piles. Quantitative data exist on spent and raw oil shales, but little information is available on the other oil-shale related solid wastes.

The following section will qualitatively discuss both major types of solid waste, spent and raw shale, and quantify effects to the extent possible with existing data. No attempt will be made to model the percolation or surface runoff from these piles or to quantitatively predict their effect on water quality.

Spent-Shale Disposal Piles

There have been many investigations on the subject of disposal of spent shales from surface operations but few on the disposal of excavated raw shale and spoil material. Let us first discuss the disposal of spent shale in general terms and then extend those observations to the disposal of raw shale.

Certain in-situ processes require partial mining of the retort in order to create adequate porosity for effective retorting. The retort is created by first mining out 20 to 40 percent of the in-place oil shale followed by rubblization of the remainder. There are several utilization/disposal schemes for oil shale mined and brought to the surface at an in-situ facility. These include (1) on-site surface retorting and subsequent disposal of spent shale, (2) direct disposal of raw oil shale without retorting, and (3) transport of mined shale to another site for surface retorting and subsequent disposal of spent shale. The actual utilization/disposal scheme selected will be determined largely by economics and site-specific conditions. It is important to recognize that transport of mined shale to another site is unlikely if there is a significant distance involved.

Surface retorting of mined oil shale presently proposed for both tracts C-a and C-b will produce significant amounts of spent shale. This spent shale may be disposed of in surface storage piles, returned to the retort as a slurry to plug the abandoned retort (Nevens et al., 1977), or upgraded for use in other industries. There has been little evaluation of the last two options, and they will not be considered in this assessment. Retort plugging with spent shale slurry, a possible control technology for insitu leachates, will be discussed in Chapter 7.

The disposal of spent shale produced by surface retorting activites in surface piles will require (1) location of an appropriate disposal site; (2) compaction of spent shale; (3) installation of appropriate controls including retention dams, dikes, liners, and drains, as required; (4) covering of spent shale with top soil, and (5) revegetation of the spent shale disposal pile. Water quality effects may occur at any stage of the disposal operation due to meteorological phenomena. During precipitation or snowmelt, a portion of the water will percolate downward into the disposal pile while the remainder (less evapotranspiration) will run off. Runoff derived from spent-shale disposal piles may adversely affect surface water quality, and water percolating through the disposal pile may adversely affect groundwater quality if it reaches the groundwater table.

Spent shale produced by surface retorting may be disposed of by piling it in nearby canyons and gulches. Several studies have been made on the piling and revegetation of spent shale (Harbert and Berg, 1978; ARCO, 1974). In general, spent shale is wetted before placement to cool it, reduce dust, and facilitate compaction. Pile stability studies by Colony, for example, indicated that optimum compaction for spent shale from the TOSCO process was at 85 lb/ft^3 with 12 percent moisture. At these values, a flow-type failure would not result from dynamic loading even though some local sloughing, slumping, and bulging might occur. After compaction, the permeability of some spent shales may be reduced, thus enhancing surface runoff and limiting percolation of water into surrounding aquifers.

Environmental and aesthetic considerations will likely require that the spent-shale surface be revegetated. Three approaches to this problem have been proposed by industry, government, and research institutions: (1) establishment of salt-tolerant or adapted vegetation directly on spent shale without modification of the shale material; (2) improvement of the retorted shale to enhance its suitability as a plant growth medium; and (3) cover the retorted shale with suitable soil and/or geologic material prior to vegetation (Redente et al., 1980). Research reviewed by Redente et al. (1980) suggests that the first two approaches do not appear to be adequate to establish vegetation due to high salt content of the shale material and long-term maintenance required. Some or all of the following steps may be required before the surface will sustain vegetation (Harbert and Berg, 1978; Ward et al., 1971, Redente et al., 1980):

1. Leach salts from the top layer of the shale pile.

2. Create 60-100 cm deep plant growth media with soil, geologic, or even spent shale material including such additives as soil conditioners, native microorganisms, top soil, and fertilizers.

3. Select a mixture of local and imported plants compatible with local climate and soil conditions.

4. Irrigate the planted surface for two years or more to establish a good root system.

5. Protect surfaces with mulches and fences so that the slopes of the pile are protected from animals and runoff erosion.

Revegetated spent-shale piles are subject to erosion which is a continuous natural process. Thus, the soil cover created during revegetation may eventually erode, particularly from steep upper slopes. This should be considered in solid-waste disposal management plans and future research (Harbert and Berg, 1978).

Leachate Composition. The composition of spent-shale leachates has been studied by Margheim (1975); Wildung (1977); Stollenwerk and Runnells (1977); Culbertson et al. (1970); Ward et al. (1971); CSU (1971); and Schmidt-Collerus et al. (1974). The composition of unvegetated surface-retorted spent shale leachate in milligrams per 100 grams of spent shale is summarized in Table 6-14. However, if the disposal piles are revegetated, or have been previously leached, surface runoff quality will be very different from that shown in Table 6-14 while percolation quality may be similar.

A discussion of factors that influence the quality of in-situ spent-shale leachate appeared in a preceding section. Some of the factors identified in that discussion will also influence the quality of surface-retorted spent shale leachate. These factors include (1) retorting conditions, (2) particle-size distribution of spent shale, and (3) chemical/mineralogical characteristics of raw oil shale. The reader is referred to the previous section for a discussion of these factors. In addition to these factors, certain other factors will influence the quality of surface-retorted spent-shale leachate, including:

1. Rate at which water is applied to surface disposal piles.
2. Temperature and quality of water applied to surface disposal piles.
3. Top soil characteristics.

The rate at which water is applied to a surface disposal pile will be a function of local precipitation and climatic conditions. A greater rate of application will cause water to percolate more rapidly into the pile, thus affecting the contact time between individual parcels of water and individual particles of spent shale. The temperature and quality of water applied will be a function of the water source. If water is derived from precipitation falling directly on the pile, it will resemble distilled water in quality and temperature. However, if the water is derived from overland runoff produced during a precipitation event, its quality and temperature will be affected by the ground surface over which it has flowed.

The specific composition of surface runoff or percolation could be calculated using the factors in Table 6-14 if the water application rates and times were known and if information were available on the attenuation of leachate constituents by the soil column and aquifer media.

Table 6-14. Leachate composition of spent shales from surface retorts.

Constituent	Margheim, (1975)			Stollenwerk and Runnells (1977) TOSCO	Data summary: surface retorts
	TOSCO[a]	USBM	UOC		
As	-	-	-	0.005-0.013	0.005-0.013
B	-	-	-	0.2[b] -1.2[c]	0.2-1.2
Ba	4.0	-	-	-	4.0
Ca	64-144	42	327	-	42-327
Cl	5-18	13	33	-	5-33
$CO_3^=$	21	-	-	-	21
F	3.4	-	-	0.09[b]-5.5[c]	0.9-5.5
HCO_3^-	20	38	28	-	20-38
K	10-32	72	625	-	10-625
Mg	27-40	3.5	91	-	3.5-91
Mo	-	-	-	0.2[b]-0.8[c]	0.2-0.8
Na	165-258	225	2100	-	165-2100
NO_3	5.1-5.6	-	-	-	5.1-5.6
Se	-	-	-	0.005-0.006	0.005-0.006
SO_4	675-775	600	6230	-	600-6230
TDS	1121-1262	970-1091	10,011	-	970-10,011
TOC	-	-	-	-	-
pH	8.40-8.43	7.78	9.94	-	7.78-9.94
Particle	68% passes 200 mesh	7% passes 200 mesh	-	90% passes 200 mesh	
Contact time for batch	5 min	5 min	5 min	~5 min[b]-127 days[c]	

[a] Ranges for three types of experiments-blender, shaker, and column.

[b] Determined from leaching curve at t = 0 for Mo, F, B. For Se and As, 33-day contact time.

[c] Determined from leaching curve at t = 127 days for Mo, F, B.

Runoff from Spent Shale Disposal Piles. Potential short-term effects from runoff occur during the construction of the pile and the development of vegetation on the surface. Sources of runoff are rainfall, snowmelt, and surface and groundwaters used for leaching and irrigation. In early stages of pile construction, runoff from working areas and slopes will contain mostly leachate from the spent shale. The character of this leachate was described in detail earlier in this chapter (Table 6-14), and it may contain high concentrations of Na, Ca, Mg, and SO_4 and lesser amounts of suspended sediment (Culbertson et al., 1970; Ward et al., 1971). As the pile construction continues, the character of the runoff changes to one containing nutrients, plant material, and suspended solids mostly derived from the revegetation zone. The quantity of the runoff is a function of the annual rainfall corrected for evapotranspiration losses and percolation. Because the pile may be relatively impermeable, the latter may be considered negligible. Runoff quantities are not computed for this report because it is assumed that all runoff will be captured behind dikes and returned to the pile for disposal. This will be the case in actual practice. Colony, for example, proposes using a dike system supplemented by benches constructed on pile slopes to collect runoff. All intercepted runoff is returned to the fill. The disposal operation site is thus isolated from the local surface waters. In addition, the benches intercept leachate from spent shales in upper levels of the embankment thus protecting vegetation on the lower slopes (ARCO, 1974).

Long-term effects of runoff derived from completely revegetated piles may be minimal. Dikes will remain in place until disposal operations are completed for a given site. Runoff will be captured and returned to the pile for evaporation and percolation. The quality of runoff from revegetated piles may approach that of the runoff from the natural ground cover of the region. It will contain similar concentrations of plant materials, suspended soils, and minerals. However, on site abandonment, catchment areas and dikes may fill with silt; and water will no longer be withdrawn for in-plant use. Under these conditions, pile runoff may reach surface waters. Thus, long-term custodial care of disosal piles may be required.

Percolation from Spent-Shale Disposal Piles. In areas of low precipitation (less than 15 inches per year), percolation may not occur because infiltrated moisture near the pile surface may evaporate. Consolidation and cementation of spent shale due to compaction with water may make the disposal piles relatively impervious under certain conditions. It may be possible to operate the surface retorts to optimize the pozzolanic nature of spent shales. These properties could be used to reduce the permeability of spent-shale disposal piles, thus minimizing the potential for percolation through the piles. Ward et al. (1971), however, have noted that snowfall may eliminate the compaction in the top foot or so, and that the top two feet may become permeable to water. Thus, most applied water would appear as runoff. However, some percolation may result during initial periods of pile compaction or as a consequence of residual pile permeability. The issue of permeability of spent shale piles is far from resolution and is presently controversial; additional research is required (Redente et al., 1980).

Water percolating through the spent shale would leach out inorganic and organic materials in a manner analogous to that previously discussed in relation to in-situ spent shales. Eventually, leachate would reach the underlying unsaturated zone where part of it would be held by capillary action while the remainder would infiltrate down to the groundwater table. When leachate reaches the groundwater table, initial dilution with groundwater will serve to decrease the levels of various constituents. Natural treatment processes (e.g., ion exchange, adsorption, microbial decomposition) and hydrologic dispersion would also decrease levels of various constituents as the water passes through the soil column and aquifer media.

Raw Oil Shale Disposal Piles

In general, raw-shale disposal piles would be constructed in much the same manner as those for spent shale. A canyon or similar topographical feature would be filled with the excavated materials. For environmental reasons, finished slopes and surfaces of the embankment might have to be revegetated. As with spent-shale piles, there are three sources of contaminants in runoff: storm water, snowmelt, and irrigation water. On passing through the pile, they would leach salts from the raw shale particles. In addition, runoff would occur from the surface of the revegetated layer.

Oil shale that is mined and directly discarded in surface disposal piles will have a different character from that of surface-retorted spent shale that is discarded in surface piles. The organic material present in oil shale consists almost entirely of kerogen and bitumen, both of which are extremely insoluble in water. This contrasts with the organic material present in spent shale which, in certain cases, may be significantly soluble in water (Amy and Thomas, 1977; Amy, 1978).

Additionally, there are several differences in the characteristics of raw and spent shales that may affect the quality of the runoff and percolation. Among these are differences in: (1) porosity and permeability of the fill due to particle size, material strength, and amount of compaction; and (2) material composition affecting the rate and amount of leaching.

The quality and quantity of runoff from raw-shale disposal sites will be somewhat different from runoff from spent-shale areas. Oil shale that is mined and directly piled will produce a leachate with much lower levels of TDS and of various inorganic constituents than corresponding spent shales. This is demonstrated in Table 6-15 which summarizes available data on the leaching of raw oil shales with distilled water. This table shows that Ca, B, Cl, K, Mg, Mo, Na, Si, SO_4, and TDS are significantly greater in leachate from spent shales than in leachates from raw oil shales. However, the pH of the raw and spent shales and the CO_3, F, HCO_3, and Se leached from them are not significantly different. This implies that direct disposal of raw oil shales without retorting could have a significant effect on water quality, depending on how the leachate is generated and ultimately controlled. Studies should be conducted to determine if raw shale piles can be vegetated. On the other hand, the quality of runoff from vegetated areas from both raw and spent shale disposal sites will be similar, assuming that factors such as irrigation and fertilizer applications do not vary significantly.

Table 6-15. Batch leaching of unretorted oil shale with distilled water.

Parameter	Anvil Points oil shale; Margheim[a] (1975)	Anvil Points oil shale; Stollenwerk and Runnells (1977)	Utah oil shale; Jackson et al[b] (1975)	Raw oil shale; summary	Surface spent shale; summary (Table 6-14)
As	-	0.015	-	0.015	0.005-0.013
B	-	0.1[b]-0.7[c]	0.019-0.057	0.019-0.7	0.2-1.2
Ca	10	-	5.2-6.7	5.2-10	42-327
Cl	2.2	-	3.6-4.5	2.2-4.5	5-33
CO_3	-	-	11-15	11-15	21
F	-	1.7[b]-6.5[c]	0.2-0.35	1.7-6.5	0.9-5.5
HCO_3	75	-	37	37-75	20-38
K	24	-	0.6-0.8	0.6-24	10-625
Mo	-	0.1[b]-0.3[c]	-	0.1-0.3	0.2-0.8
Mg	1.0	-	1.1-1.6	1.0-1.6	3.5-91
Na	48	-	1.4-20	1.4-48	165-2100
NO_3	-	-	0.2-2.0	0.2-2.0	5.1-5.6
OH	-	-	1.7	1.7	-
Se	-	0.009[d]	-	0.009	0.005-0.006
Si	-	-	0.9-2.8	0.9-2.8	-
SO_4	79	-	1.2-11	1.2-79	600-6230
TDS	277	-	61-113	61-277	970-10,011
TOC	-	-	1	1	-
pH	8.15	-	9.3-9.8	8.15-9.8	7.78-9.94

[a] Contact time: 5 min.

[b] Contact time: ~5 min.; determined from leaching curve at t = 0.

[c] Contact time: 127 days.

[d] Contact time: 33 days.

Runoff quantity from unvegetated raw shale piles may be smaller than from similar spent shale piles because material contained in the fill will be more pervious and will have less moisture retention capacity as a result of the bigger voids created by larger and stronger raw shale particles. The more permeable raw shale will allow water to pass through the fill to the underlying ground surface. From there it may either percolate to groundwater or pass horizontally to retention dikes. This is in contrast with spent-shale piles in which permeability may be reduced by cementation. Applied water may not move beyond the plant root zone and would be largely transpired instead of moving down through the interior of the embankment. For the purposes of this investigation, it is assumed that all runoff from a raw-shale pile is caught behind dikes and returned to the pile for disposal. In actual practice, water so retained would be available for project use depending on water quality requirements of intended uses.

Other Solid-Waste Disposal Piles

Solid wastes from the shale-oil recovery process also include mine spoils; solids from gas scrubbers; spent catalysts from refinery operations impregnated with arsenic and other trace constituents removed from the oil; petroleum coke, if it is not marketed for other use; and waste-water treatment sludges. Project wastes may also be liquids that cannot be reused or economically treated. These wastes generally contain high concentrations of salts, toxic materials, and hydrocarbons which cannot be released to the environment. It has been proposed that the impervious nature of the spent-shale embankment be used to contain the liquid and solid wastes. Colony, for example, uses the retort and sour waters from the retorting and upgrading facilities to cool and moisturize the spent shale before piling and compaction (Ward et al., 1971). Solid wastes would also be incorporated within the embankment as part of the placing operation. As long as the fill retains its impervious nature, contaminants will be retained within the body of spent shale. If surface water does manage to penetrate the compacted material and reach zones where solids and liquid wastes have been incorporated, leachate will be produced that contains contaminants from the additional wastes in addition to those leached from the spent shale itself. If this leachate reaches the surface of the pile and becomes part of the runoff, it will be retained by the protective dikes as long as these retain integrity.

For in-situ oil recovery operations without surface retorting or for underground disposal of spent shale (retort plugging), there may be no spent-shale piles available for convenient disposal of project wastes. For this case, disposal process waste options include treatment and recovery operations and conveyance of residuals to environmentally safe sites for disposal.

For the purpose of this investigation, it is assumed that solid and liquid wastes will be either disposed of within a spent-shale pile, if available, or conveyed to safe sites for disposal. In either case, the contaminants from project wastes will not reach surface or ground water in substantial quantities. It will also be necessary to dispose of construction debris, including slash removed from the site and building material waste. It is assumed that this debris will be burned, if air quality standards permit, or otherwise disposed of in suitable land-fill operations. In either case, the effects on water resources are assumed to be negligible.

CONCLUSIONS AND RECOMMENDATIONS

By assembling and analyzing the most significant available information on leaching of residuals from an in-situ oil shale facility, this chapter has evaluated the effects of leachate from abandoned in-situ retorts and surface disposal piles of a 50,000 barrel per day, modified in-situ facility located on tracts C-a and C-b on the Upper Colorado River Basin. This evaluation is important for it makes possible the identification of potential environmental problems and solutions for an in-situ oil shale industry in that area. The study, however, should be regarded only as a framework which will be expanded and updated as new information is gained from experimental field programs being conducted by industry. The analyses and evaluations made in this chapter have developed conclusions and recommendations which can be of significant value to these experimental field programs.

Conclusions

The major conclusions of this study are:

1. Groundwater disruption is a key concern because it is largely irreversible and may have long-term consequences. Because flow velocities are low, it will take many centuries for natural processes to remove the leachate. Aquifer cleanup may require removal of leachate by pumping, followed by surface treatment. Even though it may take centuries for leachate to move an appreciable distance, there is no guarantee that during those centuries the water will not be withdrawn and used.

2. Groundwater in the vicinity of an in-situ facility may be modified by mixing of two dissimilar waters and by leaching of spent residuals. Both of these effects may increase or decrease certain constituents due to mixing and solubility considerations. In the Piceance Creek Basin, many constituents may be lowered, in the absence of significant leaching, when flow is downward. On the other hand, when flow is upward, the better quality water in the upper aquifer may be degraded more by mixing with poor quality lower aquifer water than by leaching per se.

3. Upper and lower aquifer waters in the vicinity of an in-situ facility may be degraded decades or centuries after site abandonment if control measures are not developed and implemented. The largest increases would likely occur in pH, SO_4, Na, HCO_3, and CO_3, and in certain organics, such as phenols and organic nitrogen compounds. Other constituents, such as Ca and Mg, are expected to decrease due to precipitation, ion exchange, and other reactions.

4. The major components of spent shale leachate, SO_4, HCO_3, CO_3, Na, Cl, Si, and K, are not highly toxic, are not detrimental for many water uses, and may be tolerated at rather high levels under certain circumstances. The minor components in spent shale leachates, which include As, Pb, F, phenols, organonitrogen compounds, and others, are considered to be toxic at the levels at which they are present in leachates. However, there has been inadequate investigation of these minor components to properly evaluate their importance.

5. Upper and lower aquifer waters in the Piceance Creek Basin are presently not extensively used. Most users of the basin's waters rely on alluvial aquifers. Therefore, short-term effects on upper and lower aquifer waters may not be serious. In the long-term (for centuries following facility abandonment), upper and lower aquifer waters in the vicinity of an in-situ facility would not be suitable for municipal supply or stock watering without a high level of treatment. However, they may be adequate for irrigation of certain salt-resistant crops.

6. The effect of in-situ leachates will not be immediate. After dewatering ceases, it will take decades to centuries for the groundwater to invade and leach the retorts. Thus, serious problems may not occur until after the site is abandoned, and preventive measures will have to be taken on abandonment to prevent long-term consequences.

7. The effect of in-situ leachates will be highly site-specific due to large variations in local hydrology. Estimates presented in this report indicate that if a facility were located on Tract C-a, leachate release from a single retort could continue for two to six years, the leachate would be transported in the lower aquifer at about 160 feet per year, and it could take one to four centuries for it to discharge into the nearest stream. If the same retort were located on Tract C-b, it might release leachate for six to 60 years, the leachate would be transported in the upper aquifer at about 20 to 30 feet per year, and it might take two to 14 centuries for it to discharge into the nearest stream.

8. The consequences of leaching on Tract C-a may not be as significant as on Tract C-b if predevelopment flow conditions are re-established on site abandonment. On Tract C-a, leachate is discharged into the lower aquifer which does not directly recharge surface streams and is not used locally. It could take millennia for lower aquifer leachates to degrade the upper aquifer, and thus surface streams, by slow leakage through vertical cracks in the Mahogany Zone. The water quality impacts on Tract C-b would be more immediate because leachates discharge into the upper aquifer which recharges local surface streams and is used for stock watering and irrigation.

9. It may be possible to operate field retorts to minimize leaching. At temperatures in excess of 800°C, silicates, which are relatively insoluble, are formed. The reactions are enhanced in the presence of steam. Efficient and uniform combustion will be required before these reactions will have a significant effect on the leachability of spent shale. This significantly reduces the conductivity and alkalinity of leachates but has little effect on pH, F, B, and other minor constituents.

10. In-situ leachates may reach surface streams by discharge into Piceance Creek or Yellow Creek several centuries after the completion of retorting. The quality in local streams may approach that of the initial leachate. This would render these streams unsuitable for drinking water, irrigation, or stock watering without treatment. This effect would be greatly diluted at downstream points. The TDS in Piceance Creek at the White River may increase by 4,100 mg/l to 46,100 mg/l and at Lees Ferry on the Colorado River, by 5 mg/l to 56 mg/l.

11. If leachate from abandoned in-situ retorts degrades local groundwaters and surface waters, measures will have to be taken to control the release of leachate from abandoned in-situ retorts.

12. If the mined oil shale is retorted, the resulting disposal piles may produce leachates. These will primarily affect surface waters. Percolation under such conditions may affect groundwater quality. Consolidation and cementation of some types of spent shale on compaction with water could reduce the permeability of disposal piles and make them more susceptible to run off. Erosion of the soil cover will be a long-term concern and should be considered in disposal plans. The primary effects of spent-shale disposal piles will be felt during pile construction and vegetation. Subsequently, runoff may resemble that from native areas and likely contain nutrients, plant material, and suspended solids. Piles of raw shale and other solids, however, will be less impervious and percolation through them may affect underlying groundwaters.

13. It may be possible to make grout out of the spent shale and to use the grout to seal the retort (Nevens et al., 1977). This would decrease the size of the disposal pile by about 80 percent. The effect of the spent-shale grouting on water quality is unknown and should be investigated. This is discussed in more detail in Chapter 7.

14. Available data suggest that raw oil shale is not inert and may release quantities of CO_3, HCO_3, Se, and F similar to those released by spent shales. If the amount released differs significantly from runoff from native soils, special control measures may be required for disposal piles of raw oil shale.

15. The high concentrations of TDS and TOC in leachates suggest that these parameters may be suitable tracers for in-situ leachates.

Recommendations

Research on many of the topics covered in this report is too incomplete or too inadequate to quantitatively assess water quality effects or to define control technology requirements. The following are specific areas where additional work is required:

1. Laboratory leaching of in-situ spent shales has focused on simulated spent shales and used distilled water with contact times typically less than 30 days. These conditions do not adequately represent field conditions. The contact time between the leach water and the spent shale may be of the order of one to ten years, the composition of the leach water will be significantly different from distilled water, and simulated spent shales may differ in important ways from those generated in the field. The most important difference may be maximum retorting temperature and retorting rate. Field temperatures and exposure time to peak temperatures will exceed those encountered in the laboratory. Therefore, more realistic laboratory simulations of field leaching need to be performed. High-temperature spent shales should be leached with local groundwater in continuous-flow columns using approach velocities similar to those anticipated in field retorts. Mass-transfer theory should be used to design experimental simulations.

Complete elemental surveys and organic characterizations need to be performed on select samples and the potential toxicity of the leachates determined.

2. Some technological development is required to obtain definitive estimates of the effect of in-situ spent shale leaching and to study control strategies. Experimental programs such as those under way at Tract C-a and in Wyoming should go forward so that much needed data can be obtained to better design commercial-sized plants. These field programs should be coordinated with laboratory studies. If the results of field environmental studies indicate that the effects of these experimental facilities on groundwater quality will be significant, then plans to mitigate the effects should be made. These plans would likely include pumping the leachates to the surface for treatment. This may be a feasible control strategy--leaching data collected to date indicate that most leachables are removed with the passage of the first few pore volumes of leachate.

