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FINAL ENVIRONMENTAL STATEMENT FOR THE PROTOTYPE OIL SHALE LEASING P

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FINAL
ENVIRONMENTAL STATEMENT
FOR THE
PROTOTYPE OIL SHALE LEASING PROGRAM

Volume I of VI

Regional Impacts of Oil Shale Development

U.S. DEPARTMENT OF THE INTERIOR

1973

FINAL

ENVIRONMENTAL STATEMENT

FOR THE

PROTOTYPE OIL-SHALE LEASING PROGRAM

Volume I of VI

Regional Impacts

of

Oil Shale Development

Prepared in Compliance With

Section 102 (2) (c) of the National Environmental

Policy Act of 1969

Prepared by

UNITED STATES DEPARTMENT OF THE INTERIOR

1973

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SUMMARY

Final Environmental Statement
Department of the Interior, Office of the Secretary

1. Administrative type of action:

2. Brief description of action:

   This action would make available for private development up to six leases of public oil shale lands of not more than 5,120 acres each. Two tracts are located in each of the States of Colorado, Utah, and Wyoming.

   Such leases would be sold by competitive bonus bidding and would require the payment to the United States of royalty on production. Additional oil shale leasing would not be considered until development under the proposed program had been satisfactorily evaluated and any additional requirements under the National Environmental Policy Act of 1969 had been fulfilled.

3. Summary of environmental impact and adverse environmental effects:

   Oil shale development would produce both direct and indirect changes in the environment of the oil shale region in each of the three States where commercial quantities of oil shale resources exist. Many of the environmental changes would be of local significance, and others would be of an expanding nature and have cumulative impact. These major regional changes will conflict with uses of the other physical resources of the areas involved. Impacts would include those on the land itself, on water resources and air quality, on fish and wildlife habitat, on grazing and agricultural activities, on recreation and aesthetic values, and on the existing social and economic patterns as well as others. The environmental impacts from both prototype development at a level of 250,000 barrels per day of shale oil and an industry producing a possible 1 million barrels per day by 1985 are assessed for their anticipated direct, indirect and cumulative effects.

4. Alternatives considered:

   A. Government development of public oil shale lands.
   B. Change in number and location of tracts to be leased.
   C. Delay in development of public oil shale lands.
   D. No development of public oil shale lands.
   E. Unlimited leasing of public oil shale lands.
   F. Obtaining energy from other sources.

5. Comments have been requested from the following:

   Federal agencies, State agencies, and private organizations listed in Volume IV, Section F.

6. Date made available to the Council on Environmental Quality and the Public:

   Draft Statement: September 7, 1972

   Final Statement: August 1973

INTRODUCTORY NOTE

THIS FINAL ENVIRONMENTAL STATEMENT HAS BEEN PREPARED PURSUANT TO SECTION 102 (2) (C) OF THE NATIONAL ENVIRONMENTAL POLICY ACT OF 1969 (42 U.S.C. SECS. 4321-4347). ITS GENERAL PURPOSE IS A STUDY OF THE ENVIRONMENTAL IMPACTS OF OIL SHALE DEVELOPMENT.

THE SECRETARY OF THE INTERIOR ANNOUNCED PLANS ON JUNE 29, 1971, FOR THIS PROPOSED PROGRAM AND RELEASED A PRELIMINARY ENVIRONMENTAL STATEMENT, A PROGRAM STATEMENT, AND REPORTS PREPARED BY THE STATES OF COLORADO, UTAH, AND WYOMING ON THE ENVIRONMENTAL COSTS AND PROBLEMS OF OIL SHALE DEVELOPMENT.

THE PROPOSED PROGRAM IS IN CONCERT WITH THE PRESIDENT'S ENERGY MESSAGE OF JUNE 4, 1971, IN WHICH HE REQUESTED THE SECRETARY OF THE INTERIOR TO INITIATE "A LEASING PROGRAM TO DEVELOP OUR VAST OIL SHALE RESOURCES, PROVIDED THAT ENVIRONMENTAL QUESTIONS CAN BE SATISFACTORILY RESOLVED."

AS PART OF THE PROGRAM, THE DEPARTMENT AUTHORIZED INFORMATIONAL CORE DRILLING AT VARIOUS SITES IN COLORADO, WYOMING, AND UTAH AND 16 CORE HOLES WERE COMPLETED. THE DEPARTMENT REQUESTED NOMINATIONS OF PROPOSED LEASING TRACTS ON NOVEMBER 2, 1971, AND A TOTAL OF 20 INDIVIDUAL TRACTS OF OIL SHALE LAND WERE NOMINATED. WITH THE CONCURRENCE OF THE CONCERNED STATES, THE DEPARTMENT OF THE INTERIOR ANNOUNCED ON APRIL 25, 1972, THE SELECTION OF SIX OF THESE TRACTS, TWO EACH IN COLORADO, UTAH, AND WYOMING.

THE PROGRAM IS ESSENTIALLY UNCHANGED FROM THAT ANNOUNCED ON JUNE 29, 1971, BUT THE PRELIMINARY STATEMENT ISSUED AT THAT TIME

WAS EXPANDED TO CONSIDER THE IMPACT OF MATURE OIL SHALE DEVELOPMENT, THE IMPACT OF DEVELOPMENT OF THE SIX SPECIFIC TRACTS, AND A COMPREHENSIVE ANALYSIS OF OTHER ENERGY ALTERNATIVES.

THE DRAFT OF THIS FINAL ENVIRONMENTAL STATEMENT WAS RELEASED TO THE PUBLIC ON SEPTEMBER 7, 1972. A PUBLIC REVIEW PERIOD WAS HELD THAT ENDED ON NOVEMBER 7, 1972. THIS REVIEW PROVIDED IMPORTANT INFORMATION UPON WHICH TO EXPAND AND CORRECT, WHERE APPROPRIATE, THE DRAFT MATERIAL.

VOLUME I OF THIS FINAL SET OF SIX VOLUMES PROVIDES AN ASSESSMENT OF THE CURRENT STATE OF OIL SHALE TECHNOLOGY AND DESCRIBES THE REGIONAL ENVIRONMENTAL IMPACT OF OIL SHALE DEVELOPMENT AT A RATE OF ONE MILLION BARRELS PER DAY BY 1985. VOLUME II EXTENDS THIS STUDY WITH AN EXAMINATION OF ALTERNATIVES TO THE ONE MILLION BARREL PER DAY LEVEL OF SHALE OIL PRODUCTION. VOLUMES I AND II THUS CONSIDER THE REGIONAL AND CUMULATIVE ASPECTS OF A MATURE OIL SHALE INDUSTRY.

VOLUME III EXAMINES THE SPECIFIC ACTION UNDER CONSIDERATION, WHICH IS THE ISSUANCE OF NOT MORE THAN TWO PROTOTYPE OIL SHALE LEASES IN EACH OF THE THREE STATES OF COLORADO, UTAH, AND WYOMING. ITS FOCUS IS ON THE SPECIFIC ENVIRONMENTAL IMPACTS OF PROTOTYPE DEVELOPMENT ON PUBLIC LANDS WHICH, WHEN COMBINED, COULD SUPPORT A PRODUCTION POTENTIAL OF ABOUT 250,000 BARRELS PER DAY.

VOLUME IV DESCRIBES THE CONSULTATION AND COORDINATION WITH OTHERS IN THE PREPARATION OF THE FINAL STATEMENT, INCLUDING COMMENTS RECEIVED AND THE DEPARTMENT'S RESPONSES. LETTERS RECEIVED DURING THE REVIEW PROCESS ARE REPRODUCED IN VOLUME V, AND ORAL TESTIMONY IS CONTAINED IN VOLUME VI.

THIS DOCUMENT IS BASED ON MANY SOURCES OF INFORMATION, INCLUDING RESEARCH DATA AND PILOT PROGRAMS DEVELOPED BY BOTH THE GOVERNMENT AND PRIVATE INDUSTRY OVER THE PAST 30 YEARS. MANY FACTORS, SUCH AS CHANGING TECHNOLOGY, EVENTUAL OIL PRODUCTION LEVELS, AND ATTENDANT REGIONAL POPULATION INCREASES ARE NOT PRECISELY PREDICTABLE. THE IMPACT ANALYSIS INCLUDED HEREIN IS CONSIDERED TO CONSTITUTE A REASONABLE TREATMENT OF THE POTENTIAL REGIONAL AND SPECIFIC ENVIRONMENTAL EFFECTS THAT WOULD BE ASSOCIATED WITH OIL SHALE DEVELOPMENT.

IT SHOULD BE NOTED THAT SUBSTANTIAL AMOUNTS OF PUBLIC LANDS IN ADDITION TO THE PROTOTYPE TRACTS WOULD BE REQUIRED FOR AN INDUSTRIAL DEVELOPMENT TO THE ONE MILLION BARREL PER DAY LEVEL CONSIDERED IN VOLUMES I AND II. IF EXPANSION OF THE FEDERAL OIL SHALE LEASING PROGRAM IS CONSIDERED AT SOME FUTURE TIME, THE SECRETARY OF THE INTERIOR WILL CAREFULLY EXAMINE THE ENVIRONMENTAL IMPACT WHICH HAS RESULTED FROM THE PROTOTYPE PROGRAM AND THE PROBABLE IMPACT OF AN EXPANDED PROGRAM. BEFORE ANY FUTURE LEASES ON PUBLIC LANDS ARE ISSUED, AN ENVIRONMENTAL STATEMENT, AS REQUIRED BY THE NATIONAL ENVIRONMENTAL POLICY ACT, WILL BE PREPARED.

AVAILABILITY OF FINAL ENVIRONMENTAL STATEMENT

The six-volume set may be purchased as a complete set or as individual volumes from the Superintendent of Documents, U. S. Government Printing Office, Washington, D. C. 20402; the Map Information Office, Geological Survey, U.S. Department of the Interior, Washington, D. C. 20240; and the Bureau of Land Management State Offices at the following addresses: Colorado State Bank Building, 1600 Broadway, Denver, Colorado, 80202; Federal Building, 124 South State, Salt Lake City, Utah, 84111; and Joseph C. O'Mahoney Federal Center, 2120 Capital Avenue, Cheyenne, Wyoming, 82001.

Inspection copies are available in the Library and the Office of the Oil Shale Coordinator, U.S. Department of the Interior, Washington, D. C., and at depository libraries located throughout the Nation. The Superintendent of Documents may be consulted for information regarding the location of such libraries. Inspection copies are also available in Denver, Colorado, in the Office of the Deputy Oil Shale Coordinator, Room 237E, Building 56, Denver Federal Center, Denver, Colorado 80225, in all the Bureau of Land Management State Offices listed above, and in the following Bureau of Land Management district offices: Colorado: Canon City, Craig, Glenwood Springs, Grand Junction, Montrose; Utah: Vernal, Price, Monticello, Kanab, Richfield; Wyoming: Rock Springs, Rawlins, Casper, Lander, Pinedale, Worland.

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I. DESCRIPTION OF THE PROPOSED ACTION

A. Introduction

Oil shale is one of the Nation's most abundant energy resources. The richest deposits, located in the Rocky Mountain area of the country, represent billions of barrels of oil. Development of this resource has not been undertaken in the past because accessible supplies of oil and gas have been available at a lower development cost. The Nation's future energy needs are so large, however, that it is important to examine the possibility of supplementing our conventional domestic oil and gas deposits with synthetic fuels derived from oil shale and other convertible fossil fuel sources.

Volume I of this Environmental Impact Statement examines the regional environmental impact expected from shale development on private and public lands. A companion document (1)[1/] reviews the specific impacts associated with the development of six leases on public lands if the Department of the Interior's proposed prototype oil shale leasing program is implemented. Chapter I of Volume I is devoted principally to presenting a current state-of-the-art assessment of the technology that may be employed in oil shale development. Included in this assessment are methods of processing, technology related to the management of solid wastes within the working areas; and monitoring methods.

1/ Underlined numbers in parentheses refer to items in the list of references at the end of each chapter.

Subsequent chapters of this volume describe the regional environmental impact of oil shale development to a maximum cumulative production of one million barrels per day by 1985. Alternatives to this scale of development are analyzed in Volume II.

B. Background

Large areas of the United States are known to contain oil shale deposits, but those areas in Colorado, Utah, and Wyoming that contain the organic-rich sedimentary rocks of the Green River Formation are of greatest promise for shale oil production in the immediate future (Figure I-1). The oil shale deposits occur beneath 25,000 square miles (16 million acres) of lands, of which about 17,000 square miles (11 million acres) are believed to contain oil shale of potential value for commercial development in the foreseeable future.

The known Green River Formation deposits include highgrade shales [1/] that represent about 600 billion barrels of oil. [2/] Recovery of even a small fraction of this resource would represent a significant energy source adequate to supplement the Nation's oil supply for many decades.

1/ At least 10 feet thick and averaging 25 or more gallons per ton.

2/ An additional 1,200 billion barrels are present in place in lower grade shales in sequence more than 10 feet thick that have an average yield of 15 to 20 gallons per ton.

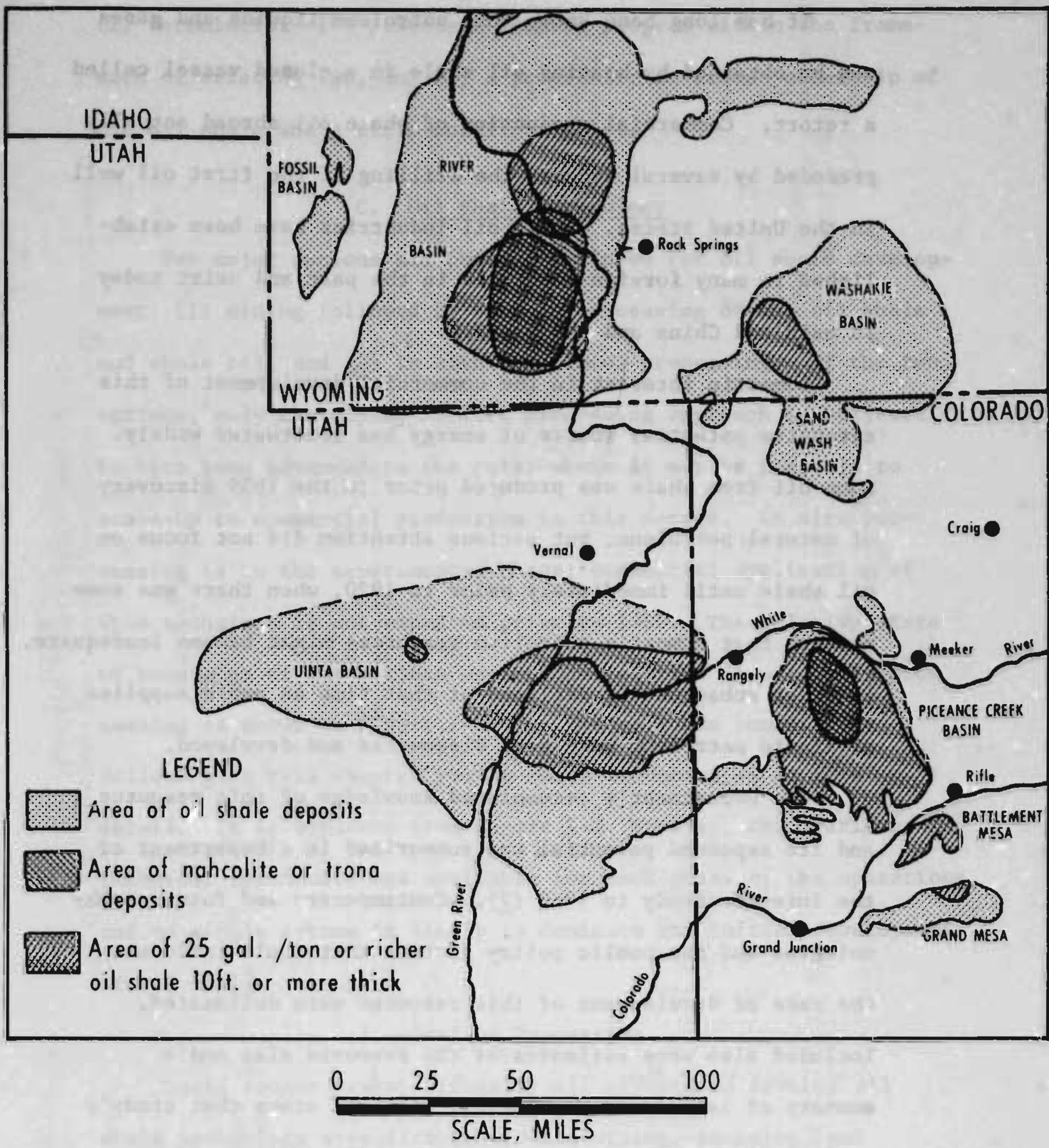

FIGURE I-1.--Oil Shale Areas in Colorado, Utah, and Wyoming.

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It has long been known that petroleum liquids and gases can be obtained by heating oil shale in a closed vessel called a retort. Commercial production of shale oil abroad actually preceded by several decades the drilling of the first oil well in the United States. Shale oil industries have been established in many foreign countries in the past and exist today in mainland China and the U.S.S.R.

Domestic interest in the commercial development of this extensive potential source of energy has fluctuated widely. Some oil from shale was produced prior to the 1859 discovery of natural petroleum, but serious attention did not focus on oil shale until immediately prior to 1920, when there was some concern that domestic petroleum resources might become inadequate. Interest subsequently declined at that time as ample supplies of liquid petroleum were soon discovered and developed.

The Department's accumulated knowledge of this resource and its expected potential was summarized in a Department of the Interior Study in 1968 (2). Contemporary and future technologies and the public policy factors that could influence the rate of development of this resource were delineated. Included also were estimates of the resource size and a summary of land ownership status. Efforts since that study's publication have been concentrated on: (1) analysis of the probable environmental impact of oil shale development,

(2) formulation of a prototype leasing program within the framework of existing law, and (3) a program to determine ownership of the oil shale where title conflicts exist.

C. Oil Shale Technology

Two major options are being considered for oil shale development: (1) mining followed by surface processing of the oil shale and shale oil, and (2) in situ (in-place) processing. Of the two options, only the mining surface processing approach is believed to have been advanced to the point where it may be possible to scale-up to commercial production in this decade. In situ processing is in the experimental phase; commercial application of this technique is not expected prior to 1980. The relative state of knowledge of the various operations required in oil shale processing is shown in Figure I-2. [1/] The sections immediately following in this chapter review these technologies in more detail. It is apparent from Figure I-2, however, that various technical approaches are available for each phase of the operations, and no single system is likely to dominate the initial development of oil shale.

1. Surface Processing

Until recent years, virtually all efforts to develop oil shale technology were directed toward mining, crushing, and

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1/ Most of the refining operations shown in Figure I-2 would be performed outside of the oil shale region, at refinery centers near markets for the products.

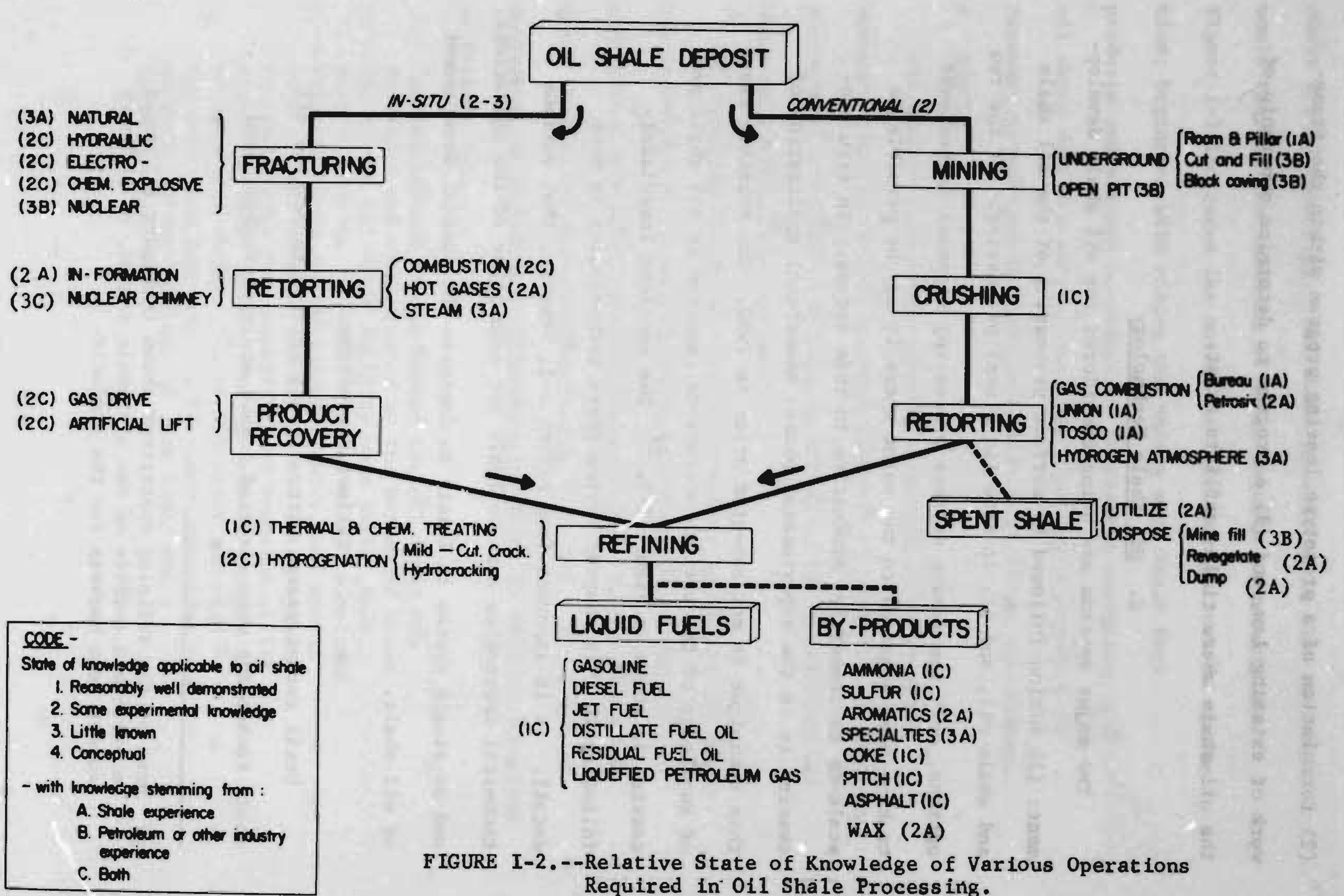

FIGURE I-2.--Relative State of Knowledge of Various Operations Required in Oil Shale Processing.

August 1972

above ground retorting. Oil shale processing in this manner would require the handling of large amounts of materials. Figure I-3 indicates the materials flow through such an operation; beginning with mining and ending with final fuel products and various byproducts. In certain locations, the oil shale deposits contain minerals that may be amenable to recovery of additional byproducts such as soda ash and alumina.

a. Mining

Oil shale may be mined by either surface or underground methods. Surface mining requires removal and disposal of whatever overburden is present, followed by mining of the underlying oil shale in a quarry-like operation.

The greatest amount of actual experience in mining oil shale has involved underground mining techniques. Major advances in underground mining of oil shale were achieved by the Bureau of Mines in its oil shale program during 1944-1956. The state of technology as reviewed by the Bureau of Mines in 1970 is described as follows (3):

> An underground mining method for oil shale was developed and demonstrated by the Bureau of Mines (4) at its oil shale facility near Rifle, Colo., during 1944-56. A "demonstration mine," sometimes referred to as an underground quarry, was opened in a 73-foot minable section of the Mahogany zone to demonstrate the feasibility of room-and-pillar mining methods, to develop and test equipment, and to determine whether low mining costs and high recovery were possible. A two-level operation was adopted: a top heading, 39 feet high; and a bench, 34 feet high.

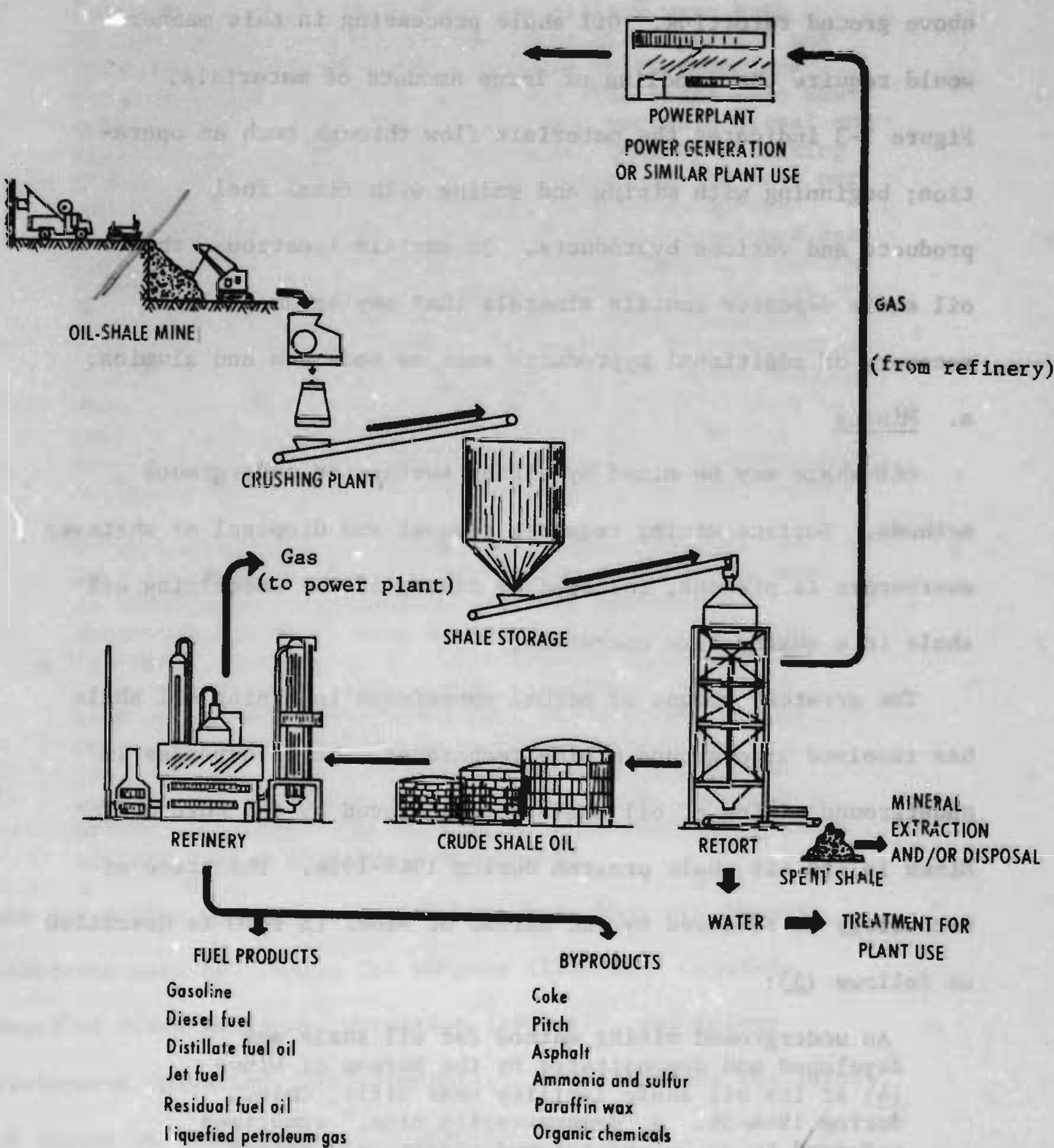

FIGURE I-3.--Schematic Diagram of Oil Shale Surface Processing.

> Room openings and roof-supporting pillars were both 60 feet square. An extraction ratio of 75 percent was attained, leaving supporting pillars which comprised the remaining 25 percent. Head and side space thus was sufficient to permit the use of large portable diesel and electrically driven mining equipment, thereby obtaining a high output per man-shift. An average of 150 tons per man-shift was achieved for sustained periods during normal operating tests. Special equipment developed for mining the high faces included drilling jumbos, a rotary drill for the benching operations, explosives-loading platforms, scaling rigs, and a mobile compressor and utility station. An electric shovel with a 3-cubic-yard dipper was used to load the broken shale. Diesel-powered dump trucks were used for haulage. Subsequent shale work by industry has followed in general the mining method demonstrated by the Bureau, but has incorporated equipment modernization and improvements in techniques.
>
> If an underground oil shale mining operation were to be undertaken in the near future, it could be expected to incorporate improvements over the Bureau's demonstration mine, such as the following: Changing to rotary drilling in the mine heading as well as in benching; blasting with a more economical explosive, such as an ammonium nitrate-fuel oil mixture; use of modern haulage and loading equipment, and other improvements based on recent advances in quarry and open pit mining engineering. Also, in the interest of safety, a retreat system might be used instead of the advance system that was demonstrated.

Room and pillar mining techniques have been improved through subsequent work by: Union Oil Company (1956-58), Colorado School of Mines Research Foundation (1964-67), and Colony Development Operation (1965-present). In considering the future, the Bureau of Mines review (3) stated:

> The room-and-pillar mining system is the only one that has been tested on the oil shales of the Green River Formation. However, open pit mining, highly developed for mining other ores, probably will be practical for oil shale in areas where conditions are favorable. Among the considerations that would be important in selecting a suitable site would be the availability of a satisfactory area for storing the overburden and the ratio of the overburden to the shale to be mined.

b. Crushing

Oil shale consists of solid organic materials intimately associated with a mixture of minerals. The organic constituents are only slightly soluble at low temperature in common solvents. A typical composition is shown in Table I-1. Much of the oil shale as mined would require crushing and sizing prior to retorting. The crushing equipment must be designed to overcome a tendency of the oil shale to form slabs; otherwise, equipment in general use can be satisfactorily employed.

Table I-1.- Typical Composition of Oil Shale Sections Averaging 25 Gallons of Oil Per Ton in the Mahogany Zone of Colorado and Utah (3)

	Weight-percent
Organic matter:	
Content of raw shale..........................	13.8
Ultimate composition:	
Carbon....................................	80.5
Hydrogen..................................	10.3
Nitrogen..................................	2.4
Sulfur....................................	1.0
Oxygen....................................	5.8
Total.............................	100.0
Mineral matter:	
Content of raw shale..........................	86.2
Estimated mineral constitutents:	
Carbonates; principally dolomite.............	48
Feldspars....................................	21
Quartz.......................................	13
Clays, principally illite....................	13
Analcite.....................................	4
Pyrite.......................................	1
Total.............................	100

The subject of crushing oil shale has also been investigated, as summarized in the same Bureau of Mines review, which stated:

> Under its 1944-46 program, the Bureau of Mines obtained substantial data on crushing Colorado oil shale using different types of equipment including jaw, gyratory, impact, and roll crushers (5). In addition, data were derived from a number of crushing tests of short duration which were conducted cooperatively between the Bureau and several industrial machinery companies. Industry subsequently has gained experience and additional knowledge in the crushing of oil shale.

Transfer of the shale between different parts of the complex can be achieved by a number of methods, but the most probable means would be truck or belt haulage from the mine, with subsequent transfer by continuously moving belts.

c. Retorting

After mining and crushing of the oil shale, it is conveyed to a processing unit called a retort, in which the oil shale is heated to the temperature (about 900°F) at which the solid organic material in the oil shale (kerogen) is converted to gas and oil vapors. The above-mentioned review described the state of retorting processes as follows:

> Many retorting processes for oil shale have been patented in the last half century, and new patents continue to be issued. Only a few processes, however, are generally considered to be prime candidates for early commercial use in first generation retorting plants in Colorado, Utah, and Wyoming. These few processes each have attractive features; they are generally compatible with requisites for successful application to Green River oil shales; and they have been demonstrated in moderate size to fairly large size experimental equipment. All retorting processes have one fundamental characteristic in common; namely, heating the shale to at least the pyrolysis temperature, which ranges from 800° to 1,000° F. This is the only practical means known for producing shale oil. Although the major pyrolysis product is oil, both gas and carbonaceous residue also are formed.

Individual retorts having capacities of about 10,000 tons per day generally are visualized as an appropriate size for the first commercial retorting plants. Designs of hypothetical retorts approaching this size have been incorporated in recent cost evaluation studies. A practical approach to scaling-up to such a size in this new field of technology involves working out solutions to engineering problems in a series of progressively larger experimental plants, the largest usually being referred to as a prototype of a commercial unit.

The principle mechanical features of the most advanced retorting processes are shown schematically in Figure I-4.

(1) The Union Oil Retort.- The retort developed by Union Oil Company of California was tested on a demonstration scale of about 1,000 tons/day, from 1956 to 1958. This retort consists of a vertical, refractory-lined vessel. It operates on a downward gas-flow principal, and the shale is moved upward by a unique charging mechanism usually referred to as a "rock pump." Heat is supplied by combustion of the organic matter remaining on the retorted shale and is transferred to the oil shale by direct gas-to-solids exchange. The oil is condensed on the cool, incoming shale and flows over it to an outlet at the bottom of the retort. This process does not require cooling water. The company announced that operation of the plant had yielded enough information that larger equipment could be designed and constructed whenever energy demand and economic conditions warranted. (6)

(2) The TOSCO II Retort.- Colony Development Operation, comprised of the Atlantic Richfield Company, the Standard Oil Company of Ohio, The Oil Shale Corporation (TOSCO), and the Cleveland Cliffs Iron Company, has conducted operations, beginning in the mid-1960's and into 1972 , that included construction of a "Semiworks" plant

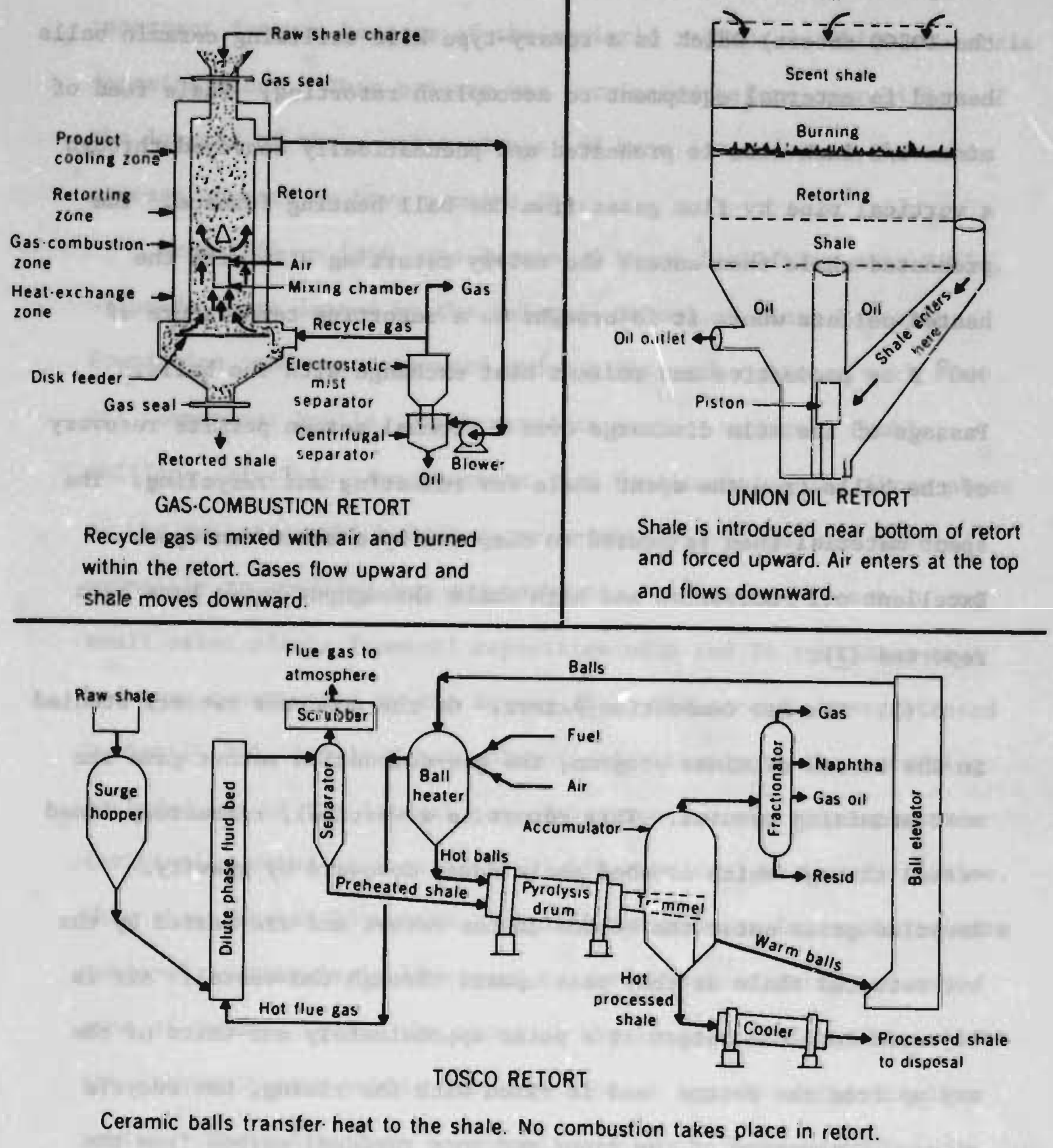

FIGURE I-4.--Schematic Representations of Three Oil Shale Retorting Processes.

using the TOSCO II retort (hereafter usually referred to simply as the TOSCO retort) which is a rotary-type kiln utilizing ceramic balls heated in external equipment to accomplish retorting. Shale feed of minus 1/2 inch size is preheated and pneumatically conveyed through a vertical pipe by flue gases from the ball heating furnace. The preheated shale then enters the rotary retorting kiln with the heated pellets where it is brought to a retorting temperature of 900° F by conductive and radiant heat exchange with the balls. Passage of the kiln discharge over a trommel screen permits recovery of the balls from the spent shale for reheating and recycling. The spent material then is routed to disposal by a screw conveyor. Excellent oil recoveries and high shale throughput rates have been reported (7).

(3) The Gas Combustion Retort.- Of the numerous retorts studied in the Bureau of Mines program, the gas-combustion retort gave the most promising results. This retort is a vertical, refractory-lined vessel through which crushed shale moves downward by gravity. Recycled gases enter the bottom of the retort and are heated by the hot retorted shale as they pass upward through the vessel. Air is injected into the retort at a point approximately one-third of the way up from the bottom and is mixed with the rising, hot recycle gases. Combustion of the gases and some residual carbon from the spent shale heats the raw shale immediately above the combustion zone to retorting temperature. Oil vapors and gases are cooled by the incoming shale and leave the top of the retort as a mist. The novel manner in which retorting, combustion, heat exchange, and product recovery are carried out gives high retorting and thermal

efficiencies. The process does not require cooling water, an important feature because of the semiarid regions in which the shale deposits occur. This program was terminated before operability of the largest of three pilot plants had been demonstrated, but the process appears to have promise (8).

From 1964 to 1968, the Bureau of Mines facilities near Rifle, Colorado, were leased by the Colorado School of Mines Research Foundation, and were operated under a research contract with six oil companies: Mobile, which acted as project manager, Humble, Phillips, Sinclair, Pan American, and Continental. The first phase of the research, which lasted approximately 2 years, was devoted primarily to studying the gas-combustion retorting process in two small pilot plants (nominal capacities of 6 and 24 tons/day) that had been constructed by the Bureau (8). The second phase, started in April 1966, involved both mining and retorting. The retorting included use of the largest gas-combustion process pilot plant (originally rated at a capacity of 150 tons/day) at the facilities. This phase lasted 18 months. Significant process improvements were achieved, particularly in regard to throughput capacity per unit size of retort. Under the terms of the lease, all data obtained in the program became public property after a 3-year confidentiality period. These data have been published by the Bureau of Mines (9, 10).

(4) Separation Systems.- Beyond having a common heating requirement, retorting processes also require provision for effective recovery and separation of the oil and gas products. Typically, this procedure involves transfer of the mixed product via a piping system to a closed train of commonly available equipment such as

impingement-type separators, centrifugal separators, and electrostatic precipitators. Absorbers and similar recovery equipment commonly used in petroleum refineries also may be included. Regardless of the details of the recovery system, which would vary depending upon the retorting process and operating parameters, the principal functions to be served are separation and recovery of oil and gaseous products in relatively clean states. Concurrently, the water inevitably produced in any retorting process and any particulates that may carry over from the retorts are trapped.

(5) Characteristics of Products From Surface Retorts.- Crude shale oils produced from surface retorts may generally be classed as low-gravity, moderate-sulfur, high-nitrogen oils by petroleum standards. Characteristically, these are more viscous and have a higher pour point (congealing temperature) than many petroleum crudes. Oils from the different processes also differ somewhat from one another as shown by the selected characterization data of Table I-2. Gas properties and yields also will vary from process to process. Internal-combustion retorts such as the gas-combustion or Union Oil Company types produce gases diluted with the products of combustion and the inert components of the air introduced to support combustion. The gas from an indirectly heated retort such as the TOSCO type is composed only of the undiluted components from the oil shale itself. Gas characterization and yield data generally illustrative of each general type of retort are presented in Table I-3.