3. The effect of the leachate on local groundwaters and surface waters must be better evaluated. This will require the development and application of a computerized model of the retort system and local aquifers that is capable of handling hydraulics and chemical transformations in fractured aquifers for unsaturated flow. In conjunction with this, laboratory and field studies need to be conducted to develop model input parameters.

4. No quantitative data are available on the potential for attenuation of constituents on passage through the retort or during aquifer transport. The leaching columns described in (1) above need to be followed by columns containing aquifer media to determine the retardation of leachate components.

5. Available hydrologic data are inadequate to quantitatively predict leachate transport. Hydrologic investigations, pump tests, and tracer studies should be conducted to determine effective porosity, other hydrologic parameters, and flow directions and to characterize fracture systems.

6. There is inadequate definition of the nature and leachability of solids other than raw and spent oil shale that will be disposed of in surface piles. The composition and leaching potential of those other solids should be investigated.

7. Preliminary data suggest that raw oil shale is not inert and may release large quantities of some substances, such as fluorine and boron. This should be investigated in greater detail in laboratory studies designed to simulate the effect of rainfall and snowmelt on the leachability of raw oil shales. This should be contrasted with similar experiments using native soils to determine the net effect.

8. Field studies at demonstration sites such as lease tracts C-a or C-b are required to transfer laboratory experience to the field. Cores or bulk samples need to be taken from experimental field retorts, analyzed in the laboratory for major, minor, and trace elements and leaching studies conducted. Field programs need to be established to monitor backflood waters and surrounding aquifer waters. These programs should be long term, spanning a decade or more, and should include complete elemental and organic characterizations.

9. Measures may have to be taken to control the release of leachate from the retorts. This is apt to be a technically challenging problem requiring a long lead time. Research should be initiated immediately to identify technically and economically feasible control techniques. Proper mine design may allow control of leachate flows, and this should be studied.

CHAPTER 7

CONTROL STRATEGIES FOR ABANDONED IN-SITU OIL SHALE RETORTS

As discussed in previous chapters, in-situ oil shale processing has unique characteristics which may adversely affect the environment. Unless adequate control methods are developed to prevent or mitigate these impacts, leaching and the disposal of liquid and solid wastes may have an adverse effect upon the geologic and hydrologic environments for years--even centuries--after oil has been produced and the retorts have been abandoned. The purpose of this chapter is to identify control strategies which might eliminate adverse environmental impacts associated with in-situ leaching and, whenever possible, to project cost data based upon available information for each control measure.

Because oil shale recovery and production involve relatively new industrial processes, many of the control strategies are still in the early phases of development or, in many cases, are only in a discussion stage. Exact data relating specifically to oil shale requirements are not readily available or do not exist. Therefore, literature from related fields, such as civil and reservoir engineering and deep coal mining, has been consulted to answer as completely as possible the many unresolved questions associated with various control strategies. Techniques developed in other fields have been applied to oil shale requirements because these methods parallel or are similar to the processes envisioned for oil shale control measures. For example, the use of grout by the construction industry has been examined as part of the discussion of development of a grout to fill abandoned oil shale retorts and to surround a block of retorts with a grout curtain.

This chapter discusses broadly the various control strategies and presents preliminary cost projections for each. The technical bases for the selection and use of the control measures are discussed by Persoff and Fox (1980).

CONTROL STRATEGY CATEGORIES

Control strategies discussed in this chapter may be divided into four major categories, based upon technologies involved: hydraulic isolation, hydrogeological modification, leaching, and various chemical and physical processes that would render shale less soluble.

Hydraulic isolation strategies seek to minimize the flow of groundwater through abandoned retorts by site selection or by filling the retorts with a cementitious material to reduce the permeability of spent shale remaining in the retort. The amount of leachable material in the retort would remain unchanged, but the rate of release of the leachate into the environment would be reduced by controlling the amount of groundwater penetrating the retort from adjacent aquifers. Although these strategies would not completely stop leachate from leaving the retort, they would lower the leachate concentration to acceptable levels. Methods for plugging abandoned retorts include sealing spent shale in the retort with a grout made from surface spent shale and the in-place precipitation of calcite.

Hydrogeological modification strategies are designed to minimize the flow of groundwater into the retort area by altering local geological and hydrological conditions. This may be accomplished by constructing a large underground wall or curtain around a retorted area to reroute groundwater flow. Groundwater movement might also be impeded by constructing retorts with an impervious layer, or cap rock, between retorts and adjacent aquifers. A third method, a hydraulic bypass, would surround the retorted area with a zone of high permeability (well field); groundwater would flow through the well field instead of through the abandoned retorts.

Leachate treatment strategies reduce the amount of leachable material remaining in a retort and meter out the balance to assure that the resulting concentrations are within environmentally acceptable limits. This might be accomplished by intentionally leaching the retort with mine dewatering effluents and then pumping the leachate to a surface treatment plant for upgrading and final disposal. Another method of maintaining leachate within acceptable limits would involve pumping an adsorbent or exchange resin into retorts to trap leachables as they form and meter them out over a period of time.

Several physical-chemical processes could be used to make spent shale less soluble. For example, the retorting process could be optimized to produce less leachable silicate materials by retorting in the presence of steam, by burning char on spent shale, and by maintaining the shale at high temperatures (1000°C) for several days. Another process to be considered involves use of a wetting agent to reduce the wettability of spent shale.

Although this review of control strategies has been restricted to shales of the Green River Formation in general and of the Piceance Creek Basin in particular, many of the technical conclusions drawn may also apply to other areas. Several of the strategies discussed may not fully meet the requirements of preventing or mitigating undesirable impacts. It is possible, however, that combining two or more control measures might meet environmental goals. Combinations of control strategies have not been considered in this chapter.

COST PROJECTION METHODOLOGY

The success of any control strategy depends upon its technical feasibility, its costs, and its ability to eliminate or alleviate undesirable environmental impacts. Although it is almost impossible to make accurate cost estimates without first developing and demonstrating a control strategy, there would be little incentive to develop any control measure unless there is some assurance that it would be cost-effective if proven feasible. Consequently, the cost projections developed in this chapter are highly speculative and are dependent upon assumptions which are specifically stated in the following discussions.

Costs of many control measures may be strongly influenced by logistics, retort operations, water availability, and other presently unknown factors. For example, the economics of treating recovered leachate depend strongly upon the number of pore volumes which must be treated. The number of pore volumes, in turn, depends upon spent shale characteristics, which are poorly defined at present, and upon the composition of the leachate which depends upon presently unknown factors.

The costs of some processes, such as slurrying and injecting spent shale, are without precedent and can only be estimated. Costs of water quality monitoring, which would be a necessary adjunct of any control method and presumably are the same for all control measures, are not considered in this chapter. Because many of these control strategies would not be applied until some time after oil has been recovered from shale--possibly decades to centuries later, there is an immediate economic advantage to postponing application of any control measure. However, this consideration of immediate savings must be related to probable higher costs at some later date due to inflation. Delay, however, has not been considered in the cost projections made in this chapter.

Cost projections in this chapter are based upon data from laboratory tests because data from field tests are not available. In some instances, cost projections were based upon assumptions only; this was necessary because of a complete lack of pertinent data. Consequently, actual costs may be either higher or lower than those projected. No conclusions are made regarding the cost-desirability of one control strategy compared to another. Comparisons would not be valid because, once again, cost projections for some strategies were based only upon laboratory work or upon assumptions.

All cost projections have been normalized as 1979 dollars per barrel of oil extracted using combined surface and in-situ retorting systems proposed for lease tracts C-a and C-b. Costs are presented only for those control strategies which appear economically and technically feasible. Table 7-1 summarizes the cost projections developed as part of the discussons concerning each control strategy. Cost differences between the two lease tracts reflect the deeper overburden on Tract C-b and the larger retort size and greater void volume on Tract C-a. Further study, however, may eliminate some control measures for economical or technical reasons.

Table 7-1 also presents specific assumptions upon which these cost projections were based. Cost assumptions are the basis upon which the control technology cost has been projected. Technical assumptions are conditions which must be met for a technology to succeed but which are external to the technology itself. Water availability is an example of a technical assumption. Unresolved technical questions are factors directly related to the technology which are present poorly understood, such as the ability of grout to penetrate the voids of an in-situ retort. Generally, these unresolved issues must be studied in laboratory and field investigations. The technologies evaluated in the costs summarized in Table 7-1 are presented in Table 3-6.

Several benefits, other than attaining the primary goal of preventing in-situ leaching, can be achieved by several control strategies. These benefits, summarized in Table 7-1, include preventing the mixing of upper and lower aquifer waters, eventual removal of pollutants instead of locking them in place, and strengthening abandoned retorts to prevent subsidence and to permit retorting of pillars.

Table 7-1. Candidate control strategies for VMIS retorts

Control Strategy	Benefits[1]			Projected cost[2] \$/bbl		Cost based on assumptions (*critical)	Technical assumptions (*critical)	Unresolved technical questions (*critical)
	Achieved	Partial	Possible	C-a	C-b			
Site selection	a		b	Not applicable		Not feasible on Tract C-a or C-b		
Grout abandoned retorts with spent shale	a,b,d	f	c,e	\$0.49[4]	\$0.35[4]	Grout injection from air level of retorts	Can use air level as grounting gallary; adequate water available	*Penetration of grout through rubble
				(\$0.65)[5]	(\$1.30)[5]	Grout injection from ground surface		Permanence of non-cementitious grout
						\$2/ton to prepare and inject slurry		Ultimate permeability of retort
						No addition of portland cement or fluidizers		
In place precipitation of calcite to seal pores[3]		a,b	d	\$1.88	\$1.15	Filling 10 percent of voids with $Ca(OH)_2$	Ability to place $Ca(OH)_2$ in fine pores where grout cannot penetrate	Eventual solution of precipitates
Grout curtain around block of retorts	a,b			\$0.74	\$2.85	144 retorts enclosed, \$20/foot to drill, \$3/foot[3] for grout in place, single row of grout holes	*Geotechnical feasibility of drilling deep holes parallel	Effectiveness should be estimated by modeling; fracture size in aquifers determines grout to be used.
Design retorts with hydraulic bypass[3]		b		\$0.46	\$1.76	144 retorts enclosed, \$20/foot to drill	Groundwater flows between aquifers through path of least resistance	Effectiveness should be estimated by modeling

Table 7-1. Candidate control strategies for VMIS retorts - (continued).

Control Strategy	Benefits[1]			Projected cost[2] $/bbl		Cost based on assumptions (*critical)	Technical assumptions (*critical)	Unresolved technical questions (*critical)
	Achieved	Partial	Possible	C-a	C-b			
Cap rock in place	a,b			Not applicable		Not feasible on tract C-a or C-b		
Recover and treat leachate	b,g			$0.67	$0.59	*Adequate to treat 2 pore volumes	*Treatability by reverse osmosis--fouling problems solved	*Economics of treatment process; brine disposal
Treat leachate in situ by adsorption and ion exchange	b		g	Too costly		$125/ft^3 for cation exchange resin		
Modify retort operating conditions	b			0		Modification do not affect resource recovery	Can control retorting conditions accurately	*Non-leachability of shales retorted under specified conditions
Reverse wettability of spent shale	b			Too costly		$0.20 to $4.00/lb for water-repellant coatings		Method to "coat" spent shale in-situ. Permanence, non-biodegradability
Self treatment (no action)	g			0	0		Self-treatment capacity of aquifers adequate	Mechanisms and kinetics of process

[1] Benefits: a. Prevent flow from one aquifer to another.
b. Prevent leachate from entering groundwater.
c. Disposes of retort water.
d. Prevent subsidence.
e. Permit additional resource recovery.
f. Dispose of surface-retorted shale.
g. Eventually remove pollutants.

[2] Cost per barrel in 1979 dollars based on combined surface and in-situ retorting, 40 percent voids on Tract C-a and 23 percent voids on Tract C-b.

[3] Possible application in conjunction with another technology; not adequate by itself.

[4] Air-level drilling.

[5] Ground-level drilling.

Despite the fact that these cost projections are often based upon theory and assumption, they are considered useful and necessary to properly focus future development of various control strategies. The word "projection" is used instead of the usual "estimate" to stress the degree of uncertainty caused by certain assumptions. In conventional architecture and engineering construction projects, discrepancies of 50 percent between cost estimates and bids are distressingly common. Contractors often submit high bids as insurance against unforeseen difficulties when faced with an unfamiliar project, possibly involving high-risk technology. Novel techniques, such as those proposed here, are indeed high-risk technologies because design parameters have not been established, no design work has been completed, and no field experience exists. Consequently, any cost figures developed at this stage must necessarily be rough estimates at best. As experimental work and computer modeling reveal some of the design parameters and as retorting technology progresses, these cost projections can be refined.

HYDRAULIC ISOLATION BY SITE SELECTION

The selection of retort sites which would minimize or completely eliminate in-situ leachate formation represents the most desirable condition for protecting groundwater from degradation. Site selection as a control strategy would endeavor to locate VMIS retorts in groundwater-free zones by placing the retorts above the water table or by separating them from aquifers by other means. There are presently insufficient data to determine with any degree of certainty whether or not VMIS retorts can be completely contained in groundwater-free or "dry" zones, and, if so, what fraction of the oil shale resource could be recovered. However, available hydrologic and geologic data suggest that only a very small fraction of the oil shale resource may be adaptable to this isolation strategy (Weeks et al., 1974). Site selection as a control strategy requires case-by-case evaluation.

Dry zones may not be suitable for VMIS retorting because this process requires a thick, continuous, vertical section of oil shale uninterrupted by significant thicknesses of barren rock (Smith, 1978a). Commercial designs of industrial developers indicate that about 300 feet of continuous vertical oil shale is required for the process to be economic (Gulf, May 1977; Ashland, 1977). Most of the resources with the necessary geological conditions to support this technology are in the Piceance Creek Basin where confined aquifers penetrate the oil-bearing strata (Weeks et al., 1974). In most of this area, the Mahogany Zone, a primary location for VMIS retorting, is from 100 to 200 feet thick. In order to have the economically desirable 300-foot vertical section of oil shale, the retorts must therefore intersect the water-bearing stratum immediately above or below the Mahogany Zone. It would be difficult to locate retorts only in the dry Mahogany Zone without sacrificing the economic feasibility of the VMIS process. Smith (1978a) noted that the most desirable area for VMIS development in the Piceance Creek Basin consists of the Mahogany Zone from the top of B-groove and overlying oil shale. B-groove was excluded because it is an aquifer in most areas. The developers, however, are extending their retorts through B-groove.

The two most active VMIS projects, Occidental Oil Shale, Inc. and Tenneco on lease tract C-b and Rio Blanco Oil Shale Project on lease tract C-a, are both in the Piceance Creek Basin. Development plans (Gulf, May 1977; Ashland, 1977) for both tracts call for penetration of more than one aquifer.

It is recommended that an in-depth study of site selection as a control strategy be undertaken. This strategy has no costs other than costs directly associated with normal site evaluation and selection.

HYDRAULIC ISOLATION BY GROUTING ABANDONED RETORTS

Grouting abandoned retorts as a control strategy has the primary purpose of hydraulically isolating the retort from adjacent aquifers, thus preventing seepage of groundwater into the retort or transport of leachate from the retort into the aquifers. This objective is attained by reducing the permeability of spent shale remaining in the retort. However, if the retort can also be strengthened and stiffened by emplaced grout, two additional benefits would be obtained that are not provided by other strategies: the increased strength and stiffness and the reduced voids of the abandoned retort would provide protection against subsidence and would provide an opportunity for increased resource recovery. Figure 7-1 illustrates schematically a block of retorts, as planned for lease tract C-a. The figure shows the retort space which must be plugged to isolate the retort hydraulically from adjacent aquifers. It also illustrates the large amount of unrecovered oil shale remaining as pillars to support the overburden.

Plugging a retort would be accomplished by pumping a slurry of spent shale grout into the bottom of the retort through injection pipes inserted through a pattern of holes drilled through spent shale to the bottom of the retort. As slurry is pumped into the retort, the pipes would be withdrawn upwards until the retort is completely filled with grout. The slurry would be prepared by mixing mine water or retort water with spent shale produced by a surface retort.

The required number and spacing of grout injection holes depend upon the injection pressure and the ease of grout penetration through the in-situ retort which must be determined by laboratory and field tests. Injection holes can be drilled either from the air injection level or from the ground surface; the feasibility of drilling from the air injection level must still be established. If the air injection level can be used as a grouting gallery, holes would be drilled from that level through rubble to the bottom of the retort. However, if the air injection level is too cramped or is unsafe, the grout injection holes would have to be drilled from ground surface through the air injection level and then through the rubble to the bottom of the retort. This would be more costly than drilling from the air injection level due to the greater depth. Drilling from the injection level may require the development of new types of drilling equipment.

There are many problems requiring resolution before retort grouting can be adopted as a control method. An economic and adequate spent shale grout must also be developed which will penetrate voids easily and quickly, have a relatively short setting time, and still possess the necessary strength and stiffness to provide overburden support as well as hydraulically isolating

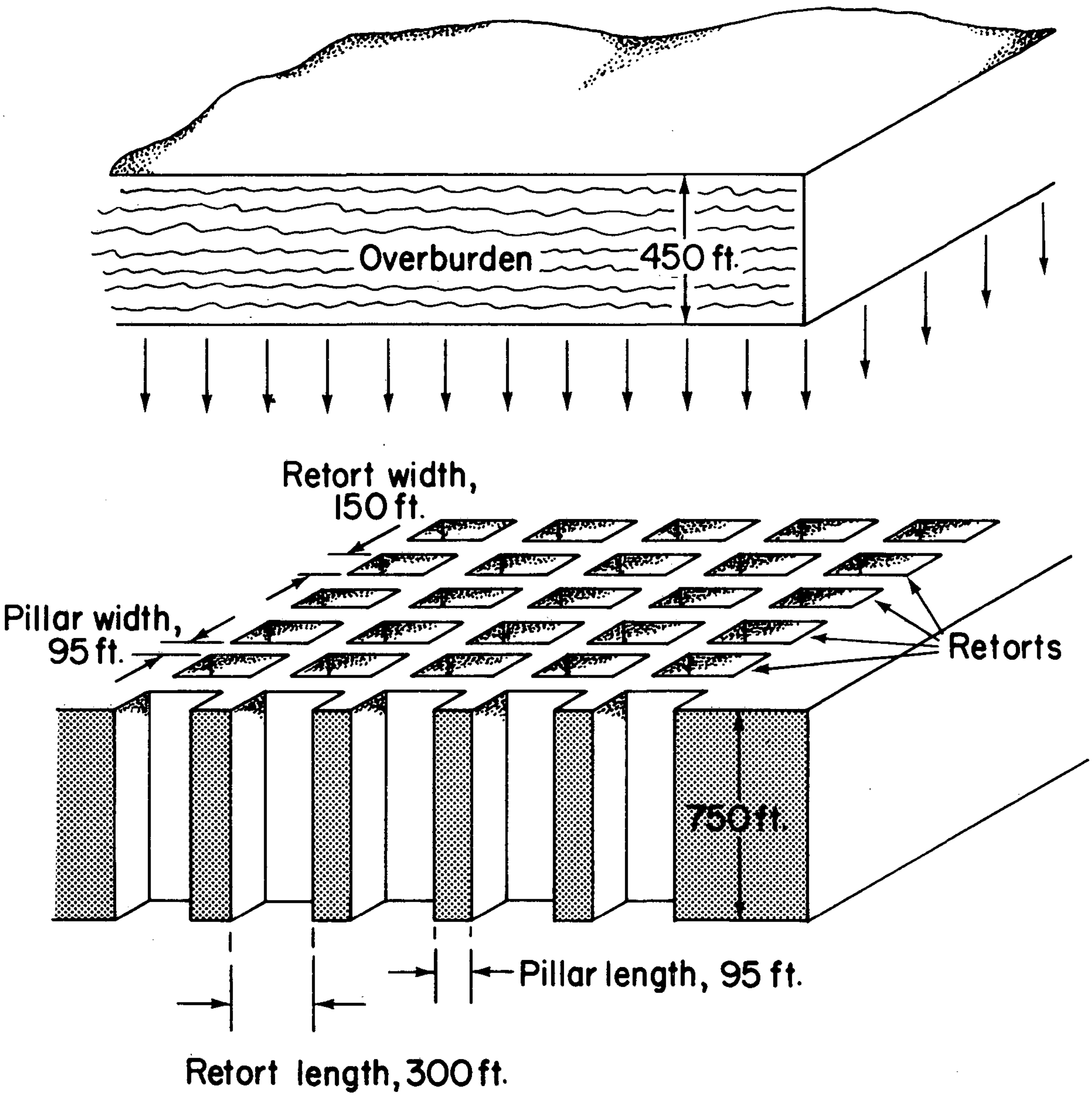

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Figure 7-1. Retort block showing retorts and pillars, as planned for lease tract C-a.

the retort. The grout used must also be relatively impervious to dissolution in the presence of a brine solution.

Cost Projection

The cost calculations for grouting abandoned in-situ retorts are based on industrial development plans summarized in Table 7-2. They assume that the mined-out shale is retorted by an existing surface retorting process such as Lurgi, Paraho, or TOSCO II and that grout is produced from surface spent shale. Based upon cost projections which follow, it appears that the cost of plugging retorts at lease tracts C-a and C-b may be \$0.49 and \$0.35 per barrel of oil produced, respectively, if drilling and grouting can be done from the air level above the retorts. The projected costs would be \$0.65 and \$1.30 if drilling and grouting must be done from the surface (Table 7-3).

The total costs for retort plugging can be divided into several components: (1) expenses associated with modifying the surface retorting procedures to produce spent shale capable of being used to produce grout; (2) cost of additives to improve the strength and flow properties of the grout; (3) costs of obtaining slurrying water; (4) capital costs and operating expenses for facilities for slurry preparation, injection, and material handling; and (5) the expense of drilling injection holes. For this cost projection, no costs have been applied for modifying the surface retorting process or for additives to strengthen or improve the flow properties of the grout used. The process considered for cost calculations would use unmodified spent shale. Therefore, these costs represent lower limits for the cost of spent shale grouting. For example, \$2 a ton was used as the cost of grout preparation and injection. Addition of ten percent portland cement by weight, which may be required to improve the cementing properties of spent shale, would increase this cost \$6 per ton, making the total cost per barrel of oil produced \$3.00 at lease tract C-a and \$1.85 at lease tract C-b, drilling and injection being accomplished from the air level.

As shown in Table 7-4, about 150 gallons of water are needed for grouting a retort per barrel of oil produced. This water is required to pre-wet the in-situ spent shale and to slurry the grout. No costs have been applied for this water since it is assumed to be available as excess mine water which would otherwise have to be disposed of either by injection into aquifers or by discharge into surface streams.

Capital and operating costs of material handling, slurry preparation, and slurry injection were determined by adapting cost estimates published for this process (Nevens et al., 1979), for the slurry transport of spent shale into deep mines (Earnest et al., 1977), and for the hydraulic backfilling of coal mines (NAS, 1975). As shown in Table 7-5, these cost estimates range from \$0.75 to \$2.48 per ton of material placed, considering only the costs of material handling, slurry preparation, and slurry injection. The expense of drilling injection holes was not included in Table 7-5 cost projections. Based upon these figures, a cost of \$2 per ton for slurry preparation and injection is used in these cost calculations.

Table 7-2. Projected industrial development plans for lease tracts C-a and C-b related to retort grouting.

	Tract C-a	Tract C-b
Retort dimensions, ft		
Length	300	310
Width	150	155
Depth	750	390
Pillar Dimensions, ft		
Between length	300x150	310x150
Between width	150x150	155x50
Drilling		
Number of holes per retort, in square grid on 50 foot centers	18	18
Distance from ground to top of retort,[a] ft	450	1400
Distance of drilling through rock, ft	8100	25,200
Distance of drilling through rubble, ft	13,500	7020
Quantity of grout		
Volume of retort, ft^3	3.38x10^7	1.87x10^7
Void percentage	40	23
Volume of voids, ft^3	1.35x10^7	4.31x10^6
Grout material placed,[b] ton	3.58x10^5	1.14x10^5
Oil produced per retort		
In-situ		
Volume of oil shale, ft^3	2.03x10^7	1.44x10^7
Weight of oil shale,[c] ton	1.42x10^6	1.01x10^6
Oil recovered,[d] bbl	5.27x10^5	3.75x10^5
Surface		
Volume of oil shale, ft^3	1.35x10^7	4.31x10^6
Weight of oil shale, ton	9.45x10^5	3.02x10^5
Oil recovered,[e] bbl	4.86x10^5	1.55x10^5
Total oil recovery, bbl/retort	1.01x10^6	5.30x10^5

[a] Varies over tract, reported values are typical.

[b] Assumed 95 lb/ft^3 in place, 56 percent solids = 53 lb/ft^3.

[c] 140 lb/ft^3 for 24 gal/ton oil shale.

[d] 24 gal/ton, 65 percent recovery.

[e] 24 gal/ton, 90 percent recovery.

Table 7-3. Projected cost of grouting one retort.