Table I-2.--Characteristics of Crude Shale Oils.

	Retorting process		
	Gas Combustion	Union 1/	TOSCO 2/
Gravity, °API	19.7	20.7	28.0
Sulfur, wt-pct	0.74	0.77	0.80
Nitrogen, do.,	2.18	2.01	1.70
Pour Point, °F	80	90	75
Viscosity, SUS @100 °F	256	223	120
Reference Source	(10)	(40)	(28)

1/ Typical of product from original Union process.

2/ Unpublished information submitted by Colony Development Operation indicates TOSCO crude shale oil may have gravity as low as 21° API and sulfur content of 0.75 wt-pct

Table I-3.--Characteristics and Yields of Untreated Retort Gases.

	Type of Retorting Process			
	Internal Combustion		Indirectly Heated	
Composition, vol. pct	2/	2/	As Produced	After Desulfurization
Nitrogen 1/	60.1	62.1	--	--
Carbon monoxide	4.7	2.3	4.0	4.2
Carbon dioxide	29.7	24.5	23.6	24.8
Hydrogen Sulfide	0.1	0.1	4.7	(0.02)
Hydrogen	2.2	5.7	24,8	26.0
Hydrocarbons	3.2	5.3	42.9	45.0
Gross Heating Value, Btu/scf	83	100	775	815
Molecular Weight	32	30	25	24.7
Yield, scf/bbl oil 3/	20,560	10,900	923	880

1/ Includes oxygen of less than 1.0 volume percent.
2/ First analysis reflects relatively high-temperature retorting in comparison with second, promoting higher yield of carbon oxides from shale carbonate and relatively high yield of total gas.
3/ Oil from the retort.

Sources: References (40, 10, 41, and 42, respectively.)

The gas produced from internal combustion retorts has a low heating value of the order of 80 to 100 Btu/scf and cannot be economically transported a substantial distance; however, it is of value in the plant vicinity. Commerical considerations generally envision the product gas being used as a fuel for generation of power and process steam. Use of the higher heating value gas from the indirectly heated retort would be less limited. This gas, after treatment to remove sulfur compounds, could be readily used in the plant as fuel. For example, the fuel gas from the TOSCO process could be used in heating the ceramic balls which, in turn, provide the energy needed to heat the shale to retorting temperature. Other uses might be for power or steam generation or as feed material for the production of hydrogen needed in connection with upgrading the crude shale oil. Still another possibility, although economically unlikely, is that the treated gas might be introduced into the natural gas transmission system in the area to supplement the natural gas supply.

Regardless of the manner in which the various retort gases were burned to utilize their fuel values, sulfur control would be required to meet air quality standards. In this regard, standard industrial treatment could be used to remove sulfur from the retort gases as such or, optionally, could be applied to the stack gases of the burning equipment. In the particular case of the TOSCO process, the first option almost certainly would be adopted, since the sulfur concentration (as hydrogen sulfide) is high enough to permit recovery of sulfur as a byproduct. Also, in the case of the TOSCO process,

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the flue gas from the ball heater is used to preheat raw shale in a dilute phase fluidized bed as indicated in Figure I-4. The incoming crushed shale contains some fine particles which could be entrained in the effluent flue gas, requiring control of particulate matter at this point. Equipment to control such potential particulate emissions has been demonstrated in connection with recent work by the Colony Development Operation.

d. Waste Disposal

(1) Water.- Water is an inherent byproduct of oil shale retorting. It may be produced at a rate as high as 10 gallons per ton of shale retorted, but more typically, it will range from 2 to 5 gallons per ton. It will contain a variety of organic and inorganic components as shown by the typical analyses of produced waters in Table I-4. These foreign constituents can be effectively removed, as indicated in the last column of Table I-4, through addition of lime, heating, and contacting with activated carbon and ion-exchange resins. These results lend assurance that waste produced during retorting can be adequately treated for any subsequent plant or even domestic uses, thus offsetting the requirements for outside water supplies. Alternatively, such water can be minimally treated to remove odorous, volatile components and then used to wet spent shale during disposal operations. If this option was chosen, the water and any remaining mineral and organic components would be physically trapped within the compacted spent shale matrix and/or by chemical reactions with components of the spent shale (12), thereby eliminating environmental hazards associated with disposal of the incompletely treated water.

Table I-4. Composition of Raw and Treated Water
(Grams per liter)

Component	Raw Water	from Internal Combustion Retorts	Treated Water
Ammonia	2.4	8.9	nil
Organic Carbon 1/	2.5	n.d. 2/	nil
Organic Nitrogen 1/	1.0	n.d. 2/	nil
Sodium	0.5	1.0	0.06
Carbonate	20.8	14.4	0.18
Chloride	1.8	5.4	0.01
Nitrate	Trace	Trace	nil
Sulfate	1.2	1.7	nil

1/ Organics present as complex mixtures of amines, organic acids, organic bases, and neutral compounds.

2/ Not determined

Source: Reference (11)

(2) Spent Shale.- Depending on the grade of shale being processed, the weight of spent shale is about 80 to 85 percent of that of the originally mined oil shale. The remainder of the original shale weight is accounted for by the oil and gas products evolved during retorting. Table I-5 lists general relationships between mined oil shales, shale oil produced, and spent shale volumes for various rates of shale oil production. The volume of the spent material, even after maximum compaction, is at least 12 percent greater than its in-place volume. This is due to void spaces in the mass of crushed and retorted material which are not present in the shale prior to mining. In practice, final densities would vary considerably depending upon the compaction technique employed and the physical characteristics of the spent material, such as its particle size distribution.

As indicated above, not all of the material can be returned to underground workings; consequently, surface disposal would be required to some extent in all cases. Depending on the retorting process, the material may vary in particle size from a fine powder to about 10 inches in diameter and would be discharged from the retort as a dry material. For disposal, larger sized materials would probably require crushing, and water (10 to 20 percent by weight) would be added to reduce dusting and aid consolidation of the disposal piles. Transport to the disposal area probably would be accomplished by a hooded belt conveyor or by a water slurry system; excess water in the latter option would be recovered and recycled. Pneumatic transport or conveyance by trucks also are possibilities, with moisture being added at the disposal site.

Table I-5. Quantities of In-Place and Spent Shales

Upgraded Shale Oil, barrels per day	Shale Mined, Million Tons per Year	Shale Volumes, billion cu. ft. per year		
		In-Place	Spent (loose)	Spent (compacted)
50,000	26.9 - 29.9	0.40 - 0.45	0.60 - 0.70	0.45 - 0.52
100,000	53.8 - 59.8	0.80 - 0.90	1.20 - 1.40	0.90 - 1.04
250,000	134.5 -149.5	2.00 - 2.25	3.00 - 3.50	2.25 - 2.60
1,000,000	538.0 -598.0	8.00 - 9.00	12.00 - 14.00	9.00 -10.40

Basis: Oil shale assaying 30 gallons per ton; upgraded oil yield of 86 - 95 vol. pct., based on in-place crude shale oil potential; loosely dumped spent shale bulk density of 71 - 75 lbs. per cu. ft.; compacted spent shale bulk density of 90 - 100 lbs. per cu. ft.

The mineral content of spent shale generally reflects the mineral composition of the raw shale (Table I-1), although many of the original components are altered under the influence of heat in the retorting step. For example, some portion of the dolomite (a complex of calcium and magnesium carbonates) will be decomposed to yield calcium and magnesium oxides. In this regard, the extent of such decomposition depends upon the type of retorting process and the conditions of operation, particularly the temperature to which the oil shale is subjected. In the case of the Union retort, for example, a peak shale temperature of about 1,800° F is reached, causing practically complete decomposition of carbonates and other temperature-sensitive minerals. In contrast, shale in the TOSCO retort reaches a temperature of only about 900° F, and very little mineral decomposition occurs. An intermediate extent of decomposition is experienced in the gas combustion retort which has a peak shale temperature of the order of 1,200° F. Regardless, the basic oxide forms of the minerals in the spent materials are similar, being represented generally by the shale ash analysis that appears in Table I-6.

Of particular interest, some components of spent shale residues are significantly water soluble, indicating the need to guard against uncontrolled leaching. Tests have indicated (12, 13, 31) that water after intimate contact with spent shale will be highly alkaline and contain high concentrations of calcium, sodium, and potassium in the form of sulfates, whether or not material mineral decomposition has occurred in the retorting process. The other components listed in

Table I-6. Mineral Composition of Spent Shale Ash

Component	Composition expressed as oxide weight percent of ash 1/
SiO_2	42.3
Fe_2O_3	4.5
Al_2O_3	13.0
CaO	23.1
MgO	9.9
SO_3	1.8
Na_2O	3.1
K_2O	2.3

1/ Trace elements not shown above include Pb-45 ppm, Hg-0.1 ppm, and Cd-1.7 ppm (Source: Colony Development Operation).

Source: (8, pg. 11)

Table 6 will contribute very little to the mineral content of leached waters.

Perhaps of equal significance to mineral composition, spent shale residues vary in regard to the amount of carbonaceous material left on the processed shale, ranging from about 5 to 6 weight percent in the case of low temperature TOSCO residue, to about 3 percent for gas combustion spent shale, to nil in the case of Union residue, which is essentially a shale ash. Experimental work on a small scale indicates that natural surface-cementation reactions will greatly retard leaching and materially expedite stabilization within a few days, particularly if the spent material is in ash form or low in carbon residue. This natural cementation process is inhibited if a material amount of carbon is present to coat the particles, as in the case of TOSCO spent shale, but the carbon coating itself tends to prevent water penetration to the extent that percolation-type leaching is not expected to be a problem. However, steps must be taken to control surface runoff from spent materials, regardless of carbon content, to minimize erosion and pickup of surface or near-surface soluble minerals until vegetative cover or other stabilization measures can become fully effective. Such surface runoff water -- as well as any percolation water should percolation occur -- should be impounded as a safeguard against release of mineralized water to the surrounding area.

e. Upgrading of Crude Shale Oil

Crude shale oils typically have high pour points, are rather viscous, and tend to form sludge and otherwise deteriorate if stored in tanks for prolonged periods of time. Consequently, crude shale oils in all probability would be partially refined soon after production at the retorting plant to decrease their pour point and viscosity and to materially improve their stability characteristics. By so doing, an upgraded oil suitable for pipeline transport and final refining elsewhere — a point that is discussed in more detail later — would be the major on-site oil product.

Various means of upgrading crude shale oil have been proposed, including heat treatment of certain fractions at 600° to 800° F. for a period of time, visbreaking the total oil along lines commonly practiced by the petroleum industry, and, in recent years, hydrogenation under cracking conditions (hydrocracking) of either the total oil or of a distillate prepared by first coking the total oil. Of the various options, hydrocracking using established techniques of the petroleum industry appears best suited to reduce pour point and viscosity and to prevent deterioration. This general approach has been quite commonly visualized by companies and other groups that are considering industrial oil shale operations and has been reasonably well demonstrated. The applicability of modern petroleum refining techniques to shale oil is brought out in the following excerpts from a recent publication, covering not only the upgrading step but also some of the final refining possibilities (3):

Numerous combinations of modern petroleum refining processes can be applied successfully to shale oil. This has been demonstrated experimentally by the Bureau of Mines and industry (14). Hydrogenation is the heart of most refining procedures currently considered suitable for shale oil. Hydrocracking, for example, may be applied to crude shale oil or to the product of a preparatory operation such as coking. The naptha fraction of the resulting hydrocracked product could be catalytically reformed to produce a satisfactory yield of high quality gasoline.

Use of hydrogen in petroleum refining began on a significant scale in the 1950's and has gained widespread use. Earlier, the cost of hydrogen had been prohibitive. Even though hydrogen is much cheaper today, it still would be a substantial cost item in commercial shale oil refining. Hydrogenation is an effective means of removing sulfur, nitrogen, and oxygen from shale oil and of stabilizing the more reactive unsaturated components, thereby reducing their gum-forming and color-forming tendencies. In combination with cracking conditions, gasoline yields can be greatly increased. Excellent yields of high-quality jet, diesel, and distillate fuels also can be obtained.

It is generally considered that satisfactory commercial shale oil refining facilities could be built, or existing units adapted, without going through an elaborate scaleup program... In 1963, it was reported that some 20,000 barrels of shale oil from the retorting plant of the Union Oil Company of California had been refined in a small, modern refinery near Grand Junction, Colorado, and the products marketed and utilized satisfactorily. More recently, Union was reported to be building a large refinery in the Chicago area that would be capable of processing shale oil and oil from Canadian tar sands.

Properties of an upgraded shale oil appear in Table I-7; for a comparison with raw shale oil see Table I-2. Additionally, the upgrading procedure will yield high-quality gas for use within the plant, and ammonia and sulfur byproducts. Excess gas may be available for generating off-site power for direct use in nearby communities (Table I-3).

Table I-7. Properties of an Upgraded Shale Oil

Property	Value
Gravity, °API	46.2
Sulfur, wt-pct	0.005
Nitrogen, wt-pct	0.035
Pour Point, °F	below 50
Viscosity, SUS @100 °F	40

Source: (28, pg. 165).

Upgraded shale oil probably would be moved to refining centers via pipelines for production of finished products, thus minimizing the need for new construction in the relatively remote area of the oil shale deposits and taking advantage of established marketing systems in areas of high product demand. Some of this oil might move to the West Coast; however, the timing of shale oil production and that of the expected North Slope oil 1/ indicates that shale oil would be largely directed toward Chicago and other Midwestern refining centers. The principal existing pipelines are shown in Figure I-5. Possible shale oil connecting lines are shown on this figure as crossed lines. Additional mainline capacity that may be needed in the future depends upon the combined amount of petroleum and shale oil that will require movement out of the Rocky Mountain region. It is reasonable to assume that mainline capacity will be developed as the need dictates, either to the east or west. At present, the excess mainline capacity out of the general oil shale region is approximately 100,000 barrels per day. Assuming that this situation does not change materially within the next several years, addtional capacity would be needed by about 1978 to serve projected needs under the proposed prototype leasing program.

f. Minerals Production

Extensive deposits of sodium minerals, one of which contains aluminum, have been discovered in or associated with the deep oil shales of Colorado's Piceance Creek Basin. Dawsonite, the aluminum-bearing mineral, was discovered in 1958 but was not investigated

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1/ See Volume II, Chapter III.

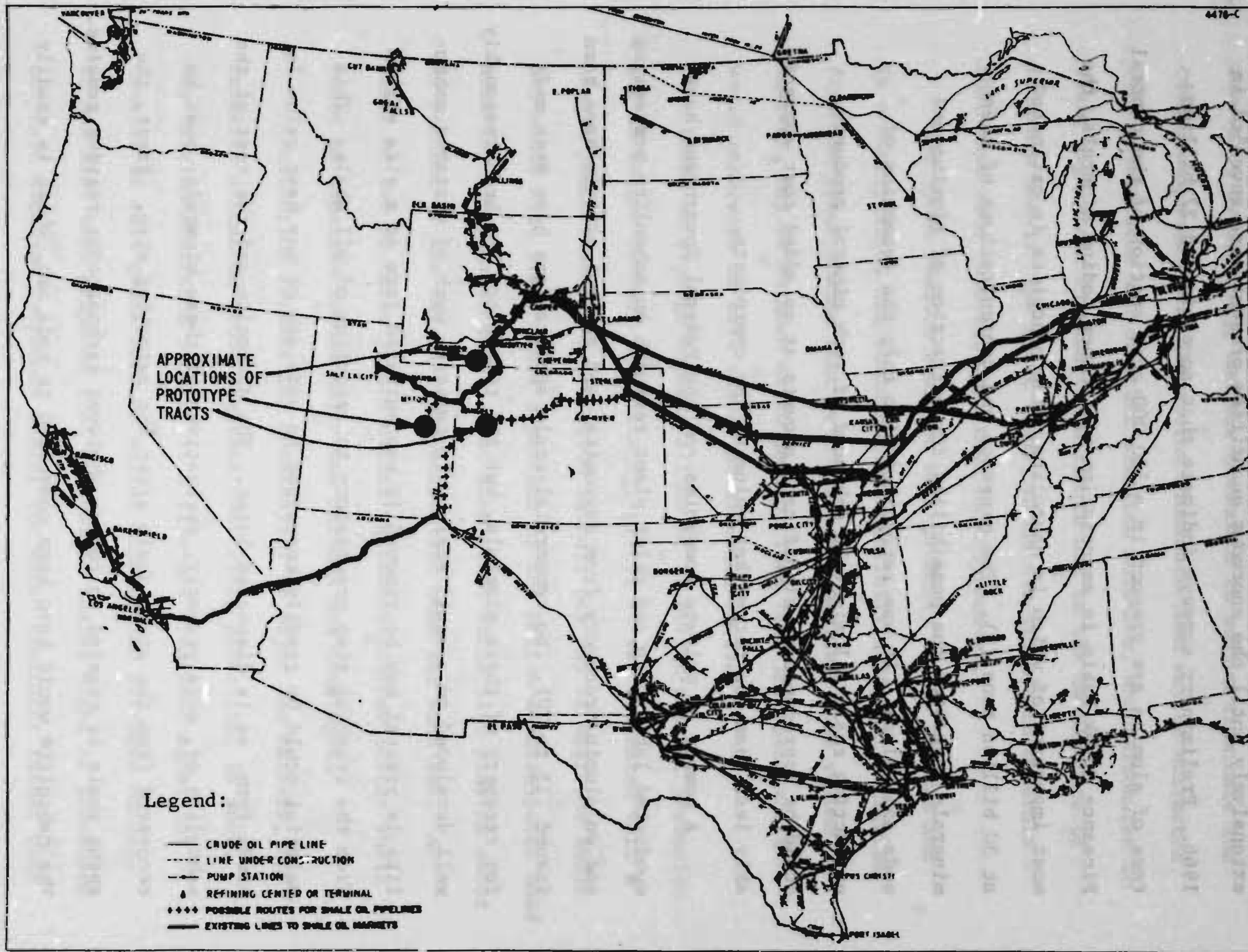

FIGURE I-5.--Crude Oil Pipelines That Could Be Used to Transport Shale Oil.

extensively until the enormous quantities present were revealed in 1966. Preliminary surveys indicate that an estimated 27 billion tons of alumina are present in a 150,000 acre section of the central Piceance Creek Basin in association with other sodium minerals, the most important of which is nahcolite. The nahcolite is estimated at 30 billion tons (2). The presence and concentrations of these minerals suggested the possibility for extraction of alumina and soda ash values. It was recognized also that the economics of extracting shale oil might be enhanced if such mineral products could be coproduced in significant amounts at an added cost appreciably less than the net market value of the coproducts.

A number of private companies and the Federal Government have conducted laboratory and pilot plant research on nahcolite processing and on alumina recovery from dawsonite, and several patents have been issued (15 to 20). No commercial-scale applications have been made for recovery of these minerals, but the technology has been reasonably well developed on a small scale. In concept, much of whatever nahcolite is present may be removed in concentrated form as a side stream from the crushing step preparatory to retorting of oil shale. This material could be readily converted to soda ash or may have value in crude form, as is discussed later. The dawsonite and the rest of the nahcolite or, more properly, derivatives of these minerals, must be recovered from the spent shale after the retorting step. First, the spent shale is roasted to remove whatever carbonaceous residue remains. The nahcolite would have been converted to soda ash, which is readily removable by leaching, and the dawsonite to sodium aluminate and additional soda ash. The sodium aluminate then may be extracted with dilute soda ash or other alkaline solution, and carbonated to yield high grade alumina for ultimate use in the manufacture of aluminum metal. The spent shale, minus the associated minerals that have been removed, must then be disposed of.

The spent residue would be wet, probably finely divided and in a slurry form, but would not be materially different otherwise from the spent shales that were discussed earlier. The volume, however, may be as much as 20 percent less than the spent shale would otherwise be as a result of minerals recovery.

Based on average concentrations of 11 weight-percent dawsonite and 15 weight-percent nahcolite (2, p.71), it was estimated that a single plant that produces 35,000 barrels per day of upgraded shale oil would also yield about 3 percent of the Nation's anticipated need need for aluminum in 1980. That same plant could also provide about 15 percent of the Nation's projected 1980 need for soda ash. A limit of two or three plants utilizing nahcolitic/dawsonitic shale would be expected unless major new markets are developed.

Considering further the possibility of major new markets, the research discussed above suggests that crude nahcolite, as such, may have considerable promise as a flue-gas treatment agent for control of acid gases such as sulfur dioxide and nitrogen oxides. It has also been proposed that dawsonitic shales might be processed to yield aluminum compounds useful for water treatment rather than to yield metallurgical-grade alumina. The first of these possibilities in particular--widespread use of crude nahcolite for treatment of flue gases--could conceivably greatly relieve the restriction imposed by current marketing considerations upon the number of plants ultimately utilizing nahcolitic/dawsonitic shales. This possibility may require more rigorous analysis at some future time if public lands, in addition to those presently proposed for leasing, should be offered and if the technology and economics of the flue gas/water treatment options become better established by a considerably larger-scale research and development effort than has currently been undertaken.

2. In Situ Processing

In situ experimentation has been conducted by various companies and the Bureau of Mines for a period of years. This process involves underground heating by such means as combustion in the formation, introduction of hot natural gas, or introduction of superheated steam. However, the technology is not yet developed to the extent that prediction of either technical or economic success is warranted.

A key problem is the creation of permeability within the shale formation. Two major approaches are in early stages of investigation. One approach proposes limited fracturing by conventional means, whereas the other proposes massive fracturing by a nuclear explosion.

Sinclair Oil Corporation (merged into Atlantic Richfield Company in 1969) experimented with conventional in situ retorting of oil shale in 1953 and 1954 at a site near DeBeque on the southern edge of the Piceance Creek Basin. From these tests it was concluded that communication between wells could be established successfully, although high pressures were required to maintain injection rates during the heating period, and that combustion could be established and maintained in the shale bed (21). Over a period of several years, in the mid-1960's, Sinclair conducted additional field research on the in situ process at a site near the center of the Piceance Creek Basin, where the shale is much deeper and thicker than it was at the site of the first experiment. The results of this experiment were not promising; fracturing techniques that were used did not produce sufficient heat transfer surfaces for successful operation (22, 23).

Also, in the 1960's, Equity Oil Company conducted field experiments on in situ processing of oil shale in the Piceance Creek Basin. The process employed the injection of hot natural gas to retort the oil shale rather than using underground combustion for this purpose. However, the experiment suffered large gas losses to the formation (24).

Several less extensive investigations of the in situ technique have been conducted by various oil companies during the last 10 years or so, but very little has been published concerning the results achieved. The Bureau of Mines also is conducting field and small-scale research on in situ retorting. Results to date are inconclusive.

The possibility of utilizing a nuclear explosive to fracture oil shale preparatory to in situ retorting has been under consideration since 1958. A feasibility study for a nuclear experiment (25), Project Bronco, was proposed in the Piceance Creek Basin. Later, a similar experiment was proposed for the Uinta Basin (26). Neither

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of these experiments is being actively considered at the present time. The lack of firm data precludes further analysis of this technique at this time. If such a project is proposed on public lands, it will require a complete environmental analysis, including the preparation of an environmental impact statement specifically addressed to this subject. Those factors that must be considered, such as ground motion and containment of radioactivity released from the explosion, have been discussed in detail in the concept documents referenced above.

A design concept for conventional in situ retorting based upon contemporary petroleum technology is presented in Figure I-6. The essential steps include: (1) well drilling, (2) fracturing to permit heat transfer and movement of liquids and gases, (3) application of heat, and (4) recovery of products.

Two major problems encountered in in situ research to date have been:

(1) Insufficient naturally occurring permeability, or failure to artificially induce permeability so as to allow passage of gases and liquids; and

(2) Inability to remotely control the process with sufficient accuracy through wellbores from the surface.

Besides surface wellbores, other methods proposed for introducing heat underground include mine shafts, tunnels, and fractures created by a variety of techniques.

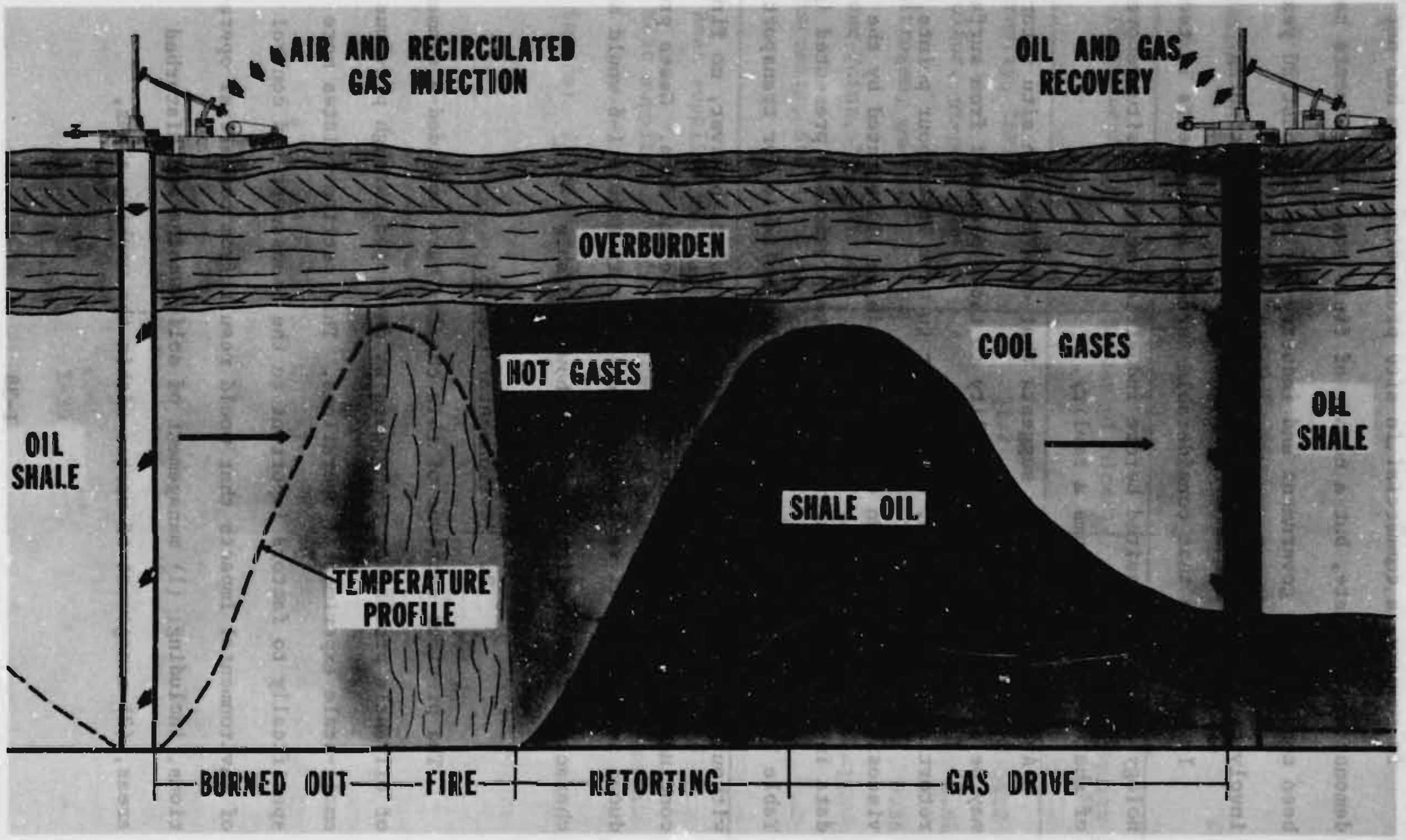

FIGURE I-6.--Schematic Representation of an In Situ Retorting Operation.

In summary, a commercial in situ processing system has not been demonstrated to date, but a number of field-scale experiments have been conducted by government and industry during the past 20 years, involving wellbores from the surface, and work is continuing.

It is obvious that considerable further improvements in technology are still required before industrial-scale in situ recovery of shale oil could become a reality.

Available information suggests that oils from in situ retorting may be somewhat superior in quality to those produced from surface retorting. Specifically, they appear to have lower pour points, viscosities, and nitrogen contents. This is illustrated by the data in Table I-8 as compared to the data previously presented in Table I-2. In situ oil may be marginally suitable for transporting witnout upgrading because of the low pour point; however, no firm conclusions are possible because of insufficient data. Gases produced in the gas/oil separation step shown in Figure I-6 would have characteristics similar to those shown in Table I-9.

D. Environmental Control

The previous sections of this chapter have provided a summary of oil shale processing techniques as developed through previous small-scale experimental operations. This section relates more specifically to factors important to the assessment and control of environmental impacts that would result from commercial operations, including: (1) management of solid wastes and disturbed areas, (2) management of wastes within the working areas,

Table I-8.--Characteristics of Oils From In Situ Retorting.

Characteristic	Bureau of Mines 1/	Sinclair 1/	Equity 2/
Gravity, °API	31.7	30.6	54.2
Sulfur, wt-pct	0.67	1.28	0.61
Nitrogen, wt-pct	1.35	1.14	0.36
Pour Point, °F	+5	+35	-15
Viscosity, SUS @ 100 °F	41.0	--	--

1 / Heat supplied by underground combustion.

2 / Heat supplied by introduction of hot natural gas to formation.

Source: (27).

Table I-9.--Characteristics of Gases From In Situ Retorting.[1]

Component	Concentration, Volume-Percent
Nitrogen	73.7
Oxygen	3.4
Propane	0.2
Carbon dioxide	21.4
Carbon monoxide	0.1
Hydrogen sulfide	0.1
Butanes	0.1
Methane	0.5
Ethane	0.5

1/ Heating value approx. 30 Btu/scf,
Yield from operation at level of 50,000 B/CD upgraded, shale oil approximately 1,485 x 10^6 SCF/CD.

Source: (27).

(3) environmental control during in situ processing, and (4) monitoring. This review of environmental control technologies is made to establish the base against which environmental impacts can be evaluated.

1. Management of Solid Wastes and Disturbed Areas

Once the spent shale has been conveyed to a disposal site, provision must be made to create a stable pile to prevent erosion and/or leaching of sediments and resident minerals. These precautions are needed regardless of whether the spent material is carbon coated, as is typical of indirectly heated retorts, such as the TOSCO type, or is essentially a spent shale ash with little or no carbon residue, as is typical of combustion-type retorts such as the Union retort, or, to a lesser degree, the gas combustion retort (See Section C.1.d.(2)).

a. Stability

Stability of a spent shale ash (carbon-free spent shale) was studied by the Denver Research Institute (12) using two approaches: (1) physical strength studies of shale ash as a function of a number of variables, and (2) chemical studies as a function of these variables in order to define the cementing components in the hydration products of shale ash. The variables studied to date include: (a) composition of shale ash, (b) burning temperature, (c) burning time, (d) moisture content, (e) degree of compaction, (f) storage time, and (g) storage temperature.

That study showed that the rate of cementation of shale ash is "...similar to that in portland cement setting (12, p.22 and 92)." The study also stated that:

Increased compaction results in greater strengths. Grain size distribution is also important. To secure greatest strength, compaction should be applied soon after mixing with water to eliminate disruption of the initial set. Much compaction can occur under the steady weight of the shale pile before several days have elapsed and setting is too far advanced. Unconfined strengths of 60-70 psi have been obtained under pressures simulating 75 foot depths with 10 percent water and preliminary 10 percent Standard Proctor compaction. For comparison, strengths of 100-200 psi are adequate for some highway base course construction.

Water saturation after initial setup produces no loss of strength with well burned material, indeed some gain was generally observed. Although the present emphasis has been on the study of the cohesive strength of more or less compacted spent shale, it should be recognized that sometimes too high a cohesive strength is a detriment if it prevents cracks in the head of a dump pile from self-healing. High cohesive strength, of course, may be of little value if the soil on which a pile is built is weak or may be weakened with moisture.

It is assumed that most spent shale will be initially disposed of in box canyons. Engineering design of this operation must consider the properties of the foundation upon which this material will rest and the angle of repose which will assure frictional stability. In general, it was concluded that (12, p. 63):

> ...a suitably processed spent shale ash will develop sufficient cohesion so that deep, well stabilized dumps with high angles of slope may be constructed. Because of the probable poorer mechanical characteristics of the soil in the bottom of the canyons where the shale ash will likely be dumped, it is likely that the foundations under the shale ash dumps will limit the allowable safe slope angles and heights which may be built.

At a 45° slope, the tolerable depth may be 100 feet and at 26°, the height may be several hundred feet. The actual slope to be constructed would require additional tests to determine the actual characteristics of the surface and subsurface foundation material.

A technically feasible scheme that would provide an 18° [1/] slope has been proposed (30) to place:

> ...processed shale in a series of horizontal layers some one to two feet thick such that the upper surface would always be a temporary surface until the last layer is placed. However, each layer would be started a little further back into the canyon, giving the front surface of the pile, or permanent surface a 3:1 [1/] slope. This slope is well below the angle of repose and insures frictional stability. Overall stability of the embankment is also assured by compaction level, vegetation, and placement of broken rock on the permanent face.

During the buildup of the waste material to its design height, some erosion will occur. The greatest concern is not with the normal snow and/or rain that occurs throughout the year, but with (12, p.62):

> ...occasional flash floods which may amount to 1.5 to 2.0 inches of rainfall in a few hours. To handle the runoff from the plateau which drains into the canyons, it will likely be necessary to either channel the water away from the canyons containing shale ash dumps or to install large conduits in the bottom of the canyons under the shale ash dumps.

Upstream flood control dams and/or conduits can be used to protect the disposal area during buildup. Additionally:

> To handle the runoff from the shale ash dumps from a flash flood, it will likely be necessary to install a small dam or retaining pond immediately downstream of the dump in order to catch the runoff from the dumps....

This water, including the brines, can then be returned and used in subsequent disposal operations. The concept of collecting surface runoff in ponds downstream of the residue pile has been confirmed by a study conducted by Colorado State University for the Environmental

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1/ A 12-18 degree slope (4.4:1 to 3:1) has been suggested by these authors in a later, private communication.

Protection Agency (13, p. 3). That study, which used carbon-bearing spent material from the TOSCO process, also detailed the chemical properties of the quality and quantity of runoff from spent oil shale residue due to rainfall. The project consisted of three phases of work (13, p. 94):

> (1) Bench-scale studies were used to determine (a) permeability, porosity, and particle size distribution, (b) the composition and maximum quantity of dissolved solids leachable by complete slurry treatment; and (c) the composition and quantity of dissolved solids leachable by simple downward percolation through residue columns. (2) Pilot studies were conducted on the TOSCO unweathered spent shale to define (a) the composition and concentration of dissolved solids in runoff from a spent shale pile; and (b) the properties of the residue within the pile before and after rainfall simulation. (3) Data was interpreted using statistical techniques to determine the quantitative relationships between the dependent and independent variables significant to spent oil shale residue leaching.

Specifically, it was shown that:

> Leaching tests show that there is a definite potential for high concentrations of Na^+, Ca^{++}, Mg^{++}, and $SO_4^=$ in the runoff from spent oil shale residues. However, with proper compaction, the piles become essentially impermeable to rainfall.

Rainfall tests were conducted in a large excavation approximately 3 feet deep, 7 feet wide, and 80 feet long. Water applied over the first experiments totaled 26 inches in 2 days -- nearly 2 years of normal precipitation for most of oil shale areas. Other tests were conducted over a period of several months and, ". . . no percolation occurred during the rainfall simulation . . . only minor fluctuations were observed in the moisture content of the shale below the 9 inch depth . . . ." (13 p.73)

Permeability of the residue to water was also shown to decrease with time, the most likely reason being the swelling of shale due to the hydration effects of the sodium ion (13, p.71), or possibly to progressive interstitial packing of the various sized particles. In addition:

> Drying of the shale surface causes movement of water from the interior to the surface by capillary action. On reaching the surface, the water evaporates leaving behind a white deposit that is clearly visible on the black surface. This deposit is dissolved during the rainfall with the result that both concentration and composition of dissolved solids in the runoff water vary with time and depend on the amount of drying prior to the rain. ...The rate at which the deposit is formed therefore is clearly dependent on the rate at which capillary action can carry the very concentrated solution from the pores within the shale residue to the surface, because the material can be evaporated more rapidly than it can be transported to the surface by capillary action (13, p.55).

The studies referenced above (12, 13) indicate that water contamination due to percolation-type leaching will be negligible and that surface leaching, although runoff waters must be impounded, will not pose critical problems. Further, the surface leaching potential should decrease with time.

Other studies were subsequently made on TOSCO carbon-bearing spent shale to show the effects of snowfall (31). These indicated that snow melting over a period of time tends to decrease compaction in the top several feet of a TOSCO-type spent shale deposit and to penetrate into the deposit to a greater degree than in the case of rainfall. As a result, the penetrated depth is made more susceptible to shifting and sliding. The tests also indicated that although runoff from melting snow would contain material concentrations of dissolved minerals, the degree of mineralization would be less than in the case of rainfall runoff.

The spent shale, for which the above results were obtained, contained 10.2 percent carbon. Spent shale, with lower carbon content, would be less permeable due to an increased tendency for cementation of the particles.

During the active buildup of a disposal area, snowfall would probably not present any uncontrollable leaching problems since the addition of new material and compaction would be continuous processes. It would, however, be necessary to impound runoff waters--and any percolation waters should percolation occur--and to safeguard the deposit against washing from heavy water flows in the area that might occur during periods of rapidly melting snow, such as in the late spring season. Once the pile has reached the desired height, it will probably be necessary to protect the top layer by adding native soils to facilitate revegetation and hence reduce overland flows and slippage.

b. Potential for Spontaneous Combustion

(1) Retorted Shale.- The potential for spontaneous combustion to occur in compacted piles of retorted shale has been examined to determine the degree of risk to the environment that might be inherent in the disposal of processed shale. This analysis must, by necessity, be hypothetical since there are no known instances where spontaneous combustion of retorted shale piles has occurred from continuous operations using research and pilot plant retorts in the Piceance Creek Basin over approximately the past 30 years. Experience indicates a

low degree of risk when retorting has been uniformly effective and compaction adequate.

Examination of the pertinent properties of retorted shales from potential processes, such as the gas combustion retorts, the Union retort, and the TOSCO retort, indicate that burning initiated by spontaneous combustion in retorted shale piles requires that three conditions be met: (1) fuel must be available; (2) a minimum temperature to initiate the combustion must be attained; and (3) oxygen must be available. Related to these primary conditions are properties of retorted shale and/or pile characteristics: (1) temperature rise from absorption of solar radiation; (2) permeability of the shale piles; (3) particle size or equivalent surface area of the retorted shale; and (4) the organic carbon content of the shale.

Spent shale is a complex waste product whose physical and chemical properties will vary widely. Primary controlling factors are: (1) composition of the oil shale before retorting; (2) preparation of the shale for retorting; (3) type of retorting process used, and (4) the conditions encountered after retorting.

The properties of some typical shales processed by the gas combustion, TOSCO, and Union Oil Company methods are given in Table I-10 (45). The size of the Union Oil Company product is not given since this retort is operated to maintain a much larger size, often by clinkering, for the retorted shale than for either of the other retorts. Bulk density for each of the shales is a measure of the density of the particles and of the void space in a volume containing the particles. The solids density from the Union retort indicates clinkering or fusing of the retorted shale. Temperatures of shale piles under storage conditions have been determined for TOSCO shale. This shale is dark in color, relative to the other two, so it should absorb the largest amount of solar energy. The temperature within the shale piles varied from 20-24° C; at the surface the temperature reached 77° C.

A separate study (46) reports the organic carbon remaining on shales after retorting by the Fischer Assay technique. This retorting is done in the absence of air--no oxidation of carbon--so the organic carbon remaining on the residue should be a maximum. The results are given in Table I-11. The carbon generally increases with an increase in oil yield from 1.81 weight percent for 17.8 gal/ton shale to 4.99 weight percent for 51.8 gal/ton shale which encompasses the broad range of values to be expected in a commercial operation.

The temperature required to initiate combustion in the residual carbon on retorted shale with about three weight percent organic carbon has been determined (47). The retorted shale was placed in a furnace, in air, and successively raised in temperature in 25° C increments. These induced properties caused the carbon residue to ignite at 470° C. Since the temperatures of the spent shale in storage is only 20-24° C (internal) or 77° C at the surface, the probability of spontaneous ignition is extremely remote.