	Tract C-a	Tract C-b
<u>Drilling</u>		
Drilling through rubble from air level to bottom of retort, assume \$10/ft	\$135,000	\$70,200
Drilling through rock from ground to top of retort, assume \$20/ft[a]	\$162,000	\$504,000
<u>Grouting</u>		
Grout material placed,[b] ton	$3.58\text{x}10^5$	$1.14\text{x}10^5$
Cost of grout preparation and and injection, \$2/ton	\$716,000	\$228,000
Credit taken for cost of surface disposal of equal amount of surface spent shale, \$1/ton	-\$358,000	-\$114,000
Net cost of grout preparation and injection	\$358,000	\$114,000
<u>Total cost</u>		
Grouting from air level	\$493,000	\$184,200
Grouting from ground	\$655,000	\$688,200
<u>Oil recovered,</u>[b] bbl/retort	$1.01\text{x}10^6$	$5.30\text{x}10^5$
<u>Cost per barrel</u>		
Grouting from air level	\$0.49	\$0.35
Grouting from ground level	\$0.65	\$1.30

[a] Include this cost if air level cannot be used as a grouting gallery.

[b] From Table 7-2.

Table 7-4. Water requirements to grout one in-situ retort.

	Tract C-a	Tract C-b
Volume of in-situ spent shale,[a] ft^3	2.03×10^7	1.44×10^7
Volume of water needed to completely wet spent shale,[b], gal	8.12×10^7	5.76×10^7
Volume of grout,[a] ft^3	1.35×10^7	4.31×10^6
Volume of water contained in grout,[c] gal	6.83×10^7	2.18×10^7
Total volume of water needed for grouting, gal	1.50×10^8	7.94×10^7
Oil produced,[a] gal.	1.01×10^6	5.30×10^5
Water needed for grouting, gal/bbl	1.49×10^2	1.50×10^2

[a] Assume equal in volume to raw shale retorted in-situ, as derived in Table 7-2.

[b] 4 gal/ft^3, based on Nevens et al., 1977. Because large blocks of spent shale may not be completely wet, this item may be over-estimated.

[c] Grout density = 95 lb/ft^3, 44 percent water = 5.1 gal/ft^3.

Table 7-5. Cost estimates for hydraulic backfilling and surface disposal (adjusted to 1979 dollars).

	Type of operation	Material placed, ton/day	Total cost $/ton
Hydraulic backfilling	Coal waste into deep coal mine[b]	3,000	2.48[a]
	Spent shale into deep mine[c]	68,000	1.48
	Spent shale into retort[d]	33,600	0.75
Surface disposal	Spent shale[d]	54,000	0.32
	Spent shale[c]	68,000	0.30
	Coal mine waste[b]	3,000	1.28

[a] Costs due to underground equipment and lost mine productivity are not included.

[b] NAS, 1975.

[c] Earnest et al., 1977.

[d] Derived from data in Nevens et al., 1979.

As indicated above, the spacing of drill holes depends upon injection pressure and the ease of penetration of the grout through the in-situ retort. For this estimate, it is assumed that grout can penetrate 35 feet from the point of injection. If holes are drilled in a square pattern, this 35-foot penetration would require that a spacing of 50 feet be used. Spacing of five to ten feet is generally used in soil grouting, but greater penetration may be possible in an abandoned retort than would occur in soil. Placing injection holes in retorts as described in Table 7-2 requires that 18 holes be drilled in each retort. The cost of drilling injection holes depends strongly upon whether or not the air injection level can be used as a grouting gallery and upon the number of air injection holes needed at the top of each retort. However, the cost of drilling air injection holes has not been included in these calculations.

Preparing grout from spent shale produced by surface retorting lessens the quantity of spent shale that must be disposed of above ground. Thus, credit is taken for the cost of surface disposal of the amount of shale used to manufacture grout. Estimates for this cost, including revegetation, ranged from \$0.30 to \$1.28 per ton of material used, as shown in Table 7-5. A cost of \$1 per ton was used for this cost projection.

HYDRAULIC ISOLATION BY IN-SITU PRECIPITATION

In-place formation of a calcite precipitate may also be used to seal pores in an abandoned retort. Lime in the spent shale would be reacted with CO_2 in groundwater or offgases to form calcite.

Limestone ($CaCO_3$) is converted to CaO by calcining; this CaO hydrates to $Ca(OH)_2$ when slurried. The $Ca(OH)_2$ reacts with CO_3 in the slurrying water, invading groundwater, or CO_2 in the offgas. Aqueous CO_3 or gaseous CO_2 is needed to react with the $Ca(OH)_2$ in place. The amount of CO_3 needed is more than can be dissolved in a flooded retort. However, adequate CO_2 is available from decomposition of carbonates in an adjacent retort (Persoff and Fox, 1980).

In addition to placing limestone in retorts, some free lime may be present in surface and in-situ spent shale. Heistand et al. (1978) found up to 7.7 percent free lime in surface retorted shale. If free lime is present in spent shales, it will react like emplaced lime to precipitate calcite. Thus, surface or in-situ spent shale could be substituted for some of the lime. This needs to be investigated experimentally.

Cost Projection

In the limestone precipitation method, hydrated lime is transported as a slurry into the retort where it reacts with the CO_2 to form $CaCO_3$. Costs shown in Table 7-6 are for sufficient lime to fill ten percent of the voids in an abandoned retort. For a higher percentage filling, the cost can be increased proportionately. However, it appears that calcite precipitation will not be economically feasible as a control technology.

Table 7-6. Projected cost of lime to fill 10 percent voids in abandoned retorts.

	Tract C-a	Tract C-b
Voids created by mining,[a] ft^3/retort	$1.35x10^7$	$4.31x10^6$
Weight of calcite to fill 10 percent of voids, tons (= 2.71)	$1.14x10^5$	$3.64x10^4$
Cost of delivered limestone, \$5/ton	$\$5.70x10^5$	$\$1.82x10^5$
Cost of calcining limestone[b] thermochemical,[b] \$8.45/ton sensible heat,[c] \$1.24/ton	$\$1.10x10^6$	$\$3.53x10^5$
Total cost of lime	$\$1.67x10^6$	$\$5.35x10^5$
Cost of preparing and injecting slurry, \$2/ton	$\$2.28x10^5$	$\$7.28x10^4$
Total cost	$\$1.90x10^6$	$\$6.08x10^5$
Barrels of oil produced,[a] per retort	$1.01x10^6$	$\$5.30x10^5$
Cost per barrel	\$1.88	\$1.15

[a] From Table 7-2.
[b] 40 kcal/mole, 9080 moles/ton, \$0.0000233 per kcal.
[c] 908,000 g/ton, 2/3 of sensible heat recovered, heated to 800°C, specific heat = 0.22.

HYDROGEOLOGIC MODIFICATION USING A GROUT CURTAIN

Grouting intended to stop water movement, rather than strengthening soil, is generally used in the form of a curtain. For this purpose, columns of closely spaced grout are injected to isolate or reroute flow of water at a specified depth of rock or soil (schematically presented in Figure 7-2). Often two or more rows of injection holes are used, with spacing of the holes determined by the distance to be penetrated by the grout. In the often-used split-spacing technique, holes are first drilled at some wide spacing and grouted. Subseqent series of holes are drilled between the earlier implaced holes until no additional grout can be injected, indicating that grout penetration is complete.

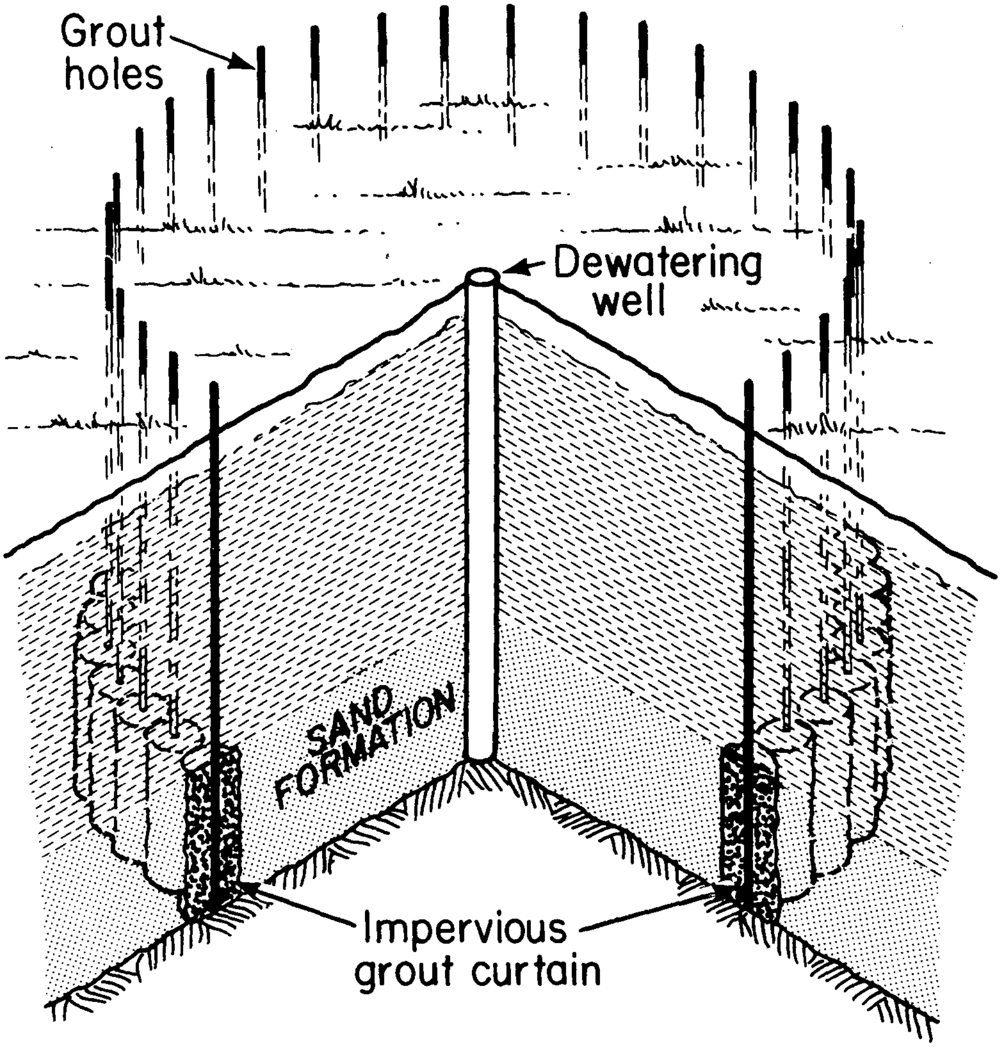
A proposed use of a grout curtain to prevent leaching of abandoned retorts is illustrated schematically in Figure 7-3. Several retort development plans call for a large number of retorts to be closely spaced in blocks, as shown in Figure 7-4. If a large area were to be enclosed by a grout curtain, the ratio of area to perimeter becomes large and the per retort cost of constructing a grout curtain around a large block of retorts --150, for example--becomes small.

Because no grout curtain will be completely impermeable, water will eventually reinvade the retort area, although at a much slower rate. This slower rate might reduce the transport of leachate into groundwaters and surface streams. The rate of leachate transport through a grout curtain needs to be estimated using a computer model of the basin. The effect of the grout curtain on the piezometry of the aquifers and on stream flows should also be studied to determine if existing water quality standards will be satisfied when equilibrium is eventually re-established.

The aquifers of the Piceance Creek Basin have a lower permeability than do the kinds of soil normally grouted; this may present a problem in forming a grout curtain in this area. The local aquifers are fractured and have a permeability of 26 to 60 millidarcy on Tract C-b (Occidental, 1979). Fractured rock, rather than soil, would be grouted. Problems may be encountered in injecting grout because it is difficult to grout a tight formation. It can be anticipated that costs will be higher for this operation than costs of grouting more porous media. The depth of this proposed grout curtain is much greater than the depth encountered in ordinary grouting projects, which may present difficulties. Construction of a grout curtain before retorting could reduce dewatering costs because the curtain would curtail water invasion into the retort area. However, this would require a large additional investment before any returns are realized. Any seismic activity or any subsidence in the region could damage a grout curtain, although, if damage is restricted to a limited area, repairs could be made at reasonable cost if detected. Custodial care would be required in this case.

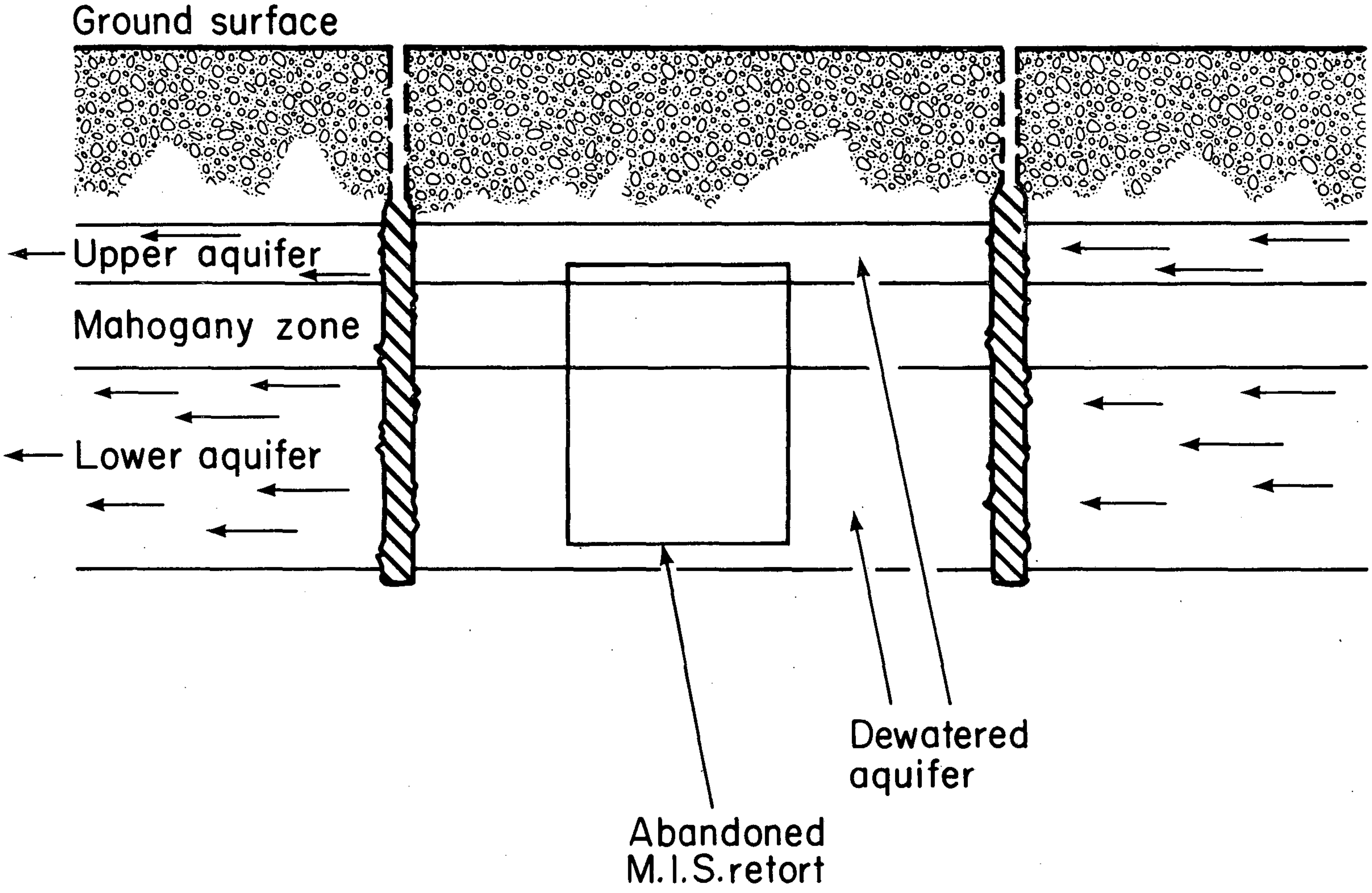
Cost Projection

The economic attractiveness of using a grout curtain as a control strategy is based upon the fact that the cost of installing the curtain around a block of retorts is relatively small per retort compared to the cost of a curtain around a single retort. Use of a grout curtain can be



XBL 804-762

Figure 7-2. Grout curtain. Adapted from Halliburton, 1970.



NOT TO SCALE

XBL793-704

Figure 7-3. Grout curtain to protect groundwater quality in Piceance Creek Basin.

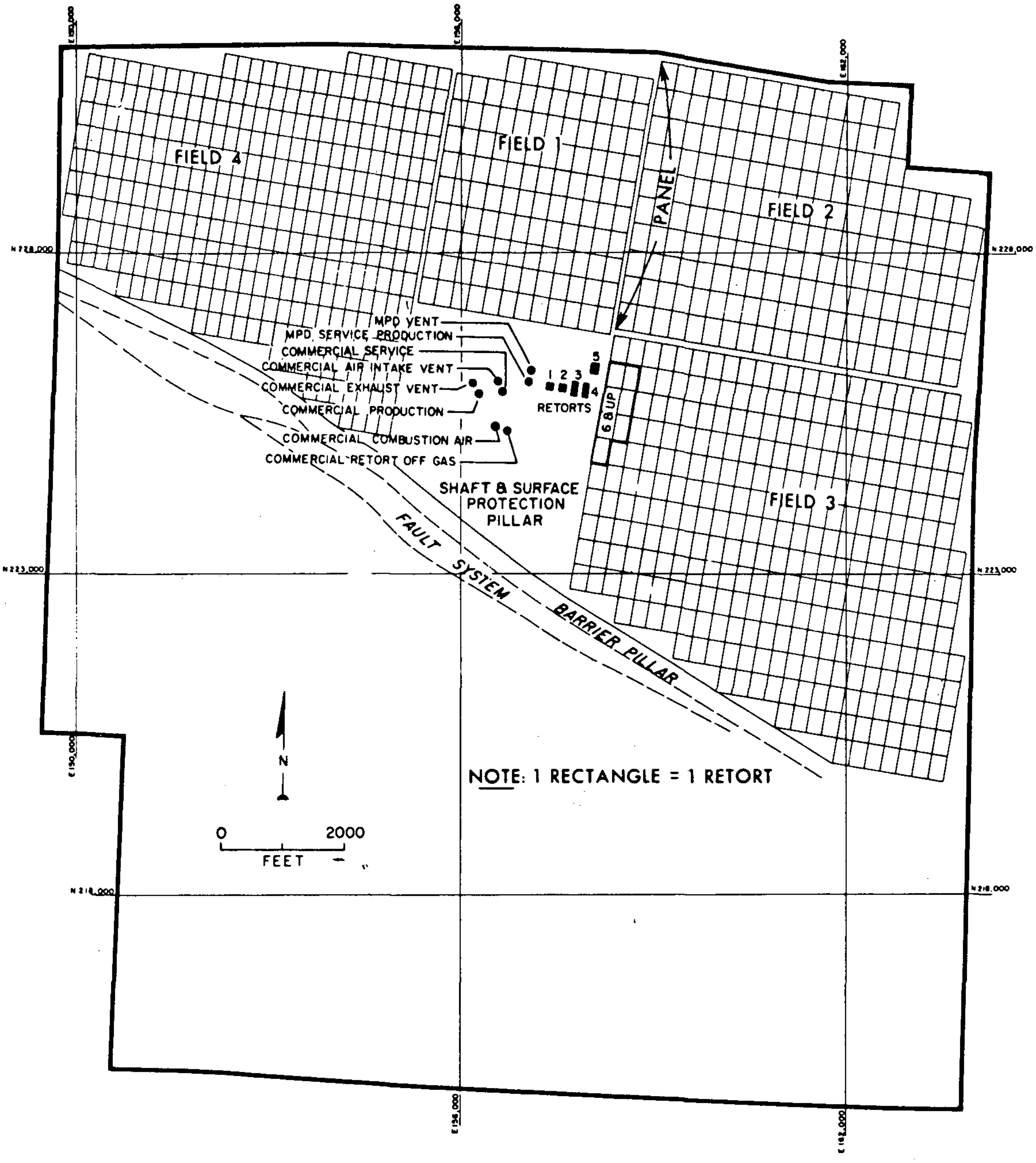


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Figure 7-4. Closely spaced retorts in blocks, as planned for lease tract C-a. Source: Gulf, May 1977. Reproduced by permission of the Rio Blanco Oil Shale Company.

considered to be economically feasible only if installed around a large block of retorts. Costs for surrounding a block of retorts, as shown in Figure 7-4, depend upon the number of retorts enclosed by the curtain. As a minimum, an entire lease tract could be enclosed by a single curtain, but the horizontal flow through a developed area would be less if the area was crossed by several curtains. The maximum size of a block of retorts to be surrounded by a curtain should be determined by groundwater-flow modeling on a site-specific basis. In this cost projection, the size of blocks to be enclosed has been taken as 4000 x 4000 feet. This is approximately the size of retort blocks planned for lease tracts C-a and C-b (Gulf, May 1977; Ashland, 1977).

The costs for the grout curtains described in Table 7-7 were estimated by assuming that a single row of holes would be drilled at five-foot centers along the perimeter of the curtain. Cement grout was assumed to penetrate to a width of ten feet; the porosity of the formation was taken as ten percent (Collins, 1978). The "take" of grout material is $(5)(10)(0.10) = 5$ ft^3 per linear foot of hole grouted. The costs per barrel of oil produced for a grout curtain are \$0.74 on Tract C-a and \$2.85 on Tract C-b. The variation in cost is due to difference in drilling distances. There is evidence that the lower aquifer on Tract C-b is actually divided into two isolated aquifers, designated Lpc 3 and Lpc 4 (Occidental, 1979). Only the upper of these two isolated aquifers intersects the retort area. Therefore, a grout curtain extending only as deep as the bottom of the Lpc 3 aquifer might achieve the desired effect of curtailing groundwater flow into the abandoned retorts. This would reduce costs of the grout curtain for Tract C-b.

HYDROGEOLGIC MODIFICATION USING A HYDRAULIC BYPASS

When retorts connect two aquifers which are at different piezometric heads, groundwater may flow through the abandoned retorts from one aquifer to another, transporting leachate from the abandoned retorts into the aquifer at the lower pressure. This leaching flow can be minimized by designing retorts or retort blocks in such a manner as to force groundwater flow through parallel paths of greater permeability instead of through the abandoned retorts. A hydraulic bypass or shunt could be installed for this purpose when the retorts are constructed.

A bypass is simply a series of holes drilled around the perimeter of a block of retorts and might be a palisade or curtain of wells or drill holes, as shown in Figure 7-5. The holes are not grouted but are left open to permit water to pass from one aquifer to another.

Some groundwater flow, however, would still pass through abandoned retorts. Therefore, this control measure dilutes leachate by mixing it with bypass flow. For example, if a 10:1 dilution is desired, the geometries and permeabilities of the retorts and bypass holes must be such that nine times as much groundwater flows through the holes as through the retorts. Because of the large cross-sectional area and high permeability of the retorts, some sealing may be required, although not to the extent required to fully seal the retorts.

Table 7-7. Cost projection for grout curtain.

	Tract C-a	Tract C-b
Grout curtain perimeter,[a] ft	15,740	15,850
Number of retorts enclosed by grout curtain[b]	16x10	11x13
Grouted depth of curtain, ft	950	1750
Vertical area of grout curtain, ft^2	1.50×10^7	2.77×10^7
Additional height drilled but not grouted, ft	235	350
Number of holes, 5 ft centers	3148	3170
Total grouted length of holes, ft	2.99×10^6	5.55×10^6
Material injected, ft^3	1.50×10^7	2.77×10^7
Material cost, $\$3/ft^3$	$\$4.49 \times 10^7$	$\$8.32 \times 10^7$
Total drilled distance, ft	3.73×10^6	6.66×10^6
Drilling cost, $20/ft	$\$7.46 \times 10^7$	$\$1.33 \times 10^8$
Total cost, $	$\$1.20 \times 10^8$	$\$2.16 \times 10^8$
Oil produced per retort,[c] bbl	1.01×10^6	5.30×10^5
Total oil produced, bbl	1.62×10^8	7.58×10^7
Total cost, $/bbl	$0.74	$2.85

[a] Assumed 4000 ft x 4000 ft area enclosed within grout curtain.

[b] Using retort and pillar dimensions as shown in Table 7-2.

[c] From Table 7-2.