(2) Raw Shale.- The processing of oil shales may require that storage piles of mined, raw shale be maintained as process feed, or as material not suitable for processing, or possibly for future blending operations. Experience with shale storage piles produced during experimental mining which took place in the Bureau of Mines Anvil Points Mine during the 1940's and 1950's, and subsequently during experimental mining conducted by Mobil Oil Company from 1964 to 1968 indicated that

TABLE I-10.--PROPERTIES OF RETORTED OIL SHALES

	Gas Combustion Retort	TOSCO Retort	Union Oil Company Retort
Geometric mean size, cm.	0.205	0.007	Not given
Permeability, cm^2	3.46×10^{-9}	2.5×10^{-10}	Not given
Bulk density, g/cc	1.44	1.30	1.80
Solid density, g/cc	2.46	2.49	2.71
Maximum size, cm	3.81	0.476	Not given
Minimum size, cm	0.00077	0.00077	Not given

Source: Reference (45)

TABLE I-11.--ORGANIC CARBON IN RESIDUES FROM RETORTED SHALES WITH VARIOUS FISCHER ASSAY OIL YIELDS
(Values Expected in a Commercial Operation)

	Retorted Shale								
Oil yield, gal/ton	17.8	18.8	19.5	21.4	22.3	29.8	36.6	38.0	51.8
Org. Carbon, wt. percent	1.81	2.01	1.69	2.47	2.49	2.97	3.53	4.20	4.99

Source: Reference (46)

spontaneous combustion will not be a problem. Each of these mining operations utilized a common disposal area. Weathering has certainly taken place to reduce the available fuel at the surface. It has been shown that weathering reduces oil yield, a measure of available organic material, about 11 percent in five years (46). The weathering probably represents oxidation with the production of heat, but not sufficient to cause ignition. However, oil shale, particularly higher grade oil shale, will burn if ignition temperature is reached. The cliff faces above the Colorado River are scarred with patches of burned shale. Ignition probably was started by lightning strikes. The surface shale burned, but combustion was not maintained, apparently because oxygen was not delivered to the burning zone at a rate fast enough to maintain the temperature required for combustion.

(3) Summary.- The experience of the past thirty years suggests that the risk of a spontaneous ignition in retorted oil shale is minimal; the fuel content of the residues is small and laboratory experiments indicate an ignition temperature higher than can reasonably be expected in practice. The low permeability of adequately compacted discard piles/dumps suggest that oxygen would not be delivered to a burning site fast enough to maintain combustion even if the ignition temperature is reached. Hence, retorted shale from a properly designed processing complex should not be subject to any appreciable chance of spontaneous combustion.

Raw shale stockpiled for processing will burn if ignition temperatures are reached. Being more permeable than compacted spent shale, it is conceivable that sufficient air would circulate through the pile to support the combustion. However, such an event is unlikely to go undetected for long periods since such piles would be located in close proximity to the processing plant and be subject to considerable control; for example, earthmoving equipment and water would be readily available. Therefore, such combustion would pose only a short-term problem that is easily controllable should it occur at all.

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2. Revegetation of Oil Shale Development Areas

Little systematic investigation of revegetation requirements was undertaken through the 1950's, but increasing attention has been given to this aspect of solid waste management in recent years.

Revegetation needs relating to oil shale development fall into two broad categories: (1) disturbed areas created by structural operations, including pits, overburdened spoil piles, roadways, utility corridors, building sites, etc.; (2) areas of spent shale deposition.

The scope of revegetation needs will not be known until detailed mining plans are announced. The type of mining operation selected will be a major factor in identifying land restoration and revegetation needs. Surface mining would create the greatest surface disturbances. Underground mining would cause much less surface disturbance and less volume of spent shale. In situ mining would create the least disturbance and little, if any, residues.

The type of retorting used will determine the nature of spent shale material produced. At present, only a few types of spent shale material are available for study from pilot plant operations.

a. Disturbed Area Revegetation

The land restoration planner has many options in preparing a revegetation plan. As indicated in the descriptions of the vegetation of the oil shale area in Chapter II, many diverse plant communities exist and there is the potential for many plant species to grow in a variety of combinations.

A sound revegetation plan must consider future planned use of the land treatment necessary to achieve stabilization. Revegetation objectives may be obtained through natural plant establishment and succession, reseeding of native species combinations, or establishment of exotic plant communities. On some tracts, alternatives will be available regarding grass, browse, or forb species. Wildlife needs will be important in selecting the proper alternative.

In the development of the mining plan, all factors that will assure successful reestablishment of the desired vegetation must be considered, soil disturbances should be minimized, slopes should be no more than 4:1 and should blend with the existing topography, fertilizers and mulches should be planned, topsoil fully utilized, firm seedbeds prepared, and proper species selected.

Several excellent guides are available to successfully implement a revegetation plan. Of particular importance is the work by Plummer (44) on establishment of browse plants in the vegetative types typical of the oil shale region. This research, which has been under way since 1955 (U.S. Forest Service Publication 68-3), has emphasized the study of shrubs and forbs and recognizes that more extensive studies have been done on grasses by the Agricultural Research Service, the Soil Conservation Service, and State Experiment Stations. Of more than 400 species and 3,000 varients tested, about 75 browse, 75 forbs, and 55 grasses show usefulness for improving game ranges.

b. Principles of Successful Revegetation

Range Improvement Notes 15(1): 1-8, 1970, Plants for Revegetation of Roadcuts and Other Disturbed Areas, illustrates the type of useful information available as a result of the Plummer studies. This publication contains the following summary statement on revegetation principles and a tabulation of browse plants adapted to the various vegetal types (Tables I-12 and I-13):

TABLE I-12--Shrubs used for stabilizing roadcuts and disturbed areas are listed in categories based on mature stature. Vegetal types are listed in the order that species are adapted to them

Low	Medium	Tall
Barberry, creeping - MB,A,SA,JP,AA	Apache plume - JP,BB,BS,MB	Apache plume - JP,BB,BS,MB
Bitterbrush, antelope - JP,MB,BS,BB	Barberry, Fremont - JP,BB	Aspen - A
Bitterbrush, desert - JP,BS,BB,MB	Bitterbrush, antelope - JP,BS,MB,BB	Bitterbrush, antelope - JP,BS,BB,MB
Buffaloberry, silver - MB,WM,JP	Bitterbrush, desert - JP,BS,BB,MB	Buffaloberry, silver - MB,WM,JP
Ceanothus, Martin - MB,JP,A,BS	Bladdersenna, common - MB,JP,A	Cherry, bitter - MB,JP,A,BS
Cherry, Bessy - MB,JP,A	Boxelder - MB,A,JP	Chokecherry, black - MB,JP,A,BS,SA
Cinquefoil, bush - SA,A,WM	Buffaloberry, silver - MB WM,JP	Cliffrose, Stansbury - BS,BB,MB
Cotoneaster, Peking - MB,JP	Cherry, bitter - MB,JP,A,BS	Cottonwood, narrowleaf - MB,JP,BS
Currant, golden - MB,JP,BS,WM	Chokecherry, black -MB,JP,A,BS,SA	Currant, golden - MB,JP,BS,WM
Eriogonum, Wyeth - MB,JP,BS,A,SA	Cottonwood, narrowleaf - MB,JP,BS	Cypress, Arizona - MB,JP,BS,BB
Ephedra, green - BS,JP,SS,BB	Currant, golden - MB,JP,BS,WM	Elder, blueberry - MB,JP,A,BS
Hopsage, spineless - SS,BS,JP,BB	Cypress, Arizona - MB,JP,BS,BB	Forestiera, New Mexican - MB,JP,BS
Lilac, common - MB,JP,BS,A	Dogwood, redosier - MB,A,SA	Honeysuckle, Tatarian - MB,JP,BS
Mountain-mahogany, birchleaf-JP,MB,BS	Elder, blueberry - MB,JP,A,BS	Lilac, common - MB,JP,BS,A
Myrtle pachistima - MB,A,SA,JP	Elder, redberry - A,MB,SA,AA	Maple, bigtooth - MB,A,JP
Peachbush, desert - JP,MB,BS,SS,BB	Ephedra, green - JP,BS,MB,SS,BB	Maple, Rocky Mountain - MB,A
Peashrub, Siberian - MB,JP,BS	Forestiera, New Mexican - MB,JP,BS	Mountain-mahogany, birchleaf - MB,JP,BS,A
Rabbitbrush, Douglas - BS,SS,JP,MB,A	Honeysuckle, Tatarian - MB,JP,BS	Mountain-mahogany, curlleaf - MB,JP,A
Rabbitbrush, dwarf - MB,BS,JP,BB	Hopsage, spiney - JP,BS,SS,BB	Oak, Gambel - MB,JP,A,BS
Rabbitbrush, Parry - SA,A,SS,MB	Lilac, common - MB,A	Russian olive - MB,JP,IS,WM
Raspberry, red - MB,A,SA	Maple, bigtooth - MB,A,JP	Serviceberry - Saskatoon - MB,JP,A,SA
Rose, woods (wild) - A,SA,MB,JP	Maple, Rocky Mountain - MB,AS	Serviceberry, Utah - JP,MB,BS,BB
Russian olive - MB,JP,IS,WM	Mountain-mahogany, birchleaf - MB,JP,BS,A	Sumac, skunkbush - MB,JP,PS,BB
Sagebrush, bis - BS,JP,MB,SS,BG,A,SA	Mountain-mahogany, curlleaf - MB,JP,A	
Sagebrush, black - BS,JP,MB,SS,BG,A	Oak, Gambel - MB,JP,A	
Sagebrush, bud - SS,BS,BG,IS	Peashrub, Siberian - MB,JP,BS	
Sagebrush, fringed - BS,JP,MB,SS	Rabbitbrush, Parry - SA,A,SS,MB	
Sagebrush, low - MB,A,JP,BS	Russian olive - MB,JP,IS,WM	
Sagebrush, silver - IS,JP,SS,MB	Sagebrush, big - BS,JP,SS,MB,BB,A,SA,BG	
Saltbush, Gardner - SS,BG,BS,JP	Salt-tree, Siberian - MB,JP,IS,BS	
Snowberry, mountain - MB,A,SA,JP,BS,AA	Serviceberry, Saskatoon - MB,JP,A,SA	
Snowberry, desert or longflower - JP,BS,A,BB	Squaw-apple - MB,JP,BS	
Sumac, Rocky Mountain - MB,JP,BS	Sumac, Rocky Mountain - MB,JP,BS	
Virginsbowder, western - MB,JP,BS,BB	Sumac, skunkbush - MB,JP,BS,BB	
Winterfat - SS,BS,JP,BG,BB,MB,IS	Wormwood, oldman - MB,A,SA,BB	
Yellowbrush - MB,A,SA,BS		

AA - Arctic alpine
JP - Juniper-pinyon
MB - Mountain brush
BS - Big sagebrush
BG - Black greasewood
SS - Shadscale saltbush
BB - Blackbrush
IS - Inland saltgrass
A - Aspen openings
SA - Subalpine
WM - Wet meadows

TABLE I-13-- Forbs and grasses useful for stabilizing roadcuts and disturbed areas with vegetal types listed in order species are adapted to them

Forbs	Grasses
Alfalfa - MB,JP,A,BS,SA,SS, BB	Bluegrass, Kentucky - SA,A,AA,MB,JP
Aster, Pacific - MB,A,JP,SA,WM,BS,IS	Brome, meadow - A,SA,AA,MB,JP
Aster, blueleaf - MB,A,SA,JP,BS	Brome, mountain - A,SA,MB,JP
Balsamroot, arrowleaf - JP,MB,BS,A	Brome, smooth - SA,A,MB,WM,AA
Bouncing-bet - MB,JP,A,BS	Fescue, hard - A,SA,MB,BS,JP
Checkermallow - A,SA,MB,WM	Foxtail, meadow - SA,WM,A,MB,IS
Crownvetch - MB,JP,A	Oatgrass, tall - A,AA,SA,MB
Daisy, common oxeye - MB,JP,BS	Orchardgrass - A,MB,SA,JP,BS,BB
Eriogonum, cushion - MB,A,SA,BS,JP	Quackgrass - SA,MB,AA,A,BS,IS,BG
Flax, Lewis - JP,MB,BS,A,SA,AA,SS,WM	Reedgrass, chee - MB,SA,A,JP,BS
Geranium, sticky - A,SA,MB	Ricegrass, Indian - JP,BS,SS,BB,MB
Gianthyssop, nettleleaf - A,SA,MB	Sacaton, alkali - IS,BG,BS,SS,BB
Goldeneye, Nevada - JP,MB,BS,BB	Wheatgrass, bearded bluebunch - BS,JP,MB,SA,A
Goldeneye, showy - A,MB,SA,AA,JP,BS	Wheatgrass, bluestem - BS,JP,MB,SS,BG,BB
Goldenrod, low - SA,AA,A,MB	Wheatgrass, Fairway crested - JP,MB,BS,SS,BB,BG
Goldenrod, Parry - MB,JP,A	Wheatgrass, Standard crested - JP,BS,SS,MB,BB
Helianthella, oneflower - MB,JP,BS,A,SA	Wheatgrass, intermediate - MB,A,JP,BS,SA,BB
Iris, German - MB,JP,BS,A,SS,BB	Wheatgrass, pubescent - MB,JP,A,BS,BB,IS
Lupine, mountain - SA,AA,A,MB	Wildrye, creeping - IS,BG,JP,WM
Lupine, silky - A,MB,JP,BS	Wildrye, Great Basin - MB,JP,A,IS,WM,BS
Penstemon, Eaton - MB,JP,BS,A,BB,SS	Wildrye, mammoth - MB,JP,IS,BS
Penstemon, little cup - MB,JP,BS	Wildrye, subulosa - MB,JP,BS
Penstemon, Palmer - MB,JP,BS,BB	Wildrye, Salina - JP,BS,BG,IS,MB,SS
Penstemon, Rydberg - SA,A,MB	
Penstemon, toadflax - MB,JP,BS,BB	
Sweetclover, yellow - MB,JP,BS,A,BG,IS	
Sweetvetch, Utah - MB,JP,BS,A,SA	

AA-Arctic alpine
MB-Mountain brush
BG-Black greasewood
BB-Blackbrush
IS-Inland saltgrass
WM-Wet meadows
JP-Juniper-pinyon
BS-Big sagebrush
SS-Shadscale saltbush
A-Aspen
SA-Subalpine

The survival and growth of plants are affected by the environmental factors in about this order: moisture, soil, temperature, exposure, and animal activity. These must be considered when choosing the plant materials to be used. When choosing a species for a site, next in importance to having adequate moisture, is the kind of substratum. How fertile is the soil? Is it alkaline, neutral, or acid? We do not have as many choices for wildland sites as do home landscapers. This is because it is usually not possible to haul in special soil to accommodate a preference of plants, nor is it feasible to continue to apply chemical fertilizers and water to modify the soil for special plants. Use of a good mulching material is generally helpful in getting establishment on severe sites, especially when direct seeding is used. Mulch conserves moisture and also reduces temperature which is often critical on southerly or westerly exposures. A lightly placed mulch around a transplant usually aids establishment and growth. However, on some sites, this mulch may not be essential. But it may be necessary to control harmful effects of animals; perhaps rodents and other small mammals may have to be poisoned. Also, livestock frequently must be excluded from revegetated areas. In carrying out the program, special attention should be given to the important principles for successful establishment and development of new vegetation. Important among these are:

1. Use only species and ecotypes adapted to the tract.

2. Plant mixtures, rather than single species, that will stabilize the soil and harmonize with the landscape.

3. Transplant a sufficient number of good quality plants; when using the direct seeding method, plant ample amounts of good seed.

4. Make certain that transplants are properly planted and that seeds are adequately covered.

5. Do the planting in a suitable season.

6. Reduce competition from other vegetation to adequate levels.

7. Protect planted areas from damage by animals.

The U.S. Soil Convervation Service's "Standards and Specifications for Critical Area Planting" contains specific guides for vegetating cuts, fills, surface mined areas, spoil, and similar areas where vegetation is difficult to establish with usual seeding or planting methods. Selection of grass, forb, shrub, and tree species; rates, time, and methods of seeding and planting; seedbed preparation, fertilization, topsoil application and mulching, and equipment selection and protection also are covered in the publication.

The U.S. Soil Conservation Service has been collecting, testing, and developing superior strains of native and exotic plants for more than 30 years. Of the 20 plant materials centers operated by SCS in cooperation with State Experiment Stations, eight are located in the Western States. Centers at Bridger, Montana, and Los Lunas, New Mexico, are primarily responsible for testing plants of the oil shale region. At each of these centers, over 400 species and 3,000 accessions of plants have been tested since 1957. The present oil shale research being conducted by Colorado State University includes the testing of many new native plants on disturbed oil shale sites.

3. Revegetation of Processed Oil Shale Depositions

While a great deal is known about plant-soil relationships and revegetation of disturbed natural soil area, mostly with grasses, information concerning the revegetation of processed shale is rather limited.

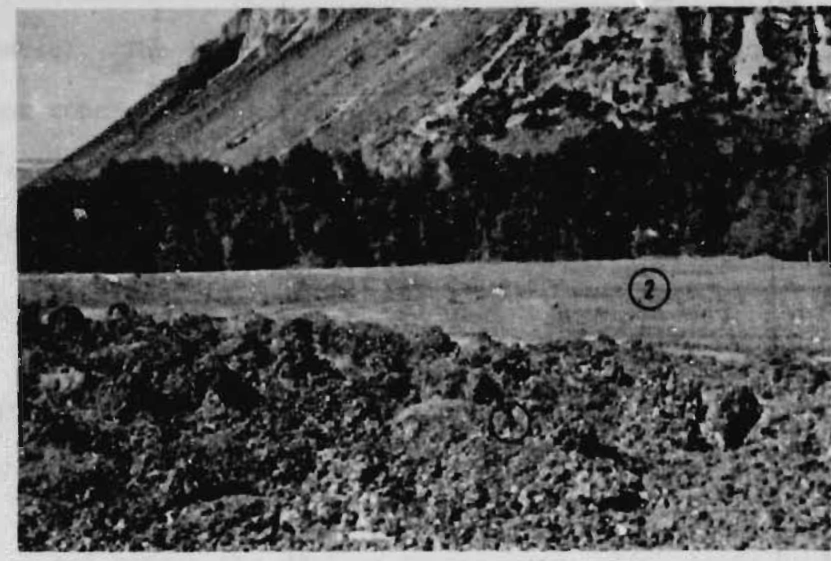
Natural revegetation apparently does take place with time, as shown by observation of the spent oil shale area left by the Bureau of Mines at its Rulison, Colorado, operation in the 1920's and the

Union Oil Company site abandoned in the 1950's. The first large-scale test of revegetation was undertaken by the Union Oil Company in 1967, when they trucked to a disposal site about 100,000 tons of material of the type produced from their retorting process (Figure I-7a). After leveling and compacting, the area was seeded with grasses. By irrigating and applying a fertilizer (quantities not reported for this test), a grass cover was developed and maintained to produce, by 1970, the vegetation growth as shown in Figure I-7b.

A systematic investigation of research was initiated by the Colony Development Operation, beginning in 1967. This work, which is still in progress, has produced an increasing body of knowledge on practical methods for accelerating the vegetation process. Under a grant by the Colony group, researchers at the Colorado Agricultural Experiment Station investigated the chemical and physical properties of processed shale which affect plant growth. The results of fertility and salinity analyses from both the TOSCO and gas combustion spent shale samples were reported as shown in Table I-14 (32).

The conductivity determinations suggest that all of these untreated materials are too high in soluble salts for normal plant growth and that the pH would need to be lowered. Soluble Na (sodium) is the principal cation present in the samples (except F), ranging from 24 percent to 74 percent of the total. Normally, plants will not grow satisfactorily where Na constitutes more than about 50 percent of the water soluble cations in the saturation extract. Consequently, a major conclusion of the study was that reclamation

FIGURE I-7A.--Union Oil Co. Spent Shale Revegetation Experiment, 1967.



Legend:
(1) Newly dumped spent shale.
(2) Dumped area prepared for seeding.

FIGURE I-7B.--Union Oil Co. Spent Shale Revegetation Experiment, 1970.

TABLE I-14.--Fertility and Salinity Analysis of Six Spent Shale Samples

Spent Shale Designation	Lab. No.	Retort Process	Conductivity mmhos/cm 25°C	pH Saturation Paste	pH 1:5 Shale:Water	$CaCO_3$ Equiv. %	Available Nutrient P ppm	K ppm	Zn ppm	Fe ppm
A	3766	TOSCO II	16.0	9.7	9.9	40.0	8.5	27	-	-
B	7972	TOSCO II	11.3	9.1	9.4	11.0	3.7	40	10.0	40
C	4216	TOSCO II	26.0	8.9	9.3	31.2	6.7	135	8.4	40
D	240	Gas Combustion	9.0	8.6	9.2	31.4	5.6	360	4.7	40
E	241	Gas Combustion	22.0	8.7	9.0	31.2	3.6	400	5.8	40
F	243	Gas Combustion	12.0	8.7	9.0	30.8	3.6	400	2.9	40

Source: (32).

treatments would be required to remove excess salinity before normal plant growth could be expected on spent shale.

Subsequent experimentation has confirmed the need for salinity control. The layer of spent shale material that constitutes the root zone of prospective vegetation should be leached, or otherwise treated, to reduce salinity before seeding or planting operations are undertaken.

Beginning in 1967, a series of outside test plots were planted at the Colony Development Operation's semi-works plant near Grand Valley, Colorado. The objectives of the program (33, p. 113) were to:

> ...reduce the alkalinity, increase the nutrient level, and reduce the surface temperature, which tends to be high because of the dark color of the material. The plots were in four basic units for study of the effects of water rate, depth of planting, artificial seed bed cover, and soil treatments. It was found that by planting seeds 1/4-inch deep in leached soil, fertilizing, and covering with a commercial seed bed cover, a viable ground cover of native grasses was obtained.
>
> Using the success of the 1967 tests as a guide, a demonstration plot was constructed on the processed shale site at the Colony semi-works plant in 1968.
>
> Working with the State Forest Service, deciduous and conifer trees were planted along the boundaries of the plot. Local shrubs and plants were also transplanted in the area in addition to native grasses. The results were good, although deciduous trees suffered badly from heavy snows, rolling rocks, and deer. The other plants were found to be hardy. The demonstration plot has now completed its third growing season with continued excellent results.

Further details of this work were released (30) as follows:

> ...we applied a custom commercial fertilizer at the rate of 150 pounds per acre twice per year and applied water by sprinklers at 1 inch per week during the summer season

(approximately 10 weeks). Healthy stands of Western Wheat and Crested Wheat now exist in the thick cover of Kentucky Blue Grass. The root zone of the Kentucky Blue Grass penetrates over 11 inches into the processed shale. We expect that the Wheat grasses, and particularly the Western Wheat, will begin to stool and spread beginning this next growing season. The native Sage shows good health and growth. Like the grasses, we expect pronounced growth from the evergreens beginning this next growing season.

A recent picture (34) of the test plot is given in Figure I-8. Figure I-9 shows another example of revegetation on a Colony test plot.

In November of 1971, the Soil Conservation Service, cooperating with Colony Development Operation, established revegetation trials at Colony's Parachute Creek site. Twelve native and exotic grasses, one alfalfa, and four native shrubs were seeded. Seedings were made on three sites: 100-percent spent TOSCO shale, 100-percent native soil, and a 50-50 mixture of soil and spent shale. In July of 1972, 12 additional species of native and exotic shrubs were added to the plots using planting stock. These plots received only moisture from natural rainfall.

Observation of the plots during the summer of 1972 showed good germination and survival of all species planted on the 100 percent soil plots, with the exception of antelope bitterbrush which showed good germination but poor survival. On the 50-50 spent-shale/soil plots, the following species showed satisfactory germination and survival: tall wheatgrass, western wheatgrass, crested wheatgrass, Indian ricegrass, basin wildrye, pubescent wheatgrass, Russian wildrye, Sodar wheatgrass, hard fescue, Ladak alfalfa, and four-winged salt bush. Tall wheatgrass seemed to do best.

On the 100-percent spent TOSCO shale plots tall wheatgrass, pubescent wheatgrass, and western wheatgrass only showed germination

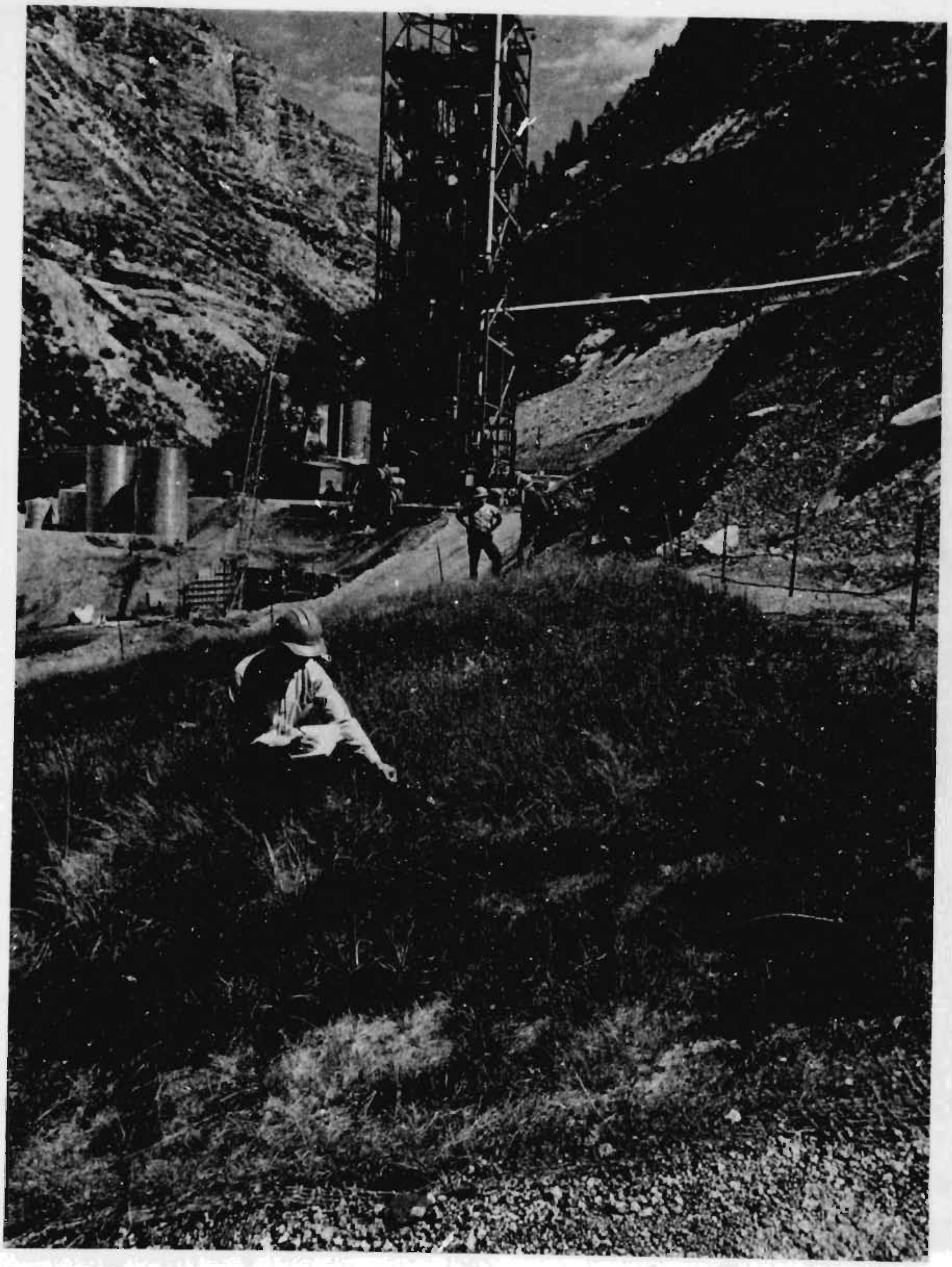


FIGURE I-8.--Colony Development Operation Spent Shale Revegetation Experiment, 1970

FIGURE I-9.-- Colony Development Operation Test Disposal Development.

and survival adequate to produce a stand. Bitterbrush germinated well, but very few plants survived. It is significant that 1972 was a record dry year.

Although more time will be required to fully evaluate these plots, early observations support the earlier Colony studies.

There appears to be no problem in establishing vegetation on native soil. As raw spent shale is mixed with the soil, the choice of revegetation species becomes more limited until only the more salt-tolerant species germinate and survive on the pure spent shale.

It is expected that natural weathering and leaching will continually improve the spent shale material and allow a greater variety of species to be established. As salts decrease in the top layers, less salt-tolerant species should move into the plant communities.

In the summer of 1972, Colorado State University began a 2-year revegetation study under the sponsorship of Federal and State Government and industry. The study includes establishment of vegetation that will persist under natural climatic conditions on spent shale materials. (See Vol. III, Chapter IX, Section D).

Another alternative for establishing vegetation on spent shale deposits is the placement of topsoil or subsoil materials on top of spent shale. Although no testing of this method has been done, experts generally agree that revegetation could be successfully accomplished if a foot or more of topsoil was placed over the shale. Where subsoil material is utilized, fertilizer amendments would be necessary.

In summary, the research conducted to date has shown that:

1. Laboratory and greenhouse studies at Colorado State University indicate that raw spent shale contains soluble salts which prohibit plant growth; that necessary nutrients (nitrogen and phosphorus) are lacking; but that the spent shale material was not otherwise toxic to plants.

2. Tests by the Colony Development Operation and Union Oil Company show that vegetation can be established successfully on spent shale material when the material is leached with water, fertilized, mulched, and irrigated.

3. Soil Conservation Service tests indicate that salt-tolerant plants do best on spent shale with minimum natural leaching and that plant establishment success increases as spent shale is leached or mixed with soil material.

4. Top dressing of spent shale with soil material is a logical alternative to direct seeding on shale material.

5. Present and planned research should produce additional information concerning revegetation of spent shale deposits.

4. Land Revegetation and Ecological Relationships

The stages of plant communities now existing in the oil shale region are not pristine climax communities in the sense of being the ultimate potential plant communities that a particular location would support had there been no man-caused influences. Grazing by livestock and manipulation of wildlife species and numbers have been the principal biotic factors responsible for the present state of plant communities. While data are not generally available to indicate early ecosystem conditions, some logical conclusions may be reached based upon historic land use and observations of relic areas.

It is known that during the late 1800's, a great number of livestock were introduced for the first time into the area. At this time, little, if any, concern existed relating to environmental effects. It was not until the Taylor Grazing Act of 1934 that any effective grazing management was practiced.

Fifty years of uncontrolled heavy grazing by livestock undoubtedly caused some drastic changes in the ecosystem. Cattle selectively grazed out many of the palatable perennial grasses which were replaced in the plant communities by less palatable shrubs and forbs. In many areas large flocks of sheep followed the cattle and grazed out the forbs and remaining grasses.

The introduction of grazing must have created significant effects on wildlife populations. Although early hunting by the cowboy and sheepherder reduced deer and elk populations, the ultimate environmental changes resulting from livestock grazing may have favored the mule deer.

Predators such as the wolf, coyote, and mountain lion, which prior to livestock grazing preyed primarily upon the deer, now found new prey in sheep and cattle.

By the late 1920's the livestock operators had eliminated the wolf and greatly reduced other predator numbers. Successional changes in vegetation, brought on by livestock grazing and

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wildlife protection actually improved deer habitat by creating more shrub-dominated plant communities. Another food supply for deer was created when ranchers established irrigated meadows planted to exotic grasses and alfalfa.

With the favorable habitat changes and the initiation of scientific game management, deer populations soared. Peak populations occurred in the 1950's, but have declined in recent years.

While the regression of plant successional stages caused by livestock grazing may have favored deer populations, other important environmental values decreased.

As the perennial grasses were replaced by shrubs, annual grasses, and weeds, soil stability and watershed values decreased. Topsoil, protected in the natural plant community, now eroded to add higher sediment yields to the region's streams. There was also a reduction of esthetic values as raw gullies cut through the landscape.

To provide for effective revegetation, mining plans must include specific revegetation programs designed for the individual characteristics of each site. The following practices will be considered in revegetation of public lands and required where appropriate.

1. Topography - shape waste piles and disturbed areas to conform with natural contours of the terrain
   - keep slopes 4:1 or less
2. Drainage - divert runoff from natural drainages around, or pipe under, fill areas to avoid erosion and stream pollution
3. Leaching - leach top layer of spent shale disposal sites that are to be revegetated

4. Topsoil - remove topsoil from waste disposal sites, stockpile and spread on waste piles

5. Seed bed - harrow and compact seed bed

6. Runoff - pit or furrow potential runoff areas to retain moisture from natural precipitation

7. Seeding - drill seed mixtures of native grass and browse species at rates necessary to establish densities that can be sustained under natural precipitation

8. Planting - plant shrub and tree seedlings of native species where adapted

9. Mulch - apply mulch to critical seedling establishment areas

10. Fertilize - apply complete fertilizer to optimize plant nutrients for existing conditions

11. Irrigation - provide temporary irrigation to aid seedling establishment

12. Protection - construct fences to protect vegetation from livestock and possibly from big game grazing during establishment period.

Application of the foregoing practices would be dictated by the specific location to be revegetated, its elevation, exposure (south, north slope, etc.), soils and plans for future use (wildlife habitat, livestock grazing, agricultural, or combinations thereof). These factors will determine the plant species to be used, seeding and planting rates, fertilization, and temporary irrigation requirements.

Disturbed land associated with oil shale development on public lands will be revegetated, and, as set forth in Volume III, Chapter V:

> ". . . Plans for revegetation, including species, density, and timing must be submitted to the Mining Supervisor for approval. The Mining Supervisor may require any reasonable methods of revegetation. . ."

If the potential natural plant community will provide the greatest overall benefits, a mixture of the major plant species found in the climax association might be planted. This course might advance the plant successional process so that a potential plant community will result in a reasonable time period. Tree and shrub seedlings can be planted initially, but growth rates are slow in these low rainfall areas and many years are required for stands to mature.

If a disclimax situation is desired, i.e., a shrub-dominated plant community on a grassland site where deer browse is critical, the appropriate browse species might be planted to encourage this type of plant community.

On some areas adapted exotic species might be desirable to achieve fast cover for soil protection. Species such as crested wheatgrass and intermediate wheatgrass are palatable to deer and will persist for many years.

Once a revegetated plant community is established, management of biotic influences will determine its successional course. If excessive grazing is allowed, the plant community will regress towards lower successional stages. If protection from excessive grazing is practiced, plant succession will move towards the potential community the site will support.

Areas of spent shale deposition will present the most complex environmental relationships. Plant communities and soils generally evolve together. On disturbed areas, revegetation will be done on soils that have evolved with the indigenous plant community.

Spent shale material, however, will have significantly different properties than the soils that have evolved on the site. Based on present knowledge, the spent shale material will more closely resemble the undeveloped saline soils of the salt desert shrub type. Unless the spent shale material is modified by leaching and fertilization, or is covered with several feet of overburden material, successful revegetation may be limited to salt-tolerant species, which are of low value to most species of wildlife. Some desirable browse species, such as big sage, require well-drained soil and send roots down to depths of 6 to 10 feet.

To achieve the desired type of vegetation on spent shale depositions, the type and degree of spent shale treatment needed to produce a suitable soil base for the desired plant species will need to be determined. As an alternative to direct seeding in the spent shale material, top dressing of the spent shale with top soil may be required. This would greatly increase the variety of plants that might be successfully established.

If salt-tolerant plants were established, some plant successional activity would probably occur as natural climatic factors modified the soil conditions. The successional stages are not known since vegetation establishment on spent shale materials on these sites has not been observed over extended periods of time.

The Colony group has demonstrated that with adequate leaching, mulching, fertilization, and continued irrigation, dense stands of vegetation can be established and maintained on spent shale material. If irrigation was withdrawn, the natural climate could not support these stands. However, stands of adapted native plants. more sparsely established by the same methods, would probably persist and progress towards a potential plant community resembling that on alkaline and saline soils, or perhaps developing a new community uniquely adapted to weathered oil shale.

5. Management of Wastes Within the Working Areas

The complete flow of materials through an oil shale processing complex is outlined in Figure I-10.[1/] This section describes the control measures that would be incorporated into a plant designed to minimize impact on the environment.

a. Mining

Plans for development would have to be approved for any new mine on public or private lands as required by applicable Federal and State laws, and the mine would be inspected to insure compliance with the approved plan and with all mine health and safety regulations.

An estimated 1.6 million tons of oil shale have been mined from experimental operations by the Bureau of Mines and by industry. No fatalities are known to have occurred from any of these operations.

Water has not been a problem in the few oil shale mines opened to date as these have been naturally well drained and the oil shale is dry. However, the volume and quality of water that may be encountered would vary throughout the three-State region as described in subsequent chapters of this regional review.

Water may be encountered in sinking deep shafts, but these shafts can be grouted or cased to stop water encroachment. Drain water into the mine would be collected and pumped to the surface for on-site use or can be controlled by pumping dewatering wells in the vicinity of the shaft. Water from surface mines can be controlled through wells drilled around the mine perimeter. Withdrawal from these wells would be at a rate sufficient to maintain the water table below the working

1/ For the quantities of material that would be expected, see Volume III, Chapter 3.

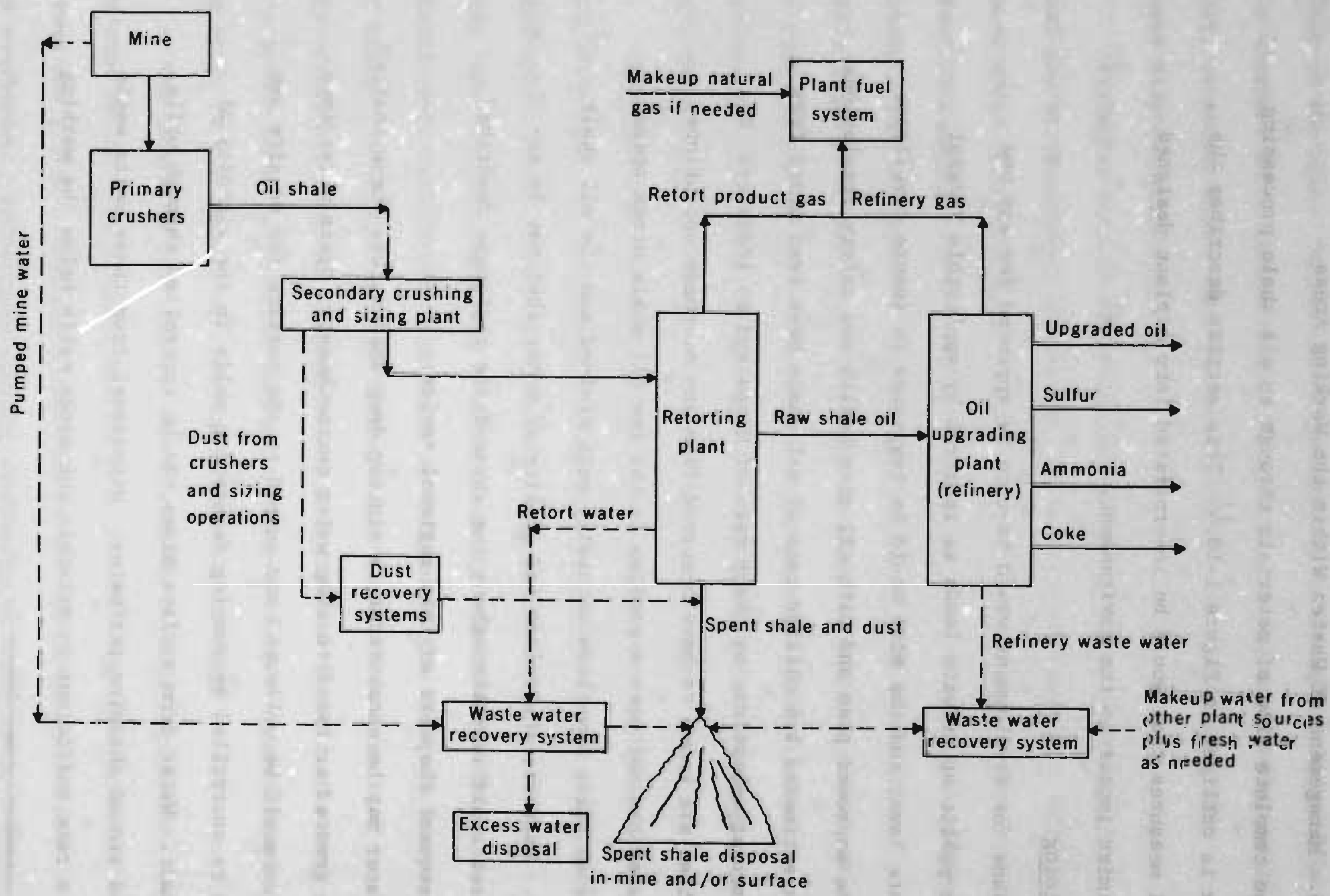

FIGURE I-10.—Flow Diagram-
Underground Oil Shale Mine and Processing Unit.

floor of the mine. Saline water encountered in mining may be used in the disposal of processed shale, except possibly for use on the uppermost, permanent layer, thereby minimizing or even eliminating any water disposal problems.

Estimates vary as to the amount and quality of the ground water that may be encountered from an underground or surface mine. Potable water would be segregated from saline water for subsequent use in other processing steps. Excess saline water above plant requirements would create pollution problems if discharged into surface waters or aquifers which contain potable water. A possible disposal method is to pump the saline water into similar underground aquifers. Each productive oil shale site will have its own characteristics which will dictate the appropriate water disposal technique.