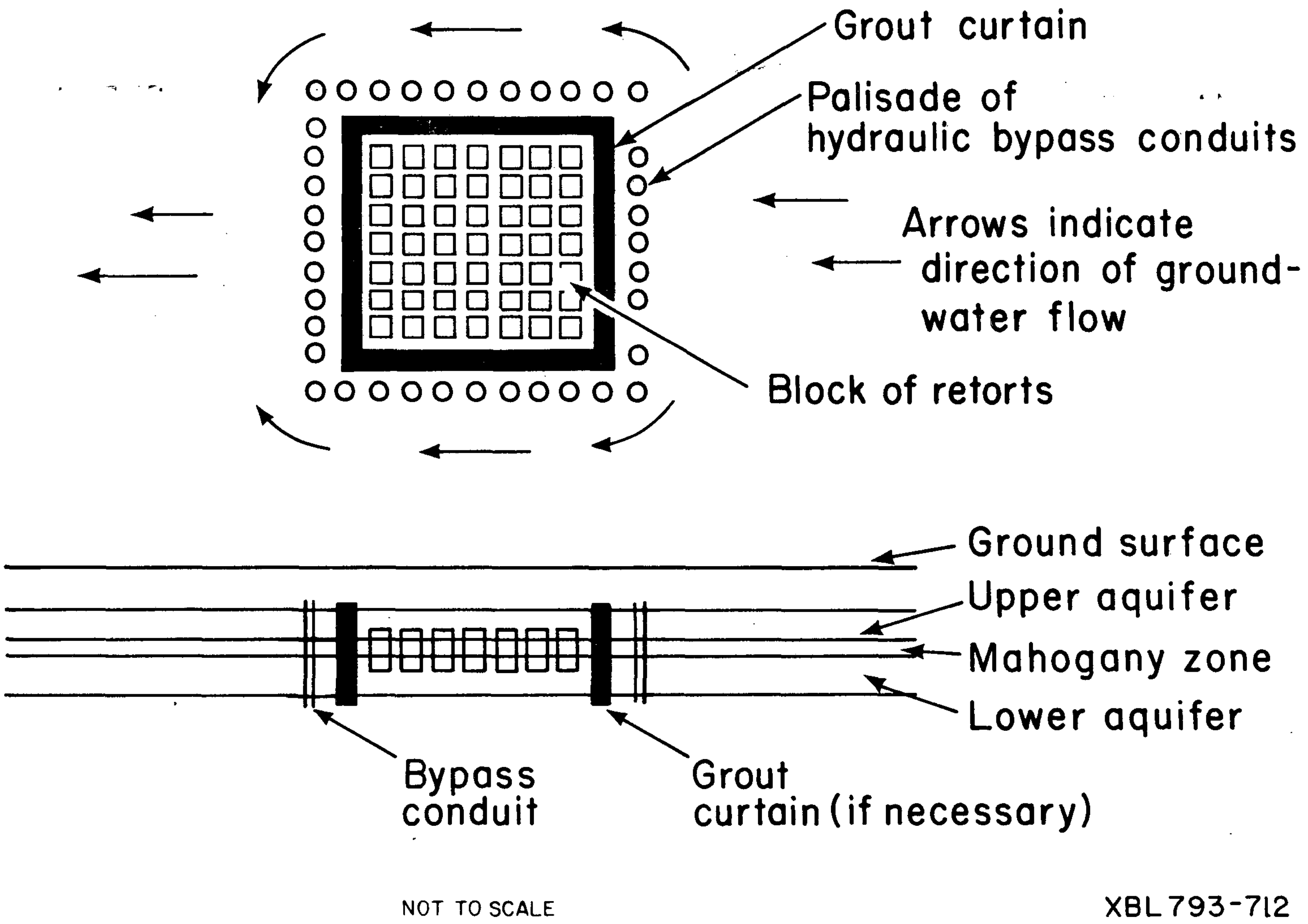

Figure 7-5. Hydraulic bypass around block of retorts.

A hydraulic bypass would minimize vertical but not horizontal flow through retorts. Therefore, a grout curtain or some other means of deterring horizontal flow may be required, depending on retort-aquifer geometries. The potential benefits of this control strategy could be quantified by computer modeling of the groundwater system.

Cost Projection

Costs for forming a hydraulic bypass around a block of retorts, similar to the bypass illustrated in Figure 7-5, are shown in Table 7-8. As in the grout curtain cost projection, it was assumed that an area 4000 feet by 4000 feet will be surrounded. Assuming that the conduits are placed around the retort block at five-foot centers and that the cost of drilling is $20 per linear foot, the total cost of providing a hydraulic bypass is $0.46 and $1.76 per barrel of oil for tracts C-a and C-b, respectively (Table 7-8). Costs for this control measure are similar to the costs for constructing a grout curtain, less the costs of slurrying and injectiong grout into the holes. Groundwater modeling should be done to test these assumptions and to determine the effects of a hydraulic bypass.

HYDROGEOLOGIC ISOLATION USING A CAP ROCK

In the Piceance Creek Basin, oil shale is located beneath the water table in the rich Mahogany Zone which lies between two confined aquifers (Weeks et al., 1974). Retorts that intersect either aquifer will be flooded after being abandoned. This control strategy would retain a cap rock of undisturbed oil shale material above and/or below the retorts to prevent flooding by groundwater. However, because the Mahogany Zone itself is permeable, a retort constructed entirely within the zone or protected by a cap rock might still be flooded by groundwater, but the rate of flow through the retort would be relatively slow.

An in-situ cap rock requires that an entire retort be confined within a dry zone, which might be from 100 to 200 feet thick. However, VMIS retorts must be tall to be economic. Fennix and Scisson (1976), for example, cite 200 feet as the minimum retort height in their economic analysis of retorting methods. Other proposed retorting systems use retorts 300 to 750 feet high. Applying a cap rock strategy in the Mahogany Zone would require using retorts far shorter than the minimum recommended by Fennix and Scisson.

Even if the Mahogany Zone were deep enough to permit efficient retorting with a cap rock in place, this technology would be difficult to use as a control measure. The retort would have to be completely isolated from the aquifers. No fractures could be present in the cap rock either before or after retorting or it would not be able to serve its preventative purpose of keeping groundwater from penetrating the retort. If the cap rock were to collapse during retorting, remedial measures would have to be taken to repair the damage. Occidental has experienced some difficulty with the stability of the cap rock (sill pillar) over Retort 6 which deteriorated during that run (Occidental, 1979). Good hydrologic data, probably involving extensive testing, would be needed to guarantee the integrity of the cap rock.

Table 7-8. Cost projection for hydraulic bypass.

	Tract C-a	Tract C-b
Bypass perimeters, ft	15,740	15,850
Total depth of drilling to bottom of lower aquifer, ft	1185	2100
Number of holes, at 5 ft centers	3148	3170
Total distance of drilling, ft	$3.73\text{x}10^6$	$6.66\text{x}10^6$
Drilling cost, \$20/ft	\$$7.46\text{x}10^7$	\$$1.33\text{x}10^3$
Number of retorts enclosed	160	143
Oil produced per retort, bbl	$1.01\text{x}10^6$	$5.30\text{x}10^5$
Total oil produced, bbl	$1.62\text{x}10^8$	$7.58\text{x}10^7$
Cost per barrel	\$0.46	\$1.76

Cost Projection

This control strategy may be uneconomical, and site specific evaluation is required. The restriction of retort size and unrecovered oil shale in the cap rock would increase the unit cost of oil recovery. It is not applicable for tracts C-a and C-b due to their unique geologic and hydrologic conditions.

RECOVERY AND TREATMENT OF LEACHATE

The objective of any control strategy is to prevent leached material from entering aquifers. Hydraulic isolation control strategies met this objective by preventing groundwater from contacting and leaching spent shale. Another method would be to leach abandoned retorts, recover the leachate by pumping it to the surface, and then treat it to remove leached material. The treated leachate would be suitable for on-site use or could be injected into an aquifer. This method removes and diposes of leachable material rather than locking it in place as the hydraulic isolation strategies do. It also uses existing technology to recover and treat leachate.

The leachate would begin to form when the retort is filled with water and then would be pumped to the surface and treated to bring the water to a quality level suitable for either on-site use or injection into aquifers. As long as leachate recovery continues by pumping, flow will be only into, not out of, the retort; no leachate will enter the aquifers. As soluble material is removed from the spent shale, leachate quality will improve until it can be released into aquifers without causing excessive degradation. At this point, no additional control measures would be required, the pumps could be removed, and groundwater could be permitted to reinvade the area.

Two methods of leachate recovery may be used. The first would permit groundwater to naturally reinvade abandoned retorts, and the resulting leachate would be pumped to the surface for treatment. However, it may take from decades to centuries for groundwater to reinvade the retort area (Fox, 1979). The long time period is problematic because: (1) there is no guarantee that an operator will be present to collect the leachate; and (2) installation and long-term maintenance of pumps would present logistic and economic uncertainties.

The second method of recovering leachate would deliberately inject water into retorts to form leachate and then pump the water to the surface for treatment. The treated water could be used in several leaching cycles. Groundwater flow into retorts would be neglible because water injected from the surface would prevent natural flow into the retort as long as the recovery process continues. This method has the advantage of requiring no delay for natural groundwater to reinvade the retorts. This control measure could be implemented on a "pay-as-you-go" basis, requiring the commercial operator to install treatment measures prior to closing down a site. Treatment, again, should be continued until leachate quality has improved to the level where it will not cause excessive degradation of groundwaters entering the retorts after leachate recovery has ceased.

Whichever method is used to recover leachate, the volumes to be treated would be large. Estimates indicate that 10 to 14 million gallons of leachate would have to be formed and collected daily in order to keep pace with a 50,000 barrel-per-day industry. These large volumes could economically limit the use of this technique. Brines and sludges may present a particularly difficult challenge. If the waste stream constitutes even ten percent of the treated flow, the land requirements for evaporation ponds could become excessive. Recovery and use of waste heat to increase the rate of evaporation could reduce the land requirement to an acceptable level.

The economics of recovering and treating leachate are strongly dependent upon the assumption that all the leachable material will be contained within a limited volume of leachate. Laboratory studies have shown that the concentration of organic and inorganic compounds declines rapidly as the leaching flow passes through spent shale and that essentially all of the leachable material is contained within the first few pore volumes that pass through the retort. For example, Hall et al. (1978) found that the majority of the organic carbon was contained in the first two pore volumes of water passing through a bench-scale leaching column and that the level of organic carbon in the leachate was not significantly higher than the background level present in the influent after six pore volumes of water had passed through the leaching column (Figure 7-6). Similar results have been found for inorganic species (CSU, 1971) (See also Chapter 6). These results indicate that a limited of leachate may be treated.

Leaching requires three consecutive steps: desorption of the species into the water phase, diffusive transport through the internal pore network to the outer surface of the spent shale, and transport by film diffusion into the bulk liquid. The slowest of these steps will be rate-limiting. In the case of large particles, pore diffusion through the relatively long distance to the outer surface of the particle may be the limiting step. Because spent shale contains a network of fine internal pores left by pyrolysis of kerogen, it is possible that the majority of the surface of the spent shale and a majority of the leachable material lie within internal pores. Internal pore diffusion did appear to be rate-limiting in leaching combustion-retorted shale in work by Amy (1978). If pore diffusion is indeed limiting, the large particles of spent shale expected under field conditions may cause the effect illustrated in Figure 7-5 to be less pronounced, and a larger volume of leachate will require treatment. Although unlikely, it is possible that large particles of shale may produce leachate so slowly that no treatment will be required. Temperature of the leaching water may also affect the leaching rate.

It will be necessary to establish an acceptable leachate concentration based upon water quality standards related to ultimate use of the treated water. This will probably be a site-specific requirement, since the composition of leachates will vary somewhat from site to site and water quality requirements may vary in different areas. Laboratory studies can be of benefit in determining the concentrations to be used. However, it is important to note that laboratory studies to date have used only small spent-shale particle sizes and that the spent shale used in laboratory tests may or may not be representative of spent shale from in-situ retorts. Field testing will be required to verify laboratory findings.

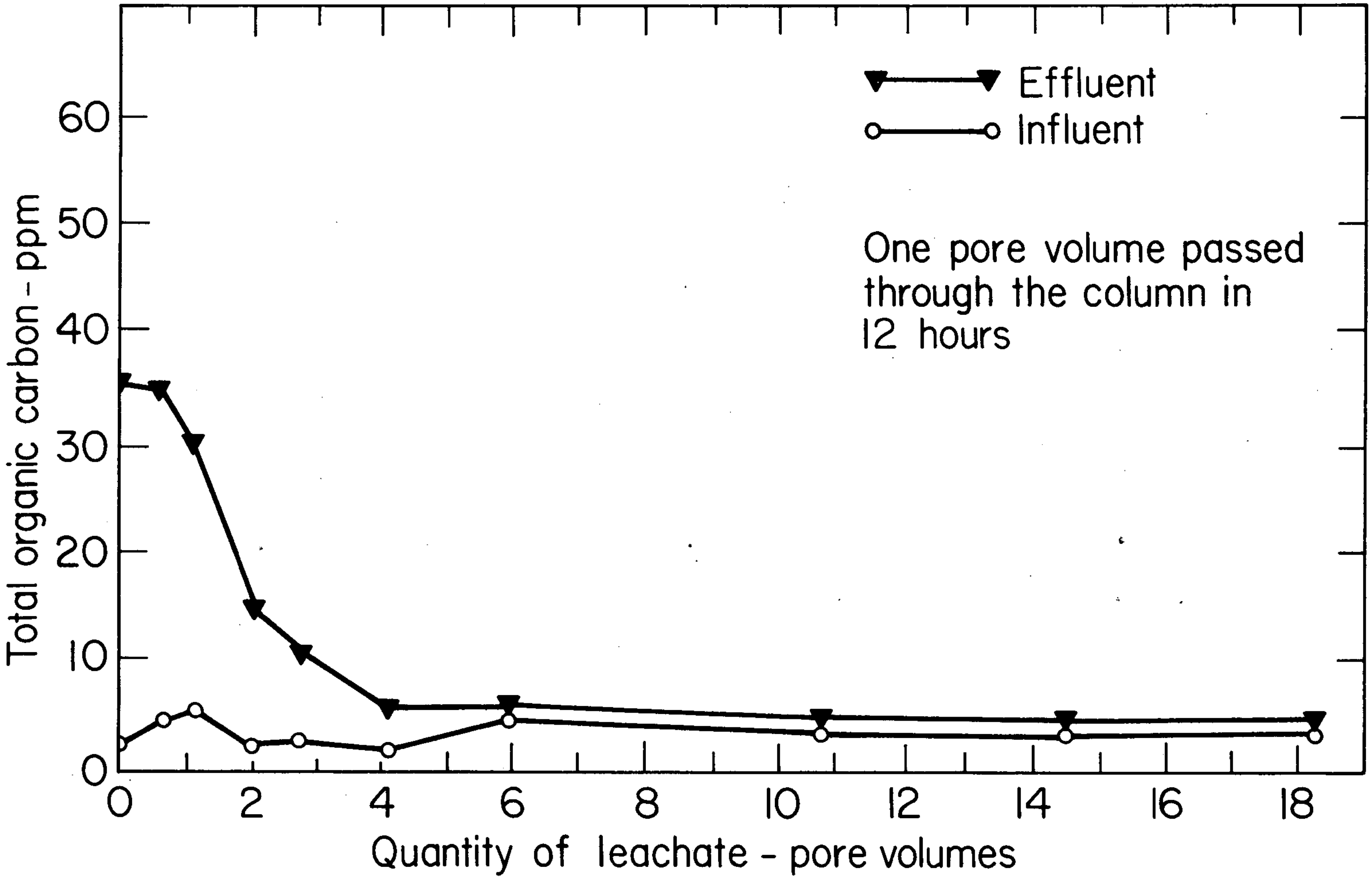

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Figure 7-6. The effect of increasing pore volumes on organic carbon concentration of leachate from spent shale from the LETC 10-ton retort. Source: Hall et al., 1978.

Natural leaching following abandonment of retorts is not considered practical because of the long lead times involved, problems related to maintenance of on-site pumping facilities, and the long-term liability of the operator. Leaching in-situ retorts with excess mine water would be a more practical method requiring a far shorter time to complete treatment of leachates. New pumping equipment and piping would have to be installed for this option. Mine dewatering effluents that would otherwise be directly reinjected into aquifers (as planned for Tract C-a) or discharged into surface streams (as projected for Tract C-b) would be introduced at the bottom of the abandoned retort and pumped up through the retort to a surface treatment plant that would remove total dissolved solids and total organic carbon. Treatment would include scale control by chemical addition, sedimentation, carbon adsorption, and reverse osmosis (RO). Salts in the leachate would be concentrated in the RO brine stream constituting not more than ten percent of the leachate flow. The brine stream would be disposed of by evaporation in ponds. Treated water would be re-used for leaching or disposed of by reinjection into retorts or by discharge into surface waters, depending upon the availability of mine water for leaching.

Cost Projection

The cost of recovering and treating leachate depends upon the volume of leachate to be treated and the cost of treatment, which can be assessed only after treatability studies have been conducted to determine the best process to use. The estimates presented here indicate that this technology may cost $0.66 and $0.59 at tracts C-a and C-b, respectively, for tertiary treatment of two pore volumes.

Leaching studies of in-situ spent shales have shown that the majority of leachable materials may be removed in the passage of from two to six pore volumes (Fox, 1979; Kuo et al., 1979); the lower value is used for this cost projection. Pore volume in a retort is the void space originally present plus additional void space left by in-situ pyrolysis of kerogen. The value of the original void space is taken from Table 7-2 (1.35×10^7 ft^3 for 1.01×10^6 bbl or 13.37 ft^3/bbl for Tract C-a, and 4.31×10^6 ft^3 for 5.30×10^5 bbl or 8.13 ft^3 for Tract C-b). The additional void space left by in-situ pyrolysis of kerogen is assumed equal to the volume of oil produced in-situ divided by the 0.65 recovery factor. As shown in Table 7-2, each retort on Tract C-a produces 5.27×10^5 barrels of oil in situ, corresponding to a void volume of 8.11×10^5 barrels, or 4.55×10^6 ft^3, caused by in-situ pyrolysis of kerogen. Since total oil production per retort (including both surface and in-situ retorting) is 1.01×10^6 barrels, the void space left by in-situ pyrolysis of kerogen is 4.51 ft^3/bbl for Tract C-a and 6.11 ft^3/bbl for Tract C-b. Thus, two pore volumes of leachate are 35.8 ft^3/bbl or 268 gal/bbl on Tract C-a and 28.5 ft^3/bbl or 213 gal/bbl on Tract C-b. A 50,000 barrel-per-day industry operating 350 days per year would therefore require 12.8 million gallons per day (MGD) on Tract C-a and 10.2 MGD on Tract C-b. If the required amount is greater than the flow rate of excess mine water, the treated leachate must be re-used for leaching; if not, the treated leachate may be processed for disposal. Total costs for treatment include costs for leaching, treatment, and disposal.

Leaching Costs. The total expenses for injecting excess mine dewatering effluents (treated leachate) into spent retorts for intentional leaching include: the capital costs of injection and recovery wells in each retort; costs of a pumping station and piping to transport water from the dewatering wells to retorts and to treatment and disposal equipment; and operating costs for the pumping station. Two different pumps are required. One pump distributes flow to retorts and circulates flow through full retorts against a low head; the other removes the last pore volume and empties the retorts against a high static lift, from water level in the retorts to the ground surface. The high static lift pump would have to be relocated after each retort, or group of hydraulically connected retorts, is leached. The capital costs and operating expenses for leaching are developed in Table 7-9.

Treatment Costs. Treatment costs include amortized capital and operating expenses for sedimentation, activated carbon adsorption, and reverse osomosis, with chemical addition for scale control. As shown in Table 7-9, costs for sedimentation and activated carbon adsorption are based upon the flow rate to be treated (Eckenfelder, 1970). The cost for reverse osmosis was estimated by allowing a suitable margin over costs observed for a 5 MGD wastewater reclamation system (Argo and Moutes, 1979).

Disposal Costs. The reject stream for the reverse osmosis process is a brine containing most of the salts concentrated into a small fraction of the water; for the purpose of this cost estimate, the fraction is assumed to be no greater than ten percent of the total volume. This waste stream, plus sludges from the treatment process, would be evaporated from lined ponds. Net evaporation from ponds is at the rate of about four feet per year in western Colorado; the cost for lined ponds would be about $58,000 per acre (Sinor, 1977). The total disposal costs per barrel of oil produced are shown in Table 7-9.

IN-SITU LEACHATE TREATMENT BY ADSORPTION AND ION EXCHANGE

Collecting and treating leachate on the surface involves costs for pumping and re-injection and is sensitive to the kinetics of leaching and the rate of re-invasion of retorts by groundwater. These would not be problems if treatment were accomplished in-situ by adsorption and ion exchange. In principle, an adsorbent could be placed in a retort to remove organics from leachate and mixed ion-exchange resins used to remove dissolved cations and anions. The amount of these materials needed would depend on the amount and nature of organics and inorganics to be removed from solution and the capacity of these materials to remove pollutants. The data presented in Figure 7-6 and Table 7-10 suggest that over 100 equivalents of anions and cations and 30 mg/l TOC would have to be removed for two pore volumes of leaching per barrel of oil recovered. While the TOC could probably be economically controlled using an adsorbent resin, the cost of ion exchange resin to remove this large quantity of TDS would be prohibitive. Therefore, this strategy would not provide adequate salinity control at a reasonable cost.

Table 7-9. Projected costs for intentional leaching.

	Tract C-a	Tract C-b
Drilling one injection well per retort		
Ground to top of retort--distance, ft	450	1400
Drilling cost, at $20/ft	$9,000	$28,000
Height of retort--distance, ft	750	390
Drilling cost, at $10/ft	$7,500	$3,900
Drilling cost per retort	$16,500	$31,900
Barrels of oil recovered per retort	1.01×10^6	5.30×10^5
Drilling cost, per barrel	$0.02	$0.06
Drilling costs, per year	$298,100	$1,098,400
Leaching		
Flow rate, gal/min[a]	8910	7100
Pumping requirements		
a. Two pore volumes circulate through retort against 100 ft friction head power requirement (80 percent efficient)	281 HP	224 HP
100 HP pumps, 1.15 service factor, number required	3	2
Capital costs		
Pumps at $9,000 each	$27,000	$18,000
Installation and controls	$27,000	$18,000

Table 7-9. Projected costs for intentional leaching (continued).

	Tract C-a	Tract C-b
b. One pore volume lifted to surface, average lift, ft	825	1595
Power requirement (80% efficient)	1160 HP	1790 HP
600 HP pumps, multistage 1.15 service factor, number required	2	3
Capital costs		
Deep well turbine pumps incl. column, at 100,000	$200,000	$300,000
Installation and controls	$100,000	$150,000
Piping--10,000 ft of PVC pipe at $25/ft	$250,000	$250,000
Total connected HP	1441	2014
Total capital cost	$604,000	$736,000
Amortized capital cost per year[b]	$120,800	$147,200
Pumping energy per year[c]	$188,800	$263,800
Total cost per year	$309,600	$411,000
Treatment		
Sedimentation		
Basin surface area,[d] ft^2	21,400	17,100
Capital cost[d]	$370,400	$305,200
Amortized capital cost per year[b]	$ 74,100	$ 61,000
Operating cost per year[e]	$321,300	$256,100
Total cost per year	$395,400	$317,100
Activated carbon		
Capital cost[e]	$4,845,900	$4,218,400
Amortized capital cost per year[b]	$ 969,200	$ 843,700
Operating cost per year[e]	$ 628,900	$ 534,300
Total cost per year	$1,598,100	$1,378,000

Table 7-9. Projected costs for intentional leaching (continued).

	Tract C-a	Tract C-b
Reverse osmosis		
Amortized capital and operating cost, including pretreatment for scale control[f]	$4,690,000	$3,727,500
Total treatment costs per year	$6,683,500	$5,422,600
Disposal		
Pond area needed to evaporate 10 percent brine streams + 1/4 percent sludge stream,[g] acre	368	293
Lined evaporation ponds		
Capital costs[h]	$21,376,000	$17,017,000
Amortized capital cost per year[c]	$ 4,275,200	$ 3,403,400
Total annual costs		
Drilling	$ 285,900	$ 1,053,300
Leaching	$ 309,600	$ 411,000
Treatment	$ 6,683,500	$ 5,422,600
Disposal	$ 4,275,200	$ 3,403,400
TOTAL	$11,554,200	$10,290,300
Total cost, $/bbl	$ 0.66	$ 0.56

[a] Two pore volumes, 50,000 bbl/day.

[b] Capital recovery factor = 0.20.

[c] 2¢/kwh = $131.00/HP-yr.

[d] Sized for 600 gpd/ft^2.

[e] After Eckenfelder, 1970--costs adjusted to 1979.

[f] After Argo and Moutes, 1979, $1000/MG.

[g] 4 ft/yr net evaporation.

[h] $After Sinor, 1977--$58,000/acre.

Table 7-10. Estimated composition of leachate from an in-situ retort located on lease tracts C-a and C-b.

Constituent	Leachate Composition, mg/l Tract[a] C-a	 Tract[b] C-b
Al	0.49 - 31	0.89 - 53
B	0.33 - 1.9	36 - 39
Ca	35 - 2350[c]	14 - 3950[c]
Cl	32 - 73	1234 - 1300
CO_3	110 - 2400	408 - 4250
Cr	<0.02 - <20	0.01 - 34
F	4.8 - 47	29 - 100
Fe	5.0 - 5.5	0.8 - 1.6
HCO_3	560 - 920	4140 - 4750
K	2.5 - 200	21 - 360
Li	0.20 - 4.8	10 - 18
Mg	52 - 140[c]	11 - 160[c]
Na	212 - 2800	2500 - 6900
NO_3	0.94 - 30	1.7 - 49
Pb	0.22 - 0.36	0.12 - 0.35
Si	120 - 990	170 - 1660
SO_4	326 - 1800[c]	65 - 2500[c]
Zn	0.26 - 0.54	0.2 - 0.7
TDS	905 - 31,700	6190 - 58,700
TOC	12 - 430	16 - 720
Phenols	0.04 - 0.44	0.06 - 0.8

[a] Assumes the retort is leached with upper aquifer water, that the mass of spent shale in the retort is 1.1×10^9 kg, and that the volume of water contained by the retort is 5.0×10^8 liters.