Dust measurements made during actual operations have shown that oil shale dust due to blasting can be readily controlled in large, well ventilated mines. Mine dust particles less than 10 microns in size have been reported (30), but data indicate that the average count is within applicable health standards, as defined by the Colorado Bureau of Mines. These studies also indicate that fugitive dust emitted to the atmosphere with ventilation air from a mine can be held to a very low level--about 25 lbs. per hour for a mine serving a complex sized at about 50,000 barrels of upgraded shale oil per day.

The amount of shale which can be removed without significant subsidence of the land surface depends upon the size and spacing of the rooms and pillars, physical properties of the formation, and depth of overburden. Assuming an average overburden of 1,000 feet, between 50 and 60 percent of the shale could be removed without significant surface effect. Percentage of extraction usually decreases as depth increases, but backfilling with retort residue would possibly permit increased extraction of the shale with little adverse subsidence effects.

If the material is to be returned to a worked-out area of the mine, a slurry system probably could be used. Although slurry emplacement has not been attempted for spent shale, experience with other materials and limited tests with shale indicate the slurry could contain 50-percent solids. After a reasonable time, the impacted material would dewater to 70 to 80 percent solids and be relatively stable. Draining water would be collected and recycled into the slurry disposal system. As an alternative to slurrying, the spent material could be transported in dampened form to worked-out mine areas via conveyors or trucks, then emplaced and compacted.

b. Crushing and Conveying

A typical system for sizing and conveying mined oil shale is shown in Figure I-11.

The only significant environmental factor in crushing oil shale, as in most crushing operations, is control of small particulates, especially fugitive dusts. There are no liquid or gaseous effluents generated in the crushing step.

Particulate emissions in crushing and sizing plants are conventionally controlled by water sprays, dust collection, enclosing the plant, filtering and scrubbing the air flow out of the enclosure, or more likely a combination of these. Similar safeguards are considered adequate for oil shale plants, which would be required to be adequately designed to protect the ambient air. Dust suppression and collection equipment would be used to provide good working conditions within the enclosure.

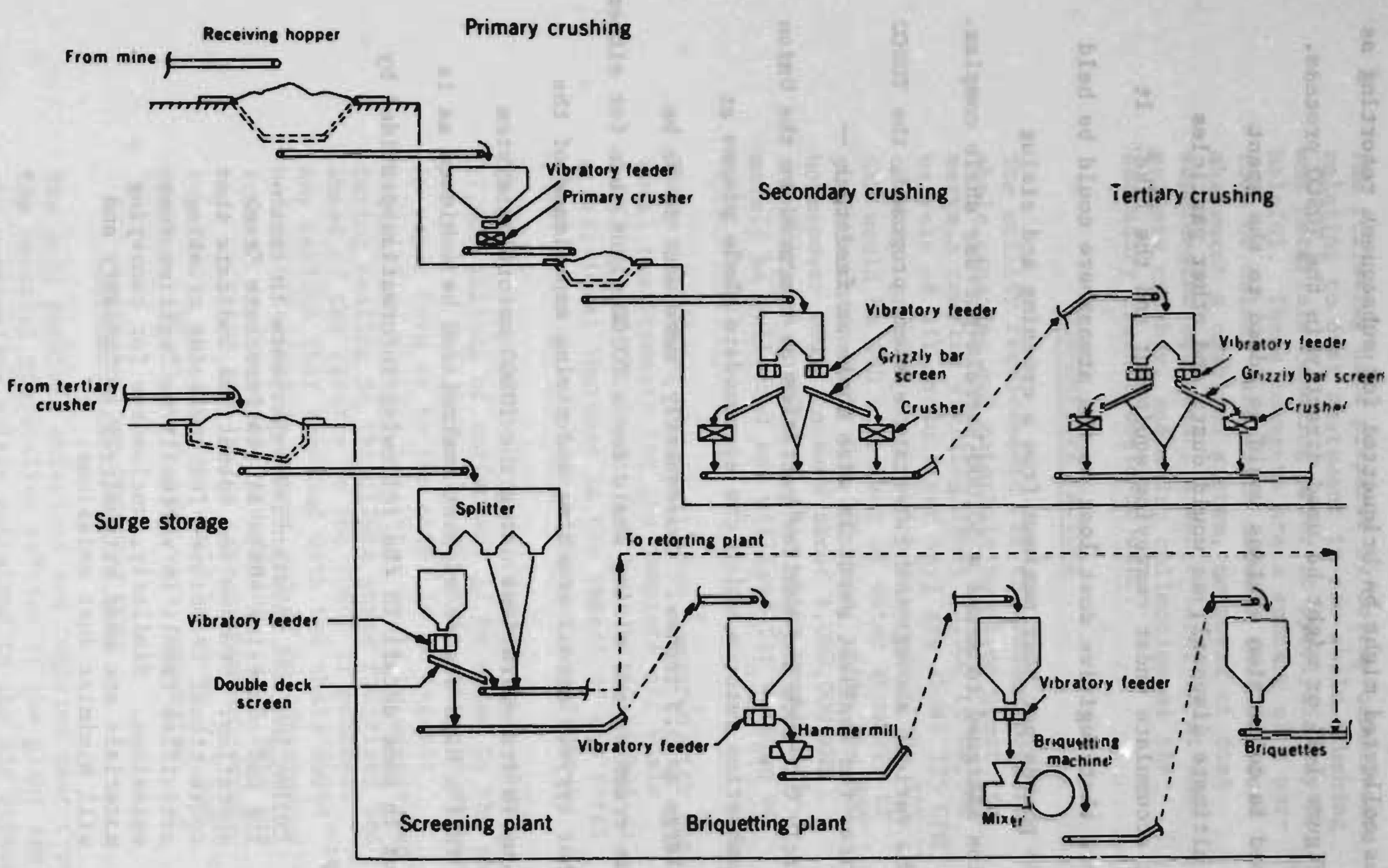

FIGURE I-11 --Crushing, Screening, and Briquetting Plants, Schematic Flow Diagram.

Fines collected might be briquetted for subsequent retorting as shown in Figure I-11 or might be used directly in the TOSCO process. Dust trapped in collection systems would be added to the spent shale for ultimate disposal, as would dusts and other particles that might accumulate under conveying equipment and the like. It is estimated that fugitive dust lost to the atmosphere could be held to about 35 pounds per hour maximum from a crushing and sizing installation designed to serve a 50,000-barrels-per-day shale complex.

Of the various aboveground retorting systems proposed, the TOSCO type requires the smallest particle size shale as feedstock -- approximately 0.5 inch and smaller particles as compared to the Union and gas combustion retorts which can accommodate shale pieces at least as large as 3.5 inches. Consequently, more dust is to be expected in crushing and sizing shale for a TOSCO plant than for either of the other types. Actual crushing and sizing experience of the Colony group in its operations using the TOSCO retorting system indicates that a high degree of dust control can be achieved as is brought out in some detail in the following information provided by that group:

> Colony has had substantial experience in crushing and conveying shale at its Parachute Creek operation. Studies and operations indicate that conventional techniques for enclosing crushing activities result in virtually no fugitive dust emissions. Similarly, enclosures for conveying materials are used extensively in industry and will minimize dust emissions.

The following data prepared by Colony consultants relating to dust abatement in raw shale crushing and materials handling prior to pyrolysis may be helpful. These comments are a summary of a portion of Colony data which assumes that for dust abatement a combined system, composed of dust suppression equipment, a wet collection at the primary crusher, and a dry collection at the secondary crusher would be used.

CONSUMPTIVE FACTORS

The utility requirements for the recommended raw shale crushing and materials handling plant [to serve a complex yielding about 55,000 to 60,000 barrels of oil product per day] are about 325 GPM of water and 800 connected horsepower. The 325 GPM would be 490 acre-feet of water annually if pumped continuously for 365 days, while the 800 horsepower would consume about 4,000,000 KWH annually. A portion of this water would ultimately be collected and utilized for wetting of spent shale.

These quantities are small when compared with the total requirements for the complete oil shale facility and the impact can best be described as a fractional increase in the impact of the total plant water consumption and power requirement.

The dust suppression system requires that about 17,000 gallons of surfactant 1/ be added to the shale per year. This surfactant which is nontoxic either in vapor form or to the skin, is an organic material in a water base that would be evaporated during heating in the dilute phase fluidized bed ahead of the retorts in the TOSCO II process. Any residue that remained with the shale would be infinitesimal in amount and of no consequence from an environmental standpoint. At a flue gas rate of 6,000,000 lbs/hr the surfactant concentration in the flue gas would be about 2.5 ppm maximum, if all surfactant were evaporated.

EMISSIONS AND FUGITIVE DUST

The only possible emissions and fugitive dust from the material preparation section of the plant are the particulate matter contained in the air streams

1/ Although not identified, an appropriate surfactant would be an aryl sulfonate.

emitted from the dust collectors, and the material that escapes from the belt conveyors. The crushed product is conveyed from this section of the plant to the pyrolysis section of the plant.

The dust collectors at the primary and secondary crushers will emit approximately 400,000 cfm and have a grain loading of approximately 0.01 grains per cu. ft. This means the particulate emission would be about 35 pounds per hour from the combined sources. At this rate of emission, all dust collector stacks would be clear.

The gas emitted from the stacks would be free of any combustion product gases, since no combustion is taking place in the crushing section. Any gases which might occur in the mine will not reach the crusher, so the concern is only with the particulate matter in the dust collector gas streams.

Material can escape from belt conveyors in three ways: It can be blown off by wind action, it can spill off thru overloading, or material can stick onto the belt and drop off at the return idlers.

It is usual practice to cover all conveyor belts to protect against the blowing of the material by wind action. This also allows the belts to run at a faster speed subject to the practical limitations of material blowing off the belt. It is the intent in a commercial plant to cover the conveyor belts to contain this fugitive dust.

Any spills that occur from overloading of conveyors belts are the result of plant upset conditions, such as plugged chutes, broken equipment, oversize feed material, and similar items. These spills are of an emergency nature only and are always cleaned up and reclaimed quickly by the plant operators so the plant can be placed back in operation.

The third area that could be classed as generating fugitive dust is material that will stick to the return run of the belt and fall to the floor or the ground under the return idlers. This is a continuing problem in many plants and the material must be cleaned routinely from under the belt as it builds up, or it will interfere with the operation of the conveyor. This build-up of material should normally be less than 1 ton/day. Other plants utilizing conveying systems have experienced problems under wet weather conditions; therefore, the conveying systems will be designed to minimize the effects of wet and freezing weather.

As a practical matter, consideration is being given to turning the belts over 180° on the return run so that this type of spill will be minimized. This would have the effect of minimizing labor and would eliminate the possible dusting of material from these piles, since the piles would not be allowed to accumulate.

In summary, any miscellaneous fugitive dust that occurs in the plant should not exceed more than an additional 20 lb/hr over that produced from the mine and crushers.

ALTERNATES

The pyrolysis feed material for the TOSCO II process needs to be crushed to minus ½-inch and should be as dry as possible to cut down on the fuel load in the pyrolysis processing plant. A discussion of the possible alternate pieces of equipment in the material preparation section follows:

The primary crusher - this unit is to take a nominal 24-inch feed material that could have lumps as big as 6 feet. A gyratory crusher is normally selected to crush material of this size and of this high tonnage throughput rate.

Jaw crushers, impact, and others are considered but don't appear as well-suited technically or environmentally because of increased dusting over the gyratory type.

Conveyors - pneumatic conveying would not be acceptable because of the large particle size, and the dust emissions from a pneumatic system could well be greater than those that will occur from conveyors. Material is often conveyed by pumping as a slurry in other plants. In TOSCO II plants, however, the most pumpable product is the minus ½-inch product that goes to the pyrolysis section. One-half inch solid material is not normally pumped, and preparing a slurry for pumping would require additional water and a dewatering station at the pyrolysis section; therefore, this alternate of pumping instead of conveying does not appear feasible.

Secondary crushing - The Hazemag-type crusher appears to be the best selection for this application. Therefore, other types of secondary crushers have not received consideration at this time.

c. Retorting

A schematic flow diagram of a gas combustion retort is shown in Figure I-12. Regardless of the retorting process, gases would be coproduced with the oil product. The mixture of oil and gas products would be conducted via a closed system from the pyrolysis section of the process operation to a separation and recovery section. The state of this mixture would vary from true vapor to mist to liquid, depending upon the particular process and its operating conditions. Treatment to recover the maximum amount of oil also would remove water and particulate matter. The remaining product gases contain sulfur, which may or may not be economically recoverable. Regardless of economics, however, sulfur emission control will be required in burning the gases as fuel in order to meet air quality standards. In the case of TOSCO gas, which is relatively rich in sulfur (See Table I - 3), sulfur recovery from the gas itself would almost certainly be practiced. In the cases of gases from other retorting processes, sulfur control could either be applied to the gas, as such, or to the flue effluent from whatever burning equipment was fired with the gas.

In the case of the TOSCO process, the incoming shale preheater (See Figure I-4) represents a potential source of particulate emissions not

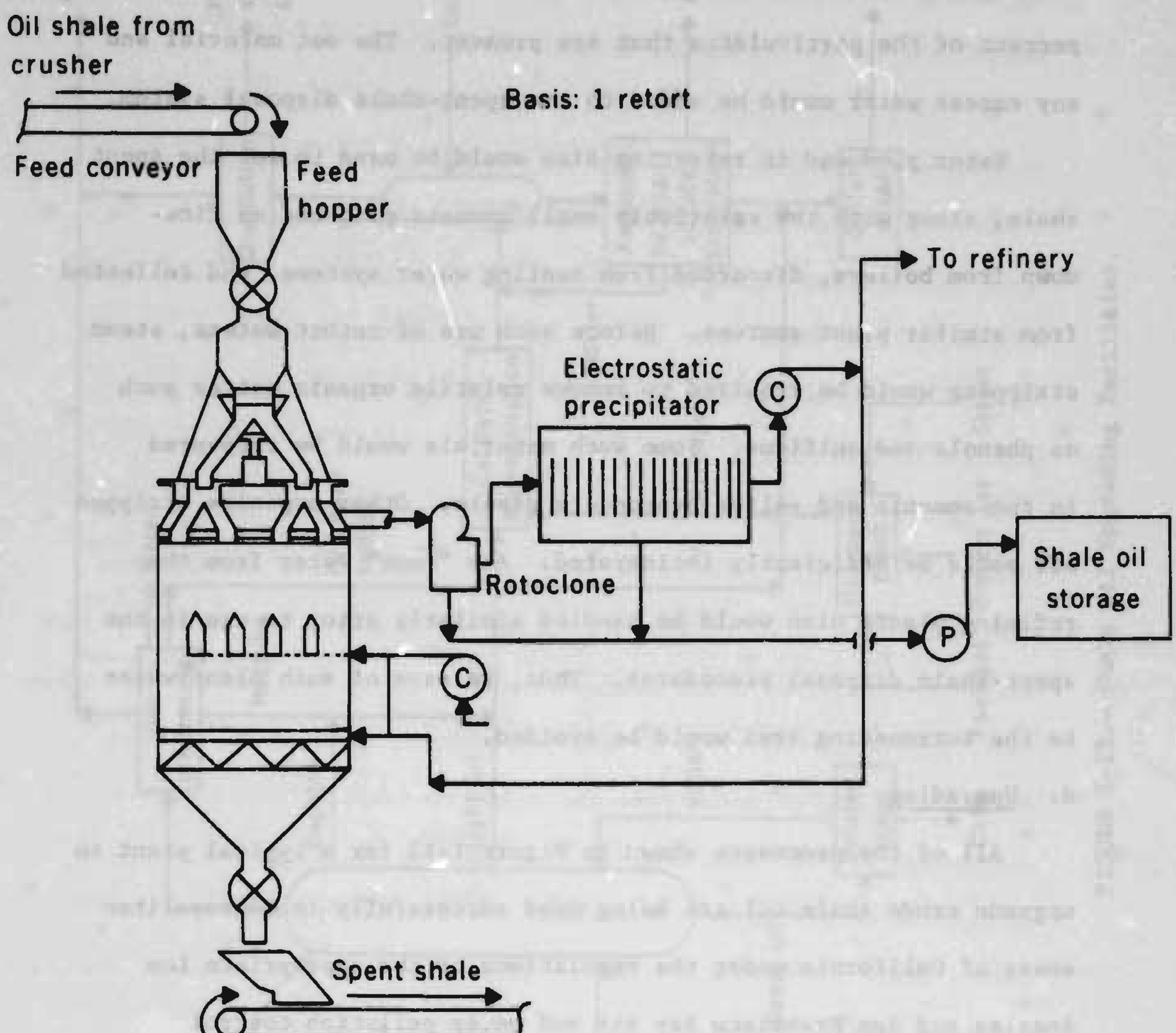

FIGURE I-12.--Schematic Flow Diagram of Gas Combustion Retorting System.

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encountered with the other advanced retorting processes. In this unique situation, high-energy venturi wet scrubbers have been shown to be effective for control of particulates, removing about 99.6 percent of the particulates that are present. The wet material and any excess water would be added to the spent-shale disposal system.

Water produced in retorting also would be used to wet the spent shale, along with the relatively small amounts produced as flow-down from boilers, discarded from cooling water systems, and collected from similar plant sources. Before such use of retort waters, steam stripping would be required to remove volatile organic matter such as phenols and sulfides. Some such materials would be recovered in the ammonia and sulfur byproducts plants. Other organics stripped off would be efficiently incinerated. Any "sour" water from the refining plants also would be handled similarly prior to use in the spent-shale disposal procedures. Thus, release of such plant water to the surrounding area would be avoided.

d. Upgrading

All of the processes shown in Figure I-13 for a typical plant to upgrade crude shale oil are being used successfully in metropolitan areas of California under the regulations of the appropriate Los Angeles and San Francisco Bay air and water pollution control authorities (33, p. 127). During shale oil upgrading, large quantities of fuel may be burned to supply heat for processes such as distillation, delayed coking, catalytic hydrogenation, and hydrogen production. The products of combustion would contain some oxides of sulfur and nitrogen. The sulfur oxides could be controlled within acceptable

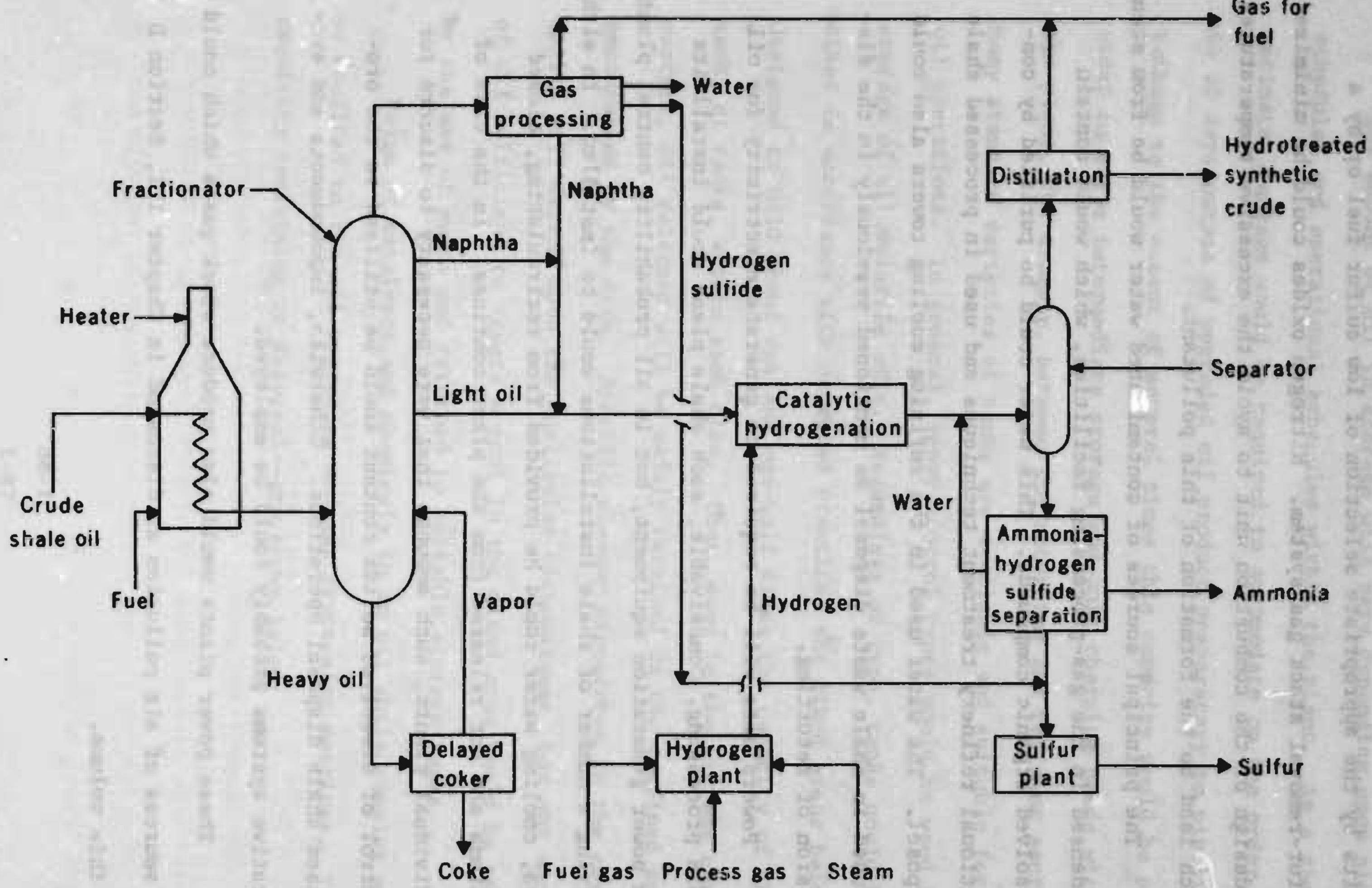

FIGURE I-13.--Shale Oil Upgrading Facilities.

limits by the appropriate selection of low sulfur fuel or by a sulfur-removal stack gas system. Nitrogen oxides could be minimized by design of the combustion unit to avoid the excessive temperatures which lead to the formation of this pollutant.

The principal sources of contaminated water would be from steam condensed in the gas-processing facilities, which would contain dissolved organic compounds. This water could be purified by conventional refinery treatment techniques and used in processed shale disposal. The water used in the refining cooling towers also could be used in shale waste disposal as mentioned previously in the discussion of retorting.

Powerplants will be required to generate electricity for oil shale processing. Conceivable, each shale plant could install its own power generation equipment, but in all probability central plants serving a number of shale installations would be installed. In either case, cooling water could be provided from recirculating, closed systems and not released from the plant confines. In the case of individual plants, such amounts that were necessary to discard for control of dissolved solids content could be utilized in the processed shale disposal operations. Otherwise, impoundments and evaporative systems probably could be employed.

These power plants would also produce stack gases which could be sources of air pollution as discussed in Chapter III, Section D of this volume.

The amount of oil in storage will vary depending upon pipelining schedules and operational schedules within the plant. As a reasonable estimate, tankage would be required to accomodate on the order of 7 to 10 days output of upgraded oil product preparatory to pipelining; tankage to the extent of several times this capacity would be provided to serve imtermediate storage and unit charging needs within the plant, for example, between the retorting and refining sections. Many standard varieties of tanks are available and suitable for shale oil operations. In general, vapor control types would be used for storage of all volatile oils. Regardless of type, tanks could be diked in accordance with accepted practice, the diked areas being designed to hold about one and one-half times the capacity of the tank, or tanks, within each dike. Thus, even in the extreme case of rupture, oil released will be safely retained in the confined space encompassed by the dike. Specific cleanup procedures in the case of spills will depend upon the particular circumstance, buy any amount of oil sufficient to create a pool in the diked area would be recovered by the use of pumps and returned to suitable storage tanks.

Usage of catalysts and chemicals in an oil shale complex would be confined to the oil upgrading and gas processing sections. Yearly requiring reclaiming or disposal--are shown below:

Catalysts and Chemicals Required
50,000-Barrel-per-Day Operation

Type	Tons per year
Nickel and cobalt-molybdate catalysts	1,420
Iron catalysts	158
Monoethanolamine (MEA)	50
Iron oxide	30
Char	10

All of these materials are solids except for the MEA which, in spent form, is a sludge-like liquid that is highly water soluble. The nickel and cobalt molybdate catalysts would likely be shipped to plants outside of the shale area to be reclaimed; the other chemicals may be discarded by burial within the spent shale pile, taking care to position them well away from exposed surfaces to eliminate the possibility of leaching or carryoff by erosion. The annual tonnage to be discarded is extremely small in relation to the tonnage of spent shale from the 50,000-barrel-per-day plant under consideration (248 tons of waste chemicals as compared to 27 to 30 million tons of spent shale as shown in Table I-5).

e. Off-Site Requirements

All roadways leading to and servicing a commercial operation would require paving to prevent erosion. If sidehill areas are disturbed by construction activities, erosion controls could include revegetation, crushed rock implacement, or equivalent measures. Plant area fencing and selected road fencing may be required to control animal movements.

The average water required for a 50,000-barrel-per-day processing complex is estimated to be 8.0 to 13.0 cubic feet per second. If this were all imported via pipeline, it would require a 16-inch-diameter line. Assuming a ditch double the size of the pipeline and burial below the frost line, a trench approximately 3 feet wide and 6 to 7 feet deep would need to be constructed. Following burial, the surface area would be restored.

Pipelines to handle the oil produced would be installed in the same manner. A 12-inch diameter line would be required for a 50,000 barrel-per-day plant. A 100,000 barrel-per-day plant would require a line 18 inches in diameter. The likelihood of a major spill or rupture is remote. Based on pipeline statistics for failure1/ and a total output for the prototype leases of 250,000 barrels per day (1), it is estimated that the accidental discharge from an estimated total of 150 miles of pipeline required for the prototype operations would average about 1 barrel per year. However, this could be as high as 100 barrels per year.2/ The chance of accidental rupture due to plows or other miscellaneous digging equipment of this nature would be largely obviated by the depth

1/ For 1968, 210,000 miles of petroleum pipeline in the U.S. transported 6.5 billion barrels of liquid petroleum commodities. Only six thousandth of 1 percent of this was spilled due to pipeline failure and much of this was recovered (37).

2/ See letter 7, Volume V, from the Environmental Protection Agency.

of burial, and the oil shale area is not an active seismic province. Considering the possibility that ruptures may occur, the amount of oil that may be released would vary considerably and depend on actual conditions. Each linear mile of a 12-inch pipeline will contain about 700 barrels of oil; the 18-inch line will contain about 1,400 barrels. In the event of a rupture, only the oil contained above the point of break may leak out (assuming the pumping equipment has been shut down as required by the lease stipulations for development on public lands, see Volume III, Chapter V). Since the terrain over which this pipeline may pass is generally rolling, the oil contained in some 5 to 10 miles may be released--a maximum of between 3,500 and 14,000 barrels of shale oil. However, the probability of rupture is small (37), and the earth surrounding the pipeline will normally provide a high resistance to flow. In the event that such a rupture does occur, it can be fixed without draining the entire line; broken sections for a major line break are normally replaced or repaired within 12 to 24 hours.

Some natural gas may be needed, but for use within the plant the amount would be small. Alternatively depending on the process and operating conditions, there may be a small amount of excess plant gas for use in nearby communities. Most of the commercial processes envision that gas requirements would be balanced with the gas available from various process streams. If required, natural gas pipelines would be constructed similar to those for water and oil.

Power may be produced on site or transmitted to the site from nearby high-voltage lines. The requirements are relatively small (about 50,000 kWh /hr for a 50,000-bbl/d plant) and would be transmitted via overhead power lines. Guidelines for construction of such lines on public lands have been published. (38)

6. In Situ Processing; Environmental Controls

In situ processing, if it can be developed, would be a dynamic process that continues to move across the surface of the area being developed. To illustrate this process, consider the concept depicted in Figure I-14 for a 90-100-ft- thick strata of Washakie Basin oil shale. Five rows of wells would comprise various operational modes; the first row of wells would be in a drilling and preparation stage, and the second row would be producing liquid and gaseous products driven by the injection of air and/or some other gases into the third row. Behind this area, plugging and restoration would be taking place.

In this concept, up to 100 wells may need to be drilled each month while the same number would need to be plugged as the retorting zone advanced through the producing zone. The active area encompassed by the five well patterns would total about 115 acres if 100 foot spacing were used between wells. If greater spacing between wells can be used to effectively retort the area, then fewer wells would need to be drilled. While it is hypothesized that a 50,000 bbl/d shale oil project can be achieved, available technology is very limited to support this conclusion. If it is assumed that such an operation proves feasible, then careful preplanning would be required to reduce the environmental impact caused by a number of truck-mounted drilling rigs and other heavy equipment. Since about 4 wells would be required for each acre, a large portion of each tract would be contacted sometime during the course of operations by such equipment. Such contact would inevitably cause surface disfigurement to the extent that some of the original vegetative cover would be destroyed, and wheel tracks and similar surface indentations would occur. However, it is anticipated that restoration of the affected areas could be accomplished by grading and reseeding. As indicated in Figure I-14, restoration would follow close behind the advancing zone of wells in active use, thus minimizing the amount of surface that would be in a disfigured condition at any given time.

As brought out earlier in this Chapter, in situ retorting technology is relatively undeveloped at present in comparison to aboveground retorting technology. It is possible that continuing research efforts now underway by Government and industry will result in a viable in situ technology, including environmental controls, by the time that

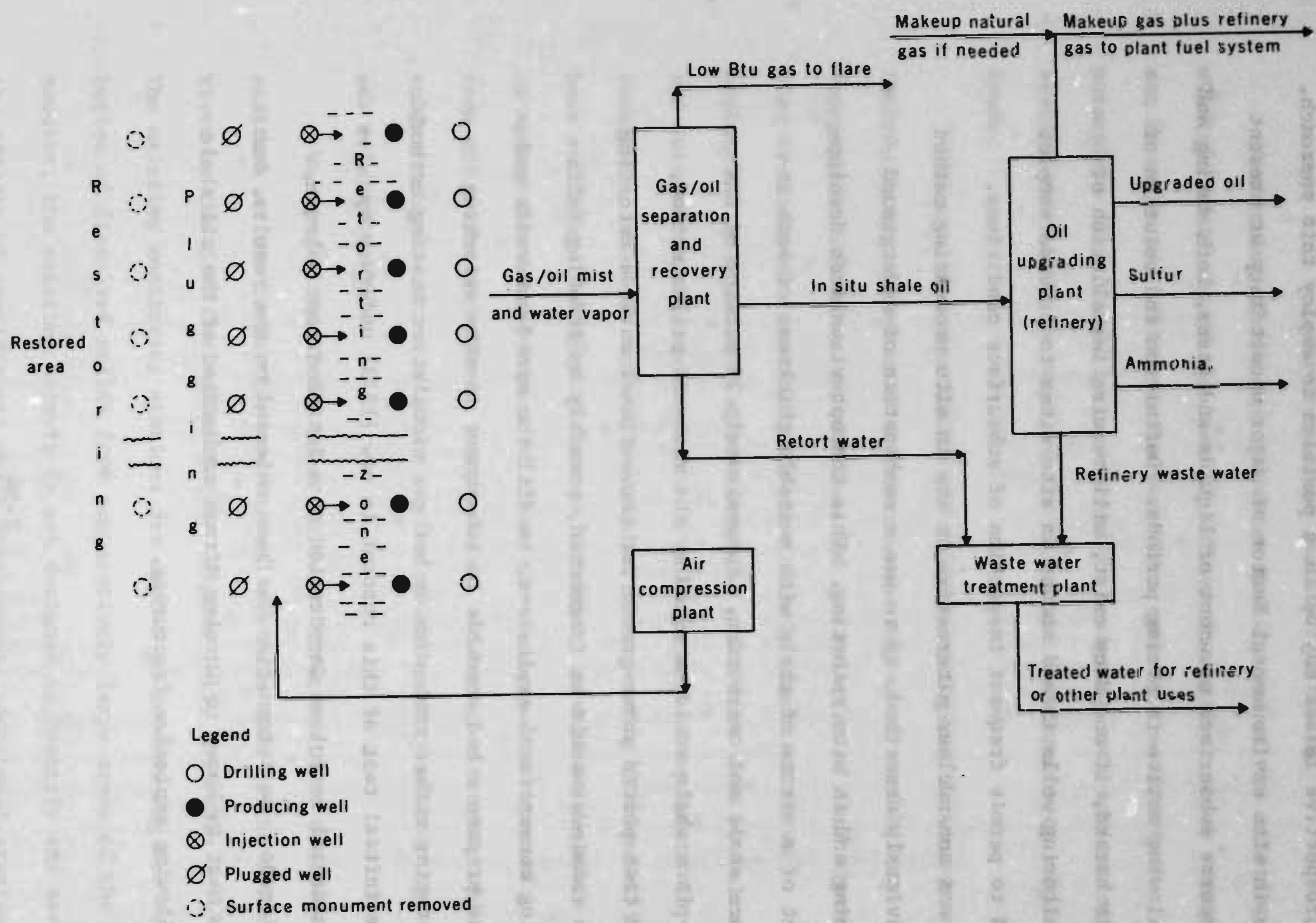

FIGURE I-14. —Flow Diagram of 50,000-Barrel-Per-Calendar-Day In Situ Recovery System.

a prospective lessee may be in a position to employ this approach. The in situ environmental factor of major uncertainty at present concerns subsurface movement of liquids and gases, both during and following active retorting periods. Definition and solution of this hazard, if one does exist, will require installation of monitoring wells in and around in situ sites to provide samples and to permit frequent inspection of subsurface conditions.

A non-nuclear alternative to the in situ processing method previously described, is to use a combination of underground mining and in situ retorting. This concept visualizes development of a strata of shale with suitable thickness of both in-place shale and overburden. Approximately 25 percent of the in-place shale would be mined by the room-and-pillar method, and transported above-ground for conventional surface retorting. The remainder would be fragmented, possibly by inducing falls using conventional explosives, to fill the mined-out voids and thus prepare a bed amenable to subsequent in situ retorting featuring either combustion or hot gas circulation heating methods. The initial test of this concept is now (1973) underway by Occidental Petroleum Corporation at a location near Debeque, Colorado. No information has been released on the results, but the test is known to involve direct combustion of the oil shale following explosive fracturing.

7. Environmental Quality Monitoring

Monitoring of the air and water quality and of the existing wildlife would expand the base of information against which changes can be measured. This section considers some of the important parameters that should be considered in designing such monitoring systems which will be required for oil shale development on public lands.

For air, the area limits and the meteorological factors must include long term seasonal influences and degree of variability. Topographic influences on air flow and the relation of land elevation to atmosphere stability is particularly important to an evaluation of a specific site. Sampling grids must then be calculated and suitable equipment obtained. A wide variety of equipment is available, based on various principles of monitoring (Table I-15). Once sufficient background data is obtained, it will be possible to assess the actual impact of those air contaminants expected from oil shale operations; particulates, oxides of nitrogen, and sulfur oxides. For a complete review of air quality monitoring, see reference (39).

Water quality of the Upper Colorado River Basin is monitored at stations on the larger tributaries and the main stem of the Colorado River by the U.S. Geological Survey (Figure I-15, and Table I-16). The existing monitoring stations are useful in determining the contribution of dissolved solids from comparatively large areas of the basin. However, the existing network is not designed to identify and assess the effects of specific oil shale development; additional stations will be required in and near the tracts to separate possible impacts

Table I-15. Measurement Principles in Air Quality Monitoring.

Classification	Application	Measurement principle	Energy transducer
Infrared absorption	Gases-CO, hydrocarbons	Absorption of IR energy	Thermistors, thermopiles, capacitor microphones
Ultraviolet absorption	Gases-O_3, NO_2	Absorption of UV energy	Phototubes
Light scattering	Aerosols	Scattering of visible light	Phototubes
Reflectance	Filtered particulates	Visible light reflectance	Phototubes
Ionization	Hydrocarbons	Ionization current measurement	Ionization chamber
Colorimetry	Reactive Gases- O_3, NO_2, SO_2, HF	Absorption of visible or near UV energy by colored compound	Barrier layer cells, phototubes
Conductometry	Acid gases-SO_2	Electrical conductivity	Conductivity cell
Coulometry	Electroreducible and oxidizable gases- O_3, SO_2	Electrical current measurement	Coulometric or galvanic cell
Fluorescence	Fluorescible materials-fluorides	Emission of UV or near UV energy	Phototubes

Source: (39).

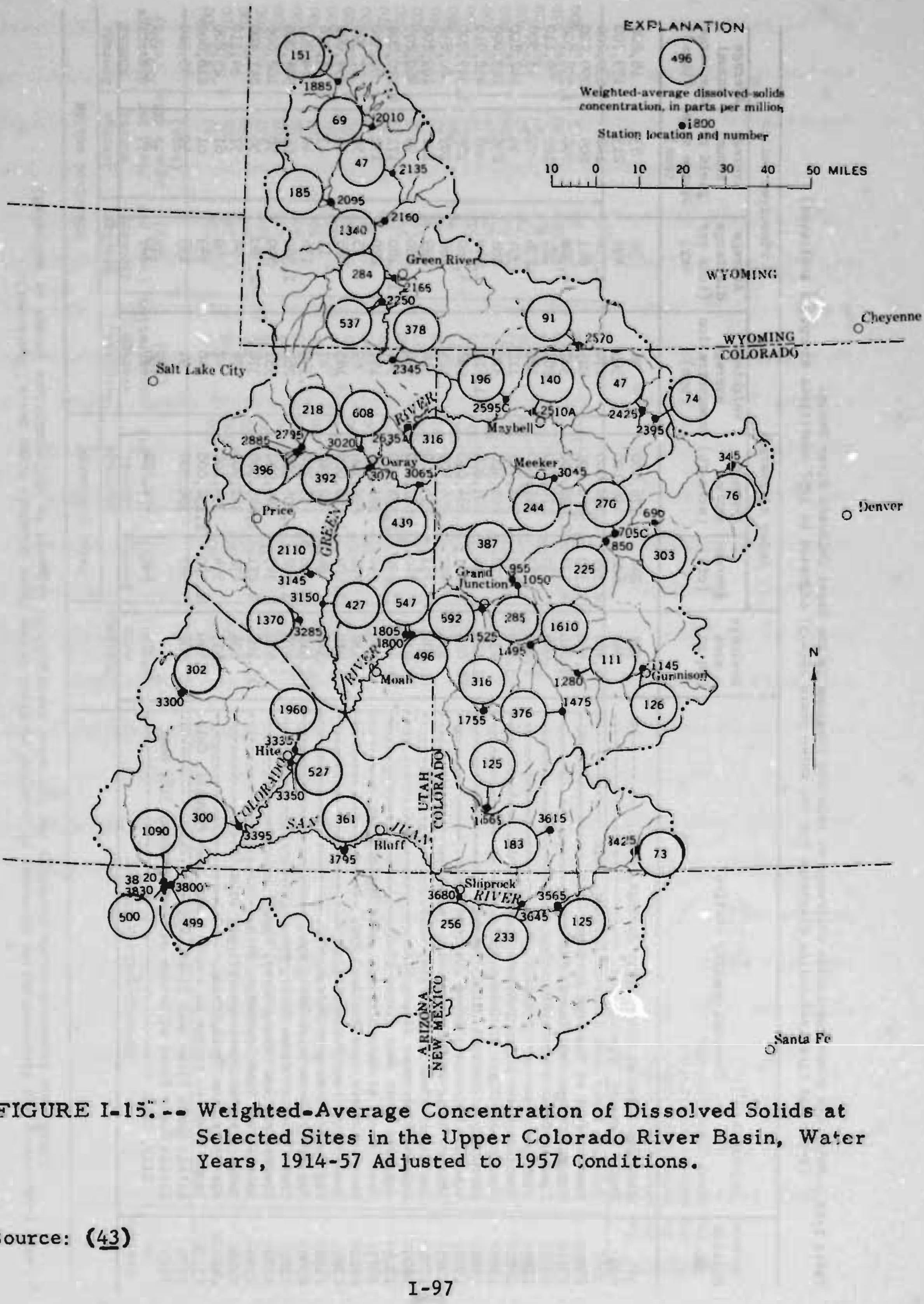

FIGURE I-15. -- Weighted-Average Concentration of Dissolved Solids at Selected Sites in the Upper Colorado River Basin, Water Years, 1914-57 Adjusted to 1957 Conditions.