[b] Assumes the retort is leached with lower aquifer water, that the mass of spent shale in the retort is 7.5×10^8 kg, and that the volume of water contained by the retort is 2.0×10^8 liters.

[c] These constituents may be reduced on passage through the groundwater aquifer.

Source: Table 6-9.

Cost Projection

The cost of the method depends upon the amount of organics and inorganics to be removed and the cost of the required amounts of adsorbent or ion-exchange resin. Based upon an expected leachate composition for treating two pore volumes of leachate, as shown in Table 7-10, using ion-exchange resins for TDS removal by this method is too costly to be considered. For example, Duolite GPA-9316, a typical cation-exchange resin in hydroxide form, has an exchange capacity of 0.9 eq/l (25.5 eq/ft^3) and costs \$126/ft^3 or \$5 per equivalent. Two pore volumes on Tract C-b, about 780 liters per barrel (more on Tract C-a) would contain about 200 meq/l (see Table 7-10). The large amount of material to be removed makes it obvious that in-situ ion exchange is too costly for consideration.

MODIFY RETORT OPERATING CONDITIONS

Several studies have shown that leachability of organics and inorganics from spent shale depends upon retorting conditions. Amy (1978) found that more organic carbon was leached from spent shales retorted in externally heated inert gas than from spent shales retorted in combustion runs. He also noted that recycle gas in combustion runs contributed greatly to leachable organic carbon. Parker (1978) reported that shale retorted at 1000°C or 430°C contained lesser amounts of soluble metals than shale retorted at 780°C. Campbell (1978) found that, at high temperatures, the major elements in oil shale are largely converted to silicates (e.g., diopside, gehlenite, akermanite) that are largely insoluble. Kuo et al. (1979) stated that this conversion to silicates took over 200 hours to reach equilibrium when shale was retorted at 760°C in a nitrogen atmosphere containing one percent oxygen. Burnham et al. (1978) reported that ten percent or more steam in the retorting atmosphere catalyzes the conversion to silicates and that retorting in an atmosphere of 100 percent CO_2 delayed formation of silicates.

Based upon these reported experimental results, several retorting conditions that would minimize the leachability of organics and inorganics from spent shale can be listed:

- Combustion retorting to burn off as much char as possible.
- Use of a sweep gas to remove CO_2 as it is formed.
- High retorting temperatures, above 1000°C.
- Steam retorting.
- Slow retorting rates, i.e., long residence time at high temperatures.

However, the effect of these conditions on environmentally important elements such as aluminum, boron, or fluoride has not been studied and these constituents may not be reduced by these treatments. These conditions approximate those presently proposed for use by the developers of lease tracts C-a and C-b. Combustion retorting in the presence of steam at slow retorting rates, about one foot per day, are proposed by the C-b operators; similar conditions at higher rates, about ten feet per day, are planned by the C-a operators. The issue of slow versus fast retorting has not been resolved and is presently a controversial topic among oil shale process developers. Low retorting rates, however, favor the formation of a low-solubility spent shale, and this factor should be considered in the final analysis of slow versus fast retorting.

Uniform rubblizing and burning of the retort will be necessary to ensure that all the shale meets the conditions required to minimize leachability. Channeling of the reaction zone and uneven temperature distributions might leave zones of highly leachable shale. Examination of recovered cores from commercial retorts will be required to determine how effective these conditions are in minimizing leachability of spent shale in abandoned retorts. The most likely prognosis, however, is that commercial practices will produce spent shale that is less leachable than simulated in-situ spent shales, but that some additional control technology will still be required.

Cost Projection

None of the modifications to retort operating conditions will add materially to the costs of retorting oil shale since they all improve oil recovery. However, it should be noted that uniform rubblization and retort burning will be necessary to ensure that most of the spent shale meets the conditions necessary to minimize leachability. This will be difficult to accomplish using present rubblization and retorting methods. Additionally, the leachability of select elements may not be covered by these techniques. Consequently, it is possible that additional control measures may be required in addition to modification of retorting procedures.

REVERSE WETTABILITY OF SPENT SHALE

The voids in an abandoned retort will be completely filled by air or retort gases immediately following retorting. If leaching of the spent shale is to take place, groundwater must displace air from the void spaces and wet the surface of the spent shale. If shale were rendered non-wettable, leaching would not occur; this could be accomplished by applying a water-repellant coating to the shale.

Although no studies have investigated water-repellant coatings on spent shale, tests have been made on other materials. For example, Fink and Myers (1968) conducted laboratory and field experiments in which coatings such as waxes and silicones were applied to different soil types. The silicones appeared to substantially reduce wetting at monolayer coverage (2×10^{-5} g/m^2).

It may be technically complex to introduce a coating into an abandoned retort to provide efficient monolayer coverage of spent shale. Among the problems which might be encountered are the cost of drilling injection holes, securing a coating which would be fluid enough to penetrate all voids, and the length of setting time. Fink and Myers found that the coatings they applied were not permanent and suspected that hydrolysis of the silicones had taken place. Coatings which are not permanent would not be suitable for oil shale use.

Cost Projection

The high costs of water-repellant coatings makes reversing wettability an uneconomical means of controlling leaching of in-situ retorts. Silicones cost at least $4.00 a pound; waxes, $0.20 per pound. Spent shales have relatively high surface areas, about two to four square meters per gram of shale. The large volume of spent shale to be coated in each retort makes it economically infeasible to use such coatings. Unless a more permanent and less costly water-repellant coating can be developed, reversing the wettability of spent shale is uneconomic.

SELF TREATMENT IN AQUIFER MEDIA

As a general rule, all natural waters have some capacity for self-purification. Mechanisms of self-treatment in Piceance Creek Basin aquifers might include precipitation, natural decomposition of complex organic molecules, microbial degradation, and adsorption and ion exchange on aquifer media. Since it is anticipated that it will take many years for discharged leachate to reach any downstream users or surface waters, even a slow rate of self-treatment may be sufficient to preserve groundwater quality. This self-treatment capacity of aquifers has never been measured, but controlled laboratory or field studies could quantify that capacity. This rate of self-treatment could then be used in computer models of an aquifer-retort system.

SUMMARY

This chapter has reviewed several control strategies which have potential application for an oil shale industry. The analysis of information obtained from a comprehensive literature survey and from laboratory tests suggests that some of these strategies can meet requirements for preventing or mitigating the adverse environmental impacts of oil shale processing and that most of the technologies involved are economically feasible. Although some control measures do not fully meet preventative requirements, it is possible that these strategies would accomplish that purpose if used in combination with other techniques. The cost projections developed in this chapter were based on laboratory test data and therefore may be lower than actual costs which might exist in the field. Although this study concentrated on the VMIS process and used the oil shale resources of the Piceance Creek Basin for primary information, the techniques involved apply equally to other retorting methods and could be used in other oil shale areas. Without the use of control strategies, such as those discussed in this chapter, commercial oil shale retorting may have a severe adverse impact upon the environment for years, even centuries, after processing has been completed in a particular area and the retorts abandoned. Therefore, additional in-depth study is required to ascertain the best possible and most economical control technologies which should be applied by commercial oil shale industries.

CHAPTER 8

REUSE AND DISPOSAL OF EFFLUENTS FROM AN IN-SITU OIL SHALE INDUSTRY

The Green River oil shale deposits are located in the Upper Colorado River Basin where water supply and water quality have long been issues of national and international importance. A large-scale oil shale industry may consume from 71 to 278 gallons of water per barrel of oil produced and may produce even larger volumes of wastes that must be disposed of. Because of the stringent state and federal standards governing the discharge of wastes to local waters (Chapter 5) and the limited water supplies in this area, an oil shale industry will probably reuse process effluents to the maximum extent possible and evaporate the residuals. Therefore, discharge of effluents to surface and ground waters may not occur and attendant water quality effects would be nonexistent. The principal water quality effects in this case would be from accidental spills of oil and aqueous effluents and from salinity increases due to stream flow reductions from diversions for in-plant use.

The purpose of this chapter is to present the characterization of effluents from an in-situ oil shale industry and to put into perspective the disposal options available within the legal framework existing in the oil shale region (Chapter 5).

EFFLUENTS

Water is used at an oil shale plant for mining operations, dust control, steam and power generation, compaction of processed shale, irrigation, potable water supply, pre-refining, and other uses (Chapter 5). Each of these uses produces an effluent that must be collected, treated, and discharged somewhere on site. The types of effluents produced include mine waters, brines from ion exchange, reverse osmosis, filtration and other treatment processes, storm water runoff from the plant area, and various process waters. All of these effluents, except the process waters, are normally found in other types of industrial operations and can be treated with conventional control technology. However, the process waters--the retort water and gas condensate--are unique to oil shale retorting and represent a difficult and challenging treatment and disposal problem.

This section will discuss the anticipated volume and composition of the major aqueous waste streams from an in-situ oil shale industry with particular emphasis on process waters. A subsequent section will use this information to evaluate disposal and reuse options.

Retort Water and Gas Condensate

Two unique types of water are produced during oil shale retorting from combustion, mineral dehydration, input steam, and groundwater. These are referred to as retort water and gas condensate. They are produced in rather large volumes, from about 0.1 to 22 barrels of water per barrel of oil (Table 8-1), and they have proven to be very difficult to treat. For a 500,000 barrel per day plant, which represents about six percent of the 1977 crude oil production, this represents about two million

Table 8-1. Retort water produced by some surface and in-situ processes.

Process	Ratio of water to oil (volume basis)
In-situ retorts:	
True in-situ Rock Springs Site 9	22.2[a]
Modified in-situ with steam Occidental Retort #5	11.5[a]
Simulated in-situ with steam Lawrence Livermore Laboratory 125-kg retort	2.30[b]
True in-situ Rock Springs Site #7	0.66[a]
Horizontal in-situ Geokinetics Retort #11	0.68[a]
True in-situ Rock Springs Site #4	0.40[a]
Simulated in-situ with nitrogen Lawrence Livermore Laboratory 125-kg retort	0.40[b]
Surface retorts:	
Fischer Assay	0.15
Paraho Direct	0.17[c]
Paraho Indirect	0.08[c]
TOSCO II	0.30[d]

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[a] Farrier et al., 1978.

[b] Fox, 1980.

[c] McKee and Kunchal, 1976.

[d] ARCO, 1974.

to 500 million gallons of water, depending on the type of process and the plant location. Water production for surface processes is at the lower end of this range (0.10-0.30), while it is at the upper end for in-situ processes (0.4-22). The high value of 22.2 gallons of water per gallon of oil is due primarily to groundwater inflow and is probably not realistic for a commercial industry if the site is carefully dewatered. If this water could be successfully renovated, it would represent a valuable resource for the arid oil shale region.

These waters are produced within an in-situ retort system as a vapor that is condensed with the oil and separated from it by decantation, heat treatment, or condensation. Retort water condenses in the retort with the oil, collects in an underground sump at the bottom of the retort, and is separated from the oil on the surface by heat treatment and decantation. The water removed from the gas stream in the above ground condenser train is referred to as gas condensate (Figure 8-1).

The relative proportions and composition of each type of water depend on the exit gas temperature and product collection system design and operation. The retort water travels down the packed bed of shale in an emulsion with the oil, and thus may leach constituents from the shale matrix and from the oil itself. Therefore, this water is expected to contain high concentrations of some elements by virtue of its intimate contact with the oil and shale. The gas condensate, which leaves the retort as steam, contains lower concentrations of most organics and inorganics than retort water and higher concentrations of dissolved gases, such as ammonia and carbon dioxide.

In a commercial in-situ operation, the retort water and gas condensate will be collected and treated separately due to their different compositions. However, the design and operation of a commercial product collection system has not been investigated, and the effect of such a system on water production and composition has not been studied. In simulated in-situ retorts and field experiments, which have provided the majority of the data on these process waters, these two types of waters have not been distinguished; they have generally been combined into a single fraction or only the retort water has been collected. The reader is therefore cautioned that the results presented here may not be representative of a commercial in-situ oil shale industry. In this work, the term "retort water" is applied to the aqueous fraction collected from a retort by its operators. Since retort waters are produced in large volumes, are chemically unique, and are difficult to treat, the available literature on them is reviewed here.

In-Situ Retort Waters. In-situ retort waters are brown to yellow, they have a pH that ranges from 8 to 9, they contain high levels of many inorganic and organic constituents, and they are known to support bacterial growth when maintained at temperatures above $40^{o}F$ (Farrier et al., 1977). A summary of water quality parameters for various in-situ retort waters is presented in Table 8-2. This table indicates that these waters have high concentrations of solids, NH_3, NH_4, HCO_3, CO_3, and SO_4. The organic constituents are primarily polar, and the principal components are the normal carboxylic acids (Cook, 1971; Yen, 1976b; Ho et al., 1976). The other constituents, which have also been identified, include: ketones, pyridines, pyrroles, lutidines, anilines, amines, indoles, and quinolines

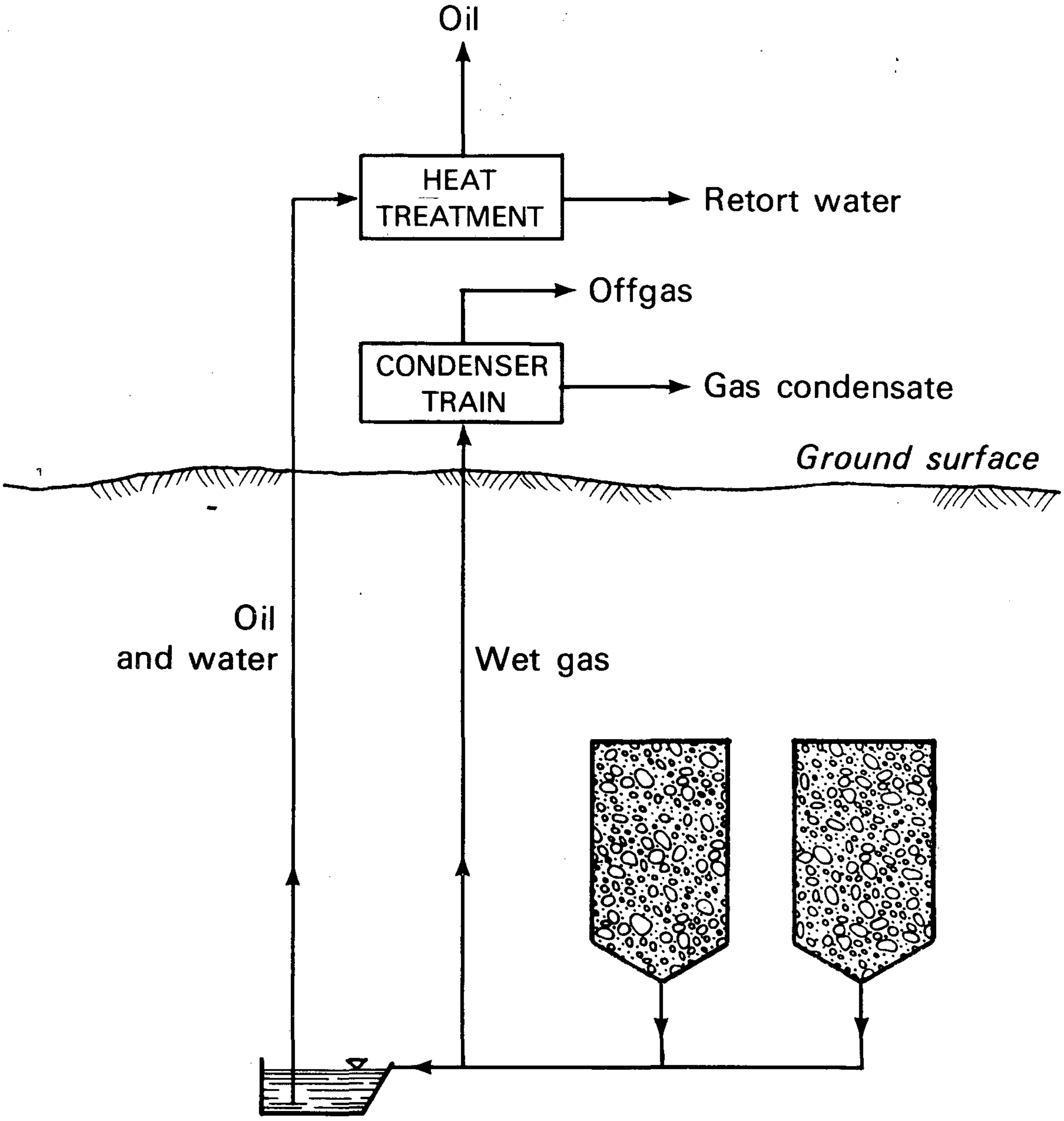

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Figure 8-1. Production of retort water and gas condensate during in-situ retorting.

Table 8-2. Water quality parameters for some in-situ retort waters, mg/l.

	SIMULATED IN-SITU RETORTS				
	LETC 150-ton retort[a]	LETC 10-ton retort[b]	LETC 10-ton retort[c]	Various LETC and LLL retorts[d]	LETC 150-ton retort[e]
Alkalinity (as $CaCO_3$)	32,900	-	-	18,200-110,900	38,000
Biochemical oxygen demand (5-day)	-	350-5,500	-	350-5,500	5,325
Carbon, bicarbonate (as HCO_3)	-	4,200-16,000	10,000-42,000	4,200-73,640	-
, carbonate (as CO_3)	-	-	0-7,500	0.0-15,210	-
, inorganic	6,250	-	-	1,960-19,200	6,400
, organic	5,380	3,200-19,000	2,830-10,660	2,200-19,000	3,300
Chemical oxygen demand	11,100	12,500-20,000	-	8,500-43,000	8,800
Nitrogen, ammonia (as N)	7,850	4,790	-	1,700-13,200	8,400
ammonium (as N)	-	-	4,800-14,200	930-24,450	-
organic	733	1,510	-	73-1,510	-
Kjeldahl	-	-	-	6,600-19,500	11,000
pH				8.1-9.4	8.8
Phenols	8.5	2.2	-	2.2-169	
Solids, total	39,900	-	-	6,350-121,000	-
Solids, dissolved				1,750-24,500	4,210
Sulfur, sulfate (as SO_4)	1,180	59-930	320-2,100	42-21,200	1,100

[a] Harding et al. (1978)

[b] Yen (1976)

[c] Jackson et al. (1978)

[d] Fox et al. (1978)

[e] Fox et al. (1980)

[f] Geokinetics (1979)

Table 8-2. Water quality parameters for some in-situ retort waters, mg/l (Continued).

	FIELD RETORTS		
	True in-situ Geokinetics, Utah[f]	True in-situ Rock Springs Site 9[d]	Modified in-situ Occidental Retort No. 6[e]
Alkalinity (as $CaCO_3$)	17,840	16,200	6,471
Biochemical oxygen demand (5-day)	-	740	-
Carbon, bicarbonate (as HCO_3)	17,175	15,940	-
, carbonate (as CO_3)	2,825	500	-
, inorganic	-	3,340	1,102
, organic	-	1,003	2,195
Chemical oxygen demand	3,680	8,100	7,146
Nitrogen, ammonia (as N)	1,270	3,125	970
ammonium (as N)	-	2,700	-
organic	-	148-630	-
Kjeldahl	-	3,420	-
pH	8.56	8.65	9.17
Phenols	11.6	60	-
Solids, total	-	14,210	-
Solids, dissolved	22,145	14,210	11,650
Sulfur, sulfate (as SO_4)	609	1,990	1,900

[a] Harding et al. (1978)

[b] Yen (1976)

[c] Jackson et al. (1978)

[d] Fox et al. (1978)

[e] Fox et al. (1980)

[f] Geokinetics (1979)

(Wildung, 1977; Pellizzari et al., 1979). The elemental composition of several in-situ retort waters summarized in Table 8-3 indicates that the major elements are As, Se, B, F, Ca, Fe, K, Mg, Na, S, and Cl.

Surface Retort Waters. These are waters produced by surface retorts such as Paraho and TOSCO. They are typically more concentrated than waters from in-situ retorts because water production is low (Table 8-1) by comparison. The elemental composition of several surface retort waters is summarized in Table 8-4 which indicates that the concentration of most elements falls within the limits of those reported for in-situ retort waters (Table 8-3). The organic carbon and pH are considerably higher in Paraho waters than in in-situ retort waters (Cotter, 1977).

Mine Waters

Oil shale in the Green River Formation is laced with groundwaters (Chapters 4 and 6). These waters must be removed before mining and retorting operations can be a carried out to prevent groundwater inflow into shafts, adits, mines, and rubblized retorts. Mine inflow during site preparation could impede construction progress and lead to safety problems; and, during retorting, it could extinguish the combustion front.

Thus, many in-situ sites will have to be dewatered prior to and during retorting. This may be achieved by dewatering the site with a well field, by internal drainage, or by a combination of the two methods. Aquifer dewatering lowers the water level in the surrounding aquifer system as shown in Figure 8-2 to reduce the possibility of groundwater entry into the retorting area. The resulting waters are referred to here as "dewatering effluents." Mine drainage removes groundwater that enters shafts, adits, and the mine by internal drainage; the resulting waters are referred to here as "mine drainage." This latter method has been proposed by Tipton and Kalmbach (August, 1977) for use at lease tract C-b and is conventionally used to dewater underground coal mines. Since aquifer dewatering using a well field is rarely perfect, mine drainage may also be used in combination with aquifer dewatering to remove any residual water.

Estimates of the discharge from dewatering of lease tracts C-a and C-b are summarized in Table 8-5. This table shows that rather large volumes of water must be handled in the dewatering operation and that the volumes are adequate to meet a significant fraction of projected water requirements (Chapter 5). However, state water rights may prevent extensive consumptive use of these waters due to possible adverse effects on other existing water rights (Chapter 5).

Table 8-3. Elemental composition of in-situ retort waters, mg/l.

	SIMULATED IN-SITU RETORTS					
	LETC 10-ton retort, Colorado[a]	LETC 10-ton retort, Colorado[b]	LETC 10-ton retort, Colorado[c]	LLL 125-kg retort, Colorado[c]	LETC controlled-state retort and LLL 125-kg and 6000 kg retorts, Colorado[d]	LETC 150-ton retort, Colorado[e]
Al	0.11-0.66	0.024	-	-	12.5-16.4	16.6
As	4.6-10	0.26	5.89	1.8	0.28-15.3	1.4
B	4.4-8.8	0.26	-	-	-	3.4
Ba	0.002-0.081	0.026	0.13	<0.3	0.097-0.57	0.17
Br	0.019-0.66	-	0.28	0.1	0.038-0.53	1.5
Ca	0.41-36	0.6-35	-	-	6-26	3.3
Cd	-	-	-	-	0.00069-0.054	-
Cl	-	0.023	-	-	11-1175	57
Co	0.002-0.32	0.37	0.65	0.023	0.031-0.64	0.31
Cr	0.011-0.037	0.012	<0.02	0.08	0.028-1.40	0.018
Cs	0.002-0.005	0.002	0.007	0.002	0.0056-0.066	-
Cu	0.007-0.016	0.003	-	-	<0.09-139	15.6
F	14-54	-	-	-	-	26
Fe	9.6-77	0.49	<1	14	1.21-27.2	4.7
Hg	<0.1-0.10	0.01	0.39	0.024	< 0.0005-0.196	-
I	0.003-0.33	0.003	-	-	0.13-0.25	0.11
K	3.4-33	8-70	-	-	<4-54	37
Li	0.004-0.75	-	-	-	-	-
Mg	5.4-87	3.2-350	-	-	<3.1-<39	24
Mn	0.042-0.14	0.023	-	-	0.0022-0.39	0.22
Mo	0.056-0.34	0.47	-	-	0.010-1.39	-
Na	8.3-130	54-1300	98	20	3.06-1780	655
Ni	0.37-2.6	0.26	-	-	0.24-10.7	0.014
P	0.58-9.2	0.36	-	-	-	8.5
Pb	0.062-0.37	0.01	-	-	<0.24-1.15	0.3
Rb	0.036-0.59	0.14	-	0.07	0.019-0.80	-
S	14-310	93	-	-	0.05%-0.85%	406
Sb	0.004-0.036	0.007	0.016	0.047	0.0033-1.10	-
Se	0.003-0.10	0.005	0.98	1.7	0.228-1.42	0.24
Si	1.7-11	48	-	-	-	25
Sr	0.003-0.48	0.093	0.15	-	0.10-0.91	-
Ti	0.64-21	0.2	-	-	<0.57-2.7	-
U	0.010-4.6	0.002	0.35	<0.03	0.0011-0.195	-
V	0.004-11	1.2	-	-	0.023-0.19	1.8
Zn	0.26-0.47	0.037	0.43	14.4	0.09-13.3	6.4

[a] Poulson et al. (1977)

[b] Jackson et al. (1975)

[c] Fruchter et al. (1978)

[d] Fox (1980)

[e] Fox et al. (1980)

[f] Geokinetics (1979)

[g] Fox et al. (1978)

Table 8-3. Elemental composition of in-situ retort waters, mg/l (Continued).