Source: (43)

Table I 16.--Water and dissolved-solids discharge at selected stations in the Upper Colorado River Basin.
(Water and dissolved-solids discharge for the water years 1914-57 adjusted to 1957 conditions except as indicated)

Station No.	Chemical-quality station	Drainage area (sq mi)	Water discharge		Dissolved solids			
			Average (cfs)	Average annual (acre-ft)	Weighted-average concentration (ppm)	Average discharge (tons per day)	Average annual yield per square mile (tons)	Average annual discharge (tons)
345	Colorado River at Hot Sulphur Springs, Colo.	782	244	176,800	76	50	23	18,200
690	Eagle River at Gypsum, Colo.	844	602	436,100	303	492	213	179,700
705C	Colorado River near Glenwood Springs, Colo.	4,486	2,399	1,738,000	270	1,750	142	639,200
850	Roaring Fork at Glenwood Springs, Colo.	1,460	1,353	980,200	225	821	205	299,900
955	Colorado River near Cameo, Colo.	8,060	4,138	2,998,000	387	4,320	196	1,578,000
1050	Plateau Creek near Cameo, Colo.	604	235	170,200	285	181	109	66,110
1145	Gunnison River near Gunnison, Colo.	1,010	753	545,500	126	256	93	93,500
1280	Gunnison River below Gunnison Tunnel, Colo.	3,980	1,303	944,000	111	391	36	142,800
1475	Uncompahgre River at Colona, Colo.	437	278	201,400	376	282	236	103,000
1495	Uncompahgre River at Delta, Colo. 1/	1,110	286	207,200	1,610	1,240	408	452,910
1525	Gunnison River near Grand Junction, Colo.	8,020	2,601	1,884,000	592	4,160	189	1,519,000
1665	Dolores River at Dolores, Colo.	556	492	356,400	125	166	109	60,630
1755	San Miguel River at Naturita, Colo.	1,080	351	254,300	316	299	101	109,200
1800	Dolores River near Cisco, Utah	4,630	940	681,000	496	1,260	99	460,200
1805	Colorado River near Cisco, Utah	24,100	7,639	5,534,000	547	11,280	171	4,120,000
1885	Green River at Warren Bridge, near Daniel, Wyo.	468	540	391,200	151	220	172	80,360
2010	New Fork River near Boulder, Wyo.	552	401	290,500	69	75	50	27,390
2095	Green River near Fontenelle, Wyo.	3,970	1,609	1,166,000	185	805	74	294,000
2135	Big Sandy Creek near Farson, Wyo.	320	86.6	62,740	47	11	13	4,020
2160	Big Sandy Creek below Eden, Wyo.	1,610	48.8	35,350	1,340	176	40	64,280
2165	Green River at Green River, Wyo.	7,670	1,802	1,305,000	284	1,380	66	504,000
2250	Blacks Fork near Green River, Wyo. 2/	3,670	345	249,900	537	500	50	182,600
2345	Green River near Greendale, Utah	15,100	2,271	1,645,000	378	2,320	56	847,400
2395	Yampa River at Steamboat Springs, Colo.	604	472	341,900	74	94	57	34,330
2425	Elk River near Trull, Colo.	415	544	394,100	47	69	61	25,200
2510A	Yampa River at bridge on county road, near Maybell, Colo.	3,590	1,590	1,152,000	140	599	61	218,800
2570	Little Snake River near Dixon, Wyo.	988	547	396,300	91	135	50	49,310
2595	Little Snake River at bridge on State Highway 318, near Lily, Colo.	3,355	622	450,600	196	330	36	120,500

Table I-16.--Water and dissolved-solids discharge at selected stations in the Upper Colorado River Basin (Continued).
(Water and dissolved-solids discharge for the water years 1914-57 adjusted to 1957 conditions except as indicated)

Station No.	Chemical-quality station	Drainage area (sq mi)	Water discharge: Average (cfs)	Water discharge: Average annual (acre-ft)	Dissolved solids: Weighted-average concentration (ppm)	Dissolved solids: Average discharge (tons per day)	Dissolved solids: Average annual yield per square mile (tons)	Dissolved solids: Average annual discharge (tons)
2635A	Green River at Jensen, Utah	26,100	4,607	3,338,000	316	3,930	55	1,435,000
2795	Duchesne River at Duchesne, Utah	660	323	234,000	218	190	105	69,400
2885	Strawberry River at Duchesne, Utah	1,040	157	113,700	396	168	59	61,300
3020	Duchesne River near Randlett, Utah	3,920	767	555,700	608	1,260	117	460,200
3045	White River near Meeker, Colo.	762	638	462,200	244	420	201	153,400
3065	White River near Watson, Utah	4,020	764	553,500	439	905	82	330,600
3070	Green River near Ouray, Utah	35,500	6,223	4,508,000	392	6,590	68	2,407,000
3145	Price River at Woodside, Utah	1,500	116	84,040	2,110	662	161	241,800
3150	Green River at Green River, Utah	40,600	6,292	4,558,000	427	7,260	65	2,652,000
3285	San Rafael River near Green River, Utah [3]	1,690	141	102,100	1,370	521	113	190,300
3300	Fremont River near Bickness, Utah [2]	776	85.8	62,160	302	70	33	25,570
3335	Dirty Devil River near Hite, Utah [4]	4,360	102	73,890	1,960	541	45	197,600
3350	Colorado River at Hite, Utah	76,600	14,167	10,260,000	527	20,170	96	7,367,000
3395	Escalante River at mouth, near Escalante, Utah [5]	2,010	85.2	61,720	300	69	13	25,200
3425	San Juan River at Pagosa Springs, Colo.	298	403	292,000	73	79	97	26,850
3565	San Juan River near Blanco, N. Mex.	3,560	1,519	1,100,000	125	512	53	187,000
3615	Animas River at Durango, Colo.	692	859	622,300	183	425	224	155,200
3645	Animas River at Farmington, N. Mex.	1,360	971	703,500	233	611	164	223,200
3680	San Juan River at Shiprock, N. Mex.	12,900	2,679	1,941,000	256	1,850	52	675,700
3795	San Juan River near Bluff, Utah	23,000	2,800	2,028,000	361	2,730	43	997,100
3800	Colorado River at Lees Ferry, Ariz.	107,900	17,550	12,710,000	499	23,660	80	8,642,030
3820	Paria River at Lees Ferry, Ariz.	1,570	31.9	23,110	1,090	94	22	34,300

1/ For Water years 1939-57.
2/ For Water years 1948-57.
3/ For Water years 1938-43, 1947-57.
4/ For Water years 1947-57.
5/ For Water years 1951-55.

Source: Reference (43).

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of the oil shale industry from other impacts, such as those due to agriculture, transbasin diversions, and additional storage and regulation.

To adequately measure impact of an oil shale mine or other installation, it would be necessary to install continuous recording stream flow stations that include a recording turbidity meter, water quality monitors to record temperature and specific conductance, and an automatic device to collect samples for chemical analysis with control for variable sampling rates according to stream flow. In addition, an automatic sampler for suspended sediment would be required and rigged to collect one sample each day and be actuated when stage exceeds predetermined levels so that extra samples of the peaks are obtained. Chemical quality samples collected by the automatic samplers would be analyzed for calcium, magnesium, sodium, aluminum, silica, carbonate, bicarbonate, dissolved-solids concentration, chloride, and total organic carbon (unfiltered samples). Other ions such as fluoride or boron would be determined periodically to establish transient concentrations. Sediment samples would be analyzed for concentration and for size where concentrations are sufficient to permit determination. Bed material samples would be collected for size analyses about twice a year. About once each month, the sampling sites would be sampled for macroinvertebrates and periphyton.

Monitoring of fish and wildlife populations and their habitat would need to be established on an annual basis and be tailored to specific plant or animal species. Populations would be monitored through relative abundance indices, which would involve species specific sampling quadrats, pellet and dropping counts, observation periods, etc. Big game and wild horse populations would probably be monitored through a coordinated system of scheduled observation and counts of the animals themselves, droppings, and tracks. Impacts upon wildlife habitat can be monitored by a variety of methods and techniques including permanent and temporary plots and transects, photography, and recently developed remote sensing techniques.

Fish species abundance and population composition would be sampled at selected stations on the White and Green Rivers and selected at tributaries. Fish sampling would occur several times a year in order to keep track of seasonal population differences. These data would in turn be evaluated with the above-mentioned water quality data.

Information from these monitoring studies would be used to avoid or minimize development damage to fish and wildlife populations and their habitat and as a record upon which to base reestablishment of suitable wildlife food and cover.

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II. DESCRIPTION OF THE ENVIRONMENT

This chapter contains a description of the environment existing in the oil shale areas of Colorado, Utah, and Wyoming and is presented in 4 parts. The first part, section A, contains a summary description of the three-State area, including physiography, climate, geology, mineral resources, water resources, fauna, soils, vegetation, aesthetic resources, recreational resources, socio-economic resources, and ownership. Sections B, C, and D of this chapter contain the same type of information but in more detail for each of the individual basins. Section B is a description of Colorado's Piceance Creek Basin; Section C, Utah's Uinta Basin; and Section D, Wyoming's Green River and Washakie Basins. By this arrangement, the reader is able to gain an overview of the region as a whole or to obtain detailed knowledge about a given area.

A. General Regional Description

Large areas in the States of Colorado, Utah, and Wyoming contain rich oil shale in the Green River Formation (See Figures II-1 and II-2). These oil shales occur beneath 25,000 square miles (16 million acres) of land, of which about 17,000 square miles (11 million acres) are believed to contain oil shale of potential value for commercial development.

The oil shale-bearing rocks, named the Green River Formation for their exposures near the town of Green River, Wyoming, underlie several broad areas of high plateaus, high plains, isolated mesas, and broad topographic basins.

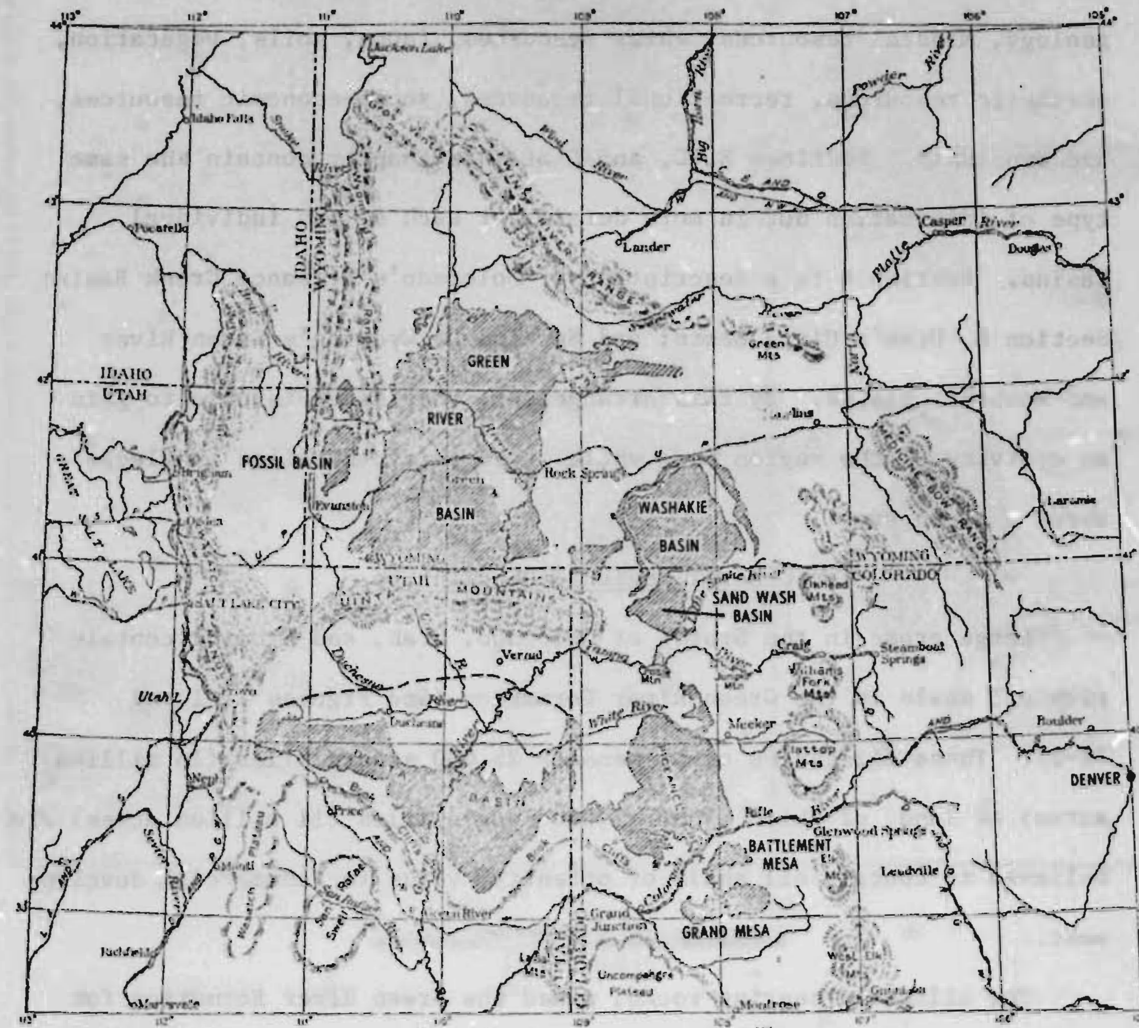

FIGURE II-1.-- Distribution of the Principal Oil Shale-Bearing Areas of the Green River Formation (Shaded Areas) in Colorado, Utah, and Wyoming.

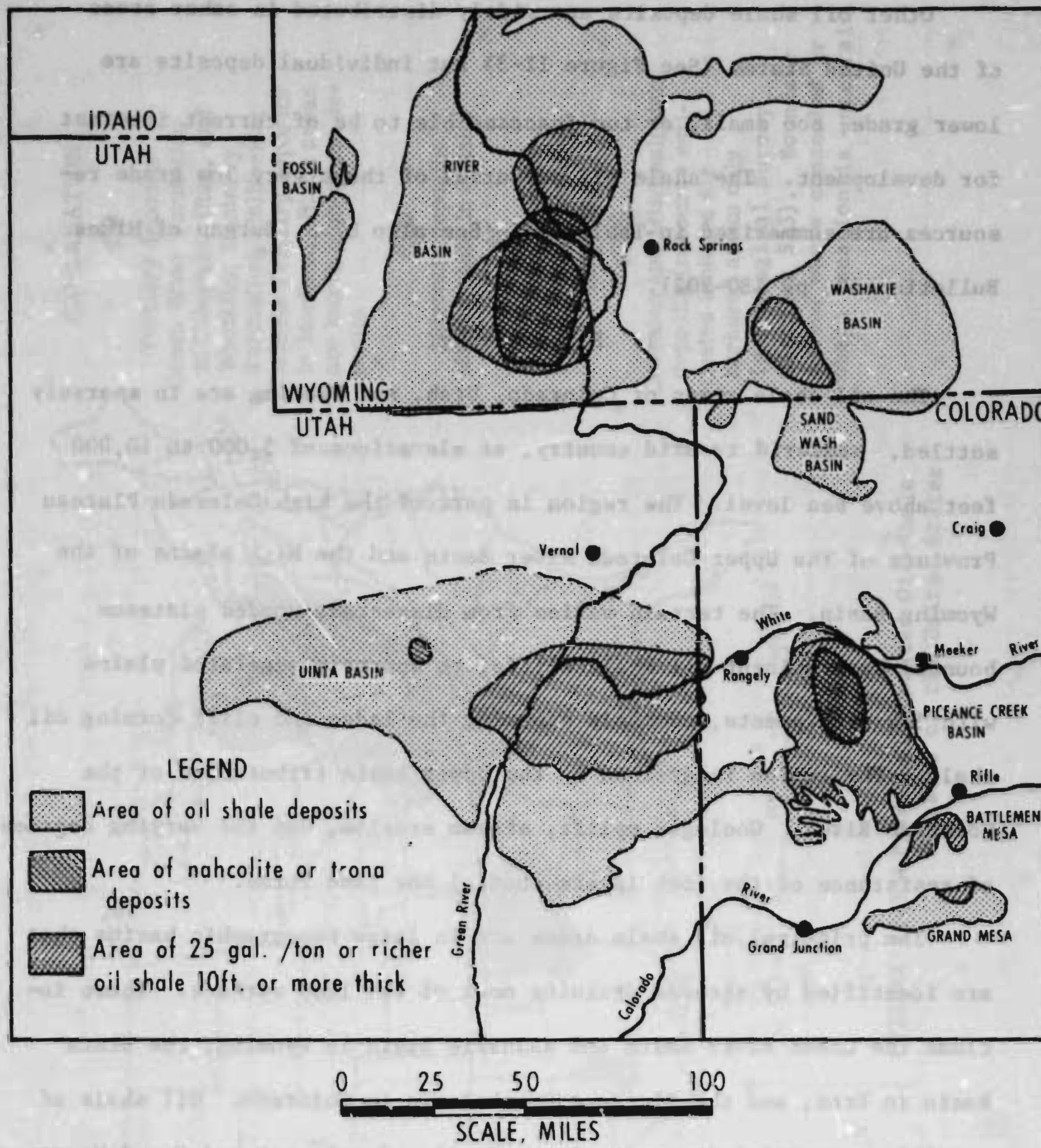

FIGURE II-2.--Oil Shale Areas in Colorado, Utah, and Wyoming.

Other oil shale deposits are widely distributed in other areas of the United States (See Figure II-3) but individual deposits are lower grade, too small, or too inaccessible to be of current interest for development. The shale oil potential of these very low grade resources are summarized in Table II-I (See also U. S. Bureau of Mines Bulletin 650, p. 180-202).

1. Physiography

The oil shale areas of Colorado, Utah, and Wyoming are in sparsely settled, semiarid to arid country, at elevations of 5,000 to 10,000 feet above sea level. The region is part of the high Colorado Plateau Province of the Upper Colorado River Basin and the high plains of the Wyoming Basin. The terrain varies from dissected, wooded plateaus bounded by prominent oil shale cliffs, to sparsely vegetated plains with low escarpments, commonly exposing the ledge and cliff forming oil shale. The region is drained by the Upper Basin tributaries of the Colorado River. Geologic uplift, stream erosion, and the varying degrees of resistance of the rock layers control the land forms.

The principal oil shale areas are in large topographic basins that are identified by streams draining most of the land surface. These include the Green River Basin and Washakie Basin in Wyoming, the Uinta Basin in Utah, and the Piceance Creek Basin in Colorado. Oil shale of possible commercial interest also underlies Battlement and Grand Mesas in Colorado.

Minor deposits also occur in the western escarpment of the Wasatch Plateau, and in the San Pitch Mountains bordering the Great Basin in Utah, in the Fossil Basin, Wyoming, and in the San Wash Basin, Colorado.

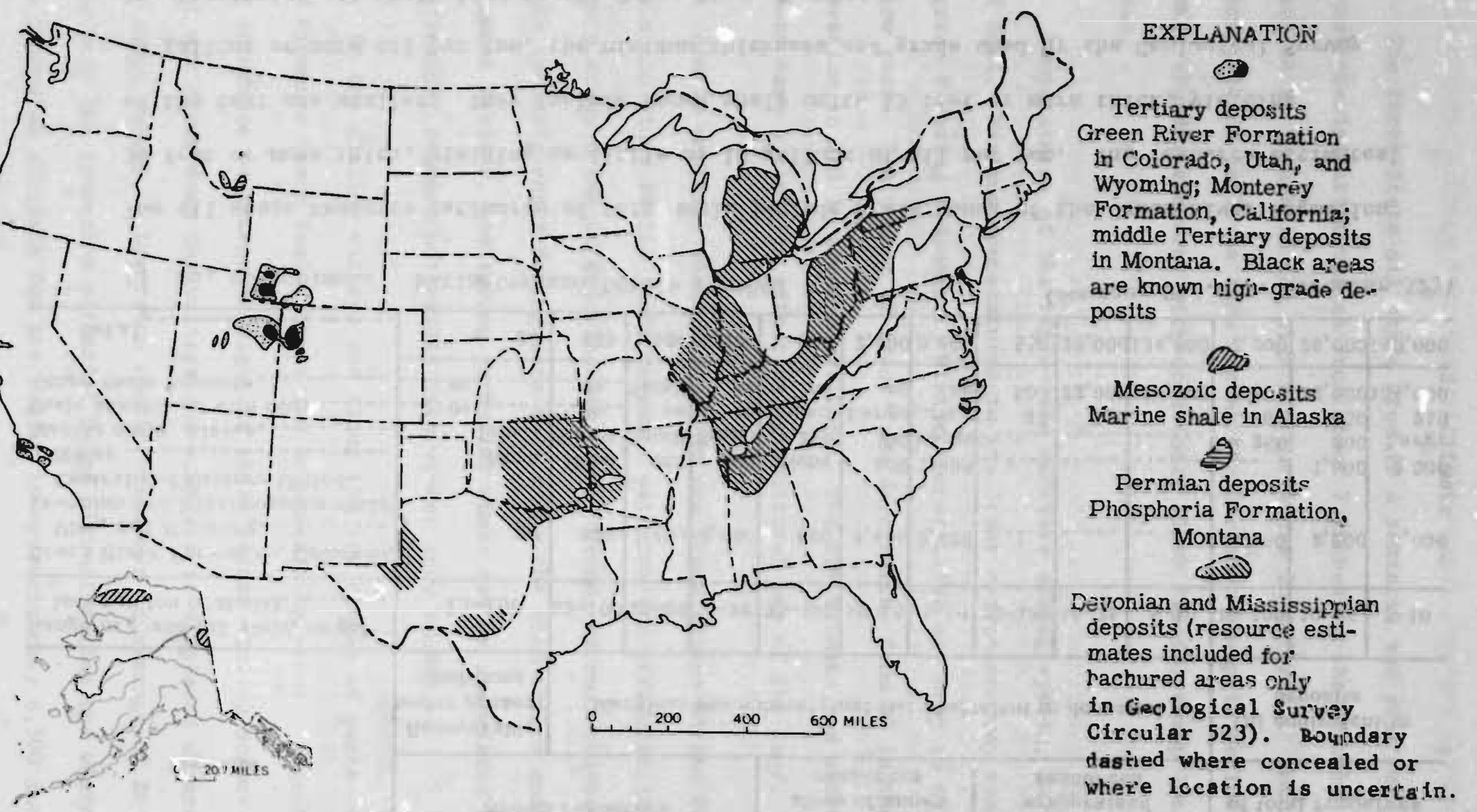

FIGURE II-3.--Principal Reported Oil-Shale Deposits of the United States.

TABLE II-1. —*Shale oil resources of the United States, in billions of barrels* 1/

Deposits	Known resources				Order of magnitude of possible extensions of known resources			Order of magnitude of undiscovered and unappraised resources			Order of magnitude of total resources		
	Recoverable under present conditions	Marginal and submarginal (oil equivalent in deposits)									Oil equivalent in deposits		
Range in grade (oil yield, in gallons per ton of shale)---------	25-100	25-100	10-25	5-10	25-100	10-25	5-10	25-100	10-25	5-10	25-100	10-25	5-10
Green River Formation, Colorado, Utah, and Wyoming-----------	80	520	1,400	2,000	600	1,400	2,000	------	------	------	1,200	2,800	4,000
Devonian and Mississippian shale, Central and Eastern United States ---------------------	None	None	200	200	None	800	1,800	------	-----	------	------	1,000	2,000
Marine shale, Alaska-----------	Small	Small	Small	Small	250	200	Large	------	-----	------	250	200	Large
Shale associated with coal ------	---do-------	--do--	ne 1/	ne	Small	Large	--do--	60	250	210	60	250	210
Other shale deposits -----------	---do-------	--do--	Small	ne	ne	ne	ne	500	22,000	134,000	500	22,000	134,000
Total------------------	80	520	1,600	2,200	850	2,400	3,800	550	22,000	134,000	2,000	26,000	140,000

1/ ne, no estimate. Estimates and totals rounded

(Source, U.S.G.S. Circular 523)

The oil shale resource estimates of this table include shale zones of the Green River Formation 10 feet or more thick, yielding as little as 10 gallons of oil per ton. The resource estimates of the text are smaller. They include known shale units 15 feet or more thick, yielding 15 gallons or more oil per ton, the minimum thickness and grade used by the Geological Survey in classifying oil shale land in the Green River Formation.

2. Climate

The three-State oil shale area is a semiarid and arid region. Annual precipitation varies from about 7 inches in the Wyoming Plains areas to 24 inches in the high plateau areas in Colorado. Much of the precipitation falls as snow during the December-to-April period. Summer thunder showers, with occasional flash floods, sweep local areas.

Temperatures of the region are moderate during spring, summer and fall. Maximum temperatures in the lower elevations may reach 100 degrees F during midsummer. Winter temperatures may drop to 40 degrees below zero. The number of frost free days varies from 50 in the higher elevation to 125 in lower elevations. The dry climate and short growing season have a limiting effect on agricultural use of the land.

Gentle westerly winds prevail in the broad plains of the Washakie Basin and Uinta Basin. Air movement patterns are irregular in the high plateau areas of Colorado and Utah. Strong thermal convection winds commonly occur during warm days along the Roan cliffs and adjacent divides, and strong turbulent winds may be associated with the thunder showers but rarely with winter snow storms.

In the shallow valleys and along the low ridges of parts of the Uinta and Piceance Creek Basins there are no prevailing winds. A gentle air inversion is common at night in these areas. During summer months cool air flows down the valleys and warm air is displaced upward to the ridge crests. Inversion conditions occur an average of 20 days per year with the inversion potential being highest during the winter months. The inversion altitude for the region is approximately 8,500 feet.

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A general pattern of wind direction and wind speed is available from weather stations in the vicinity of the region. These stations include Lander and Casper, Wyoming; Salt Lake City, Utah; and Eagle, Durango, Denver, Grand Junction, and Project Rio Blanco Sites RB1, RB2, RB3, and RB4, Colorado. Application of this data to the proposed oil shale development sites gives a synthetic description of wind speed and wind direction frequency for these sites (Table II-2).

Using measurements from these stations, the major prevailing wind direction is through the southwest quadrant approximately 40 percent of the time for Colorado and Wyoming. In Utah the major wind direction is through the southeast quadrant approximately 40 percent of the time. Minor prevailing winds 180^{o} from the major winds are also found. Since the annual average pressure patterns and average winds aloft show only minor variations over the entire area, differences between stations are the result of local topography affecting low level winds.

The average annual maximum wind speed is approximately 14 miles per hour falling in the sector southwest through west northwest.

3. Geology

The sedimentary rocks in and near the oil shale region comprise a rock sequence more than 26,000 feet thick in some areas. The oil shale-bearing rocks of the Green River Formation, which ranges from 3,000 to 7,000 feet thick, are near the top of the rock column.

Table II-2 Synthesized Annual Wind Pattern

Wind direction	Percent frequency Colo (a)	Colo (b)	Utah (a/b)	Wyo. (ab)	Mean wind speed (mph)
N	4.2	5.2	4.3	9.2	7.2
NNE	5.2	9.2	3.4	5.2	7.9
NE	9.2	5.2	3.0	4.3	6.8
ENE	5.2	4.3	2.9	3.4	7.2
E	4.3	3.4	4.8	3.0	6.7
ESE	3.4	3.0	5.0	2.9	6.7
SE	3.0	2.9	21.3	4.8	6.5
SSE	2.9	4.8	12.4	5.0	6.7
S	4.8	5.0	8.2	21.3	7.8
SSW	5.0	21.3	4.2	12.4	9.8
SW	21.3	12.4	3.6	8.2	9.2
WSW	12.4	8.2	3.1	4.2	9.9
W	8.2	4.2	4.2	3.6	11.1
WNW	4.2	3.6	5.2	3.1	10.4
NW	3.6	3.1	9.2	4.2	8.1
NNW	3.1	4.2	5.2	5.2	7.9
Total	100.0	100.0	100.0	100.0	8.1

Source: Engineering Science - 1973.

They are underlain by about 22,000 feet of older sediments that locally contain other minerals of potential commercial interest, principally oil and natural gas accumlations and coal. For further information on the general geology, the oil and gas exploration and development, and other mineral resources of the region, see the following:

Exploration for Oil and Gas in Northwestern Colorado, Rocky Mountain Association of Geologists - 1962;

Guidebook to the Geology and Mineral Resources of the Uinta Basin, Utah's Hydrocarbon Storehouse, Intermountain Association of Petroleum Geologists - 1964; and

Symposium on the Tertiary Rocks of Wyoming, Wyoming Geological Association - 1969.

The region in which the Green River Formation was deposited was warped into large structural basins and later elevated several thousand feet above sea level. The major streams and their tributaries traversing the region have eroded much of the sediments from these exhumed basins. The stream erosion has exposed the oil shale in cliff and ledges in many places. Gentle folds and minor faults locally deform the deposits, but the sedimentary rocks of the oil shale areas as a whole are remarkably undisturbed structurally, except in the areas where the strata are steeply tilted on the flanks of the Uinta Mountains in Utah and Wyoming and along the Grand Hogback in Colorado

4. Mineral Resources

a. Oil Shales

The Green River Formation in the three-State region shown in Figure II-2 contains known oil shales with about 600 billion barrels of equivalent oil in the high-grade deposits, averaging more than 25 gallons per ton and a minimum of 10 ft in thickness. In lower grade oil shale zones of the Green River Formation, averaging 15 to 25 gallons per ton, there are an additional 1,200 billion barrels. The known parts of the oil shale deposits of the region contain a total of at least 1,800 billion barrels oil equivalent. Some 80% of the known higher grade reserves are located in Colorado, 15% in Utah, and 5% in Wyoming.

A 1972 review of these deposits by the National Petroleum Council indicated that shale of first interest for development, deposits 30 feet or more thick, yielding 30 gallons or more oil per ton, and less than 1500 feet below surface, contain about 130 billon barrels oil potential in place.

Colorado has the smallest geographical area of oil shale, but it has the richest, thickest, and best known deposits. In the Piceance Creek Basin the higher grade deposits previously defined total 480 billion barrels, in strata varying from 10 to 2,000 ft in thickness, and with overburdens from zero to 1,600 ft. Substantial quantities of saline minerals are also present in the northern half of the Basin (see Section b, below).

The largest oil shale-bearing area of the Green River Formation occurs in Utah. The richest shales occur in the east-central part of the Uinta Basin, at depths up to several thousand feet below the surface. These rich deposits total more than 80 billion barrels.

Total known deposits of rich shales in Wyoming occur in the Green River Basin and are estimated to be 30 billion barrels, the smallest of the rich deposits in the three States. Leaner shales exist over a wider area, including the Washakie Basin. Some of the higher grade shales in the Green River Basin are associated with trona. Overburden ranges from 400 to 3,500 ft.

b. <u>Saline Minerals</u>

Sodium minerals have been discovered in association with certain deep shales of the Green River Formation, principally in the Piceance Creek Basin of northwestern Colorado. Trona and halite are associated with or adjacent to the shallow oil shales in the Green River Basin of Wyoming; however, the existence and/or extent of dawsonite and other saline minerals has not been established. In the Uinta Basin of Utah, the existence of sodium minerals has been shown in a few core holes, but again, the extent of these minerals has not been defined.

In Colorado's Piceance Creek Basin, halite, dawsonite, and nahcolite are intermixed or intermingled with oil shale in certain zones underlying the area. Three nahcolite strata are present near the base of the saline zone (Figure II-4), and two halite-bearing strata exist in the upper part of the zone. The dawsonite and other saline minerals, are finely disseminated in and associated with the oil shale in beds which are up to 700-ft thick near the center of the Basin. Dawsonite (a dihydroxy sodium aluminum carbonate) is technically suitable for recovery of alumina by roasting and leaching.

c. Other Minerals

Within that portion of the upper Colorado region in Colorado, Utah, and Wyoming containing the Green River Formation oil shale, there are certain additional mineral deposits of significance. Among the more important of these are petroleum, natural gas, asphaltite, tar sands, and coal.

The known crude oil reserves of the oil shale regions are approximately 680 million barrels. An additional

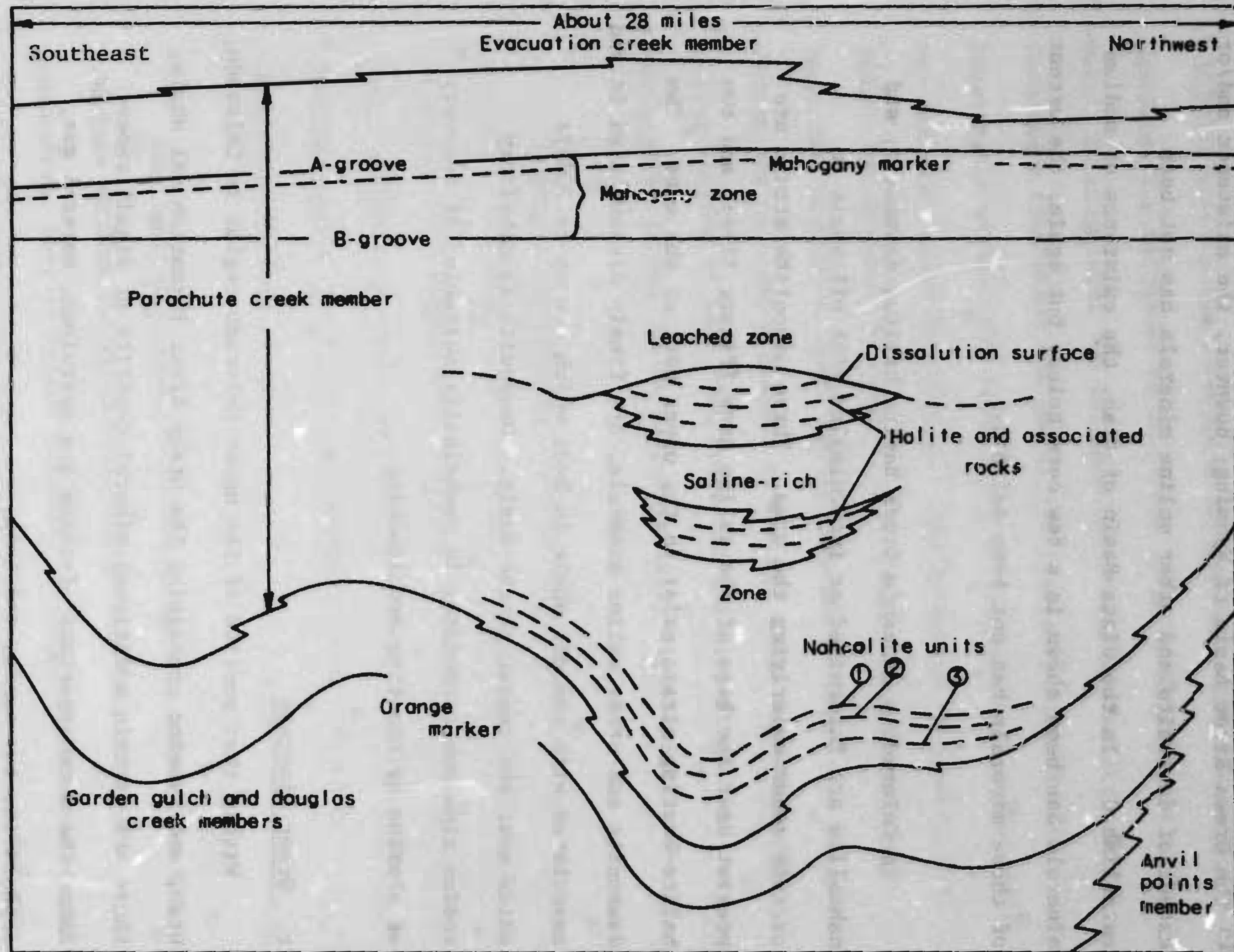

FIGURE II-4. - Diagrammatic Cross Section Showing the Saline Rich Zones in the Oil Shale-Bearing Rocks of the Piceance Creek Basin.

5 billion barrels are inferred to be present. Total natural gas resources are estimated to be of the order of 85 trillion cubic feet. An additional 300 trillion cubic feet may exist in tight formations from which the gas is not presently economically recoverable without the development of suitable techniques, which may include nuclear fracturing. (Environmental Statement, Rio Blanco Gas Stimulation Project, U.S. Atomic Energy Commission Rept. No. Wash-1519, April 1972). Certain of these oil and gas fields lie in close proximity to the oil shale deposits. The sulfur content of both the crude oil and natural gas is believed to be too low to be commercially significant.

Gilsonite (asphaltite) deposits in proximity to the oil shales occur primarily in Uintah and Duchesne Counties, Utah, where the total resource is estimated to be some 36-40 million tons. Bitumens in other rock asphalts occur in Carbon and Uintah Counties (Utah), to the extent of over 7 billion equivalent barrels of oil.

Coal beds of present or future commercial value (15- to 30-inch minimum thickness) are exposed near the oil shale deposits. Beds of lesser thickness or beds probably buried too deeply for commercial exploitation are even more extensive and underlie much of the oil shale. The "indicated" coal reserves alone, in, or adjacent to the oil shale regions of the three States, may be of the order of 6 to 8 billion tons, of which two-thirds are in Wyoming and most of the remainder in Colorado.

The mineral resources of the Upper Colorado River Basin are summarized in a State-Federal Interagency Group Comprehensive Framework Study. The report titled "Upper Colorado Region, Appendix VII, Mineral Resources, (1971)" includes maps of the oil shale deposits (Figure II-5), oil and gas fields (Figure II-6), coal deposits (Figure II-7), gilsonite and rock asphalt deposits (Figure II-8) in an near the oil shale region. The maps show the spatial relationship of the different mineral resources.

The previously discussed major saline minerals (dawsonite, halite, nahcolite, and trona) in or associated with the oil shales, and the crude oil, natural gas, bituminous rocks, and coal immediately adjacent to the shale deposits are believed to constitute the primary minerals of significant interest in connection with the study of the environmental impact of an oil shale industry. The existence of nearby gypsum deposits in Garfield County in Colorado and phosphate deposits in Wyoming and Utah are considered to be outside the area of interest of the present study. No commercial concentrations of other base or precious metals or uranium are known to be present in the oil shale area.

FIGURE II-5.--Oil-Shale Deposits in Colorado, Utah, and Wyoming.

FIGURE II-6.--Oil and Gas Fields in the Upper Colorado Region.

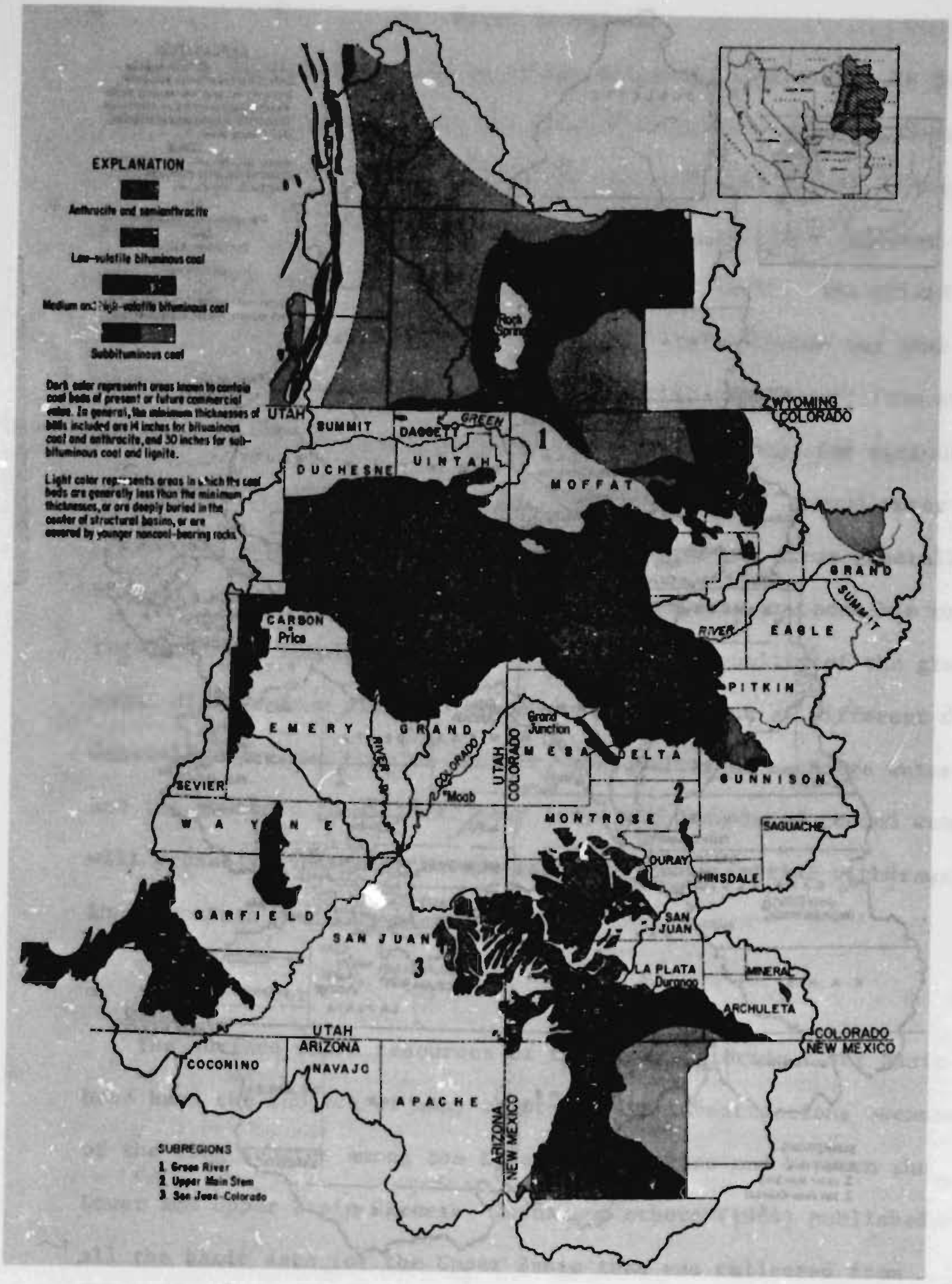

FIGURE II-7.--Coal Deposits in the Upper Colorado Region.

FIGURE II-8.--Gilsonite and Rock Asphalt Deposits and Metalliferous District in the Upper Colorado Region.

5. Water Resources

The major water supplies of the oil shale region are the through-flowing rivers of the Upper Colorado River Basin. The larger rivers such as the Green, White, Yampa, and the main stem of the Colorado receive most of their water from the higher elevations adjacent to and upstream from the oil shale areas (Figure II-9). The relatively lower oil shale areas receive from about 7 to 24 inches per year of precipitation and most streams are ephemeral. The runoff from the shale areas is committed, through State water rights, for agricultural use and stock watering supplies. Local supplies of ground water occur in the oil shale areas. The yield of wells in the areas generally will be small or moderate except where large drawdowns are possible or are required to maintain a dry mine. The chemical quality of the ground water differs from place to place and is different at different depths depending upon the type of aquifer, the quality of recharge water, and the geologic formations. Any large withdrawals of ground water will probably eventually become saline although initial withdrawals in some areas would be of good quality.

a. Surface Water

The surface water resources of the Upper Colorado River Basin have been the subject of many comprehensive investigations because of the long debates among the Lower Basin States and between the Lower and Upper Basin States. Iorns and others (1964) published all the basic data for the Upper Basin that was collected from 1892 to 1957. Their interpretations of the data were published

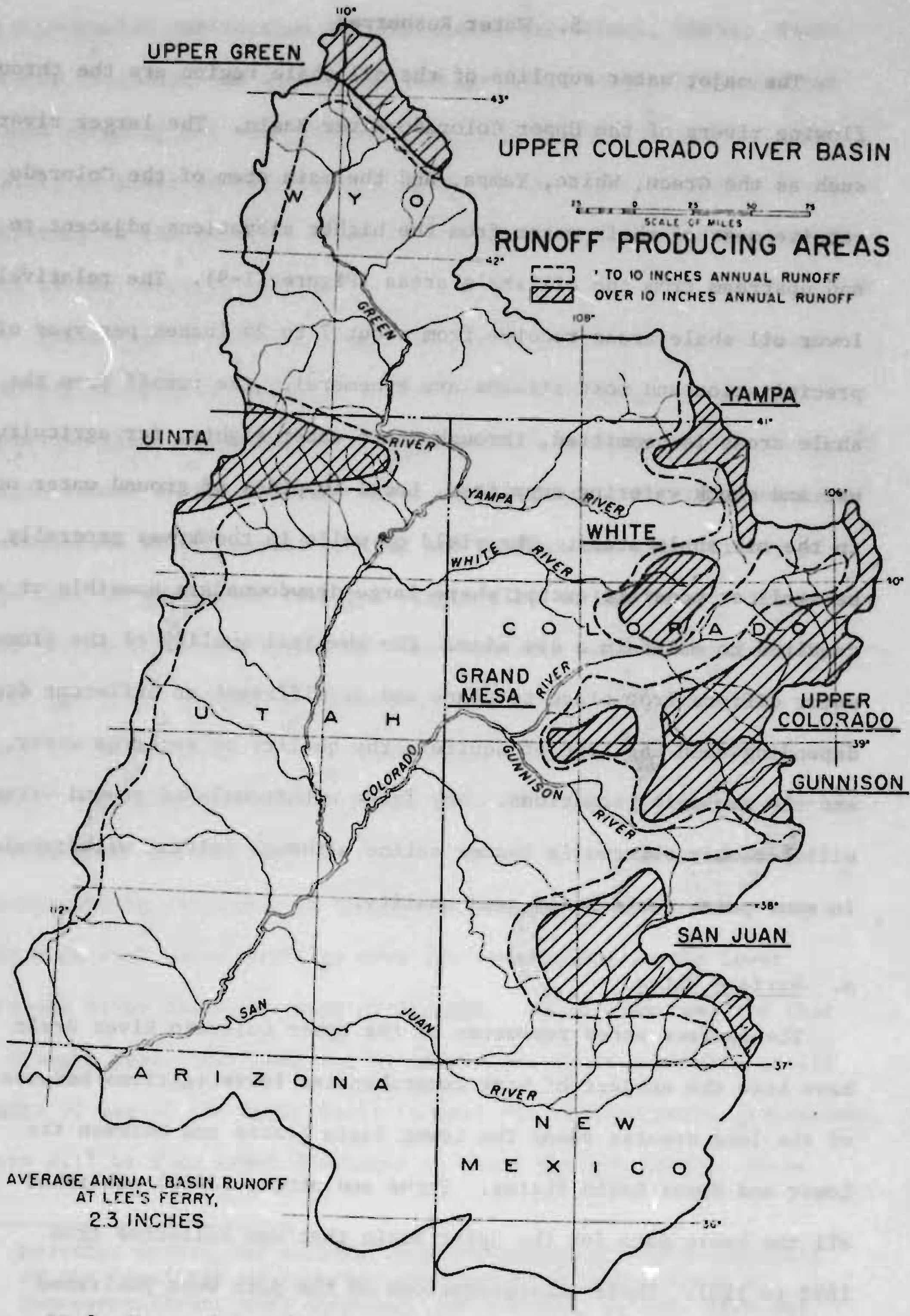

Figure II-9. -Upper Colorado River Basin Run-off Producing Area.

in a companion publication in 1965 (Iorns and others, 1965). Basic data on discharge and quality of streams in the Upper Basin are published annually for each State by the U.S. Geological Survey. The quality of water in the Colorado River is assessed biannually by the Secretary of the Interior at the direction of Congress (U.S. Department of the Interior, 1973).

The Bureau of Reclamation 1/ estimated that an average annual quantity of up to 5.8 million acre-feet is available for Upper Basin depletion (i.e., consumption). This quality is based on the estimated virgin runoff of the Colorado River at Lee Ferry. The commitments of the Colorado River Compact of 1922 and the Mexican Water Treaty of 1944 must be subtracted from the virgin flow at Lee Ferry. The treaty with Mexico allocated 1,500,000 acre-feet each year to Mexico. The Upper and Lower Basins are presently supplying equal quantities of water in satisfaction of the treaty requirements (750,000 acre-feet each). The estimate of 5.8 million acre-feet is further based on the provision of approximately 26 million acre-feet of active storage capacity being available in the Upper Colorado Basin to carry water over from high water years to meet the commitments to the Lower Colorado River Basin in years of drought. It is also realized that in drought years there may not be sufficient water available at all points of use in the Upper Basin to meet all requirements. Therefore, there will be some water shortages in these drought years. These

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1/ Hearings before the subcommittee on Irrigation and Reclamation of the Committee on Interior and Insular Affairs, House of Representatives, 90th Congress, 2nd Session, on H.R. 3300 and S.1004, January 30, 1968, page 751.

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shortages will generally be sustained by agricultural water users because they cannot economically pay the cost to provide enough storage regulation to eliminate all shortages in their water supply. Municipal and industrial water users can pay the cost of providing storage regulation to eliminate shortage; therefore, in most cases, they should have a firm water supply.

The Upper Colorado River Basin Compact of 1948 gave Arizona the right to the consumptive use of the first 50,000 acre-feet per year, and the remaining water is apportioned to the other Upper Basin States in the following percentages:

Colorado	51.75
New Mexico	11.25
Utah	23.00
Wyoming	14.00

The allocated share of the 5.8 million acre-feet of depletion for the three oil shale States would be, in acre-feet:

Colorado	2,976,000
Utah	1,322,000
Wyoming	805,000

The Upper Colorado Region, Comprehensive Framework Study, Appendix V - Water Resources, estimated the 1965 depletions in the three States. With the aid of information being developed for State water planning, the 1970 depletion of each of the three States was estimated to be as shown in Table II-3.

It is realized that there are competing uses for this same water, such as domestic, agriculture, recreation, power generation, and other industrial uses. Some of the factors which will affect the determination of the amount of that water available for oil

TABLE II-3.--Estimated Water Resources Depletion for 1970

Type of use	On-site depletion (Acre-feet) Colorado	Utah	Wyoming
Municipal and industrial	19,000	5,000	11,700
Electric power (thermal)	6,000	1,300	10,700
Minerals	14,000	9,400	13,200
Fish and wildlife	4,000	7,900	100
Recreation	1,000	300	200
Stock-pond evaporation and livestock use	21,000	6,200	2,600
Subtotal	65,000	30,100	38,500
Irrigation:			
Consumptive use	1,038,000	416,000	221,200
Incidental use	209,000	81,600	20,400
Reservoir evaporation	30,000	38,000	23,900
Total irrigation	1,277,000	535,600	265,500
Export:			
Diversions	432,000	109,500	--
Reservoir evaporation	14,000	11,400	--
Less water import	--	(2,600)	--
Total Export	446,000	118,300	--
GRAND TOTAL	1,788,000	684,000	304,000

The estimate of committed future use of water is based on the following development and their depletion:

Colorado:	Depletion (acre-feet)	Project	Status
Fryingpan - Arkansas	70,000	Federal	Under construction
Ruedi Reservoir M&I	33,000	Federal	Completed
Bostwick Park	4,000	Federal	Under construction
Fruitland Mesa	28,000	Federal	Authorized
Savery - Pot Hook	26,000	Federal	Authorized
Denver Expansion	215,000	City	Planning
Colorado Springs Expansion	6,000	City	Planning
Homestake	48,000	City	Planning
Englewood	10,000	City	Under construction
Pueblo	3,000	City	Completed
Green Mountain - M&I	45,000	Federal	Completed
Hayden steam power plant	16,000	Utility Co.	Under Construction
Independence Pass Expansion	14,000	Private	Completed
Animas - La Plata	112,000	Federal	Authorized
Dolores	87,000	Federal	Authorized
Dallas Creek	37,000	Federal	Authorized
West Divide	77,000	Federal	Authorized
San Miguel	84,000	Federal	Authorized
Four County	40,000	Private	Planning
Total	955,000		

TABLE II-3 (continued)

	Depletion (acre-feet)	Project	Status
Utah:			
Bonneville Unit...........	160,000	Federal	Under construction
Energy County-Huntington Canyon..................	6,000	Federal	Completed
Jensen.....................	15,000	Federal	Authorized
Upalco.....................	10,000	Federal	Authorized
Uintah.....................	30,000	Federal	Authorized
Deferred Indian lands......	50,000	Federal	Commitment to the Indians
Kaiparowitz power plants...	102,000	Utility Co.	Planning
Huntington Canyon power plant..................	24,000	Utility Co.	Under construction
Total..........	397,000		
Wyoming:			
Cheyenne...................	24,000	City	Planning
Lyman......................	10,000	Federal	Under construction
Savery - Pot Hook..........	12,000	Federal	Authorized
Private industrial water rights...................	57,000	Private	Under construction
Seedskadee.................	274,000	Federal	Completed
Private irrigation.........	15,000	Private	Planning
Total..........	392,000		

Although it is unlikely that all of the foregoing projects will be constructed as projected, they represent the estimation of the amount and nature of water which may be developed in the future and result in depletions to Colorado River water supplies.

The remaining amount of depletion within the 5.8 million acre-feet allocated to the three States is, in acre-feet:

Colorado....................	12,000
Utah........................	107,000
Wyoming.....................	48,000

Additional water from existing reservoirs or authorized projects that are included in the aforesaid estimate of committed future use are, in acre-feet:

Colorado:	
Ruedi Reservoir...........	33,000
Green Mountain Reservoir...	45,000
West Divide...............	77,000
Total.........	155,000

TABLE II-3 (continued)

Wyoming:	
Fontenelle Reservoir (Seedskadee)...	19,000 1/

When these figures are added to the remaining water not identified, the potential water supply available for oil shale development is:

Colorado..................................	167,000
Utah......................................	107,000
Wyoming...................................	67,000

1/ This 19,000 acre-feet is all that Cameron Engineers projected for the State of Wyoming as being required for oil shale development by the year 2030. There is additional water in Fontenelle Reservoir that could be used for oil shale development.

shale use are (a) priority of water right, (b) the amount of water available in tributaries within transportation range of the oil shale region, (c) the nature of the decreed use, (d) the extent of domestic and agricultural demands, and (e) the relative time of development of oil shale and competing industrial uses.

Table II-4 is a summary of estimates, made by the Bureau of Reclamation, that shows the amount of water available for potential development after accounting for present use and presently committed future uses.

The remaining uncommitted water in the three oil shale States of Colorado, Utah, Wyoming, within their compact allotments, is over-appropriated many times by conditional decrees, applications, and permits, including recent claims of the United States in Colorado's Water Divisions 4, 5 and 6.

As a practical matter, many of these water rights may never be perfected or proven due to lack of water and the development for which they were filed never coming to realization. What the final disposition of these water rights will be is one of the unpredictable items in any attempt to forecast future demands for the use of water.

Several firms interested in oil shale development began many years ago to acquire water rights (Tables II-5 and II-6). In addition, water rights have been obtained through the purchase of land in the oil shale area. Although land thus purchased is almost always leased by oil companies back to farmers or ranchers and the water involved is presently being used for agricultural purposes, a company can obtain a change of use for the water to a municipal

TABLE II-4.--Present and Future Water Use in the Upper Colorado River Basin
(Thousand acre-feet per year)

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

1/ Arizona received the right to the consumptive use of the first 50,000 acre-feet per year.

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

3/ From the existing Fontenelle Reservoir - Seeskadee Project.

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

TABLE II-5--Water Right Applications For Colorado Oil Shale Area[1/]

Colorado filing No.	Applicant and project name	Date of appropriation	Quantity of water claimed CFS	AFY	Status[2/]
18062	Union Oil Co., Union Oil Pumping Pipeline.	14 Feb 49	118.5	85,770	CD
18957	Cities Service Oil Co., Cities Service Pipeline.	2 Aug 51	100.0	72,380	CD
18191	Chevron Oil Co., Dragert Pumping Pipeline.	16 Nov 51	94.0	68,040	CD
19625	Getty Oil Co., Pacific Western Pumping Pipeline.	19 Nov 51	56.0	40,530	CD
18720	Chevron Oil Co., Eaton Pumping Pipeline.	21 Nov 51	100.0	72,380	CD
19645	Chevron Oil Co., Pacific Oil Co. Pipeline.	9 Jun 53	57.25	41,440	CD
19646	Colony Development Operation[3/] Pacific Oil Co. Pipeline.	9 Jun 53	28.63	20,720	CD
20281	Colony Development Operation, E. Middle Fork Pipeline.	19 Oct 54	20.0	14,476	CD
20280	Colony Development Operation, Dow Middle Fork Pipeline.	20 Oct 54	10.0	7,238	CD
21304A	Colony Development Operation, Dow Pumping Plant & Pipeline.	24 Jan 55	1,178.0	128,840	CD
21245	Atlantic Richfield Co., Sinclair Pumping Pipeline.	29 Nov 56	33.0	23,885	CD
22265	Mobil Oil Corp., Piceance Pipeline.	10 Jun 61	50.0	36,190	CD
22421	Humble Oil & Refining Co., White River Pumping Pipeline.	15 Dec 63	100.0	72,380	F
22545	Humble Oil & Refining Co., White River/14-mile Creek Pipeline.	12 Sep 64	200.0	144,760	CD
22662	Sohio Petroleum Co., Clear Creek Feeder Pipeline.	8 Feb 65	50.0	36,190	CD
22662	Sohio Petroleum Co., Conn Creek Feeder Pipeline.	8 Feb 65	50.0	36,190	CD
23011	White River Resources Inc., White River/Piceance Creek Pipeline.	5 Aug 66	100.0	72,380	F
23382	Industrial Resources Inc., Wolf Ridge Resv. & Feeder Pipeline.	19 Nov 66	100.0	72,380	F
23060	The Oil Shale Corp., Story/Gulch Parachute Creek Pipeline.	28 Feb 67	55.0	39,809	F
23448	Superior Oil Co., Superior Pipeline.	14 May 68	24.0	17,370	F

1/ All data obtained from water filings made with Colorado State Engineer. Virtually all of these direct flow applications are accompanied by separate appropriately sized storage reservoir applications.

2/ CD = Conditional Decree has been awarded by Colorado State Court.
F = Filed only -- no conditional decree yet awarded.

3/ Partners in Colony are Atlantic Richfield Co., The Oil Shale Corporation, Sohio Petroleum Co. and Cleveland Cliffs Mining Co.

Table II - 6. Utah Water Right Applications 1/

Application No.	Applicant	Quantity requested CFS	Quantity requested AFY	State use for water	Status
36,730	Sohio Petroleum Co.	15.0	10,857	Oil Shale	Pending
37,111	Western Oil Shale Corporation	15.0	10,857	Oil Shale	Pending
37,139	F. H. Larson	30.0	21,714	Oil Shale	Pending
37,270	Atlantic Richfield Company	25.0	18,095	Power Plant & Oil Shale	Pending
37,271	Atlantic Richfield Company	15.0	10,857	Power Plant & Oil Shale	Pending

1/ All data obtained from water rights applications filed with Utah State Engineer.

or industrial category. No estimate of the number of acre feet involved in these transactions is currently available. Generally speaking, however, the quantities of water obtained in this manner are small. A change from irrigation use to municipal or industrial use or a change in the point of diversion must be approved by the district courts. A change from agricultural to municipal or industrial use generally results in a decrease in the amount of water that can be diverted under the right, because the future diversion is limited to the actual consumptive use that took place when diverted for agricultural purposes.

The Colorado River Basin Project Act (Public Law 90-537 September 30, 1968) recognized the need for augmenting the water supply of the Colorado River. Under Title II, Section 202, the Congress declared that the satisfaction of the requirements of the Mexican Water Treaty from the Colorado River constituted a national obligation.

Waters of the Colorado River are becoming more saline. Great concern and a sense of urgency to halt the increase in salinity [1/] have been expressed by those who depend upon the river as a lifeline. The salinity control problem extends to the Republic of Mexico and has become an important aspect in our international relations with that nation.

1/ Salinity refers to the concentration of dissolved solids and is reported in milligrams per liter (mg/l). This unit of concentration is nearly equivalent to parts per million (ppm) up to concentrations of 7,000 mg/l.

The average annual salinity concentration of the Colorado River at Imperial Dam during the period 1941 to 1970 (most recently published data) was 757 mg/1. The annual salinity concentrations during this same period ranged from a minimum of 649 mg/1 in 1949 to a maximum of 918 mg/1 in 1956. The monthly salinity concentrations of the Colorado River at Imperial Dam during the period 1941 to 1970 experienced an even wider range from a minimum of 551 mg/1 in December 1952, to a maximum of 1,000 mg/1 in January 1957.

Calculations of salinity concentrations present in the lower Colorado River give different levels for different periods used to describe the level. As indicated above, the average for one year was greater than the average level during the period 1941 to 1970 and the peak monthly concentration is even greater than the level for a year.

At the headwaters, the average salinity in the Colorado River is less than 50 mg/1; the concentration increases downstream until, at Imperial Dam, the present modified [1/] condition is 850 mg/1. Projection of future salinity levels without a control program suggests that values of 1,200 mg/1 or more will occur at Imperial Dam by the year 2000. The following table shows the increase in salinity in a downstream order for the present modified and future projected (year 2000 or after) conditions.

1/ Present modified refers to the historic conditions (1941-1970) modified to reflect all upstream existing projects in operation for the full period.

Table II-7.--Increase in Salinity of the Colorado River for Present Modified and Future Projected Conditions.

	Concentration in mg/l	
	Present modified	Future projected
Green River near Green River, Wyoming	323	346
Green River at Green River, Utah	473	537
Colorado River near Glenwood Springs, Colo.	310	379
Colorado River near Cisco, Utah	662	817
San Juan River near Archuleta, N.Mex.	165	170
San Juan River near Bluff, Utah	471	906
Colorado River at Lee Ferry, Arizona	609	767
Colorado River below Hoover Dam, Arizona-Nevada	745	971
Colorado River at Imperial Dam, Arizona-California	850	1,200

Future salinity concentrations based on the projected depletions to the Colorado River are listed in Table II-8 (data on projected depletions from Table 19, Progress Report No. 6).[1/]

Other projected future concentrations of salinity have been made by the Environmental Protection Agency, the Colorado River Board of California, and the Water Resources Council. These projections are compared in Table II-8.

1/ Quality of Water, Colorado River Basin, Progress Report No. 6, January 1973, U.S. Department of the Interior, Bureau of Reclamation.

Table II-8.--Projected Concentrations of Dissolved Solids (mg/l) at Imperial Dam (Average values)

Source	1980	1990	2000	2010	2020	2030
EPA	1,060	-	-	1,220	-	-
CRBC	1,070	-	1,340	-	-	1,390
WRC	1,260	-	1,290	-	1,350	-
USBR	930	1,100	1,200	-	-	-

EPA: Environmental Protection Agency
CRBC: Colorado River Board of California
WRC: Lower Colorado Region Comprehensive Framework Study (Water Resources Council)
USBR: Bureau of Reclamation (1973)

The differences in the values projected by the various agencies arise from assumptions made regarding completion dates for water development projects, estimates of the amount of salt loading or concentration effects produced by these projects, the period of analysis used, and estimates of the time involved for the effects to emerge in the lower reach. All studies by the various agencies predict that proposed developments will cause a considerable increase in the future salinity of the river.

Initial investigations conducted on the potential impact of future salinity levels reveal that only small effects on water uses could be anticipated in the Upper Basin. 1/ Water in the Upper

1/ The Mineral Quality Problem in the Colorado River Basin Summary Report, U.S. Environmental Protection Agency, 1971.

Basin will be suitable for most purposes even after the projected increases in salinity take place. Increases in salinity from activities in the Upper Basin will take place whether the water is diverted for industrial use which may or may not have returns to the river or is used largely for agricultural purposes and excess applied water returns to the river. Diversion of the relatively low-salinity water in the Upper Basin for industries will decrease the dilution of higher salinity water entering the system below the oil shale area. Diversion of the same water for agricultural purposes will decrease the amount of water in the river less than diversion for industry but could add to the salt content, both because the return flow will be concentrated by evapotranspiration and because it will contain minerals and fertilizers leached from the soil. Subsequent discussions are limited to the impact of future salinity levels in the following main study areas: the Lower Main Stem and Gila areas in the Lower Basin, and the Southern California area encompassing the southern California water service area. The boundaries of these study areas follow political rather than hydrological boundaries (Figure II-10).

The direct economic costs of mineral quality degradation may be summarized in two basic forms, total direct costs and penalty costs. Total direct costs incurred for a given salinity level result from increases in salinity concentrations above the threshold levels of water uses. Penalty costs are the differences between total direct costs for a given salinity level and for a specified base level. They represent the marginal costs of increases in salinity concentrations above base conditions.

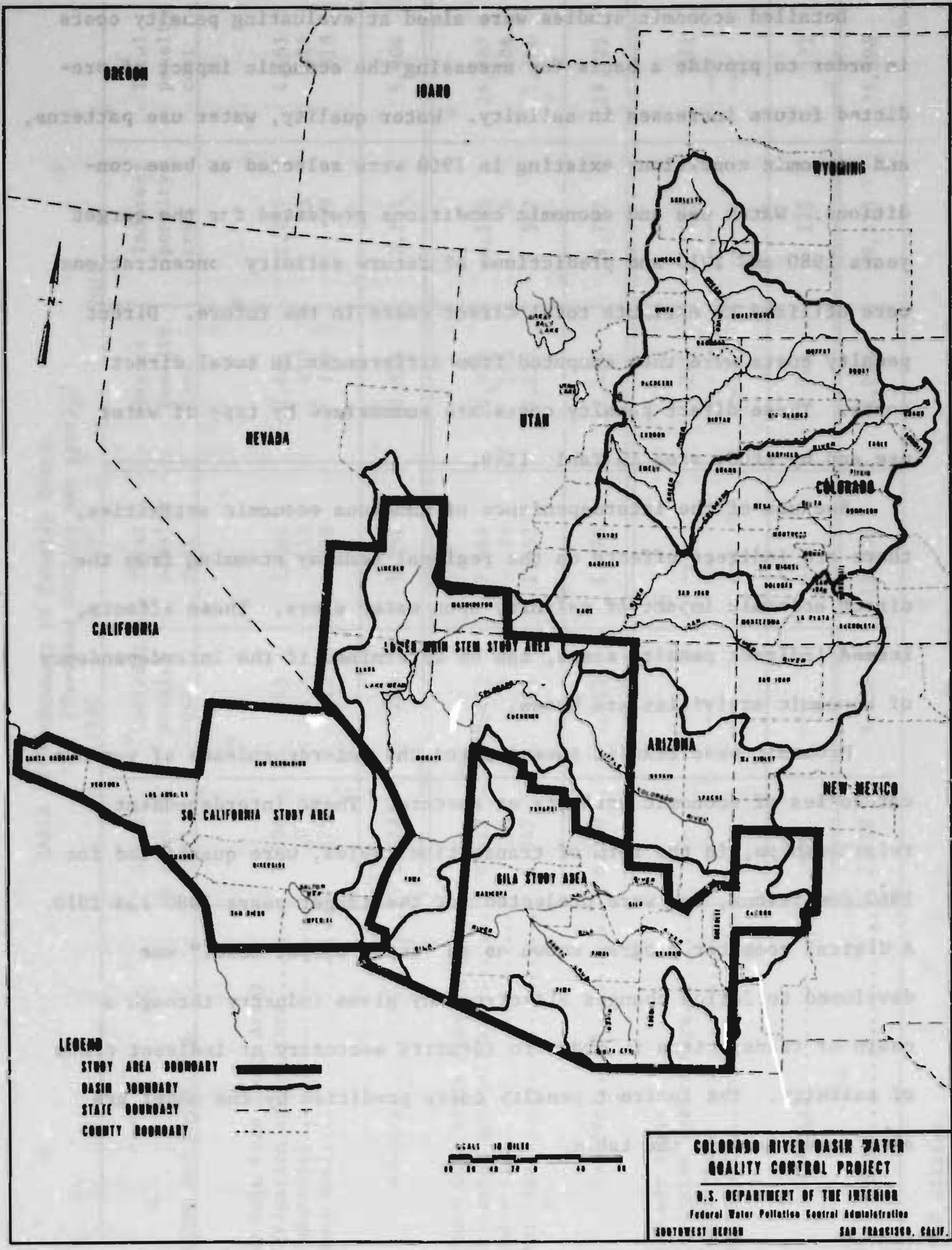

FIGURE II-10.-- Location of Salinity Impact Study Areas

Detailed economic studies were aimed at evaluating penalty costs in order to provide a basis for assessing the economic impact of predicted future increases in salinity. Water quality, water use patterns, and economic conditions existing in 1960 were selected as base conditions. Water use and economic conditions projected for the target years 1980 and 2010 and predictions of future salinity concentrations were utilized to estimate total direct costs in the future. Direct penalty costs were then computed from differences in total direct costs. These direct penalty costs are summarized by type of water use and by study area in Table II-9.

Because of the interdependence of numerous economic activities, there are indirect effects on the regional economy stemming from the direct economic impact of salinity upon water users. These effects, termed indirect penalty costs, can be determined if the interdependency of economic activities are known.

Economic base studies investigated the interdependence of various categories of economic activity or sectors. These interdependent relationships, in the form of transaction tables, were quantified for 1960 conditions, and were projected for the target years 1980 and 2010. A digital computer program known as an "input-output model" was developed to follow changes affecting any given industry through a chain of transactions in order to identify secondary or indirect costs of salinity. The indirect penalty costs predicted by the model are also summarized in the table.

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TABLE II-9.-Summary of Penalty Costs.
(Thousand dollars per year)1/

Location and Water Use	1980 Direct penalty cost	1980 Indirect penalty cost	1980 Total penalty cost	2010 Direct penalty cost	2010 Indirect penalty cost	2010 Total penalty cost
Lower Main Stem Study Area:						
Irrigation agriculture........	1,096	765	1,861	2,424	2,237	4,661
Industrial..................	107	4	111	410	15	425
Municipal...................	275	14	289	779	39	818
Subtotal..............	1,478	783	2,261	3,613	2,291	5,904
Southern California Study Area:						
Irrigated agriculture.........	4,617	2,447	7,064	10,072	6,195	16,267
Industrial..................	56	3	59	103	5	108
Municipal...................	1,347	305	1,652	2,239	507	2,746
Subtotal..............	6,020	2,755	8,775	12,414	6,707	19,121
Gila Study Area:						
Irrigated agriculture.........	---	---	---	246	125	371
Industrial..................	---	---	---	---	---	---
Municipal...................	---	---	---	---	---	---
Subtotal..............	---	---	---	246	125	371
Total..................	7,498	3,538	11,036	16,273	9,123	25,396

1/ 1960 dollars.

Total penalty costs represent the total marginal costs of increases in salinity concentrations above base conditions. They are the sum of direct penalty costs incurred by water users and indirect penalty costs suffered by the regional economy.

Several conclusions can be drawn from the table:

1. The majority of the penalty costs (an average of 82 percent) will result from water use for irrigated agriculture. This fact may be attributed to the heavy utilization of Colorado River water for irrigation along the Lower Colorado River and in the southern California area.

2. Over three-fourth of the penalty costs will be incurred in the southern California water service area. These costs will result primarily from agricultural use in the Imperial and Caochella Valleys, and municipal and industrial uses in the coastal metropolitan areas.

3. Penalty costs in the Gila study area will be minor and will not occur until after 1980, when water deliveries to the Central Arizona Project begin. (It was assumed that all Central Arizona Project water would be utilized for agricultural purposes).

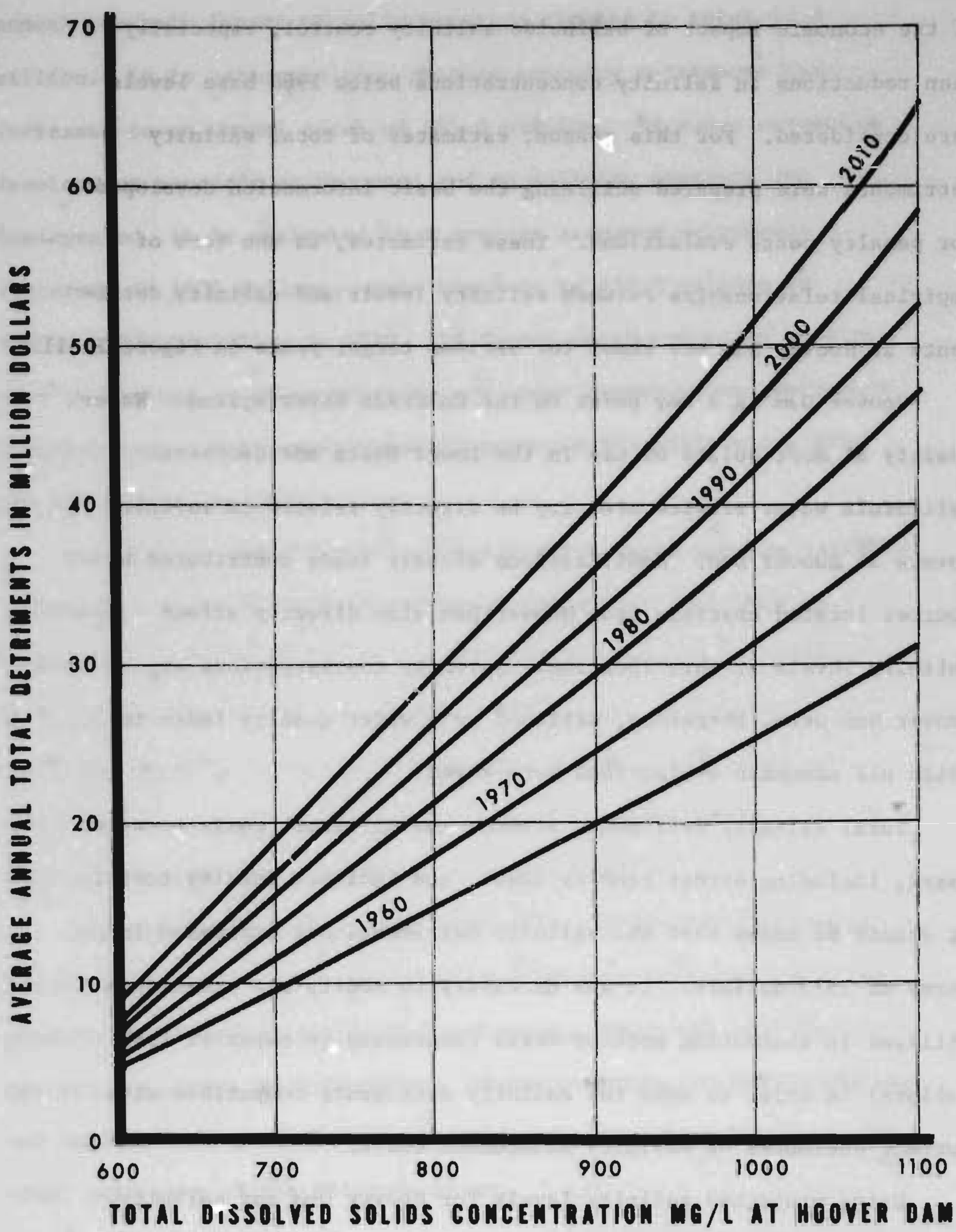
It should be noted that the penalty costs summarized in the table do not represent the total economic impact of salinity but only the incremental increase in salinity detriments resulting from rising salinity levels. There are economic costs known as salinity detriments that were being incurred by water users in 1960 as a result of salinity levels exceeding threshold levels for certain water users. These costs would continue in the future if salinity levels remained at the 1960 base conditions.

The detailed economic analysis forms a basis for evaluating the distribution of the total economic impact of future salinity increases. Penalty costs are not practical, however, for evaluation of the economic impact of basinwide salinity control, especially when reductions in salinity concentrations below 1960 base levels were considered. For this reason, estimates of total salinity detriments were prepared utilizing the basic information developed for penalty costs evaluations. These estimates, in the form of empirical relationships between salinity levels and salinity detriments at Hoover Dam are shown for various target years in Figure II-11.

Hoover Dam is a key point on the Colorado River system. Water quality at most points of use in the Lower Basin and southern California water service area may be directly related to salinity levels at Hoover Dam. Modifications of salt loads contributed by sources located upstream from Hoover Dam also directly affect salinity levels at this location. Salinity concentrations at Hoover Dam were, therefore, utilized as a water quality index to which all economic evaluations were keyed

Total salinity detriments are the sum of direct costs to water users, including direct penalty costs, and indirect penalty costs. It should be noted that the salinity detriments are expressed in terms of 1970 dollars. It was necessary to modify the basic data utilized in evaluating penalty costs (expressed in terms of 1960 dollars) in order to make the salinity detriments compatible with current estimates of salinity management costs.

Using projected salinity levels for Hoover Dam and salinity detriment functions shown in the graph, it is possible to compare the total economic detriments of salinity under various conditions of water use and resource development. Under 1960 conditions, the



Colorado River Basin Water Quality
Control Project.
U. S. Dept. of the Interior
Federal Water Pollution Control Administration

FIGURE II-11.--Salinity Detriments at Hoover Dam.

annual economic impact of salinity was estimated to total $9.5 million. It is estimated that present salinity detriments have increased to an annual total of $15.5 million. If water resources development proceeds as proposed and no salinity controls are implemented, it is estimated that average economic detriments, expressed in 1970 dollars, would increase to $27.7 million in 1980 and $50.5 million in 2010. If future water resources development is limited to those projects now under construction, estimated annual economic detriments would increase to $21 million in 1980 and $29 million in 2010.

Research is under way or scheduled which would provide valuable inputs to a salinity control effort. Included is such work as developing better predictions of irrigation return flow quality, deriving the systems for assessing ecologic impacts of water resource projects, developing procedures for management and use of saline water, testing advanced irrigation systems, and identifying waste water reclamation opportunities.

A comprehensive 10-year Water Quality Improvement Program is now under investigation. It is integrated with programs involving weather modification, geothermal resources, desalting, and the Western U.S. Water Plan Westwide. These programs, if found feasible and implemented, could help to control increases in salinity in the lower main stem of the Colorado River.

At the "Seventh EPA Enforcement Conference in the Matter of Pollution of the Interstate Waters of the Colorado River and its

Tributaries," held in Las Vegas, Nevada (February 15-17, 1972), and Denver, Colorado (April 26-27, 1972), the State and Federal conferees adopted a resolution recommending to the Environmental Protection Agency that salinity increase in the river be minimized through a salinity control program, as described in the Bureau of Reclamation's Report "Colorado River Water Quality Improvement Program," dated February 1972. The objective of this program is to arrest or reduce the salinity increases in the Colorado River. The salinity problem is to be treated as a basin-wide problem that needs to be solved to control salinity levels, while the Upper Basin continues to develop its compact-apportioned waters. On this basis then, any salinity increases arising from development in the Upper Basin are proposed to be offset by the Water Quality Improvement Program and related activities.

Early emphasis is being placed on those activities most likely to achieve water quality improvement at least cost. Construction of a mathematical model may reveal better ways to operate the river system to generate water quality benefits without incurring capital investment costs for structural control measures. Irrigation source control, involving close integration of on-farm irrigation-water scheduling and management, with water systems improvement and management, is expected to significantly reduce salt loadings.

Table II-10 was developed to show the projected reductions in salinity concentrations for each program augmentation and water quality improvement and the estimated effects on the synthesized salinity levels at Imperial Dam.

TABLE II-10.--Projected Reductions in Salinity Concentrations - Colorado River at Imperial Dam
(Average annual values in mg/l - 1941-1970 period of record)

	1970	1980	1990	2000
Estimated Salinity Level a/	850	930	1100	1200
Range	(730-1030)	(790-1150)	(950-1340)	(1040-1460)
Projected Salinity Reductions				
Source Control	(-)	(-54)	(-130)	(-130)
Vegetative Management	(-)	(-)	(- 20)	(- 40)
Desalting	(-)	(-)	(- 40)	(- 90)
Weather Modification	(-)	(-20)	(- 40)	(- 70)
Other Practices	(-)	(- 6)	(- 20)	(- 20)
Total Reduction	(-)	(-80)	(-250)	(-350)
Estimated Salinity Level with control programs	850	850	850	850
Range	(730-1030)	(730-1030)	(730-1030)	(730-1030)

a/ No salinity control programs

The values in the table are initial estimates based on the average hydrologic conditions for the period of record 1941-1970. The 1970 average annual value was 850 mg/l at Imperial Dam. The average annual values for the years 1980, 1990 and 2000 were synthesized to reflect the influence on water quality during the period of record of water resouce developments expected to be completed by those dates. These estimates are initial approximations. The feasibility and related studies, buttressed by additional research, will provide more reliable estimates.

It should be recognized that the values in the table are computed average annual values at Imperial Dam under the stated assumptions. The average annual modified value for 1970 of 850 mg/l based on the 1941 to 1970 period would probably have ranged from an annual minimum of 750 mg/l to an annual maximum of 1,060 mg/l. However, with Lakes Powell and Mead regulating the Colorado River, it would require several consecutive, low-flow years to produce an annual salinity concentration of 1,000 mg/l or higher, at Imperial Dam.

Historically, records at Imperial Dam show that the average salinity concentration for January 1957 was 1,000 mg/l and for December 1967 it was 992 mg/l. Six other months in the period 1941-1970 had average concentrations above 960 mg/l. However, with present development, it is probable that the average monthly concentrations for these 8 months would have exceeded 1,000 mg/l. Furthermore, with present development, the 1,000 mg/l mean monthly concentration at Imperial Dam would have been exceeded in 40 months during the period 1941-1970.

It is not possible to predict future salinity concentrations for any particular month, nor can it be assumed that past flow and concentration cycles will be repeated in the future.

b. Ground Water

Ground water resources within the oil shale areas are less well known than the surface water resources but are believed to be of significan quantities only within the Piceance Creek Basin, Colorado. Table II-11 summarizes the water bearing characteristics of the geologic units in the Piceance Creek Basin.

The Green River Formation is the best potential source of ground water in the Piceance Creek Basin. The leached and fractured zones of the Parachute Creek Member and the Evacuation Creek Member are aquifers and contain water under artesian pressure in most of the area. There are many flowing wells and the maximum depth to water is about 200 feet in the shallowest aquifer. The depth to water may be as much as 500 feet in the deeper aquifer. The Garden Gulch Member, the high resistivity zone of the Parachute Creek Member, and the Mahogany Zone of the Parachute Creek Member have very low permeability. Fractures in the Mahogany Zone permit water to move between aquifers in some areas (See diagrammatic section, Figure II-12). The leached zone and its lateral equivalent contain water in fractures and solution openings and are considered the principal bed-rock aquifer in the Piceance Creek Basin because they have the greatest areal extent, permeability, and storage capacity. This aquifer may contain as much as 25 million acre-feet of water in storage in the 630 square mile drainage area of Piceance and Yellow Creeks (See Section B.5.b).