	FIELD IN-SITU RETORTS		
	True in-situ Geokinetics, Utah[f]	True in-situ Rock Springs Site 9 (Omega 9), Wyoming[g]	Modified in-situ Occidental Retort No. 6, Colorado[e]
Al	-	<0.03-19.1	-
As	2.55	1.0	0.12
B	-	27	17
Ba	0.54	0.71	-
Br	0.18	2.4	-
Ca	33	12	<0.1
Cd	0.084	0.0016	-
Cl[a]	3016	824	540
Co	0.56	0.030	-
Cr	0.078	0.02	0.1
Cs	-	0.0021	-
Cu	0.21	0.10	-
F	35	60	42
Fe	14.0	1.2	-
Hg	0.004	0.0003-0.021	-
I	-	0.59	-
K	121	47	92
Li	0.18	0.18-0.8	-
Mg	17	20	0.8
Mn	0.94	0.09	-
Mo	12	0.60	-
Na	9392	4333	3625
Ni	1.62	0.06	-
P	-	3.2	-
Pb	0.64	0.0045-0.02	-
Rb	-	0.16	-
S	-	0.20%	-
Sb	0.011	1.9	-
Se	0.22	0.21	0.048
Si	8.4	8	-
Sr	0.002	1.12	-
Ti	-	<0.02-2	-
U	-	0.55	-
V	0.43	0.12	-
Zn	0.095	0.31	-

[a] Poulson et al. (1977)

[b] Jackson et al. (1975)

[c] Fruchter et al. (1978)

[d] Fox (1980)

[e] Fox et al. (1980)

[f] Geokinetics (1979)

[g] Fox et al. (1978)

Table 8-4. Elemental composition of some surface retort waters, mg/l.

	Fischer Assay retort Colorado[a]	Fischer Assay retort Colorado[b]	TOSCO II retort Colorado[c]	Paraho Indirect (semi-works) retort Colorado[d]
Al	-	-	-	0.8
As	4.2	0.0	1.0	1.0
B	2.8	0.55	0.44	~5
Ba	-	-	0.09	2.0
Be	-	0.0	-	-
Br	-	-	-	0.009
Ca	1.4	-	-	>10
Cd	-	0.00-0.0	-	-
Cl	-	-	-	2.0
Co	-	0.002-0.005	0.005	<0.04
Cr	-	0.004	0.007	0.3
Cs	-	-	-	0.01
Cu	-	0.16	0.16	0.2
F	-	2.6-3.5	0.3	7
Fe	1.0	-	5.7	5.0
Ga	-	-	-	<0.02
Ge	-	-	-	<0.05
Hg	-	-	-	<0.01
K	20	-	-	>10
Li	-	-	0.006	1.0
Mg	-	-	-	>10
Mn	-	0.02	0.019	0.3
Mo	0.13	0.006	0.006	0.1
Na	43	-	-	>10
Ni	2.3	0.034	0.03	0.2
P	-	-	-	5.0
Pb	-	0.0	<0.002	0.2
S	-	-	-	>10
Sc	-	-	-	<0.05
Se	3.1	0.1	0.096	0.1
Si	-	-	-	>10
Sr	0.06	-	-	3.0
Ti	-	-	-	0.3
V	-	0.0	0.002	0.03
Zn	0.2	0.045	0.045	0.4
Zr	-	-	0.003	-

[a] Wildeman and Meglen (1978)

[b] Shendrikar and Faudel (1978)

[c] EPA (1978)

[d] Cotter et al. (1978a)

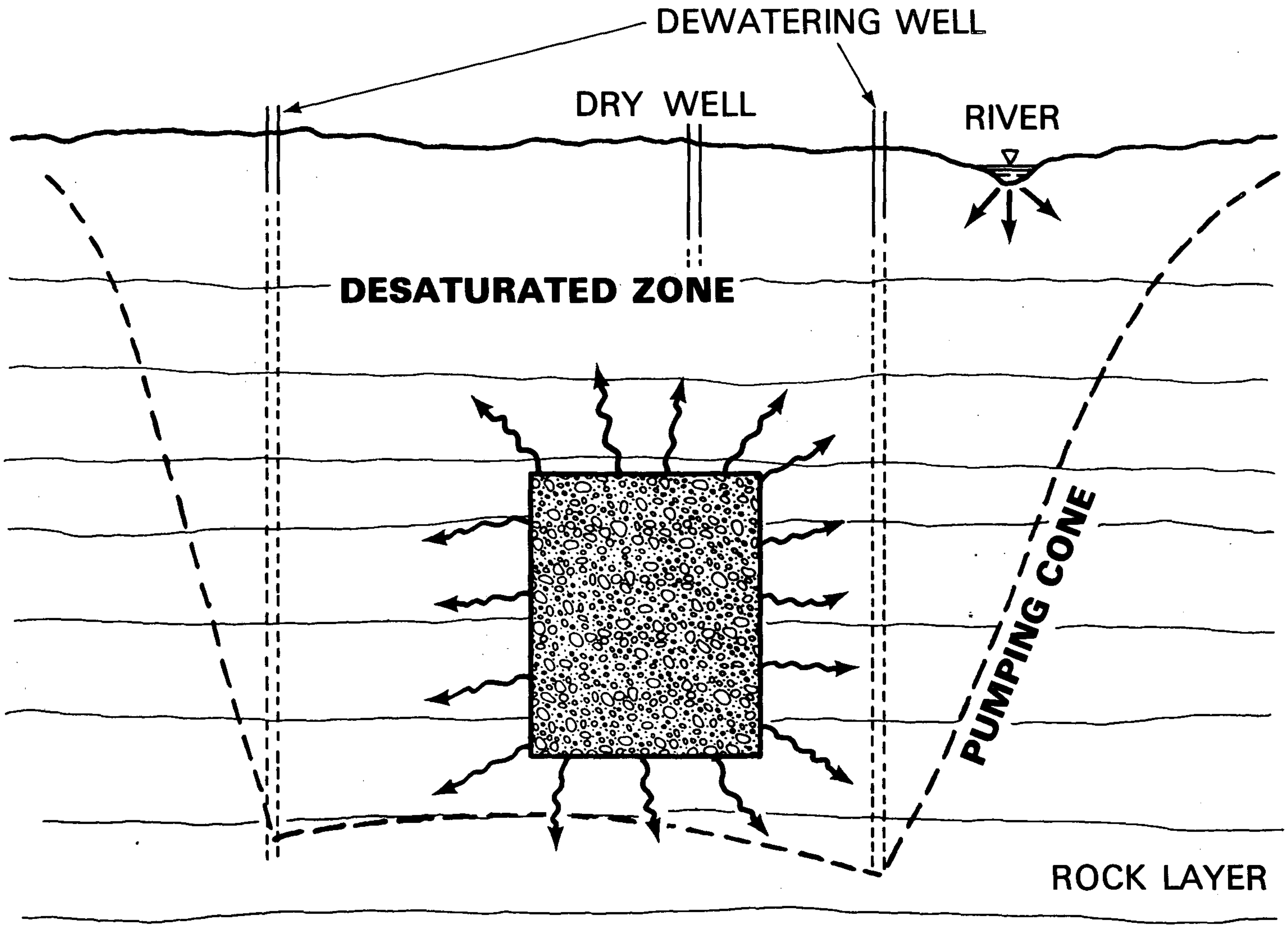

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Figure 8-2. The effect of aquifer dewatering on water table levels.

Table 8-5. Estimates of discharge from dewatering (gpm).

	Weeks et al., 1974	Tipton and Kalmbach, 1977
Tract C-a	3140-4040	--
Tract C-b	9000-12,600	500-400

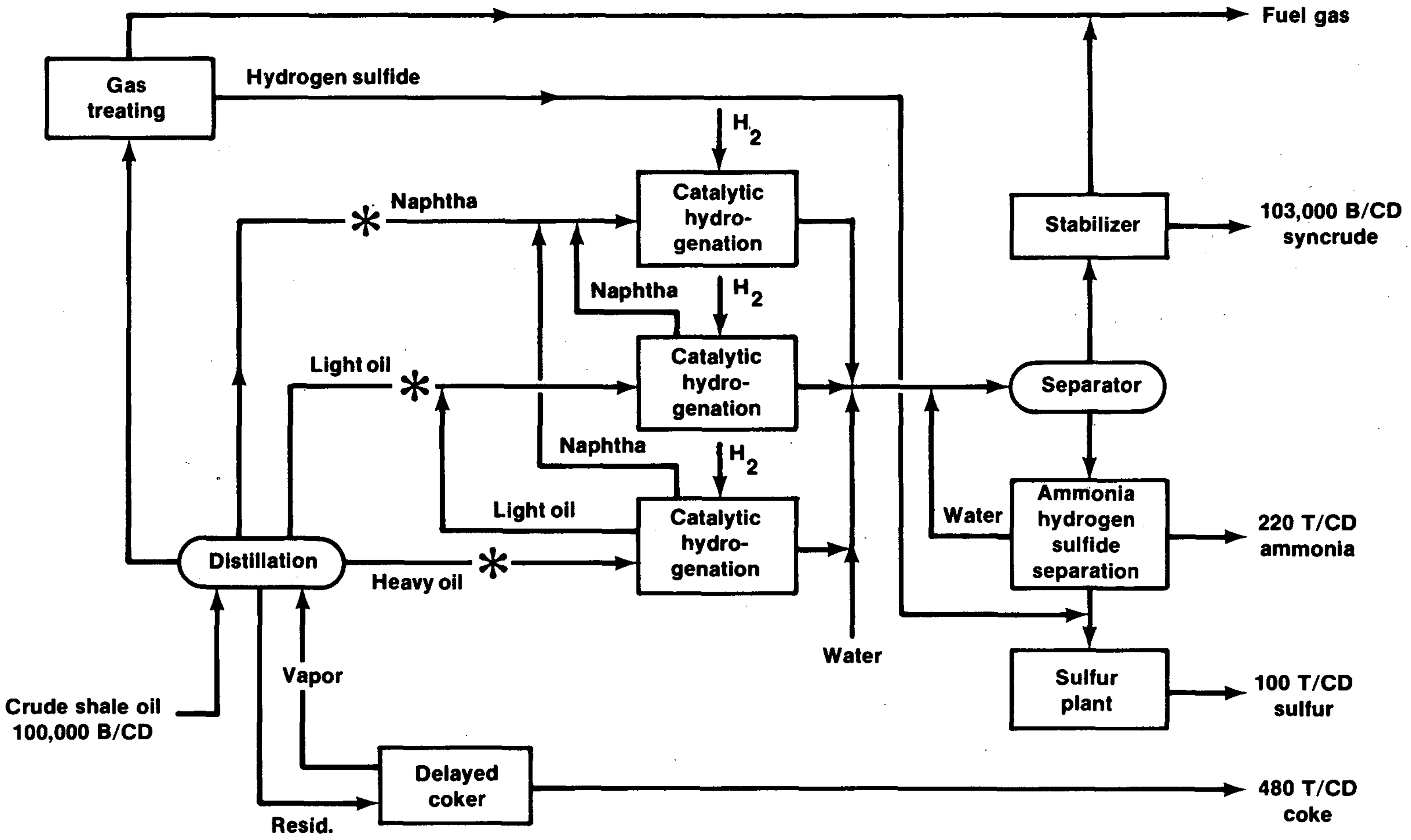
Dewatering effluents and mine drainage will have the same composition as water in the aquifers (Tables 4-15 and 4-16) except that mine drainage may also include wastes from drilling and mining operations and thus may contain higher suspended solids and oil and grease. Tables 4-15 and 4-16 indicate that mine waters from the upper and lower aquifers on tracts C-a and C-b will have an average TDS of 2,300 mg/l and range from 356 to 42,000 mg/l. Similarly, Weeks et al. (1974) indicated that TDS concentrations of up to 60,000 mg/l have been reported in the Piceance Creek Basin. These high concentrations would require special consideration for use and disposal if encountered in actual practice. The principal ions in these waters are CO_3, HCO_3, SO_4, Cl, Ca, Mg, K, Na, and Si. Most trace elements, with the exception of B and Fe, occur at concentrations that are less than 1 ppm. The quality of mine waters will vary over time as the relative contributions of the aquifers change. In addition, modifications in the underground flow regime due to extensive dewatering may bring waters with different compositions from other regions in the aquifer.

Pre-refining Effluents

Two levels of pre-refining are considered: basic and advanced. The basic pre-refining includes all steps necessary to reduce the pour point and the viscosity of the shale oil to a point where it can be economically transported. Advanced pre-refining includes additional processing steps to produce an oil compatible with conventional refineries.

The principal reason for developing the upgrading steps in two discrete steps is to allow for the possibility that one or more of the upgrading steps will be performed elsewhere in a less environmentally sensitive area. A specific illustration might be to reduce viscosity by distillation and coking and then perform the additional steps at another location where more water is available for processing and the overall environmental effect less. There might also be a secondary benefit in that conveyance costs of by-products, such as ammonia and sulfur, would be less since pipelining is one of the more economical ways to transport materials.

The basic pre-refining operation is assumed to include distillation and coking (Figure 8-3). Distillation separates the raw oil into hydrocarbon fractions by weight. The heaviest hydrocarbons are then passed to the coker in which the inorganic solids and the coke are removed. The coker distillate is combined with the lighter products from the distillation tower. At this point, the viscosity and pour point of the



* *Arsenic removal-process not specified.*

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Figure 8-3. Flow diagram of a shale oil upgrading process (Frost et al., 1976).

oil are greatly reduced. Many trace elements and inorganic solids that were in the raw oil become associated with the heavy coke and are thus removed from the oil.

The distilled and coked product still needs further processing before it is compatible with conventional petroleum crude oil. Nitrogen and sulfur compounds and arsenic are not removed by coking and distillation. Advanced pre-refining includes the additional processes intended to make the shale oil suitable for refinery or petrochemical plant feedstock.

There is assumed to be an arsenic removal stage prior to hydrogenation. The method of arsenic removal is not specified as there is little experience in removing arsenic from shale oil.

Catalytic hydrogenation consumes hydrogen gas under high pressure and temperature to react with the nitrogen and sulfur to form ammonia and hydrogen sulfide, respectively. These two latter products are then stripped from the oil and gas and processed separately for marketing as sulfur and ammonia gas. A sulfur recovery plant is included to convert hydrogen sulfide to elemental sulfur by controlled combustions and by reactions in catalytic beds.

Several process effluents produced by pre-refining operations are briefly described below.

- Distillation: Sour-water originates from condensed stripping steam; contains high levels of sulfides, ammonia, and some soluble hydrocarbons.
- Coking: Two waste streams originate from coking: the effluent from the overhead accumulator on the coker tower and cooling and wash water from the coker drum. These contain H_2S and NH_3 in addition to oils.
- Arsenic Removal: The waste stream may include caustics or solvents.
- Sulfur Removal: No liquid waste streams are generated by this process.
- Hydrotreating: The strength and quantity of waste waters generated by hydrotreating depends on the process used and the feedstock. Ammonia and sulfides are the main contaminants.

In addition to these waste streams, there are effluent streams associated with pre-refining operations that are not process specific, such as boiler and cooling tower blowdowns. Steam and cooling water are required for a number of plant uses in addition to upgrading. These include plant power production and steam for injection into the in-situ retort during the recovery operation. Since these two activities are plant-wide, they are discussed in subsequent sections.

Pre-refining waste streams cannot be individually characterized due to lack of data. Therefore an order of magnitude estimate of pollutant concentrations in wastewater effluents that might be expected from oil shale pre-refining operations is made from actual waste loadings from several petroleum refineries (EPA, 1973). As might be expected, these loads vary widely depending on such factors as plant age, plant operation, and process configuration. In a development document made for the effluent guideline program of the U. S. Environmental Protection Agency (EPA), an attempt was made to classify the data in broad groups, each representing a level of refining. The lowest group or category, called crude topping, was defined to include crude oil distillation and catalytic reforming. Catalytic reforming is normally used to convert low octane petroleum stocks to higher octane products. It is not the same as the catalytic hydrogenation assumed here. The classification of topping is sufficiently broad so that the data may be used to give an indication of wasteloads to be expected from the upgrading of shale oil. Typical raw waste loadings from topping plants are shown in Table 8-6.

Data are for plant effluents from API separators which are normally used in refineries to remove floatables and suspended solids from waste waters. In view of the two or three orders of magnitude between the 10 and 90 percent occurrences for some parameters, caution must be exercised when using values from the table to characterize waste streams.

Cooling Tower Blowdown

Cooling, or the dissipation of heat, will be used primarily for on-site power production and during pre-refining in distillation, coking, and hydrogenation. Cooling is usually accomplished by evaporating water. A simplified schematic of a cooling water system is shown in Figure 8-4. The cooling occurs in the cooling tower which dissipates heat by evaporating a portion of the circulating water. Recirculating cooling towers, in which the water is cycled through a cooling loop more than once, will probably be used by an oil shale industry because water supplies are limited. Each time the water is circulated, some of it is evaporated and some is discharged to the atmosphere (drift). These losses cause the dissolved solids in the circulating water to increase. Since excessive levels of certain constituents cause operating problems and equipment failure, the level of dissolved solids is controlled by discharging a portion of the circulating water (blowdown) and adding an amount of fresh water (makeup) equal to the amount removed by evaporation, drift, and blowdown. Blowdown, then, is the constant or intermittent discharge of a portion of the circulating water in a closed cooling system to prevent the buildup of high concentrations of dissolved solids. The quantity of blowdown is a function of the makeup water quality, evaporation and drift rates, and the number of cycles of concentration (i.e., the number of times the concentration of any constituent present in the circulating water is increased from its original value in the makeup water). The composition of cooling tower blowdown, on the other hand, depends primarily on the number of cycles of concentration and the type of internal chemical treatment used. The number of cycles of concentration that can be obtained from a water depends on the chemical composition of the makeup water which can be controlled by external treatment. In addition, internal treatment is used to control corrosion, scale, and biological growth. This typically consists of the use of chemical inhibitors to control corrosion, acid to control scale, and chlorine to control biological growth.

Table 8-6. Topping subcategory raw waste load effluent from refinery API separator.[a]

Parameter	Probability (percent) of raw waste loads ≤ values shown; waste loads in net kg/1000 m^3 (lb/1000 bbl) of feedstock throughput					
	10%		50% (median)		90%	
BOD_5	0.26	(0.09)	7.1	(2.5)	286	(100)
COD	0.72	(0.25)	24.0	(8.4)	858	(300)
TOC	0.086	(0.03)	4.9	(1.7)	269	(98)
TSS	0.30	(0.105)	6.6	(2.3)	123	(43)
Oils	0.97	(0.34)	5.1	(1.8)	45.8	(16)
Phenols[b]	0.001	(0.00035)	0.029	(0.01)	0.92	(0.32)
Ammonia	0.18	(0.064)	1.43	(0.5)	11.4	(4.0)
Sulfides	0.0037	(0.0013)	1.57	(0.55)	7.2	(2.5)

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[a] Topping includes distillation and catalytic reforming.

[b] Values may be high for shale oil refining operations because phenol levels in raw shale oil are low.

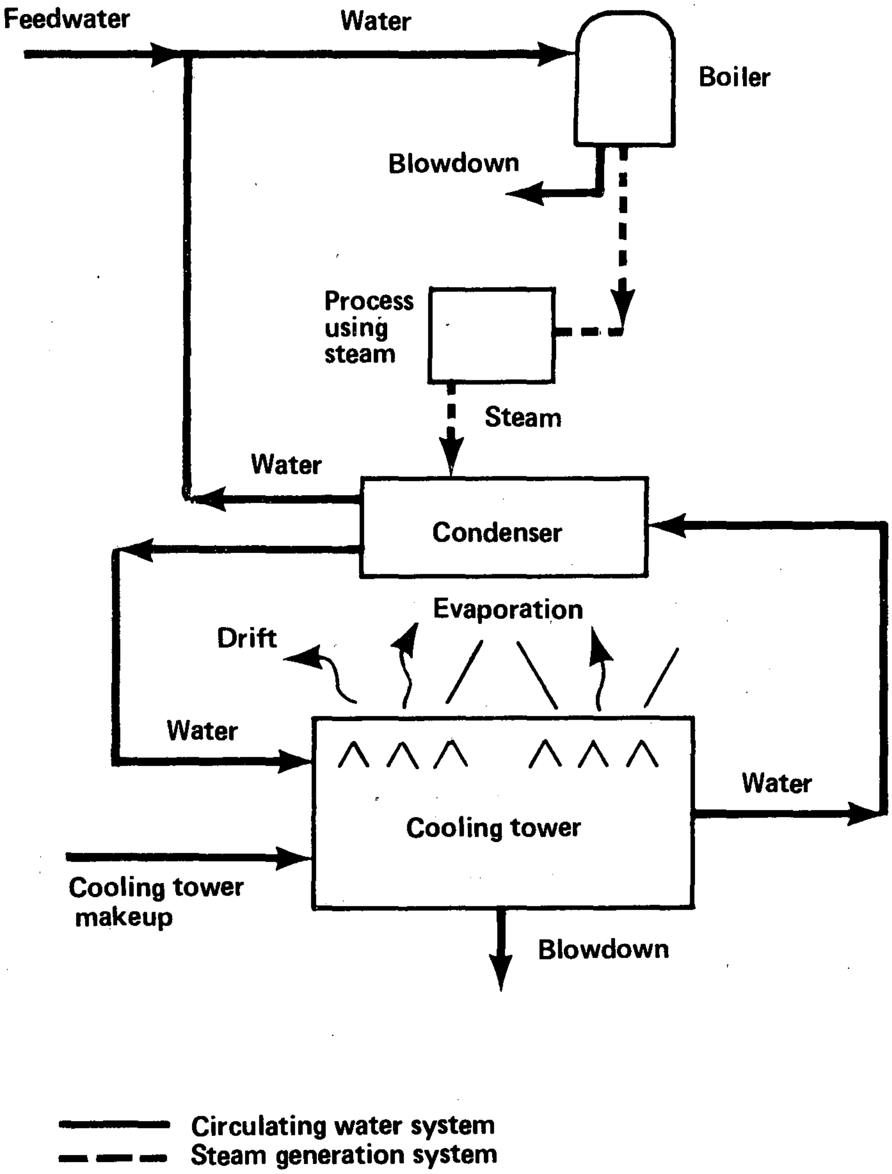

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Figure 8-4. Schematic of typical cooling water system.

Estimated composition of cooling tower blowdown for an in-situ oil shale plant is summarized in Table 8-7. The table shows a typical range for the composition of cooling tower blowdown. The range is based on data collected in an EPA survey of 12 steam electric generating units operating on fresh water (EPA, 1974). That range is compared with the estimated composition of cooling tower blowdown for an in-situ oil shale industry using local surface waters, dewatering effluents, and retort water as cooling tower makeup and operating at three cycles of concentration. These data indicate that cooling tower blowdown may have moderately high levels of dissolved solids and lower levels of suspended solids and chemical and biochemical oxygen-demanding substances. The principal ions present are chloride, sodium, sulfate, calcium, and magnesium.

Boiler Blowdown

Boilers are used to convert water into steam for direct use in processing, for heating, and to drive steam turbines. This process generates a waste stream referred to as boiler blowdown. Plant steam is consumed in the production of hydrogen and is used in steam stripping of ammonia and hydrogen sulfide, in hydrocracking and distillation, and for steam injection into in-situ retorts.

Steam is generated in boilers that operate at a wide range of pressures and under varying conditions. Steam for an in-situ oil shale plant, will be primarily used in retorting and pre-refining using low and medium-pressure industrial boilers. A typical schematic of a steam generation system is shown in Figure 8-4. Steam is generated in a boiler by transferring heat produced from the combustion of fuel to water by radiation and convection. A portion of the steam may be consumed during use and the condensate, minus any losses, returned to the boiler. Salts present in the feedwater are left behind when the water is converted to steam. These salts together with chemicals added to control scale and corrosion, are periodically removed from the system. The resulting waste stream is boiler blowdown.

The composition of boiler blowdown depends primarily on the type of boiler, blowdown frequency, and the type of internal chemical treatment used. Boiler pressure largely determines the amount of dissolved solids that can be tolerated, with higher pressure boilers requiring very low solid levels ($\leqslant 0.5$ mg/l). The lower the dissolved solids in the feedwater and the higher the frequency of blowdown, the lower the dissolved solids in the blowdown stream. Internal conditioning chemicals affect the composition of blowdown:

- Sodium phosphate ($NaPO_3$) or chelating agents such as Na_4-EDTA, are added to control scale. Both contribute sodium to boiler blowdown.
- Caustic, such as lime or soda, is added to prevent corrosion. This gives the blowdown a characteristically high pH.
- Sodium sulfite (Na_2SO_4) or hydrazine (N_2H_4) are added to remove oxygen; sodium sulfite contributes sulfate and dissolved solids to blowdown and hydrazine adds ammonia and nitrogen.