Alluvium is a source of ground water along the Piceance, Yellow, Roan, and Parachute Creeks. The alluvial aquifer is capable of stor-

TABLE II-11 SUMMARY OF GEOLOGIC UNITS AND THEIR WATER-BEARING CHARACTERISTICS

System	Series	Geologic unit		Thickness (feet)	Physical character	Water quality	Hydrologic character
Quaternary	Holocene and Pleistocene(?)	Alluvium		0-140	Sand gravel and clay partly fill major valleys as much as 140 feet, generally less than half a mile wide. Beds of clay may be as thick as 70 feet, generally thickest near the center of valleys. Sand and gravel contain stringers of clay near mouths of small tributaries to major streams.	Near the headwaters of the major streams, dissolved-solids concentrations range from 250 to 700 mg/l. Dominant ions in the water are generally calcium, magnesium, and bicarbonate. In most of the area, dissolved solids range from 700 to as much as 25,000 mg/l. Above 3,000 mg/l the dominant ions are sodium and bicarbonate.	Water is under artesian pressure where sand and gravel are overlain by beds of clay. Reported yields as much as 1,500 gpm. Well yields will decrease with time because valleys are narrow and the valley walls act as relatively impermeable boundaries. Transmissivity ranges from 20,000 to 150,000 gpd per ft. The storage coefficient averages 0.20.
Tertiary	Eocene	Green River Formation	Evacuation Creek Member	0-1,250	Intertonguing and gradational beds of sandstone, siltstone, and marlstone; contains pyroclastic rocks and a few conglomerate lenses. Forms surface rock over most of the area; thins appreciably westward.	Water ranges from 250 to 1,800 mg/l dissolved solids.	Beds of sandstone are predominantly fine grained and have low permeability. Water moves primarily through fractures. The part of the member higher than valley floors is mostly drained. Reported to yield as much as 100 gpm where tested in the north-central part of the basin. Member has not been thoroughly tested, and larger yields may be possible.
			Parachute Creek Member	500-1,800	Kerogenaceous dolomitic marlstone (oil shale) and shale; contains thin pyroclastic beds; fractured to depths of at least 1,800 feet. Abundant saline minerals in deeper part of the basin. The member can be divided into three zones—high resistivity, low resistivity or leached, and Mahogany (oldest to youngest), which can be correlated throughout basin by use of geophysical logs.	Water ranges in dissolved-solids content from 250 to about 63,000 mg/l. Below 500 mg/l, calcium is the dominant cation; above 500 mg/l, sodium is generally dominant. Bicarbonate is generally the dominant anion regardless of concentration. Fluoride ranges from 0.0 to 54 mg/l.	High resistivity zone and Mahogany zone are relatively impermeable. The leached zone (middle unit) contains water in solution openings and is under sufficient artesian pressure to cause flowing wells. Transmissivity ranges from less than 3,000 gpd per ft in the margins of the basin to 20,000 gpd per ft in the center of the basin. Estimated yields as much as 1,000 gpm. Total water in storage in leached zone 2.5 million acre-feet or more.
			Garden Gulch Member	0-900	Papery and flaky marlstone and shale; contains some beds of oil shale and, locally, thin beds of sandstone.	One water analysis indicates dissolved-solids concentration of 12,000 mg/l.	Relatively impermeable and probably contains few fractures. Prevents downward movement of water. In the Parachute and Roan Creeks drainages, springs are found along contact with overlying rocks. Not known to yield water to wells.
			Douglas Creek Member	0-800	Sandstone, shale, and limestone; contains oolites and ostracods.	The few analyses available indicate that dissolved-solids content ranges from 3,000 to 12,000 mg/l. Dominant ions are sodium and bicarbonate, or sodium and chloride.	Relatively low permeability and probably little fractured. Maximum yield is unknown, but probably less than 50 gpm.
			Anvil Points Member	0-1,870	Shale, sandstone, and marlstone grade within a short distance westward into the Douglas Creek, Garden Gulch, and lower part of the Parachute Creek Member. Beds of sandstone are fine grained.	The principal ions in the water are generally magnesium and sulfate. The dissolved-solids content ranges from about 1,200 to 1,800 mg/l.	Sandstone beds have low permeability. A few wells tapping sandstone beds yield less than 10 gpm. Springs issuing from fractures yield as much as 100 gpm.
		Wasatch Formation		300-5,000	Clay, shale, lenticular sandstone; locally, beds of conglomerate and limestone. Beds of clay and shale are the main constituents of the formation. Contains gypsum.	Gypsum contributes sulfate to both surface-water and ground-water supplies.	Beds of clay and shale are relatively impermeable. Beds of sandstone are poorly permeable. Not known to yield water to wells.

(After Coffin and others, 1971)

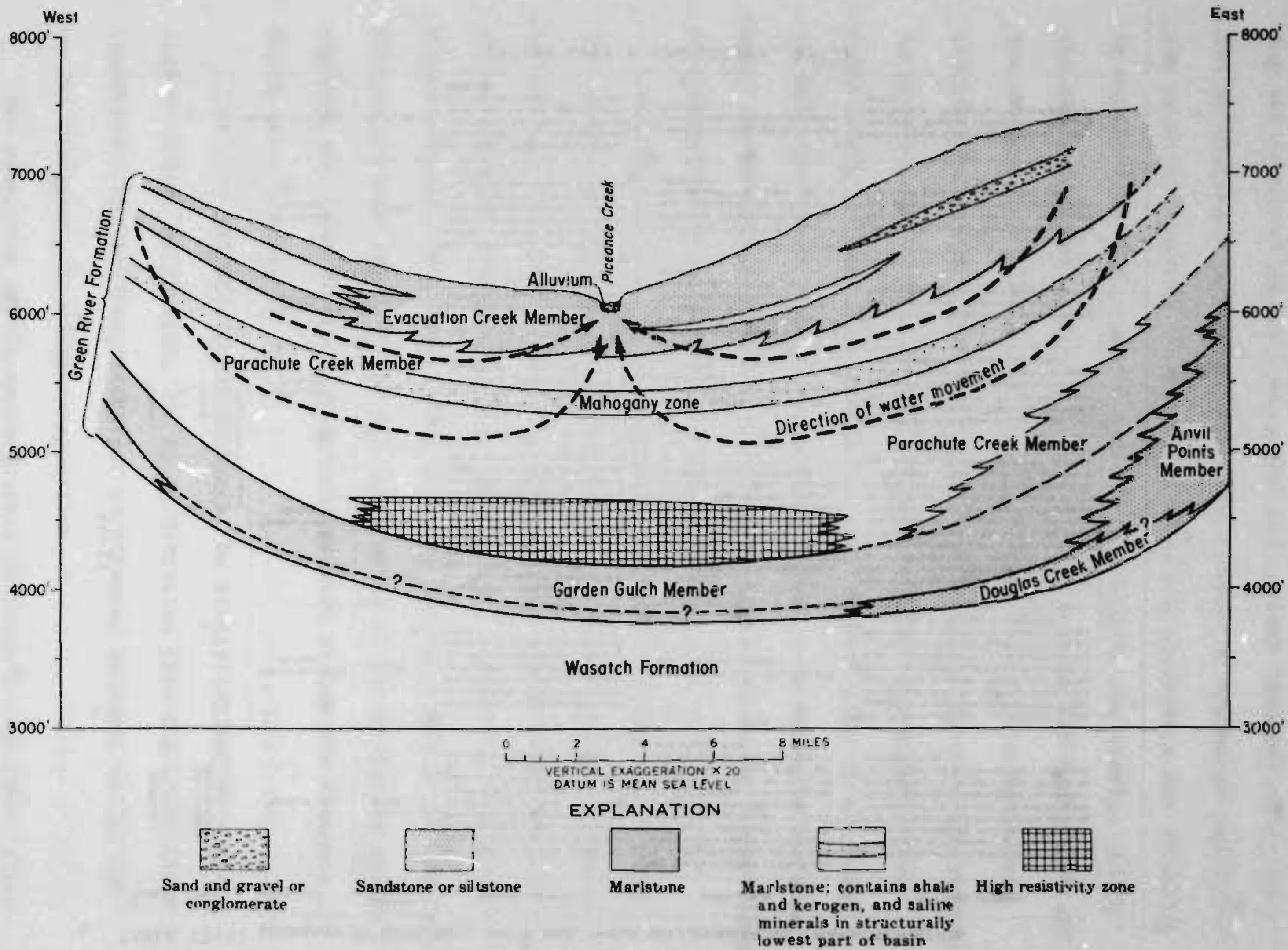


Figure II-12--DIAGRAMMATIC SECTION ACROSS THE BASIN
(After Coffin and others, 1971)

ing and transmitting more water per unit volume than any other aquifer in the basin. However, the areal extent and volume of the deposits is small compared to that of the bedrock aquifers. The alluvium is confined to belts less than 1 mile wide along the creeks. Along the major drainages, the alluvium ranges from 0 to 140 feet thick and the saturated thickness may be as much as 100 feet in a few places (Coffin and others, 1968). The depth to water in the alluvium generally is less than 40 feet. Water in the alluvium occurs under both water-table and artesian conditions. The permeability of the clay is much less than that of the sand and gravel, and where it confines water in underlying sand and gravel under enough pressure, water flows at the land surface when tapped by a well.

Ground water in the Green River Formation is recharged around the margins of the basin by direct infiltration of precipitation on outcrops of the aquifers and by downward percolation of water from narrow alluvial deposits in the higher streams valleys. The water moves down dip toward the central part of the basin and is discharged through springs and seeps in the lower parts of the principal stream valleys, as shown in the diagrammatic section across the Piceance Creek Basin (Figure II-12).

The alluvial aquifer is recharged by precipitation, by applied surface water, by streams, and by infiltration from the Green River Formation. The aquifer discharges to streams, springs, wells, and to the atmosphere by evapotranspiration.

The dissolved solids concentration of water in the Green River Formation ranges from 250 to 63,000 mg/l. Water near the edges of the basin contains less than 2,000 mg/l dissolved solids and the dominant ions are calcium, magnesium, and bicarbonate. About halfway between the edges of the basin and the center, dissolved solids are about the same as at the edges, but the dominant ions are sodium and bicarbonate. Near the center of the basin, the water has dissolved considerable amounts of saline minerals and the dissolved solids average 25,000 mg/l, and the principal constituents are sodium and bicarbonate. In the same area, chloride concentration ranges between 500 and 2,500 mg/l. Water in the Parachute Creek and Evacuation Creek Members are chemically similar in the higher parts of the basin (Coffin and others, 1968). However, in the lower parts of the basin, water in the Parachute Creek Member becomes highly mineralized from contact with the saline minerals. Summaries of analyses of water samples from the Evacuation Creek Member and from the Parachute Creek Member are given in bar graphs in Figures II-13 and II-14.

The dissolved solids concentration of water in the alluvium ranges from 250 to 25,000 mg/l. Water in alluvium in the upper reaches of the major drainages contains less than 700 mg/l dissolved solids. In general, the principal ions in the alluvial water are calcium, magnesium, sodium, and bicarbonate; the dissolved solids concentration increases downstream. The dissolved solids concentration is about 700 mg/l at Cow Creek and 2,500 mg/l at Dry Fork. Below Dry Fork the concnetration increases to 8,300 mg/l and sodium becomes the dominant cation. These changes occur by solution and ion exchange and reflect the change in nature of the bedrock underlying the alluvium and the contribution of water by see page from the bedrock in the lower reach of the creek. Above Dry Fork the alluvium is underlain by the Evacuation

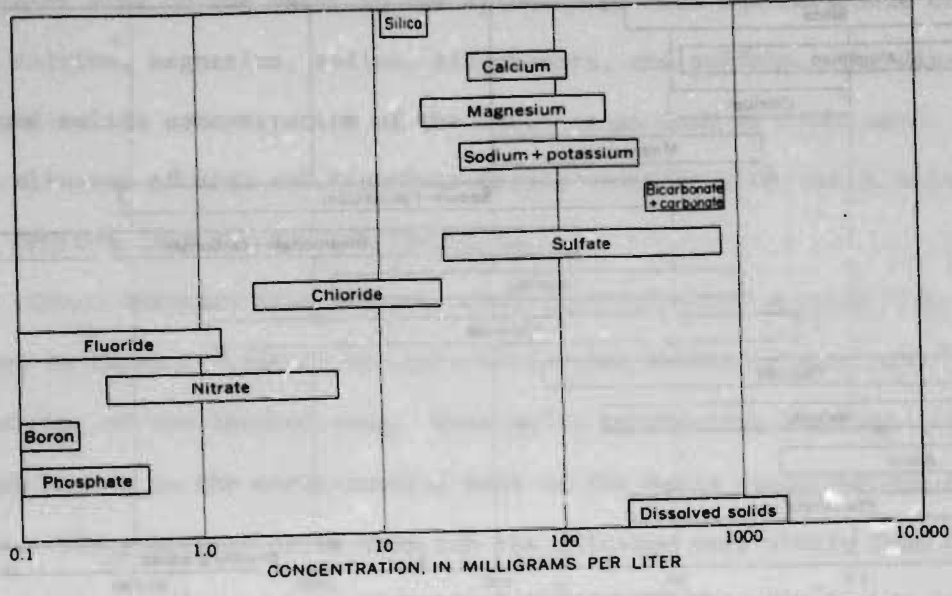


Figure II-13.--Bar Graph Showing Range of Water Quality in the Evacuation Creek Member. (After Coffin and others, 1971)

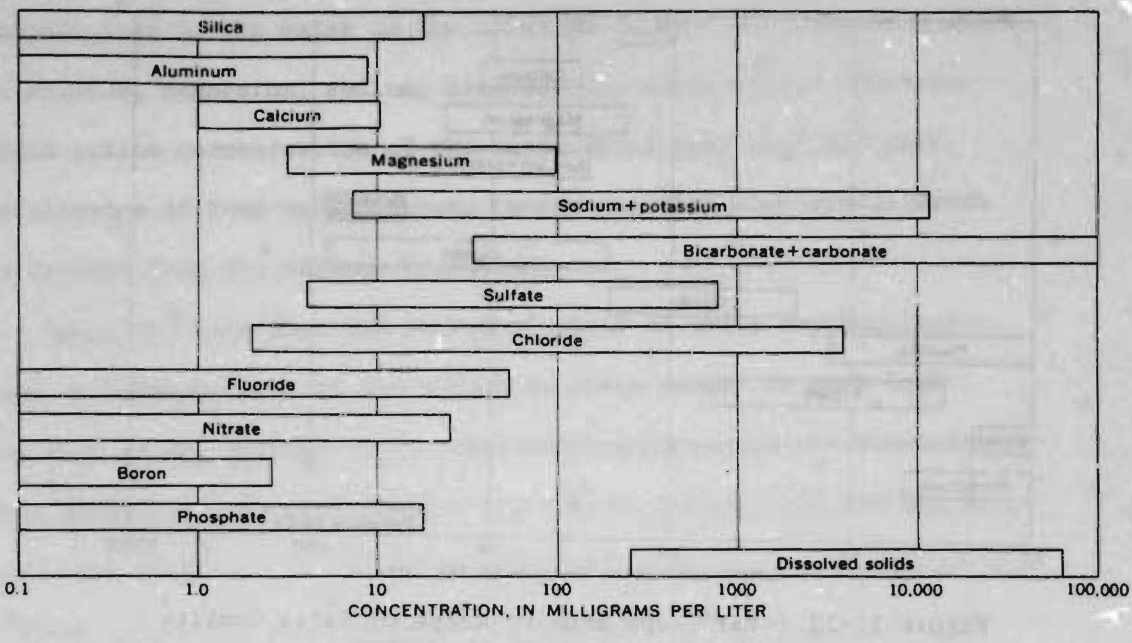


Figure II-14.--Bar Graph Showing Range of Water Quality in the Parachute Creek Member. (After Coffin and others, 1971)

Creek Member and below by the Parachute Creek Member. Water in the alluvium in Yellow Creek appears to be within the range in composition and concentration of the water in the alluvium of Piceance Creek. Dominant ions in the water in the alluvium of Roan and Parachute Creeks are calcium, magnesium, sodium, bicarbonate, and sulfate. The dissolved solids concentration of the water is as much as 7,200 mg/l. The alluvium of Roan and Parachute Creeks contains some gypsum which was derived from the Wasatch Formation.

Tests indicate that the potential yield of wells tapping fractures in Mahogany Zone of the Parachute Creek Member is much less than that of the leached zone. Test wells penetrating the Evacuation Creek Member in the north-central part of the basin yield 300 gpm or less. The yields of wells that tap the alluvium vary widely from place to place according to variations in lithology of the alluvium at the well and proximity of the well to hydrologic boundaries. Initial yields from properly located, developed, and constructed wells are estimated to be as much as 2,000 gpm. An irrigation well in alluvium adjacent to reported to yield 1,500 gpm.

Ground water could present a serious problem to underground mining in the Piceance Creek Basin. On the other hand, ground water could be a significant part of the water supply for initial oil shale development.

Water wells are widely scattered in the Piceance Creek Basin. Except for two or three irrigation wells, the alluvial aquifer is used for watering livestoack and wildlife. Numerous springs throughout the basin also supply water for livestock and wildlife.

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In the oil shale area of the Uinta Basin, Utah, the Green River Formation is the principal aquifer. Weir (1970) reported that water levels and hydrostatic heads indicate that water in the Green River Formation probably moves from peripheral recharge areas toward central parts of the basin.

The Green River formation yields as much as 220 gpm of water to wells in the Uinta Basin. However, yields that large cannot be expected throughout the area.

The Uinta Formation, which overlies the Green River Formation, yields as much as 225 gpm of water from springs. The potential yields of wells probably would be as large in some areas.

The volume of water in storage in the Uinta Basin has not been estimated, but it certainly would be much less than in the Piceance Creek Basin.

The chemical quality of water in the Green River Formation in the Uinta Basin ranges from fresh to briny. Feltis (1966) reported that analyses of 73 water samples from 51 wells and 1 spring indicate that 4 were fresh, 18 were slightly saline, and the remainder were moderately saline to briny.

On the south flank of the Uinta Basin, the Green River Formation is a potential source of small supplies of fresh or slightly saline water that could be used in the process of oil extraction from oil shale, but large supplies are not available.

In the northeastern part of the Uinta Basin, the Morgan Formation and the Madison Limestone are potential sources of fresh water. These formations probably underlie the entire basin, but they have not been explored as sources of water in the interior of the basin because of their great depth.

Water wells are sparse in the Uinta Basin and the use of ground water is limited almost exclusively to stock and wildlife supplies.

In the Washakie Basin, Wyoming, strata dip generally toward the center of the basin at angles ranging from about 2^{o} to 12^{o}. According to Welder and McGreevey (1966) water in the basinwarddipping strata is almost entirely under artesian pressure. Water-table conditions exist locally in some alluvial valleys and where saturated rocks are near the surface. The movement of water in the Laney Shale Member of the Green River Formation and in the Bridger and Uinta Formations is probably controlled by the topography of the basin. The direction of movement in the deeper formations probably is both down dip and upward into the overlying formations. Recharge to the aquifers in the Washakie Basin is principally from the percolation of rainfall and melting snow. Much of the precipitation, however, leaves the area as surface runoff before it can seep into the ground. Ground water discharged from the basin is principally by evaporation, but some ground water leaves the area as underflow along the streamways that have dissected the basin.

Sandstone beds in the Wasatch Formation, the principal aquifers of the Washakie Basin, generally are very fine to medium grained, but locally are coarse grained. Individual beds vary in distribution and character. Beds of claystone and shale in the Green River, Bridger, and Uinta Formations overlie the Wasatch Formation in most of the Washakie Basin.

About 20 water wells tap the Wasatch Formation in the vicinity of the outcrop, but none are known to penetrate the formation in the interior of the basin. The wells tapping the Wasatch have yields that are reported to range from 1 to 67 gpm; maximum yields at favorable locations probably would not exceed 400 gpm. Larger yields might be obtained from deep wells penetrating several formations, and artesian flows might occur in topographically low areas. Ten wells tapping the Laney Shale Member of the Green River Formation have reported yields ranging from 0 to about 200 gpm. The maximum yield of wells tapping the Laney probably is not much greater than 200 gpm in the south and west parts of the basin, and only a few gallons per minute elsewhere in the basin. One hole penetrating the lower part of the Laney was dry. Wells drilled in the Tipton Tongue of the Green River Formation and the Bridger and Uinta Formations can be expected to have very low yields.

The quality of the water in the various geologic formations underlying the Washakie Basin ranges from poor to good. Stock water from a Wasatch well in sec. 12, T. 13N., R. 94W, has a dissolved solids content of about 4,000 mg/l. On the other hand, the water from a Laney well in sec. 10, T. 15 N., R. 99 W. has a dissolved-solids content of about 450 mg/l.

The predominant use of ground water in the Washakie Basin is for livestock and wildlife. A small number of wells and springs are used for domestic supplies, and a few wells provide water for businesses along Interstate Highway 80. Industrial uses include oil well drilling, coal mining, and sodium-sulfate processing.

According to Welder (1968), recharge to ground-water reservoirs in the Green River Basin, Wyoming, is mainly by see page from precipitation and streams. Discharge is mainly by evaporation, see page to streams and lakes, transpiration by plants, and pumpage from wells.

Ground water occurs in the area under both water-table and artesian conditions. Under water-table conditions, the zone of saturation is overlain by permeable material, and water seeps downward from the surface to the saturated zone. A number of unconfined aquifers are present in the area. They are generally unconsolidated alluvial, windblown, glacial, and gravel deposits. Many of the thicker and widespread consolidated formations have an upper zone of unconfined water that extends from near the surface to depths possibly as much as 300 feet.

Artesian aquifers are confined by relatively impermeable rocks. Water may enter an artesian aquifer at the outcrop where water-table conditions prevail or it may move in from adjacent rocks. The Green River, Wasatch, Fort Union, and older formations generally contain water under artesian pressure in the Green River Basin. Inidvidual water-bearing units within the formations may differ greatly in thickness and extent, but they are probably interconnected sufficiently to permit indirect or partial hydrologic connection in varying degrees.

The depth to the water surface in both water-table and artesian wells is generally less than 200 feet, but the drilling depth to artesian aquifers exceeds 1,000 feet in the deeper parts of the basin.

The maximum yields of existing wells in the Green River Basin probably range from 1 to about 500 gpm, but yields of most wells range from about 10 to 100 gpm. Yields greater than 500 gpm could probably be obtained from deep wells (2,000 to 5,000 feet) penetrating thick, sandstone sections in the Wasatch and Fort Union Formations, and from shallow wells tapping some of the well-sorted alluvial and gravel deposits.

The quality of ground water in the Green River Basin ranges from very poor to excellent. Water in the alluvial and gravel deposits and in the more permeable sandstone of the Wasatch Formation near the surface in the northern two-thirds of Sublette County generally contains less than 500 mg/l dissolved solids. In southern Sublette County and southward, water ranging from 500 to 3,500 mg/l is generally available from at least one aquifer; other aquifers may contain water with a higher mineral content. In general, ground water in the Green River Basin becomes more mineralized with increased depths.

The predominant use of ground water in the Green River Basin is for stock and domestic supplies. A few wells are used by small businesses along the highways and by oil companies for water flooding and drilling.

Although ground water supplies are not large in the Green River Basin, ground water could be a hindrance to development of oil shale, as it has been in the trona mines.

6. Fauna

Sections on fauna in this volume relate generally to the entire oil shale region, although occasional references do occur with respect to adjacent land areas which would be influenced by full oil shale development. The reader is referred to Sections B, C, and D of this chapter for more specific materials on fauna of the oil shale lands on a State-by-State basis.

Faunal resources are of considerable importance in the three-State oil shale region, as well as in the Upper Colorado River Basin as a whole. 1/ This Rocky Mountain area with its limited human population and extensive areas of public lands has escaped most of the pressures of expanding population and land development, which has displaced native habitat in so much of the United States.

1/ Much of this discussion on faunal resources of the oil shale region has been developed from Appendix XIII of the Upper Colorado Region Comprehensive Framework Study (1971), by the Upper Colorado Region State - Federal Interagency Group.

Many species of mammals, birds, reptiles, fish, and invertebrates are found within the oil shale region. There are estimated to be seven species of big game (of which mule deer is the most abundant), three species of small game, 27 species of migratory waterfowl and shorebirds, six species of upland game birds, five species of fur bearers, 21, species of non-game mammals 200 species of nongame birds and 24 species of raptors. Several wild horse herds range over the areas. Figures II-15 to II-20 show the distribution of several more significant species and habitat deatures across the Upper Colorado River Basin in relation to the oil shale region.

Fishery habitat of the Upper Colorado Region includes more than 36,000 acres in natural lakes, 275,000 acres in impoundments, and 9,000 miles of fishing streams (See Tables II-12 and II-13 and Figure II-17). There are hundreds of miles of such high-quality trout streams, some of the more outstanding of which are listed in Table II-12.

Fishery habitat of the semiarid oil shale region itself is quite limited and most of the existing habitat supports various nongame species. Little systematic fishery investigation has taken place since 1900, and the status of many species is not known. The more significant fishery resources are in the Colorado, Green, and White Rivers. Several streams, particularly the headwaters, support native populations of

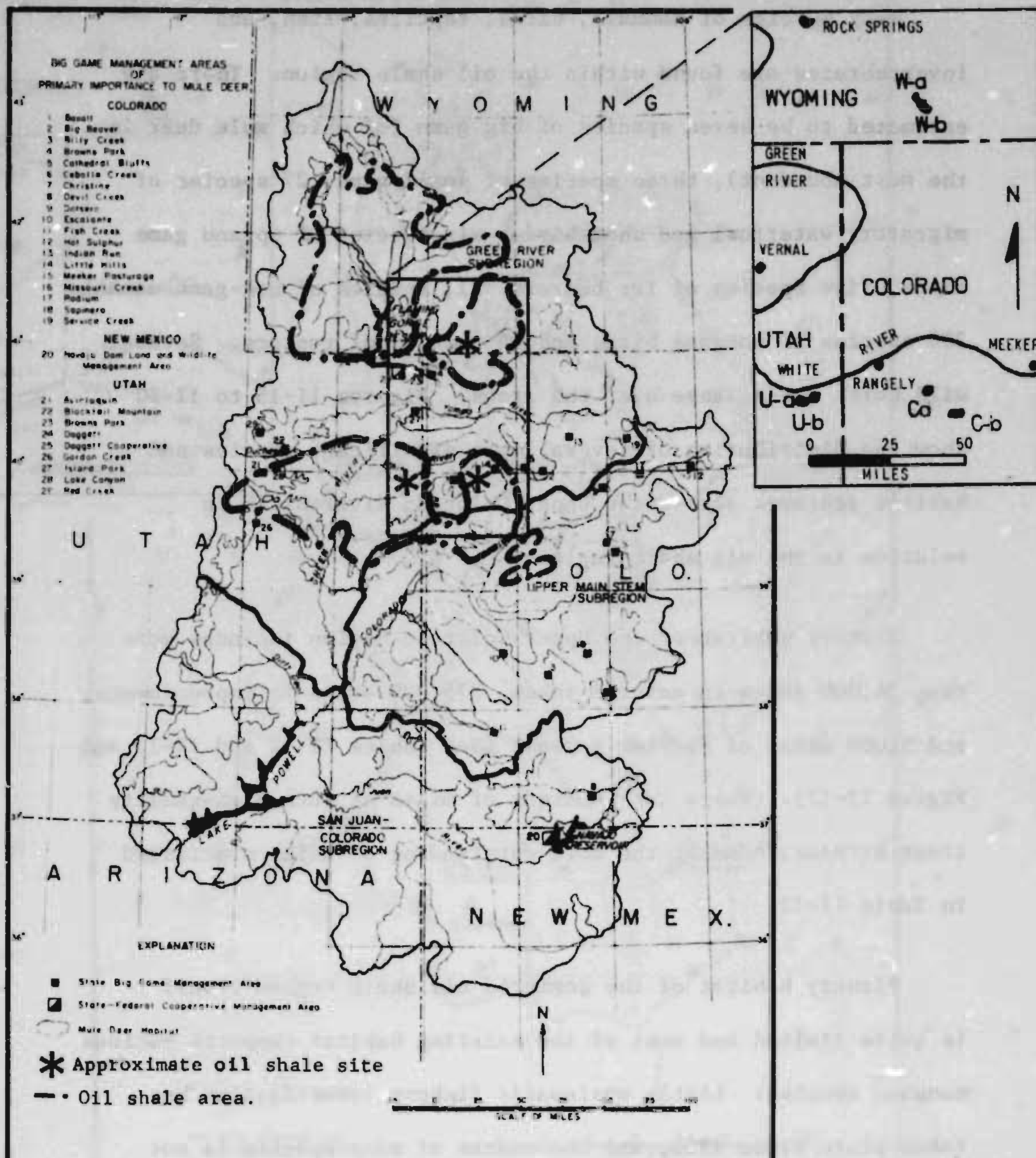

FIGURE II-15.--Proposed Oil Shale Tracts as They Relate to Mule Deer Habitat of the Upper Colorado Region.

FIGURE II-16.-Proposed Oil Shale Tracts as They Relate to Key Antelope and Elk Habitat in the Upper Colorado Region.

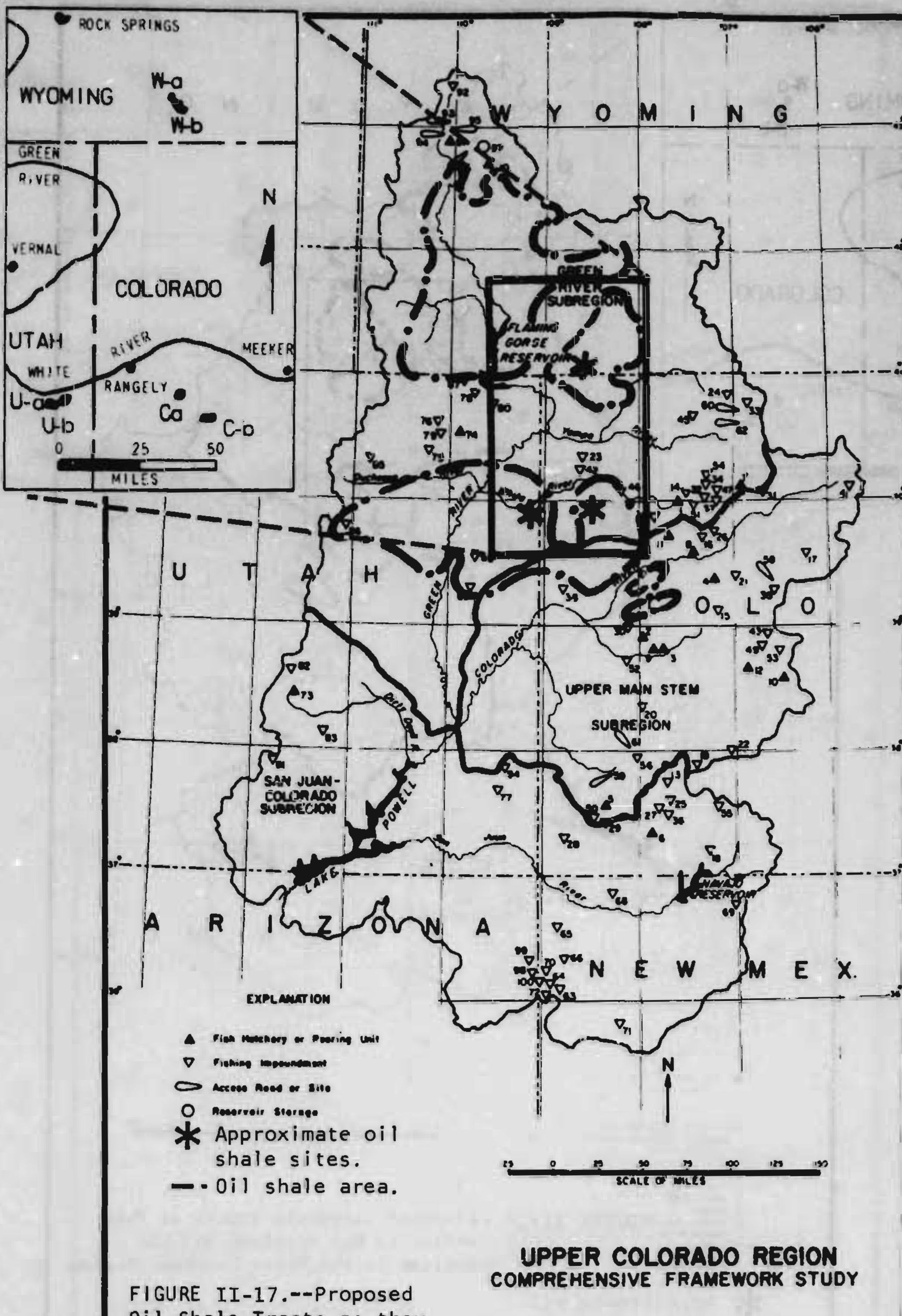

FIGURE II-17.--Proposed Oil Shale Tracts as they relate to Fish Installation and Facilities Existing in 1965 for the Upper Colorado Region.

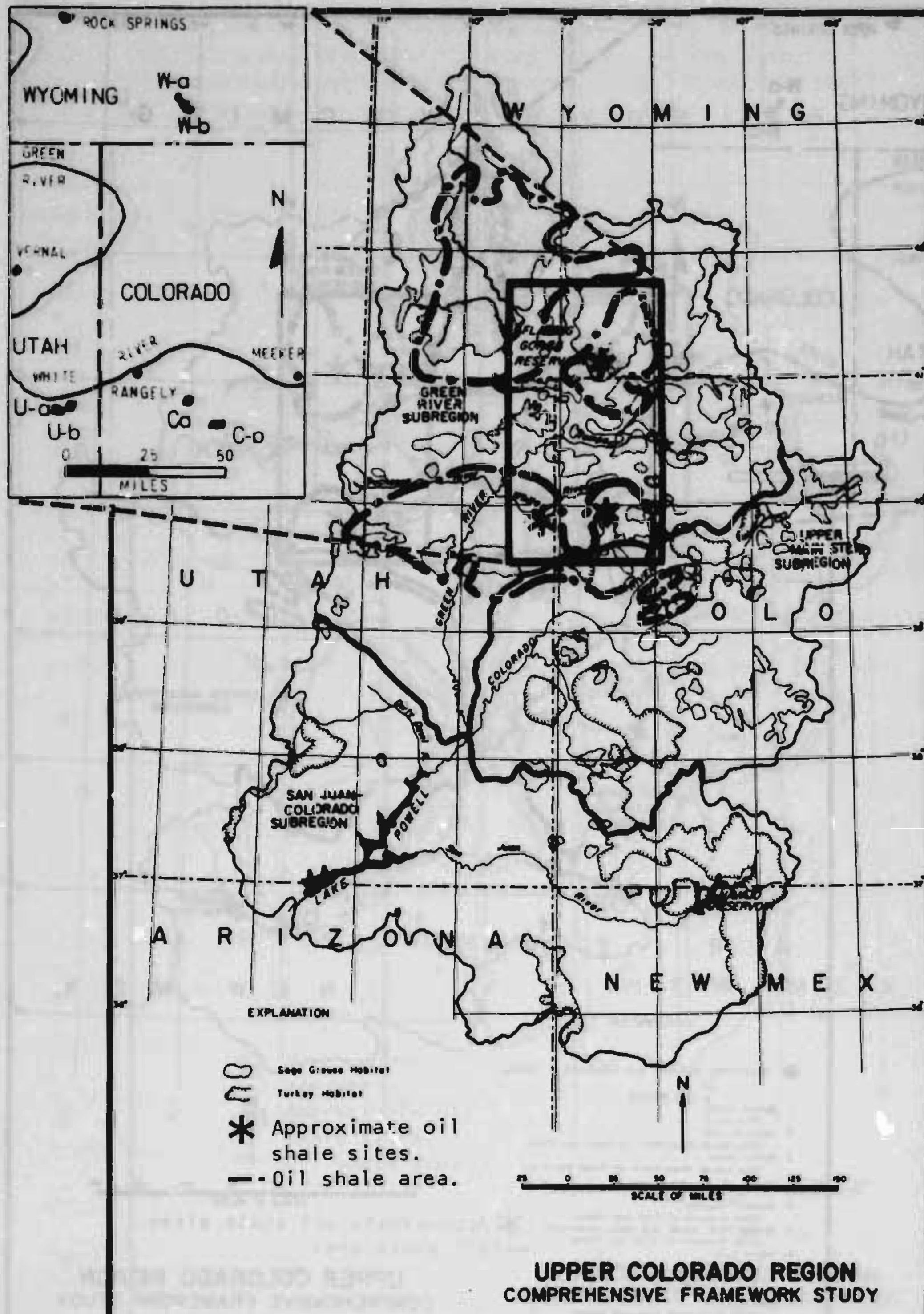

FIGURE II-18.--Proposed Oil Shale Tracts as they relate to Key Habitat for Sage Grouse and Turkey in the Upper Colorado Region.

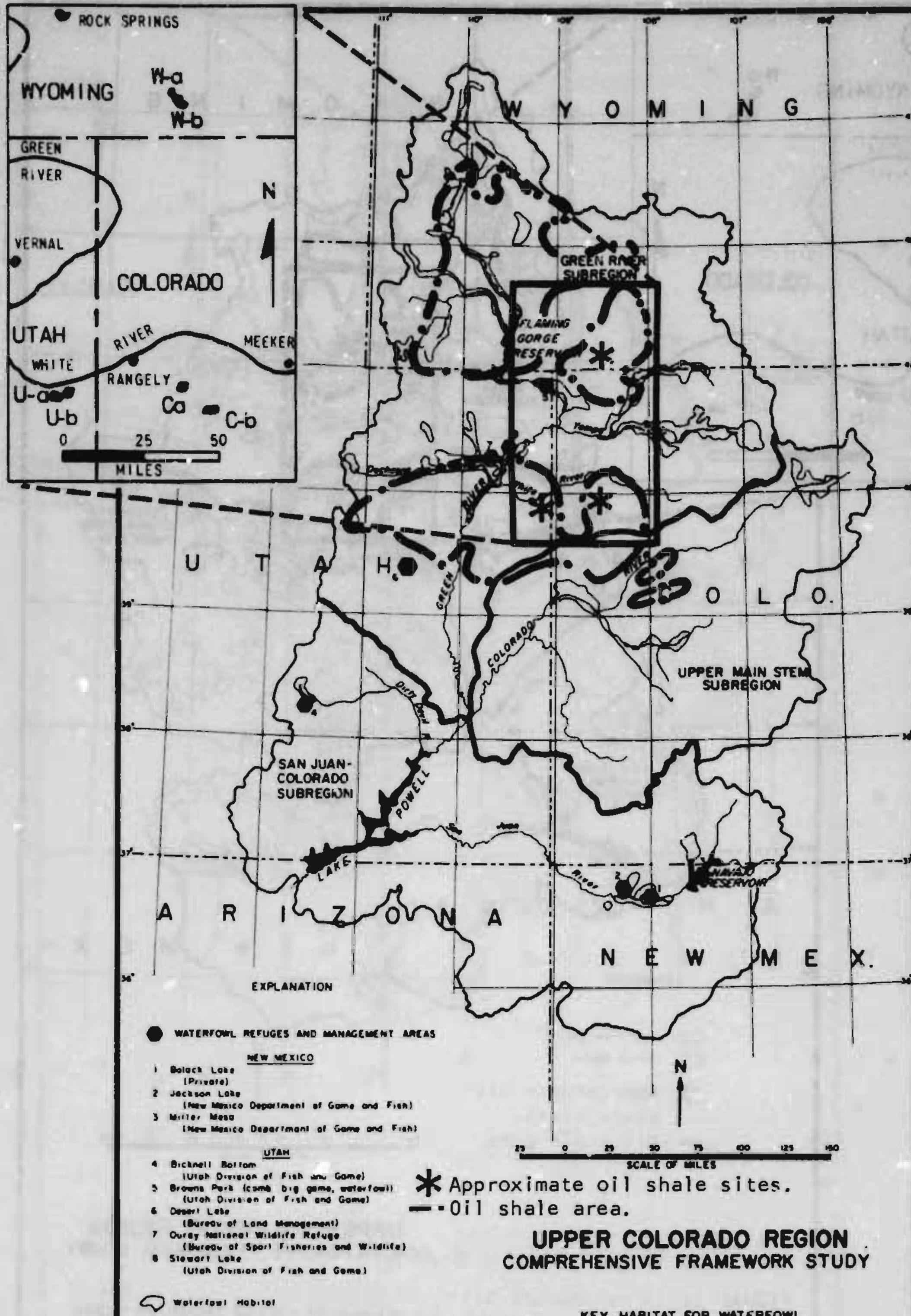

FIGURE II-19.--Proposed Oil Shale Tracts as they relate to Key Waterfowl Habitat in the Upper Colorado Region.