Table 8-7. Composition of cooling tower blowdown for three cycles of concentration for makeup water from untreated local surface waters and local groundwaters.

Parameter	Average concentration,[a] survey of 11 electric generating stations		Local surface water[b]		Local groundwater[c]	
	Minimum	Maximum	Minimum	Maximum	Minimum	Maximum
Alkalinity ($CaCO_3$)	10	560	520	710	160	13,500
Ammonia ($NH_3 \cdot N$)	0.05	10	0.03	0.6	0.06	600
BOD	0	95	-	-	-	-
Calcium (Ca)			85	300	2	780
Chloride (Cl)	10	1400	25	420	<0.3	29,400
COD	0	435	0	110	<0.1	1200
Hardness ($CaCO_3$)	85	1700	330	1020	60	3330
Magnesium (Mg)	2	160	30	100	5	600
Nitrate (NO_3-N)	0.1	15	0.0	1.1	<0.03	21
Silica (SiO_2)	-	-	30	60	0.3	180
Solids, dissolved	150	4100	610	2140	1070	126,000
Sulfate (SO_4)	10	1100	150	960	6	2700
Sodium	15	230	40	450	130	51,000

[a] EPA, 1974

[b] Based on White River near Watson, Table 4-2

[c] Based on upper and lower aquifers, tracts C-a and C-b, Tables 4-15 and 4-16

Estimated composition of boiler blowdown is shown in Table 8-8. These values are ranges for medium-pressure boiler blowdown as reported by EPA (1974). They assume that sodium phosphate is used to control scale and sodium sulfite to remove oxygen. These data indicate that boiler blowdown has a high pH and low concentrations of suspended and dissolved solids. Biochemical and chemical oxygen demand is characteristically low. The predominant ions are sulfate, sodium, and chloride. The high quality of this water, compared with other effluents, suggests that it could be upgraded at minimal expense for use elsewhere in the plant.

Storm Water Runoff

The compositon and volume of storm water runoff from surface facilities, parking lots and on-site roads, and transport facilities depend on the nature and area of the surface. The volume of water involved depends on the physical layout of the plant and its location. Annual average rainfall for the oil shale region is from 12 to 22 in. Developed land area for the in-situ plants may range from 125 acres (Ashland, 1977) to more than 200 acres (Nevens et al., 1979). Since the proportion of pervious and impervious surfaces is not known, a runoff factor of 50 percent is assumed. This implies that from 30 to about 120 gpm of storm drainge must be handled each year. The average composition of the water is shown in Table 8-9.

The potential surface water effects from diffuse sources other than surface disposal piles (Chapter 6) can be related to short-term and long-term activities. Short-term effects are due to activities occurring during the plant construction. Long-term effects are derived from activities taking place during plant operation. The major short-term concern is sediment loading in the runoff since sediment loss from newly exposed soil surfaces can be extensive.

Estimation of quantities of sediment in runoff is site-specific. Factors that significantly affect sediment yield from a particular site are:

- Specific rainfall intensities and frequencies.
- Soil characteristics such as permeability and composition.
- Drainage basin slope.
- Distance to major drainage channels.

The following estimate of sediment yield is based on average rainfall intensities with no soil loss abatement measures included, such as traps and catchment basins.

Table 8-8. Composition of boiler blowdown.

Parameter	Boiler breakdown composition,[a] mg/l
Alkalinity ($CaCO_3$)	25-127
Ammonia (NH_3 as N)	0-2
Biochemical oxygen demand (BOD_5)	0-6
Chemical oxygen demand (COD)	0-25
Chloride (Cl)	3-466
Hardness ($CaCO_3$)	0-348
pH	10-11
Phosphorus (as P)	0.02-30
Solids, suspended	0-22
Solids, dissolved	100-560
Sodium	58-110
Sulfate	47-218
Zinc	0-1.2

[a] Ranges from plant data sheets for boiler blowdown for TDS falling in range of 100-600 mg/l (medium-pressure boilers) for steam electric power generating plants (EPA, 1974).

Table 8-9. Annual average composition of surface runoff from pre-refining and retorting areas of an in-situ oil shale plant.

Parameter	Annual average[a] mg/l
Biochemical oxygen demand (BOD_5)	175
Chemical oxygen demand (COD)	1280
Chromium	5
Copper	1
Cadmium	0.05
Coliform, total (No/liter)	12×10^6
Coliform, fecal (No/liter)	3×10^6
Iron (Fe)	420
Manganese	10
Nickel	0.5
Nitrate	5
Oil and grease	high
Organic nitrogen	20
Phosphorus	20
Strontium	0.5
Zinc	5
Volume	30-120 gpm

[a] Based on annual average rainfall of 16 in. and loading factors for heavy industrial areas (Amy et al., 1974).

Leopold (1968) reports that sediment yield from an area under construction can be substantially higher than that occurring prior to construction. For small areas (one acre), sediment yield during construction could be 20,000 to 40,000 times the amount eroded prior to construction. Using Leopold's data and assuming a site alteration of 200 acres (all surface facilities except disposal sites and project access road land requirements), the sediment yield is about 2000 tons per year. In comparison, 25,000 tons of natural sediment are discharged each year from the Piceance Creek, as measured at a gage below Ryan Gulch. Thus, sediment from construction activities could be eight to ten percent of the total discharge from the Basin. It is important to note than an analysis of this nature does not take into account any of the site-specific factors affecting the sediment yield, such as slope or soil characteristics, and that it does not include sediment production from surface spent shale disposal and long-term erosion of the piles.

Short-term sediment yield from the site-access construction is more difficult to estimate since variations in sediment-yield parameters may occur along the length of the highway route. If extensive cuts and fills are required, considerable areas of unprotected soils or relatively steep slopes would be exposed, and sediment yields in runoff would be high.

Long-term effects are associated with constituents other than suspended solids found in runoff from site alterations. These include toxicants, organics, and salts. In general, the types and amounts reflect specific activities at a plant. There will undoubtedly be spills from all stages of the recovery and upgrading process. In a well-managed operation, these will be minimized but not completely avoided. There will also be additional loadings from vehicular and other sources common to most industrial activities. An estimate of the toxicant and other loadings from these latter sources can be made by using a method reported by Amy et al. (1974). Factors are presented which cite total amounts of solids produced per curb mile per day for various activities. For a heavy industrial land-use classification, the equivalent curb mile per street mile per acre is 0.40 miles. The total solids loading per square mile is given as 200 pounds of dry solids per curb mile per day. These factors, applied to the 200 acres of the site development, result in about 3000 tons of dry solids per year.

Domestic Wastes Production

Water is supplied for use by on-site personnel for drinking, washing, and conveying wastes. Approximately 10 percent of the supplied water is consumed; the balance, referred to as raw domestic sewage, is an effluent which must be disposed of.

The amount of domestic sewage produced depends on the number of on-site employees which, in turn, depends on the specific in-situ process selected. Sewage production is determined from per capita water usage. For industrial applications, this is assumed to be 20 gallons per person per day. The industrial developers of tracts C-a and C-b presently envision 42 and 67 employees per 1000 barrels per day of production, respectively. For the 50,000 bpd plants assumed in this analysis (Table 3-6), this corresponds to 2100 and 3350 on-site personnel at tracts C-a and C-b. The volume of raw domestic sewage produced by this worker population would be 26 and 52 gpm, respectively.

The composition of domestic wastes from an oil shale plant will be similar to municipal sewage with the exception that laundry and kitchen wastes will not be included. The composition of this waste depends on the original water supply, the treatment the original water supply receives, and the manner in which the water is used. Typical composition of medium strength municipal sewage is shown in Table 8-10. In this table, some constituents are reported as "increment added." These are the parameters that are present in the original supply and that are also added to the water during use. Since the level of the parameter depends on the composition of the raw water supply and how it is used, the amount added during use is reported. The "increment added" may be added to the concentration in the waste. Other parameters, such as organic carbon, biochemical oxygen demand, chemical oxygen demand, and grease are largely absent in the original water supply and are added during use. These parameters do not vary widely for domestic wastes and are reported as single values in Table 8-10.

DISPOSAL OPTIONS

The effluents produced at an oil shale plant may be discharged to surface or ground waters or reused on site. Most of these options require treatment to meet water quality standards and criteria for effluent limitations (Chapter 5). This section discusses, in general terms, the treatment requirements for reuse and discharge into receiving waters.

General Treatment Considerations

Treatment is required for conventional raw water supplies and for effluents that are to be reused or discharged into receiving waters. The type and degree of treatment required depends on the water's characteristics and its use. Table 8-11 summarizes available water supplies, potential uses, disposal options, and factors that govern the quality required for each option. For example, available water supplies include local surface waters, dewatering effluents, retort water, and various processing effluents. The type and degree of treatment that each of these potential supplies requires depends on how it will be used. If the water is used for cooling tower makeup or boiler feedwater, a high quality water is necessary. This means that extensive treatment will be required for poor quality supplies such as retort water while minimal treatment will be required for high quality supplies such as local surface waters. If, on the other hand, the water is to be used for dust control or spent shale disposal, a poor quality water is adequate and many of the available supplies, such as dewatering effluents, may be used directly without treatment.

Three factors will largely control water disposal decisions for an oil shale plant. These are:

- Western shale deposits are located in the Colorado River Basin where water is a limited resource and water supply and water quality have long been issues of national and international importance. Thus, water impacts are inextricably linked with decisions surrounding the use of the Colorado River.

Table 8-10. Composition of domestic sewage.

Parameter	Composition, mg/l: Medium strength domestic sewage[a]	Composition, mg/l: Increment added[b]
Alkalinity ($CaCO_3$)		100-150
Biochemical oxygen demand (BOD_5)	200	
Boron		0.1-0.4
Calcium		15-40
Carbon, total organic	200	
Chemical oxygen demand	500	
Chloride		20-50
Grease	100	
Magnesium		15-40
Nitrogen		
Organic	15	
Ammonia	25	
Nitrates	0	
Nitrites	0	
Phosphorus (as P)		
Organic	3	
Inorganic	7	
Potassium		7-15
Solids		
Dissolved		100-300
Suspended	200	

[a] Source: Metcalf and Eddy, 1972

[b] Increment added during use; value in effluent would be value in treated raw water before use plus increment added.

Table 8-11. Water supplies, disposal options, and governing water quality standards.

Potential water supplies	Diposal option	Factors that determine requisite quality
	<u>Use</u>	
Retort water	Backwash water	Varies with medium/resin used
Gas condensate	Domestic use	EPA 1975 Drinking Water Standards
Dewatering effluents		
	Mining	Public health criteria
Mine Water		
Local surface waters	Retorting	Application, i.e., for steam production, etc.
Local groundwater		
	Spent shale disposal	Public health criteria
Domestic sewage		
Storm water runoff	Revegetation	Irrigation water quality criteria
Cooling tower blowdown		
	Boiler feedwater	Boiler feedwater requirements
Boiler blowdown		
	Cooling tower makeup	Cooling water makeup requirements
Filter and ion exchange backwash water		
	Pre-refining	Refinery process water requirements
Pre-refining process effluents		
	<u>Discharge</u>	
	Surface water discharge	Water quality standards and effluent limitations
	Groundwater discharge	Water quality standards and effluent limitations
	Evaporation	Public health criteria

- Oil shale processing produces a large volume of poor quality water (retort water, gas condensate, dewatering effluents); the volume of water produced is sufficient to meet some of the in-plant water needs.

- Existing water quality standards and effluent limitations require that a high degree of treatment be employed before any waste can be discharged into receiving waters. Additional future limitations may be imposed.

These factors suggest that an oil shale industry will reuse most of the effluents produced during processing and evaporate any residuals. This will not only partially solve the water availability problem, but will also be economically attractive because treatment for discharge may be more costly than treatment for reuse.

Table 8-12 summarizes estimated treatment requirements for reuse and disposal of waters from various sources. Water supply sources are listed at the top of the chart. Symbols in the body of the chart refer qualitatively to the amount of treatment required based on water quality standards and criteria for surface water discharge, groundwater discharge, and reuse.

Table 8-12 summarizes the suitability of each supply for possible intended uses. Local surface waters are the highest quality supply available. However, limited water supplies (see Chapter 4) and the large volume of processing effluents which must be disposed of provides strong motivation for using these lower quality supplies to meet a portion of water requirements. Table 8-12 indicates that boiler blowdown, gas condensate, and storm water runoff are suitable for most uses with minimal to moderate treatment. Retort water, domestic sewage, and pre-refining effluents could be upgraded for reuse with a high degree of treatment. However, the treatment required for reuse and disposal to surface or ground waters is similar. Evaporation on a large scale is unlikely due to large land requirements. Therefore, even though extensive treatment may be required to upgrade retort waters, domestic sewage, and other process waters, it may be economically attractive.

All of the effluents listed in Table 8-12 except retort water are normally found in other types of industrial operations and can probably be treated with existing control technology. The gas condensate is also unique; however, there are presently no data with which to assess its treatability. Treatment of retort water, because of its complex chemical composition, is a difficult problem. Considerable research has been conducted on the treatability of retort water, but only limited success has been obtained. Many unit processes conventionally used to treat industrial wastes--including biological oxidation, carbon adsorption, and dissolved air flotation--appear to have limited applicability for the treatment of retort waters due to toxicity, fouling, and other problems.

Because of the unique nature of retort water and the problems that have been encountered in treating it, a review of literature from this field is appropriate.

Table 8-12. Treatment requirements for reuse and disposal.

		Potential Water Sources								
	Uses	Local surface waters	Mine waters	Retort water	Raw domestic sewage	Cooling tower blowdown	Boiler blowdown	Storm water runoff	Prerefining process effluents	Gas condensate
Discharge	Surface water discharge	N/A	●	●	◒	●	◒	0	●	◒
	Ground water discharge	N/A	●	●	◒	●	0	0	●	0
	Land treatment	N/A	0	●	0	0	0	0	0	0
	Evaporation	N/A	0	◒	0	0	0	0	0	0
Reuse	Cooling water (3 cycles)	0	◒	●	●	●	0	0	●	◒
	Boiler feedwater (medium-pressure boilers)	0	●	●	●	●	●	0	●	●
	Domestic water	0	0	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	Prerefining process water	0	◒	●	◒	●	◒	0	◒	0
	Revegetation	0	0	●	◒	0	0	0	0	0
	Mining	0	0	●	●	0	0	0	0	0
	Spent shale disposal	0	0	◒	◒	0	0	0	0	0

● Extensive treatment
◒ Modest treatment
0 Minimal or no treatment
N/A not applicable or not recommended

Retort Water Treatment

Retort water would be a valuable resource for the arid regions in which oil shale deposits are located, provided that effective and economical treatment methods can be found. These waters have high concentrations of organic carbon, inorganic carbon, ammonia, and salinity. These constituents would have to be removed to varying degrees for most potential uses and disposal options. Certain additional constituents, including boron, fluoride, and arsenic, may have to be removed for some uses. Additionally, the composition of water from a single retort will vary significantly during a run; elevated and fluctuating water temperatures may be encountered; and the treatment processes must operate efficiently under severe weather conditions. Many conventional unit processes have been laboratory tested on a range of retort waters with varying degrees of success. Some of this work is summarized here as a reference for evaluating the treatability of retort water.

Hubbard (1971) studied a physical/chemical treatment system for retort water that included lime addition, carbon adsorption, and ion exchange. Hubbard pretreated samples of raw retort water by filtration through filter paper to remove suspended material. Lime was added to remove ammonia and some of the soluble organics; carbon adsorption was employed to remove the remaining soluble organics; and ion exchange was used to remove soluble inorganics. Using this physical/chemical system, Hubbard succeeded in reducing the ammonia concentration from 4,800 mg/l to 120 mg/l and the TDS concentration from 45,000 mg/l to about 1,900 mg/l. Removal of organics was not reported. The large quantities of sludge produced by lime treatment makes this process ineffective for large-scale application.

Harding et al. (1978) conducted preliminary treatability studies on 150-ton retort water which indicated that several processes hold promise for application to this water. Thermal stripping demonstrated capability for reducing the concentrations of both NH_3 and CO_2. A weak-acid cation exchange system was also effective in removing these two constituents. Activated carbon showed reasonably good potential for removing the organic components and reduced the COD by 74 percent at a theoretical detention time of 57.5 minutes. However, bleeding was experienced. Adsorbent resins XAD-2, XAD-4, XAD-7, and XAD-8 were effective in removing some of the COD.

Harding et al. (1977) investigated the suitability of three weak-acid cation exchange resins for the removal of ammonia and alkalinity from retort water. Results indicate that essentially complete removal of NH_4 and HCO_3 can be obtained at practical rates. Economic studies indicated that regeneration with CO_2, rather than a strong acid, was economically more attractive.

Yen has studied the use of biological processes for the treatment of retort water (1975a-d, 1976a-c). Much of Yen's research on biological processes was devoted to attempts to isolate specific strains of bacteria that are able to biodegrade the soluble organics present in retort water. Yen noted that some components of retort water were inhibitory to bacterial growth. Inhibition was significant when the COD of diluted retort water was equal to or greater than 400 mg/l.

Yen assessed the activated sludge process for the treatment of retort water. In laboratory studies using two different seeds, the COD of diluted retort water was decreased by about 50 percent. However, Yen was unable to achieve a greater COD removal, presumably due to the presence of organic components that are resistant to biodegradation.

Yen also investigated the anaerobic fermentation of retort water. In laboratory studies using a digested sludge seed from a municipal treatment plant, the COD of diluted retort water was reduced from 3000 mg/l to 2500 mg/l over a 30-day period. In subsequent experiments, the COD of diluted retort water was reduced from 500 mg/l to 400 mg/l over a 55-day period.

Ossio and Fox (1980) used anaerobic fermentation to remove 89 to 90 percent of the BOD_5 and 65 to 70 percent of the COD from pretreated 150-ton retort water. Pretreatment included ammonia reduction to 360 mg-N/l, pH adjustment to 7.0, sulfide control, and the addition of the nutrients calcium, magnesium, and phosphorus. The high hydraulic mean cell residence time required in these experiments, 50 days, would limit the use of this process for large-scale application.

In addition to conventional biological processes, Wen and Yen (1977) evaluated electrolytic oxidation for the reduction of soluble organics. In electrolytic-oxidation, organic material is oxidized by oxygen produced at the anode of an electrochemical cell containing retort water. The reason for using this process was to determine if long-chain organic components in retort water could be broken down into smaller fragments that could be more readily biodegraded in a subsequent biological treatment process.

Wen and Yen's experiments (1977) with electrolytic oxidation have indicated that over 40 percent of the total solid residue and 80 percent of the benzene-soluble compounds present in retort water are removed. In addition, a 65 percent reduction in COD and 92 percent reduction in color intensity were obtained. Recovery of ammonia and carbon dioxide for use in the synthesis of other products may provide an economic basis for the process.

Mercer (1979) and others at Battelle are conducting studies of steam stripping, anaerobic and aerobic biological treatment, and carbon adsorption. These studies, to date, have indicated that steam stripping is viable and that biological treatment of some waters may be feasible if powdered activated carbon is added to the reactor and if long cell residence times are used.

In Mercer's work, steam stripping of Geokinetics retort water (initial NH_3 = 3,000 mg/l) removed 90 percent of the ammonia with recycle of condensate at a boiloff rate of 4.5 percent and over 99 percent of the ammonia without recycle at a boiloff rate of 5.3 percent. Some fouling of the packing was observed. Anaerobic fermentation was used to successfully treat retort water by adding 2,000 mg/l of powdered activated carbon. Batch activated sludge treatment removed 45 percent and 65 percent of the TOC and COD, respectively, from a mixture of activated-carbon-treated retort water and untreated-steam-stripped retort water. Addition of 300 mg/l activated carbon increased these removals to 55 percent and 75 percent, respectively. COD reduction by activated carbon columns was relatively poor due to high concentrations of thiosulfate which is not adsorbed by activated carbon; results were favorable when biologically treated retort water was passed through the columns.

Fox and Jackson (1980) investigated the ability of three surface spent shales and three in-situ spent shales to modify the composition of four in-situ retort waters. Their studies demonstrated that spent shales are effective in removing the inorganic carbon, organic carbon, and electrical conductivity and elevating the pH of retort waters. They proposed that packed columns of spent shale be placed ahead of an air stripping unit to elevate the pH for ammonia removal and to reduce inorganic carbon, organic carbon, and salinity loads on downstream treatment units.

These studies indicate that major emphasis has been placed on the removal of dissolved gases and organics from retort waters. Little or no work has been conducted on the removal of oil and grease, salinity, and trace organics and inorganics. The work completed to date indicates that dissolved gases may be removed by steam stripping, weak-acid cation exchange resins, or spent shale treatment. No definitive work has been performed on the removal of organics from retort waters, and work completed to date suggests that biological oxidation may be unsuitable due to toxicity problems, technically and economically prohibitive pretreatment requirements, and severe temperature conditions present in the oil shale region. Because of the great uncertainty surrounding the reduction of organics, which is required for most of the uses shown in Table 8-12, retort water treatment may be technically and economically unfeasible for high quality water uses, such as boiler feedwater or cooling tower makeup.

Surface Water Discharge

The discharge of waste streams into surface waters is governed by water quality standards and effluent limitations. These were discussed in Chapter 5 and differ for each state. The water quality standards governing discharges in Colorado, Utah, and Wyoming were summarized in Tables 5-5, 5-7, and 5-8 and are abstracted in Table 8-13 for specific streams adjacent to oil shale lands that may be commercialized at an early date. In addition to these water quality standards, effluent limitations exist for some of the waste streams from an oil shale plant as follows:

- Colorado has general effluent limitations which apply to all industrial discharges into Colorado's receiving waters. These were summarized in Table 5-6.

- Domestic wastes must conform to the municipal effluent limitations set under Public Law 92-500. These were summarized in Table 5-4 and are identical with Colorado's general limitations for BOD, suspended solids, and pH.

- Pre-refining effluents, including process streams and plant storm runoff, may fall into one of the subcategories of EPA's Effluent Guidelines and Standards for Petroleum Refining. This is open to interpretation and the regulations as written may have to be revised to accommodate refining of shale oil.

The degree of treatment required to meet these existing water quality standards and effluent limitations is summarized in Table 8-12. The indicated treatment is largely controlled by two aspects of the existing regulations--the Colorado River salinity policy and dissolved oxygen standards. In addition, all three states have adopted general standards on toxicity, taste, odor, and solids which could result in additional specific limitations before discharge permits are granted. The possible additional limitations are summarized in the column "Controlling Water Quality Criteria" of Table 8-13. The impact of these three regulatory considerations on required treatment summarized in Table 8-12 is addressed below.

- Salinity

  The salinity standards of PL 92-500 encourage reuse of all effluents to the maxium extent possible, and requires that any effluent discharged into feeder streams of the Colorado River cause no increase in salinity relative to 1972 conditions. This means that the salinity of discharged effluents must be less than or equal to the average annual flow-weighted river salinity. Average annual river salinities in the vicinity of the oil shale tracts range from 415 mg/l at White River near Watson to 2,369 mg/l along the Yellow Creek. The salinities of effluents are considerably higher, ranging up to 42,000 mg/l for dewatering effluent from the lower aquifer on Tract C-b. Therefore, demineralization of all waste streams will be required prior to surface water discharge.

- Dissolved Oxygen

  Minimum dissolved oxygen levels are set on all receiving waters to protect aquatic life. Effluent discharges can reduce stream dissolved oxygen by initial mixing and by biological or chemical oxidation. Typically, this type of standard is met by reducing the BOD and COD of the effluent such that, on discharge, the existing water quality standards are not violated. However, all of the oil shale tracts are drained by small streams. The flow in these streams may be less than the effluent discharge. Since the dissolved oxygen in the waste stream is typically near zero, this means that the dissolved oxygen in the river at the point of discharge may drop below the minimum allowable levels due to mixing alone. Achievable reductions in BOD and COD may not be adequate to meet DO standards. Therefore, the effluents may have to be aerated before discharge or transported to a stream with a greater assimilative capacity. In effect, a tradeoff exists between the cost to aerate and the length of pipeline that can be built to transport the wastes to a more favorable discharge location.

Table 8-13. Water quality standards and criteria governing discharges to surface water in Colorado and Utah.

Parameter	Colorado[a]		Utah[b]	Controlling Water Quality Criteria[c]
	Piceance Creek Parachute Creek	Colorado River (1) White River (2)	White River (3) Green River (4) Colorado River (5)	D = domestic water L = livestock watering I = irrigation A = aquatic life/wild life
Aluminum				5 (L,I)
Ammonia				0.02 (A)
Arsenic			0.05	0.1 (D,I)
Barium			1.0	1 (D)
Beryllium				0.1 (I)
Biochemical Oxygen Demand (5 day)			<5	
Boron				0.75 (I)
Cadmium			0.010	0.0004 (A)
Carbon alcohol extract				1.5 (D)
Carbon-chloroform extract				0.3 (D)
Chloride				0.003 (A)
Chromium			0.05	0.05 (D,A)
Coliform, Total			5000/100 ml	
Coliform, Fecal	1000/100 ml	1000/100 ml	2000/100 ml	
Color	Free from	Free from	Free from	
Copper				0.2 (I)
Cyanide				0.005 (A)
Dissolved Oxygen	6	5	>5.5	
Fluoride			1.4-2.4	1 (I)
Foaming Agents				0.5 (D)
Iron				0.3 (I)
Lead			0.05	0.03 (A)
Lithium				0.075 (I)
Manganese			0.05	0.05 (D)
Mercury				0.00005 (A)
Molybdenum				0.010 (I)
Nickel				0.20 (I)
Nitrate-nitrogen				10 (D)
Nitrite-nitrogen				1 (D)
Odor	Free from	Free from	Free from	
Oil and Grease	No film	No film	Free from	
pH	6.0-9.0	6.0-9.0	6.5-8.5	6.0-9.0 (A)
Phenolics				0.001 (D)
Polychlorinated biphenyls				0.000002 (A)
Radioactivity	DWS	DWS	DWS	
Selenium			0.01	0.01 (D)
Silver			0.05	
Sodium				
Solids, dissolved	no increase	no increase	no increase	
Solids, floating	Free from	Free from	Free from	
Solids, settleable	Free from	Free from	Free from	
Sulfate				250 (D)
Sulfide				0.002 (A)
Taste	Free from	Free from	Free from	
Temperature	<68°F	<90°F	>80°F	
Toxic Materials	Free from	Free from	Free from	
Turbidity	Increase <10 TU	Increase <10 TU	Free from	
Zinc				2.0 (I)

[a] Table 5-5
[b] Table 5-7
[c] NAS, 1973
DWS = Drinking water standards

(1) Colorado River from mouth of Parachute Creek to Utah state line.
(2) White River from mouth of Piceance Creek to Utah state line.
(3) White River from Utah state line to junction with Green River.
(4) Green River from junction with White River to junction with Colorado River.
(5) Colorado River from Utah state line to junction with Green River.

- General Regulations

  All three states require that discharges into receiving waters cause no toxicity, color change, odor, scum, or taste. The interpretation of these regulations is uncertain and open to discussion. Typically, additional specific limitations may be set at the time that a discharge permit is issued. To assess what these additional limitations might be, water quality criteria are used in this work. Water quality criteria are recommended water quality levels for receiving waters, and they are based on the use of the water. If a stream reach supports multiple uses and if the recommended concentration of a substance for one of these uses is lower than for the other uses, the lower value is the limiting value. Limiting water quality criteria are summarized in the last column of Table 8-13. By comparing these water quality criteria with effluent composition, parameters that will be exceeded on discharge to surface waters can be identified. Additional regulations may be set on these parameters by a regulatory agency.

Groundwater Discharge

Underground disposal of wastewaters is governed by state water quality standards, by effluent limitations, and by the Underground Injection Control Program (Chapter 5). The governing water quality standards are less clear for groundwater disposal than for surface water discharge because the states do not have adequate groundwater regulations (i.e., the waters are not classified or no standards exist and the federal program is not yet in place. Both Colorado and Utah have a nondegradation policy that applies to groundwaters and would require that water quality be maintained at existing levels unless it can be demonstrated that a change is justified. Similarly, the Underground Injection Control Program stipulates that drinking water standards (Chapter 5) apply to all aquifers with a TDS of less than 10,000 mg/l unless an exception is granted. Thus, unless exceptions are obtained, underground disposal of effluents would require essentially the same degree of treatment required for surface water discharge. Since reinjection is more expensive than surface discharge, due to the added costs for the well field, this option may not be selected for economic reasons.

Reuse

An oil shale processing plant requires water for the following uses:

- cooling tower makeup
- boiler feedwater
- domestic supplies
- revegetation
- pre-refining process water
- spent shale disposal

- mining
- treatment process cleanup operations.

These water demands may be met by treating local surface waters or by upgrading processing effluents such as dewatering effluents, retort water, or blowdown streams. As noted previously, a strong motivation exists for upgrading processing effluents. Discharge limitations make direct surface and ground water disposal expensive; prior rights may complicate obtaining adequate surface supplies from the Colorado River system; and the large volume of water generated by oil shale processing is not only adequate to meet most in-plant needs with appropriate treatment, but also would be difficult to dispose of directly.

The following sections will discuss each major water use and the treatment required to upgrade plant effluents for that specific use. Plant effluents, as well as conventional water supplies, will be considered as potential water sources for each use indicated in Table 8-12. The purpose here is not to select the optimum treatment alternate nor to assemble water supply/disposal alternatives but merely to put into perspective the various options that are available.

Cooling Water. The suitability of a water for cooling purposes depends on its chemical composition. The water should be nonscaling, nonfouling, noncorrosive, and nonfoaming. Scaling or fouling waters will form deposits on heat exchanger surfaces, reducing their efficiency. This may be caused by precipitation of compounds such as calcium carbonate or aluminum silicate, by oily deposits, or by biological growth. Corrosive water, on the other hand, will shorten the useful life of system components and cause operating problems. This is caused by the presence of such substances as hydrogen sulfide, carbon dioxide, and ammonia.

The amount of makeup and blowdown required decreases as the number of times the water circulates through the system (cycles) increases. The number of cycles that can be obtained from a water depends on the chemical composition of the makeup water which can be controlled by treatment. Conventional cooling water treatment uses chemical inhibitors to control corrosion, acid to control calcium carbonate scale, and chlorine to control biological growth. Blowdown is used to keep silica, calcium sulfate, and other substances that might precipitate, below their solubility limit. The lower the concentration of the substances that may precipitate, the less blowdown required and the higher the number of cycles that can be obtained from the water. Therefore, makeup water may be pretreated to reduce the level of critical substances before the water is introduced into the cooling system.

There are no absolute limits on the quality of cooling tower makeup water. The needs of any specific system must be established on the basis of makeup water composition and construction and operating characteristics. Waters of widely varying composition, from fresh water to sea water and reclaimed municipal effluents, have been successfully used with varying degrees of treatment. However, as the concentration of certain critical constituents (e.g., hardness, alkalinity, silica) increases, the cost of supplemental treatment and the quantity of blowdown increase.

The suitability of dewatering effluents, retort water, and local surface waters for cooling tower makeup is indicated in Table 8-14. This table compares the quality of these potential supplies with guidelines for the quality of cooling tower makeup. The values shown for cooling tower makeup are maximum permissible levels for the water after it has been cycled the requisite number of times. Pre-refining process effluents are not included in this comparison as their composition is variable and depends on the makeup water source and operating conditions. Domestic sewage is omitted because the volume is too small to justify extensive treatment.

In addition to the water supplies considered in Table 8-14 for cooling tower makeup, blowdown under same circumstances can be economically recovered and reused for makeup or other in-plant requirements. This was studied by Kluesener and Heist (1977) who showed that water recovery schemes, in their case, were more cost effective than discharge directly into evaporation ponds.

It is informative to compare treatment requirements for cooling water makeup with those for surface water disposal (Table 8-12). Equivalent or more extensive treatment is required for retort waters and dewatering effluents for surface water disposal than for reuse as cooling tower makeup. This is primarily due to the restrictions on the discharge of salinity into feeder streams of the Colorado River system and to existing water quality standards on dissolved oxygen in surface streams draining the oil shale tracts.

Local surface water is the highest quality water available and could be used directly for cooling tower makeup with minimal treatment. Magnesium, calcium, and alkalinity levels could limit recirculation to three cycles. If those parameters were reduced, up to ten cycles could be obtained. Although no suspended solids data are available, surface waters are usually turbid and would require some suspended solid removal before they can be used as cooling tower makeup. Although surface waters are superior for cooling tower makeup, the shortage of water in the oil shale region, coupled with the fact that oil shale production generates large volumes of low quality water (retort water and dewatering effluents) which must be disposed of if not used, provides a strong motivation for using the poorer quality waters.

Dewatering effluents can be economically treated for cooling tower makeup. These waters could be used for two cycles if alkalinity were reduced to 750 mg/l $CaCO_3$. However, if alkalinity is reduced by conventional lime treatment, magnesium, phosphate, silica, suspended solids, organics, and, under some circumstances, calcium would also be reduced. This would allow more than two cycles to be obtained from the treated water.

Domestic sewage requires a significant level of treatment before it can be used as cooling tower makeup water. Since the volume to be treated is small, a separate treatment system to upgrade it would not be economically attractive. It would be more economical to discharge treated domestic sewage directly into surface waters or to blend domestic sewage treated for surface discharge with dewatering effluents or retort water and treat the combination.

Table 8-14. Comparison of quality requirements for cooling water after maximum number of cycles with quality of available supplies.

Parameter	Effect on Cooling Water System	Maximum value for cooling tower makeup[a]	Dewatering effluent[b] (maximum)	In-situ retort water[c] (maximum)	Local surface waters[d] (maximum)
Alkalinity ($CaCO_3$)	Can precipitate with Ca and form hard $CaCO_3$ scale	1500*	13,500*	110,900*	236
Ammonia (NH_3)	Corrosive	91	600	16,000*	0.19
Biochemical oxygen demand	Can cause fouling	450	-	5,500*	-
Calcium	Forms hard $CaCO_3$ scale	420	260		100
Hydrogen sulfide	Corrosive	-	-	-	-
Magnesium	Forms scale	36	600*	350*	34
Silica	Forms scale	150-200	180	48*	19
Sulfate	Forms scale	2000	2700	2200*	320
Suspended solids	Can cause fouling	150	-	-	-
Orthophosphate (as P)	Forms scale	7.5	0.7	-	0.74

[a] Kluesner and Heist, 1977

[b] Lease tracts C-a and C-b upper and lower aquifer, Tables 4-15 and 4-16

[c] Tables 8-2 and 8-3

[d] White River near Watson, Table 4-2

*Must be reduced to achieve three cycles

Retort water and gas condensate require extensive and moderate treatment before they can be used as cooling tower makeup. The unusual composition of these waters dictates that careful laboratory experimentation be completed before treatment sequences are selected.

Boiler Feedwater. The same types of water quality considerations that are significant for cooling tower makeup waters are also significant for boiler feedwater. Feedwater to a steam boiler should be of such quality that:

- it forms no scale or other deposits;
- it causes no corrosion of the metals present in the boiler, feedwater system, or condensate return system;
- it does not foam or prime;
- it does not contain enough silica to form turbine blade deposits in high-pressure boilers.

Conventionally, these requirements are met by using demineralization coupled with the addition of internal conditioning chemicals.

The suitability of dewatering effluents, retort water, and local surface waters for boiler feedwater is indicated in Table 8-15. This table compares the quality of each potential supply with guidelines for the quality of boiler feedwater. Prerefining process waters and domestic sewage are not included for the reasons stipulated previously.

The quality requirements for boiler feedwater in Table 8-15 are much more stringent than for cooling tower makeup water (Table 8-14). Since the same water quality considerations exist in both cases (scale formation, corrosion, etc.), similar treatment would be required in both cases. However, for boiler feedwater, additional removals would be needed. This would require the use of a demineralization process, such as ion exchange. The treatment to produce boiler feedwater from each supply is the same as for cooling tower makeup water, except chlorine and acid addition are not required and demineralization is a necessary final processing step. The demineralization process selected depends on the level of dissolved solids in the water to be treated and process economics. Typically, ion exchange is used. The same level of treatment is required for direct discharge to streams as for boiler feedwater.

Demineralization of effluents such as retort water could be troublesome, even after extensive treatment. Large organic molecules, such as occur in retort water, would block the exchange groups of ion exchange resins or plug membranes. These large molecules are not removed by normal regeneration procedures. Oily matter could irreversibly coat ion exchange materials and filter media. Some forms of silica also irreversibly block ion exchange resins. Similar problems may be anticipated with other demineralization processes, such as reverse osmosis. Before a demineralization step is used for retort water, extensive experimental studies should be completed.

Table 8-15. Comparison of quality requirements for boiler feedwater with quality of available supplies.

	Medium-Pressure Boilers[a] (700-1000 psig)	Dewatering Effluents[b] (Maximum)	In-situ Retort Water[c] (Maximum)	Local Surface Supplies[d] (Maximum)
Alkalinity ($CaCO_3$)	40	13,500*	110,900*	236*
Aluminum	0.01	4*	19.1*	0.05*
Ammonia (NH_4)	0.1	600*	31,400*	0.19*
Bicarbonate (HCO_3)	48	25,000*	73,640*	314*
Calcium	0.01	260*	36*	100*
Chemical Oxygen Demand (COD)	1.0	92*	43,000*	38*
Copper	0.05	3*	139*	0.006*
Dissolved Oxygen (O_2)	0.007	-	-	-
Dissolved Solids (TDS)	200	42,000*	24,500*	713*
Hardness ($CaCO_3$)	0.07	1100*	-	340*
Iron	0.05	36*	77*	0.27*
Magnesium	0.01	600*	350*	34*
Manganese	0.01	1.7*	0.94*	0.03*
Silica (SiO_2)	0.7	180*	48*	19*
Suspended Solids	0.5	-	-	-
Zinc	0.01	68	14.4*	0.11*
pH	8.2-9.0	9.7*	9.4	8.3

[a] NAS, 1973

[b] Lease tracts C-a and C-b, upper and lower aquifers, Tables 4-15 and 4-16

[c] Tables 8-2 and 8-3

[d] White River near Watson, Table 4-2

*Must be reduced for use as boiler feedwater

It is recommended that only local surface waters, dewatering effluents, or gas condensates be considered for boiler feedwater due to possible operating problems and high cost of treatment for the other supplies. Retort water is not considered to be acceptable for boiler feedwater due to the high levels of critical substances and the large variability in its composition. Domestic sewage has been successfully used as boiler feedwater after extensive treatment. However, the volume involved here is small, and the quality of the waste is more suited to other uses.

Domestic Use. Potable water must be supplied for use by on-site personnel. This water is used for drinking, wash water, and waste conveyance, and it constitutes less than one percent of the water demand of an in-situ oil shale plant.

The quality of potable waters is governed by the 1975 EPA Drinking Water Standards. Additionally, the hardness of a water is an important consideration for its suitability as potable water. These standards are summarized in Table 8-16 and compared with some local surface waters and dewatering effluents. This table shows that Piceance Creek waters (Tract C-b) are suitable for potable use if TDS and hardness are reduced while dewatering effluents may require the removal of arsenic, barium, chromium, mercury, selenium, hardness, cadmium, fluoride, lead, and silver. Although no turbidity data are available, it may be anticipated that surface and groundwater turbidity would exceed 5 JTUs. In general, surface waters are more suitable for drinking water than groundwaters.

Other water sources, such as retort water or pre-refining effluents, are not included in this comparison because:

- no economic motive exists for upgrading these waters because domestic demands are small and adequate high quality supplies exist.
- inadequate information exists on the suitability of these types of wastes for domestic use.
- toxicants not covered by the EPA regulations may be present in the waste streams which would not be removed by state-of-the-art water treatment technology.

Degree of treatment necessary to upgrade local surface waters and dewatering effluents for use as potable water were summarized in Table 8-12. This table demonstrates that surface waters can be more easily treated for potable use than groundwaters (mine waters). The available groundwaters are difficult to treat for domestic use because of high salt content and high concentrations of trace constituents such as fluoride, silver, lead, and cadmium.

Revegetation. In the modified in-situ process, 20 to 40 percent of the in-place shale is mined and retorted, and the residuals are disposed of on the surface. The areas where the shale is disposed of are revegetated to maintain the region's integrity (Chapter 6). Approximately one percent of the water required for modified in-situ oil shale production is used in the revegetation process.

Table 8-16. Comparison of EPA drinking water standards with quality of local surface waters and dewatering effluents.

Parameter	Maximum Concentration[a]	Dewatering Effluent[b] (maximum)	Local Surface Waters[c] (maximum)
Arsenic	0.05	0.2	0.005
Barium	1.0	8	0.2
Cadmium	0.010	0.1	<0.015
Chromium	0.05	0.3	0.09
Fluoride	1.4-2.4	190	1.2
Lead	0.05	26	<0.016
Mercury	0.002	0.045	0.0008
Nitrate (as N)	10.0	7	3.7
Silver	0.05	0.1	-
Selenium	0.01	0.03	0.002
Turbidity (TU)	5	-	-
Total Dissolved Solids	500	42,000	1630
Hardness ($CaCO_3$)	-	1,110	700

[a] Federal Register, Vol. 40, No. 248, Dec. 24, 1975

[b] Lease tracts C-a and C-b, upper and lower aquifer, Tables 4-15 and 4-16

[c] Piceance Creek below Rio Blanco, Colorado, Table 4-2

The quality of the water used for revegetation depends on the type of vegetation and soil structure and composition. Water quality criteria for irrigation may be used as guidelines to evaluate the suitability of available supplies for revegetation. These criteria are summarized in Table 8-17 together with the quality of supplies that may be used for revegetation. This comparison shows that neither dewatering effluents nor retort water would be suitable for revegetation without extensive treatment to remove a number of trace elements including fluoride and zinc. Treatment of these waters for revegetation would not be justified because the volume of water required is small and local surface waters can be used untreated.

Other Uses. Water is also required for dust control, shale disposal, treatment process cleanup operations such as filter backwash and ion exchange resin regeneration, and pre-refining. Water quality requirements and treatment for these uses are summarized in Table 8-18.

Both dust control and shale disposal have no specific quality requirements and any plant effluent not posing a health hazard to workers could be used. Therefore, it is recommended that effluents that could not be economically upgraded for reuse or disposal be used untreated for dust control and shale disposal. Suitable effluents for these uses are cooling tower blowdown and backwash waters.

CONCLUSIONS

This chapter evaluated the reuse and disposal of effluents from an in-situ oil shale industry. The principle effluents produced by an in-situ oil shale industry were identified and characterized and potential on-site uses and disposal options for each water use were explored. This work revealed that an oil shale industry will likely employ a zero discharge system due to limited water supplies and the stringent standards governing waste discharge into surface and ground waters in the oil shale region. Specific conclusions drawn from this investigation are:

(1) Effluents produced by an in-situ oil shale industry include retort water, gas condensate, blowdown streams, treatment brines, prerefining effluents, mine waters, and storm water runoff. All of these except retort water and gas condensates are normally found in other types of industrial operations and can be upgraded with existing control technology. The two process waters are unique to oil shale retorting and represent a difficult treatment and disposal problem.

(2) Retort water and gas condensate are produced in quantities of 0.1 to 22 barrels of water per barrel of oil. The retort water has high concentrations of organics, NH_3, dissolved CO_2, sulfur compounds, and elevated levels of some trace elements such as As, Se, F, and B. The gas condensate has elevated levels of dissolved gases and organics.

Table 8-17. Comparison of quality requirements for irrigation waters for revegetation with quality of available supplies.

	Quality requirement for irrigation supplies[a]	Dewatering effluent[b] (maximum)	Retort water[c] (maximum)	Local surface waters[d] (maximum)
Aluminum	5-20	4	16.6	-
Arsenic	0.1-2.0	0.2	15.3*	0.005
Beryllium	0.1-0.5	<0.5	-	-
Boron	0.75-2.0	400*	27*	0.33
Chromium	0.1-1.0	0.3	1.4*	0.09
Cobalt	0.05-5.0	0.03	0.65	-
Copper	0.20-5.0	3	139*	0.012
Fluoride	1-15	190*	60*	1.2
Iron	5-20	36*	77*	0.16
Lead	5-10	26*	1.15	<0.016
Lithium	0.075-2.5	79	0.8	0.02
Manganese	0.20-10.0	1.7	0.94	0.25
Molybdenum	0.010-0.050	1.8*	12*	-
Nickel	0.20-2.0	0.2	10.7*	-
Selenium	0.02	0.03	1.7*	0.002
Vanadium	0.10-1.0	0.5	11*	-
Zinc	2.0-10	68*	14.4*	0.06

[a] NAS, 1973 (summarized from Table 5-9)

[b] Lease tracts C-a and C-b, upper and lower aquifer, Tables 4-15 and 4-16

[c] Tables 8-2 and 8-3

[d] Piceance Creek below Rio Blanco, Colorado, Table 4-2

*Must be removed for use as irrigation supply

Table 8-18. Water quality requirements for dust control, shale disposal, backwash waters, and pre-refining effluents.

USE CATEGORY	DESCRIPTION OF WATER USE	WATER QUALITY CONSIDERATIONS AND TREATMENT REQUIRED	RECOMMENDED WATER SOURCES
Dust Control	Water is used for dust control during mining and shale disposal operations. Virtually all of this water is evaporated. Therefore, no portion of it is available for reuse.	The water used should not pose a health hazard to workers. Otherwise, there are no quality requirements. No treatment is required.	Cooling tower blowdown Ion exchange backwash waters Aquifer dewatering effluents
Shale Disposal	Water is used to transport spent shale and to compact spent shale disposal piles.	The water should not pose a health hazard to workers. Otherwise, there are no quality requirements. Organics may have to be removed.	Cooling tower blowdown Ion exchange backwash waters Aquifer dewatering effluents
Filter Backwash	Filtration may be used in several treatment sequences. These include treatment of waters for domestic use and cooling tower makeup. When filtration media became saturated with suspended material removed from the treated water, they must be cleaned. This is called backwashing.	Low suspended solids.	Aquifer dewatering effluents
Ion Exchange	Ion exchange processes are used in treating boiler feedwater, any effluents that are discharged to surface waters, and for softening domestic waters. When the resins become saturated, they must be cleaned. This is called backwashing.	Depends on type of resin used. Typically requires a good quality water.	Storm water runoff Local surface water
Pre-refining (Wash Water)	Wash water is used for: o periodic plant cleaning o transporting solids through pipelines o operating cutters for use in decoking furnaces and de-scaling boiler tubes	No treatment is necessary. Recycled plant effluent is frequently used. Since some of the recycled water may contain sulfur compounds, objectionable odors may be present.	Storm water runoff Pre-refining effluents
Pre-refining (Dilutant Water)	Dilutant water may be used in alkaline treatment to remove arsenic	Calcium, magnesium, carbonate, and bicarbonate are undesirable as these are precipitated by the heat. Therefore, dilutant waters must be treated for the removal of these constituents. This may be done by chemical treatment (lime-soda softening), ion exchange, or stripping, depending on the composition of the water used.	Boiler blowdown
Pre-refining (Fractinator O.H. Injection)	Catalytic cracking produces ammonia and carbon dioxide that form deposits if not removed. Water is injected to keep them in solution.	Complete removal of solids is required. Deionized water or steam condensate must be used.	Steam condensate

(3) A viable method for treating retort water has not been identified. Most work has focused on removal of dissolved gases and organics and has revealed that the dissolved gases may be removed by steam stripping, weak-acid cation exchange resins, or spent shale. No method has been identified that is capable of removing organics from retort waters. Additional work is required to identify treatment methods for this waste.

(4) No characterization data on gas condensate are presently (April 1980) available, and no treatability studies have been conducted. Study in this area is required.

(5) Large volumes of mine water, from 500 to 12,600 gpm, are produced during site dewatering. This water typically has high concentrations of TDS, CO_3, HCO_3, SO_4, Cl, Ca, Mg, K, Na, and Si. Trace elements with the exception of B and Fe, occur at concentrations of less than 1 ppm. This water may be used to meet a substantial portion of on-site water requirements if prevailing water doctrines permit its consumptive use. Treatment would be required for most potential uses. The effect of consumptive use of groundwaters on prior water rights needs to be investigated.

(6) Most of the anticipated on-site uses for water require the disposal of brine streams. To achieve zero discharge, the various brines, which include treatment plant sludges and blowdown streams, must be solar evaporated in lined ponds. Because large volumes of water are involved, this may require excessive land areas.

(7) An oil shale industry will probably reuse its effluents to the maximum extent possible and evaporate any residuals because of the stringent state and federal standards governing the discharge of wastes into local waters and the limited water supplies in the area.

REFERENCES

The following abbreviations are used as text citations for the following references:

API: American Petroleum Institute

Ashland: Ashland Oil, Inc. and Occidental Oil Shale, Inc.

ASTM: American Society for Testing and Materials

ARCO: Atlantic Richfield Company

CDH: Colorado Department of Health

Colony: Colony Development Operation

CDNR: Colorado Department of Natural Resources

CRB: Colorado River Basin Salinity Control Forum

CSU: Colorado State University

DOE: U. S. Department of Energy

DRI: Denver Research Institute

EDC: Energy Development Consultants, Inc.

EPA: U. S. Environmental Protection Agency

FEA: U. S. Federal Energy Administration

Gulf: Gulf Oil Corp. and Standard Oil Co. (Indiana)

Halliburton: Halliburton Services, Inc.

NAS: National Academy of Sciences

Occidental: Occidental Oil Shale, Inc.

Skelly: Skelly and Loy, Engineers

Tipton: Tipton and Kalmbach, Inc.

UCR Group: Upper Colorado Region State-Federal Inter-Agency Group

UDWR: Utah Division of Water Resources

USDI: U. S. Department of the Interior

USU: Utah State University

VTN: VTN Colorado, Inc.

Woodward: Woodward-Clyde Consultants

WDEQ: Wyoming Department of Environmental Quality

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