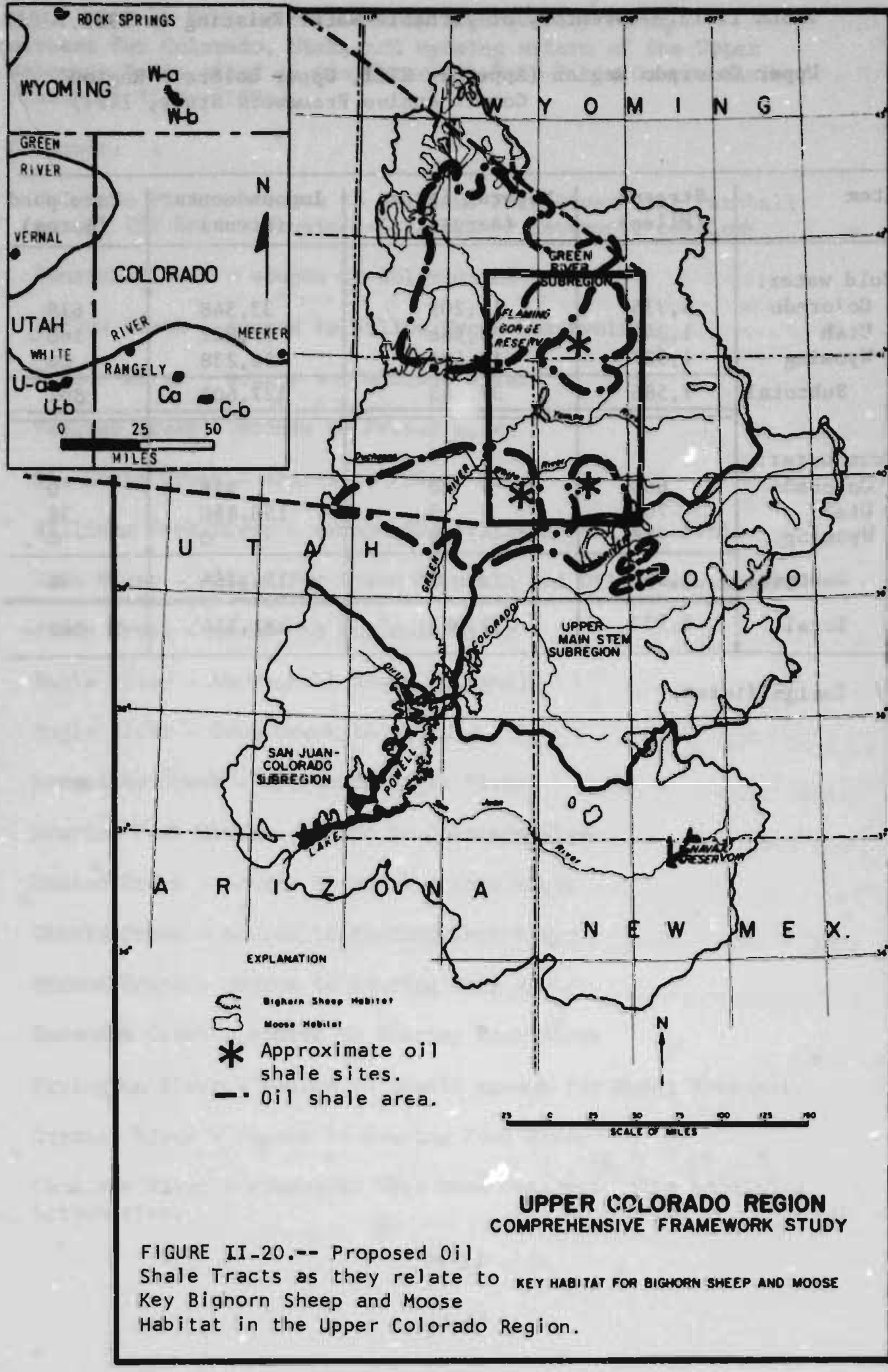

FIGURE II-20.-- Proposed Oil Shale Tracts as they relate to Key Bignorn Sheep and Moose Habitat in the Upper Colorado Region.

TABLE II-12.--Inventory of Fishable Water Existing in 1965.

Upper Colorado Region (Appendix XIII, Upper Colorado Region Comprehensive Framework Study, 1971)

Item	Streams (Miles)	Natural lakes (Acres)	Impoundments (Acres)	Farm pond (Acres)
Cold water:				
Colorado	4,715	11,209	33,548	618
Utah	1,344	8,988	37,822	160
Wyoming	1,527	17,486	56,238	24
Subtotal	7,586	37,683	127,608	802
Warm water:				
Colorado	660	0	916	0
Utah	706	0	153,850	38
Wyoming	1/	0	0	0
Subtotal	1,366	0	154,766	38
Total	8,952	37,683	282,374	840

1/ Insignificant.

TABLE II-13 .--List of outstanding high-quality trout streams for Colorado, Utah, and Wyoming waters of the Upper Colorado Basin cited in the Upper Colorado Basin Comprehensive Framework Study (1971).

Colorado:

Colorado River - source to Williams Fork River near Parshall except for Shadow Mountain-Lake Granby Reservoir complex

Tonahutu Creek - source to Colorado River

Willow Creek - source to Willow Creek Reservoir

Fraser River - source to Colorado River

Vasquez Creek - source to Fraser River

St. Louis Creek - source to Fraser River

Williams Fork River - except for Williams Fork Reservoir

Blue River - except for Green Mountain and Dillon Reservoirs

Piney Creek - source to Colorado River

Eagle River - above Fall Creek (Gilman)

Eagle River - Gore Creek to mouth

Homestake Creek - source to Eagle River

Roaring Fork River - source to Colorado River

Hunter Creek - source to Roaring Fork River

Castle Creek - source to Roaring Fork River

Maroon Creek - source to Roaring Fork River

Snowmass Creek - source to Roaring Fork River

Fryingpan River - source to Basalt except for Ruedi Reservoir

Crystal River - source to Roaring Fork River

Gunnison River - source to Blue Mesa Reservoir plus adjoining tributaries.

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TABLE II-13. (Cont.)

Colorado:

North Fork Gunnison River - Paonia Dam to mouth

Dolores River - source to Dove Creek

San Miguel River - mouth of Lake Fork to mouth of Horsefly Creek

Green River - Utah State line to mouth of Yampa River

Yampa River - source to Craig, Colorado

White River - North and South Forks from source to Buford, Colorado

Utah:

Green River - Flaming Gorge Dam to Colorado State line

Blacks Fork - source to Wyoming State line

West Fork Smith Fork - source to Wyoming State line

Henry's Fork - source to Wyoming State line

Willow Creek - source to Wyoming State line

Beaver Creek - source to Wyoming State line

West Fork Beaver Creek - source to Wyoming State line

Burnt Fork - source to Wyoming State line

Birch Creek - source to Flaming Gorge Reservoir

Willow Creek - source to Green River

Wyoming:

Green River - source to Big Sandy River excluding Fontenelle Reservoir

New Fork River - source to Green River

Hams Fork - source to Kemmerer, Wyoming

cutthroat trout, as well as rainbow and brown trout and whitefish. Exceptions to the generally limited fish resources within the oil shale areas are the important fish populations of the Green River, including the Flaming Gorge Reservoir in Wyoming and the Colorado and White Rivers in Utah and Colorado.

A number of species or subspecies occur in this area which are endangered or otherwise threatened. The endangered ones are on the Secretary of the Interior's official list of endangered species and are in immediate jeopardy. Other threatened species are not presently considered endangered under the definitions of the Endangered Species Conservation Act of 1969. However, these are considered as likely to become endangered by the Bureau of Sport Fisheries and Wildlife and are listed in the Bureau's "Red Book" entitled Threatened Wildlife of the U. S., 1973 edition. Also mentioned herein are species which may be endangered or are likely to become endangered but are not listed in either category for lack of substantiating data. These are designated as "status undetermined."

The following evaluation of threatened animal species of the Upper Colorado Region has been adapted and updated from material contained in Appendix XIII of the Upper Colorado Region Comprehensive Framework Study (1971):

An endangered mammal, the black-footed ferret (Mustela nigripes), is recorded from the vicinity of Craig, Colorado, where two specimens were collected in 1941 and 1942. There is also a published report of a ferret one mile from Meeker in 1910, and a sight record in Moffat County in the early sixties.

Birds designated as endangered include the American peregrine falcon, Falco peregrinus anatum. The bird has been extirpated as a breeding species in the eastern United States and is generally decreasing in the west. In the upper Colorado Region this falcon is rare, there being only about 20 known nesting sites in Colorado, including one is Garfield County. The endangered arctic peregrine (Falco peregrinus tundrius) migrate through the area.

Two endangered fish are the humpback chub, Gila cypha, and the Colorado River squawfish, Ptychocheilus lucius, which are native to the Colorado River drainage. Both are adapted to a swift water environment. Present indications are that reservoir construction is an inhibiting factor. The natural habitat is obliterated in the impoundment areas, while reproductive requirements are affected by lowered temperature in the tailwater areas. Both are quite rare in the natural stream segments remaining.

A recent addition to the endangered list is the Kendall warm springs dace, Rhinichthys osculus thermalis, which is found only in a warm spring-fed tributary to the Green River in the Bridger National Forest of Wyoming. The habitat of the warm springs dace consists of a stream segment about 200 yards in length which is isolated from the Green River by a deep vertical bank over which the warm spring water spills. The stream habitat is subject to pollution from visiting recreationists and the fish themselves sometimes are taken for bait. Thus the fish is not only unique but is being endangered by man's activities. However, oil shale development will not occur in the locale of this species.

Not officially included but a candidate for the endangered list is the Colorado River cutthroat, Salmo clarki pleuriticus. This native of the headwater streams of the Colorado River apparently continues to exist as a pure or relatively pure form in a few remaining areas. Isolated cutthroat populations that are evidently pleuriticus have been recently found in remnant numbers in remote tributary reaches within Colorado, Utah, and Wyoming. In some localities these populations are threatened by habitat deterioration resulting from watershed erosion. Generally, though, hybridization with rainbow trout and other types of cutthroat trout is eliminating the subspecies. Management efforts are being directed toward watershed improvement and continuance of barriers that isolate the local populations.

In addition to the endangered species there are several others that are classified as rare and thus potentially endangered should their habitat be threatened.

The spotted bat, Euderma maculatum, is evidently one of America's rarest mammal. It ranges from Mexico and the southwestern states as far north as Yellowstone County, Montana. Until recently it was thought to be limited to ponderosa and pinyon pine habitat, however, it is now known to be a permanent resident of treeless canyonlands in west Texas. The spotted bat has been recorded from the Abajo Mountains, San Juan County, Utah, and the Bryce Canyon area, Utah, and may occur in favorable habitat in any part of the Upper Colorado Region.

Another of the threatened falcons found in the Upper Colorado Region is the prairie falcon, Falco mexicanus, a bird of the canyons, deserts, and open country. It has disappeared from many localities within its overall range in recent years, and will appear on the endangered list if this trend is not halted. Pesticides are a suspected cause of the population decline.

A bird, formerly considered as threatened, and of special public interest, is the greater sandhill crane, Grus canadensis tabida. This crane breeds locally in the Green River Subregion and migrates southward across the region. Reasons for decline are described as destruction of marsh nesting habitat and would seem to be most important in the Upper Colorado Region as wetland drainage has not been a common practice.

The Montana form of the arctic grayling, Thymallus arcticus, a rare species, did not occur originally in the Upper Colorado Region but has been introduced into a number of lakes in the Green River Subregion. Grayling naturally prefer clear, cold streams with gravelly bottoms and deep holes; however, they have reproduced so well in some of the high mountain lakes that stunted populations have resulted. Because of this adaptability, the possibility of their becoming endangered is questionable.

Table II-14 is a list of rare, endangered, and threatened species that may occur within the general boundary of the three-State oil shale province.

All species of wildlife, including nongame as well as game species, contribute to public interest in the oil shale region, because they provide opportunities for hunting, fishing, observation, and photography, activities which are readily available throughout most of the region, or simply because they are essential ingredients in a natural environment.

Table II-14. -- Listing of threatened species and species of undetermined status whose range includes part or all of the three-state oil shale province.*

Common Name	Scientific Name	Status
Spotted Bat	Euderma maculatum	2/
Black-footed Ferret	Mustela nigripes	1/
American Peregrine Falcon	Falco peregrinus anatum	1/
Arctic Peregrine Falcon	Falco peregrinus tundrius	1/
Prairie Falcon	Falco mexicanus	2/
Ferruginous Hawk	Buteo regalis	3/
American Osprey	Pandion haliaetus carolinensis	3/
Prairie Pigeon Hawk	Falco columbarius richardsonii	3/
Western Snowy Plover	Charadrius alexandrinus nivasus	3/
Mountain Plover	Eupoda montana	3/
Northern Long-billed Curlew	Numenius americanus americanus	3/
Western Burrowing Owl	Speotyto cunicularia hypugaea	3/
Columbian sharp-tailed grouse	Pedioecetes phasianellus columbianus	3/
Colorado River Cutthroat Trout	Salmo clarki pleuriticus	3/
Humpback Chub	Gila cypha	1/
Pahranagat bonytail	Gila robusta jordani	1/
Colorado Squawfish	Ptychocheilus lucius	1/
Humpback Sucker	Xyrauchen texanus	3/
Bluehead Sucker	Catastomus discobolus	3/
Dusky darter	Percina sciera	3/

1/ Endangered species.

2/ Species likely to become endangered.

3/ Undetermined status.

*The Grizzly Bear is not included in this list because it exists outside the general zone of oil shale development influence. The Southern Bald Eagle is also not included. However, for lack of more detailed information, the 40th parallel has been arbitrarily designated as the probable northward nesting limit of this subspecies. Juveniles are known to migrate further northward. Therefore, it is possible that it occurs in the program area.

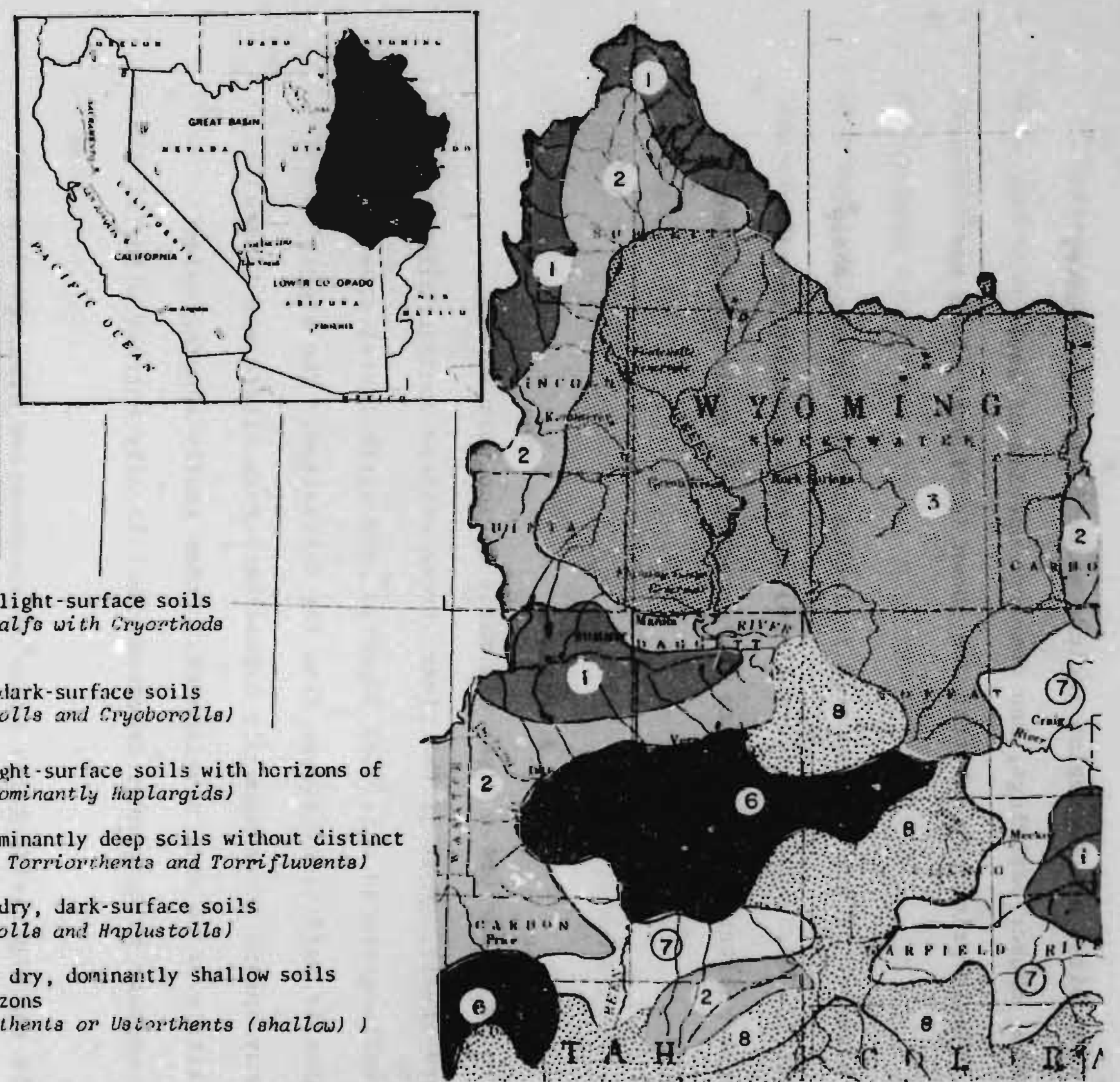
Game birds of the region include principally sage grouse, pheasant, chukar partridge, and numerous species of water fowl. Their principal habitats are shown in Figures II-18 and II-19.

A number of big game species including moose, bighorn sheep (Figure II-20), and elk (Figure II-16) are most commonly found in those habitats peripheral to the proposed oil shale development sites.

7. Soils

Soils of the Green River oil shale region vary widely (Figure II-21). Most of the wider stream valleys contain alluvium with well-developed soil that supports good agricultural growth if there is sufficient stream flow for irrigation. The slopes and many upland areas commonly expose bare rock cliffs and ledges with little or no soil development. Other gently sloping upland areas contain thin, poorly developed soil locally thicker alluvial soil.

In the high arid plains areas of southwestern Wyoming, thin soil is generally developed on the more prominant land features. Alluvial soil may be developed in valleys and swales.



LEGEND

1	Cool, usually moist, light-surface soils *(Dominantly Cryoboralfs with Cryorthods or Cryochrepts)*
2	Cool, usually moist, dark-surface soils *(Dominantly Argiborolls and Cryoborolls)*
3	Warm, usually dry, light-surface soils with horizons of clay accumulation *(Dominantly Haplargids)*
4	Warm, usually dry, light-surface soils with horizons of calcium carbonate or gypsum accumulation *(Dominantly Calciorthids)*
5	Warm, usually dry, light-surface soils with weakly developed horizons *(Dominantly Camborthids)*
6	Warm, usually dry, dominantly deep soils without distinct horizons *(Dominantly Torriorthents and Torrifluvents)*
7	Warm, intermittently dry, dark-surface soils *(Dominantly Argiustolls and Haplustolls)*
8	Warm or cool, usually dry, dominantly shallow soils without distinct horizons *(Dominantly Torriorthents or Ustorthents (shallow))*

FIGURE II-21.--General Soil Map of the Oil Shale Region.

Adapted by Land Use and Management Work Group From National Atlas Soils Compiled by the Soil Conservation Service and Published by U.S.D.I. Geological Survey 1969

25 0 25 50 75 100 125 150 MILES

Information on the soils of the oil shale region of Colorado, Utah, and Wyoming is limited to that generally derived from "soil association" type of surveys. A soil association consists of two or more soils that occur in a particular geographic area and in a repeating pattern. Each soil within an association has a characteristic type of profile and landscape of a known extent.

The soils information presented in this report was derived from several reports developed primarily by the Soil Conservation Service, U.S. Department of Agriculture. The soils maps shown in Figure II-21 is based on work done by SCS.

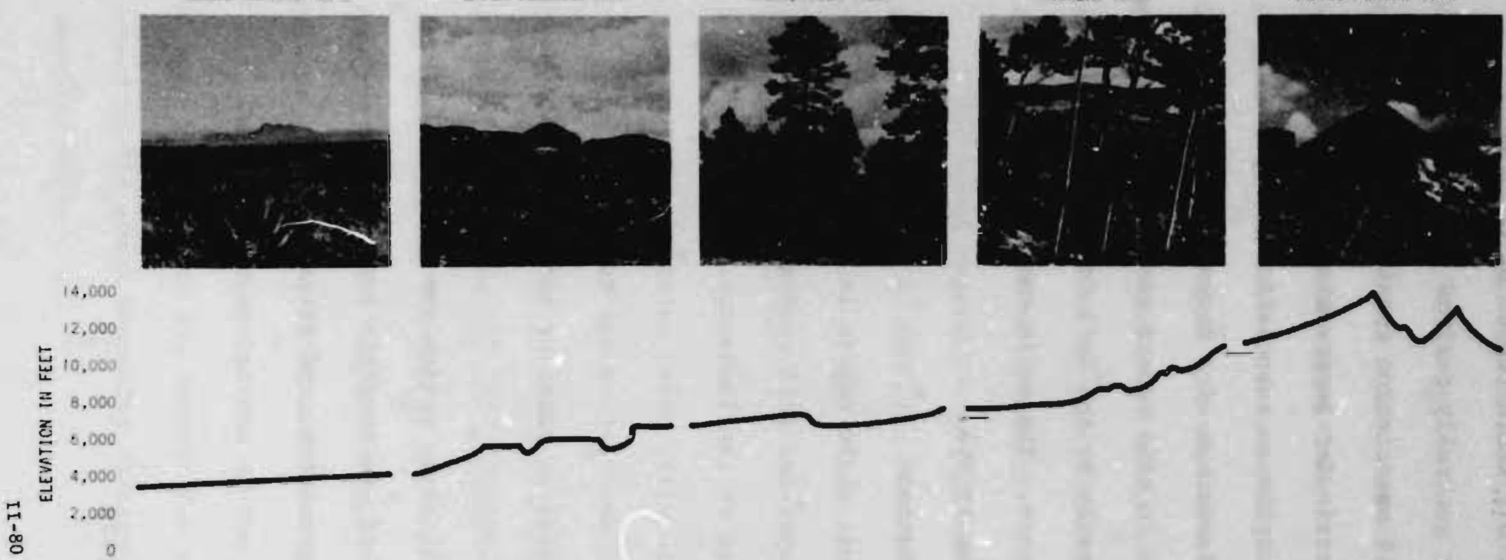
8. Vegetation

The vegetative pattern of the oil shale region is complex. Extreme variations in elevation, slope, and soil conditions produce a complex mosaic of plant communities in the landscape.

To describe the vegetation regionally, broad categories must be utilized. As geographic areas of description are reduced it becomes practical to describe potential or existing plant communities in greater detail.

The plant communities of the oil shale region are associated with the three central "life zones" of the southern continental divide area, i.e., Upper Sonoran, Transition, and Boreal (Figure II-22).

FIGURE II-22.-- DIAGRAMATIC REPRESENTATION OF THE LIFE ZONES ALONG THE SOUTHERN CONTINENTAL DIVIDE[1]



	LOWER SONORAN ZONE	UPPER SONORAN ZONE	TRANSITION ZONE	BOREAL ZONE	ARCTIC-ALPINE ZONE
CLIMATE	SUMMER TEMPERATURES Maximum--101 Minimum--72 WINTER TEMPERATURES Maximum--67 Minimum--39 AVERAGE ANNUAL PRECIPITATION 9 inches	SUMMER TEMPERATURES Maximum--97 Minimum--70 WINTER TEMPERATURES Maximum--65 Minimum--26 AVERAGE ANNUAL PRECIPITATION 12 inches	SUMMER TEMPERATURES Maximum--94 Minimum--83 WINTER TEMPERATURES Maximum--59 Minimum--31 AVERAGE ANNUAL PRECIPITATION 20 inches	SUMMER TEMPERATURES Maximum--90 Minimum--60 WINTER TEMPERATURES Maximum--56 Minimum--28 AVERAGE ANNUAL PRECIPITATION 20 inches	SUMMER TEMPERATURES Maximum--[illegible] Minimum--[illegible] WINTER TEMPERATURES Maximum--45 Minimum--14 AVERAGE ANNUAL PRECIPITATION 40 inches
PLANTS (*zone indicator)	Grama grass *Mesquite *Creosotebush Cacti (Opuntia Spp.) Yucca Century plant	*Juniper *Pinon pine *Grama grass *Galleta grass *Buffalo grass *Sagebrush	*Ponderosa pine Oakbrush Currant Gooseberry Buckthorn Mountain mahogany Snowberry Kinnikinnic	*Douglas fir *Blue spruce *Lodgepole pine *Aspen *Englemann spruce Bristlecone pine Limber pine	Lichens Alpine sunflowers Marsh marigolds Dwarf primrose Dwarf gentians Dwarf forget-me-nots Grass
ANIMALS	Desert bighorn sheep Bobcat Coyote Javalina Pocket gopher Badger Red fox Goati mundis	Mule deer Antelope Mountain lion Bobcat Coyote Badger Prairie dog Rabbit, jack and cottontail	Mule deer Black bear Elk (winter range) Mountain lion Bobcat Coyote Squirrel Cottontail rabbit	Mule deer Elk Black and Grizzly bear Bighorn sheep Mountain lion Bobcat Beaver Chipmunk Squirrel	Pika Conies Marmot
BIRDS	Roadrunner Mockingbird Red-tailed hawk Horned owl Quail (3 species) Morning dove	Owls Red-tailed hawk Quail Bluebird	Turkey Grouse Magpie Red-tailed hawk Eagle	Clark's nutcracker Canada jay Dusky grouse Band-tailed pigeon Raven Mallard	Ptarmigan Hawks Eagles

[1]Ranges of elevation for the various life zones decrease with increases in latitude along the Divide -- e.g., the Boreal Life Zone in Glacier National Park in Montana occurs between 5,000 and 8,500 feet opposed to a range of between 8,000 and 11.500 feet in New Mexico.

Source: Reference Armberger, 1954.

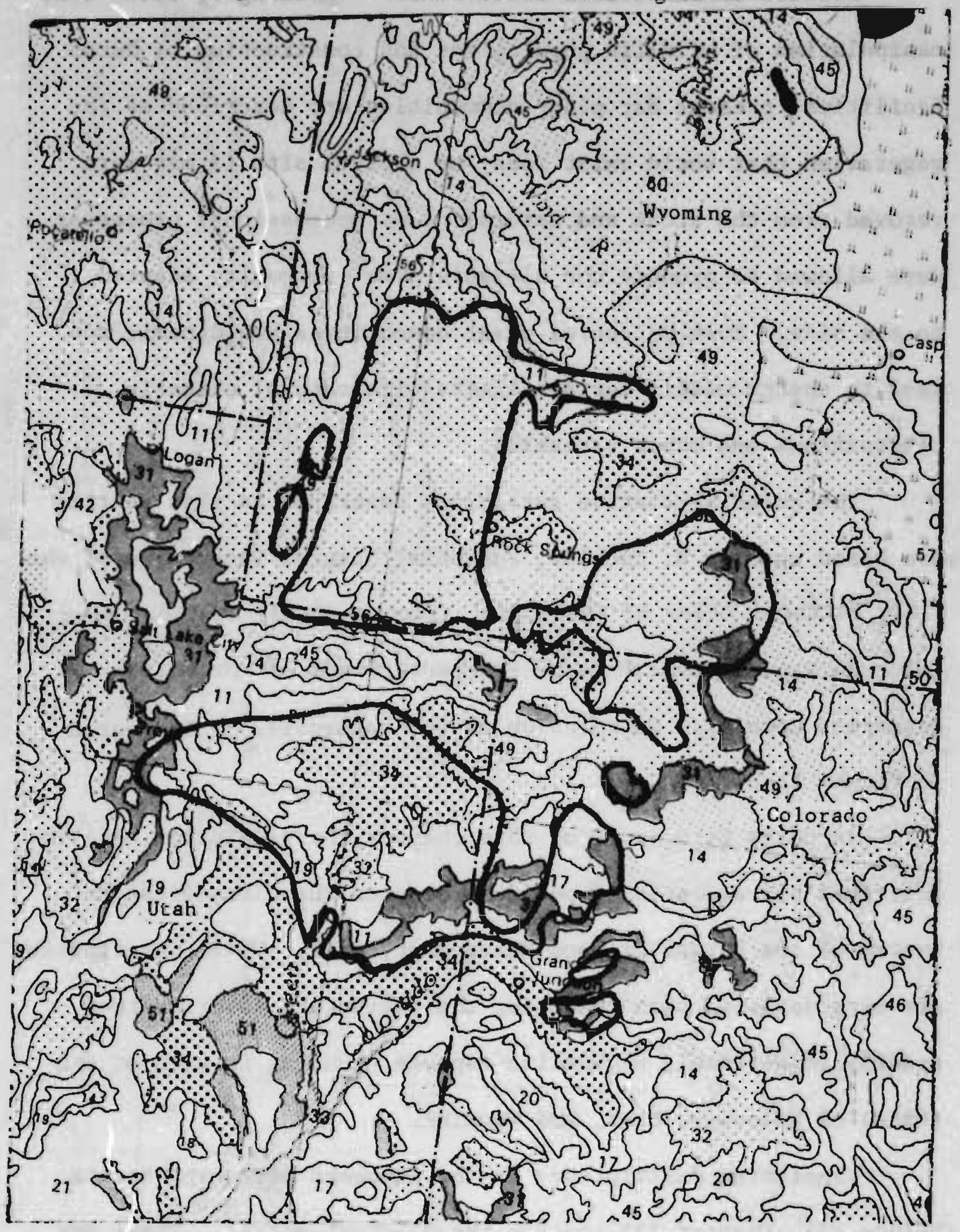
Because of man-caused disturbances (grazing by livestock, manipulation of wildlife populations and construction of human facilities), present day plant communities are described as the vegetation that would exist today on a given site if man were removed from the scene and natural plant successional processes were allowed to produce the ultimate plant community adapted to the site. Even potential plant communities are dynamic and tend to change within certain limits with natural climatic fluctuations and other variables.

The broad vegetative catagories described in this section are based upon A. W. Kuchler, Potential Natural Vegetation of the U.S., National Atlas of the U.S.A. (Figure II-23) and the Upper Colorado Region Comprehensive Framework **Study** of the Water Resources Council. Correlation of the catagories is indicated in Figure II-24.

In parts B, C and D of this chapter the vegetation will be described by vegetative types according to the classification system of the Bureau of Land Management, USDI. These descriptions are more detailed than those for the region and describe the readily identifiable vegetative aspects occuring in each of the states of Colorado, Utah, and Wyoming.

Vegetative descriptions of the proposed prototype tracts (Volume III, Chapter II) contain the greatest detail. These are based on the plant community descriptions of the Soil Conservation Service, USDA.

Figure II-23 - Potential Natural Vegetation



Forest Types

- 11 Douglas fir forest (*Pseudotsuga*)
- 14 Western spruce-fir forest (*Picea-Abies*)
- 17 Pine-Douglas fir forest (*Pinus-Pseudotsuga*)
- 18 Spruce-fir-Douglas fir forest (*Picea-Abies-Pseudotsuga*)
- 21 Juniper-pinyon woodland (*Juniperus-Pinus*)

Shrub Types

- 31 Mountain mahogany-oak scrub (*Cercocarpus-Quercus*)
- 32 Great Basin sagebrush (*Artemisia*)
- 34 Saltbush-greasewood (*Atriplex-Sarcobatus*)

Shrub-Grassland Types

- 49 Sagebrush steppe (*Artemisia-Agropyron*)
- 50 Wheatgrass-needlegrass shrubsteppe (*Agropyron-Stipa-Artemisia*)

Grassland Types

- 56 Foothills prairie (*Agropyron-Festuca-Stipa*)

Source: National Atlas

Figure II-24.--Plant Communities of the Oil Shale Region

Life Zone	Upper Sonoran	Transition	Boreal
Potential Natural Vegetation (National Atlas of U.S.A.)	Saltbrush-Greasewood Sagebrush Steppe Juniper Pinyon woodland	Mt. Mahogany-Oak scrub Douglas Fir Forest Great Basin Sagebrush Pine-Douglas Fir Forest	Western Spruce Fir Forest
Existing Vegetation (Upper Colo. Region Comp Framework study)	Salt Desert shrub Southern Desert shrub Northern Desert Shrub Grass	Mountain Brush Montane Forest	Subalpine Forest

Kuchler in the National Atlas lists the following categories of natural vegetation occurring in the oil shale region:

Sagebrush Steppe (6,240,000 acres - 39%)

A sagebrush (Artemisia) - Wheatgrass (Agropyron) association occurring primarily in Wyoming as a large almost solid land block. The association extends into the northwest corner of Colorado where it intermingles with other vegetative types.

Saltbush-Greasewood (2,720,000 acres - 17%)

A saltbush (Atroplex) - greasewood (Sarcobatus) association occuring in the lower elevations on saline soils. The association is interspersed throughout the region with the largest blocks occuring in western Utah.

Juniper Pinyon Woodland (2,640,000 acres - 16.5%)

An association dominated by several specied of Juniper (Juniperus) and Pinus edulis. It occurs primarily on rocky, steep shallow soils from the Wyoming-Colorado border, south throughout the region. The association may invade other types when disturbances occur.

Mountain Mahogany-Oak Scrub (1,280,000 acres - 8%)

A brushy association dominated by mountain mahogany (Cercocarpus montanus) and Gambels Oak (Quercus cambeli) which occurs at intermediate elevations on moderate to steep slopes. This association is intermingled with others throughout the region.

Douglas Fir Forest (1,280,000 acres - 8%)

A forest community dominated by Douglas fir (Pseudotsuga menzezii) which occurs on north slopes in the intermediate elevations and in rather solid stands on slopes and drainageways along the lower reaches of the mountain ranges. Site indices are generally low in the region, making the timber value marginal.

Pine-Douglas Fir Forest (960,000 acres - 6%)

A forest community dominated by Douglas fir and several species of pine including ponderosa (pinus ponderosa) and lodgepole (pinus contorta var. latifolia). The association occurs at higher elevations on steep to moderate slopes.

Western Spruce Fir Forest (480,000 acres - 3%)

A forest community of the uppermost elevations in the region dominated by Engelman spruce (Picea Engelmani) and Subalpine fir (Abies lasiocarpa).

Great Basin Sagebrush (320,000 acres - 2%)

A high elevation association of Silver Sage (Artemisia cana) and perennial grasses which occurs as open areas scattered throughout the high coniferous forests.

Foothills Prairie (80,000 acres - 0.5%)

A grassland association dominated by wheatgrasses (Agropyron), fescues (Festuca) and needlegrasses (Stipa). This plant community occurs in limited area of southwestern Wyoming.

The following vegetative type descriptions are those contained in the Upper Colorado Region Comprehensive Framework Study. While delineations differ somewhat from those of Kuchler, they are easily coordinated. These descriptions include more detailed information concerning dominant plant species within the major vegetative types.

Forest

Forest vegetation is below the alpine zone and above rangelands in elevation. It is limited at high elevation by severity of climate and precipitation. The forest provides the basis of a stable biotic biotic community usually resistant to surface erosion.

Subalpine Forest - At higher elevations in the subalpine forest, which is sometimes called the spruce-fir forest, the dominant trees are Englemann spruce and subalpine fir. At lower elevations in the subalpine forest are three species that occupy large areas. They are lodgepole pine, Douglas fir, and quaking aspen.

Under story plants commonly found in the subalpine forest are pine-grass, eld sedge, arnica, and huckleberry. Much of the subalpine forest has dense stands of trees and little undergrowth. Stream-bank and meadow communities in the subalpine forest consist of woody woody plants usch as willow, cottonwoods, aspen, birches, and hairgrass, blue joint, sedges, and rushes. Highly productive forage is found in grazable aspen woodlands within the subalpine forest. Here wheatgrasses, bromes, wildrye, and an array of desirable forbs furnish excellent forage for livestock and game.

Montane Forest-The montane forests are characterized by the presence of ponderosa pine, intermixed with extensive areas of quaking aspen. Ponderosa pine forms open stands and usually has an abundance of understory plants. Some of the important plants are mountain muhly, Arizona fescue, Idaho fescue, slender wheatgrass, and oat-grasses. Common shrubs are big sagebrush, serviceberry, snowberries, mountain mahogany, and bitterbrush. Streambank and meadow communities in the montane forest are similar to those in the subalpine forest.

Mountain Brush - At lower elevations mountain brush includes shrub types that commonly occur as a transition between forest and other vegetation types. Common shrubs of this type are oaks, mountain mahogany, serviceberry, ceanothus, bitterbrush, cliffrose, choke-cherry, snowberry, and rose. Other plants commonly found in this zone are big sagebrush, bluebunch wheatgrass, needle-and-thread grass, junegrass, and annual bromes.

Pinyon-Juniper Woodland - Occurring in foothill and low mountain areas, pinyon-juniper types are not usually abundant at elevations higher than 7,000 feet or lower than 4,000 feet. The most common junipers are Utah, Rocky Mountain, and one-seed. Pinyon pine is the most common pine in this zone. Understory species include bitterbrush, big sagebrush, mountain mahogany, and cliffrose. Some herbaceous species present are blue grama, galleta, bluebunch wheat-grass, western wheatgrass, Indian rice-grass, Russian thistle, and cheatgrass.

Range

Range is a generalization of several specific nonforested types. Range is also commonly used as a term referring to that portion of these plant communities on which there is wildlife and livestock. Four major plant communities are found within the rangelands:

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(1) Grass,

(2) Northern Desert Shrub,

(3) Southern Desert Shrub, and

(4) Salt Desert Shrub.

The Northern and Southern Desert Shrub types are differentiated by climate, particularly temperature and timing of rainfall. Northern Desert Shrub occurs where a cold winter and a single wet season exists in early spring, while the Southern Desert Shrub occurs where there is a milder winter and two seasons of moisture-both early spring and late fall. Salt Desert Shrub as the name implies occurs under saline conditions. The grasslands are different from the desert shrubs in that they thrive in the higher rainfall portions of the range usually adjacent to forestlands.

Grass-Grasslands and grasslands mixed with shrubs or with forbs cover extensive area. At the higher elevations perennial grasses mixed with shrubs or with forbs occur as small scattered "islands." The most common perennial grasses are wester wheatgrass, bluebunch wheatgrass, squirreltail, and needlegrass. In the lower elevations the most abundant perennial grasses are blue grama and galleta. This includes annual types in which annual forbs or annual grasses constitute the dominant vegetation. Species include Russian thistle and cheatgrass.

Northern Desert Shrub-This type is identified by the presence of big sagebrush. Occurring in extensive zones, big sagebrush is not as restricted by elevations as are the other communities and is found at elevations of up to 10,000 feet. Sagebrush is found on well-drained, commonly loamy soils that are not usually saline. Many woody and herbaceous species are associated with big sagebrush. Some of these shrubs are black sagebrush, little rabbitbrush, horsebrush, winterfat and snakeweed. Understory grasses are galleta, blue grama, western wheatgrass, bluebunch wheatgrass, and squirreltail.

Southern Desert Shrub - Plants characterizing this type are four-wing saltbush, Mormon tea, yucca, blackbrush, snakeweed, and galleta.

Salt Desert Shrub - This type may be further divided into four subtypes.

Shadscale - Limited to soils that are slightly saline and that have relatively rapid surface runoff, shadscale grows in some places in nearly pure stands but is commonly mixed with other shrubs such as sagebrush, horsebrush, and spiny hopsage. Nuttall saltbush commonly occurs locally as pure stands within this zone.

Greasewood - Growing on terraces above permanent streams and along intermittent stream channels at lower altitudes, greasewood is very salt tolerant and deep rooted and may indicate the presence of groundwater. It usually grows as nearly pure stands but is in some places associated with shadscale, sagebrush, saltbush, and rabbitbrush. Herbaceous species commonly associated with greasewood are saltgrass and alkali sacaton, seepweed and pickleweed. Much of the area within the Salt Desert Shrub type which is occupied by these species is sometimes typed separately as the Salt Marsh Zone. Species occupying these areas must have the capacity to exist partially submerged in water, part or all of the year, and also must have extreme salt tolerance.

Saltbush - Nuttall saltbush grows in nearly pure stands on soils that have very low infiltration rates and that are usually clayey and commonly saline. Greasewood and sagebrush are commonly associated with saltbush in small channel bottoms. Winterfat and black sage are also mixed with nuttall saltbush in a few places or from alternate pure stands.

Desert Molly - Desert molly or summer-cypress grows in scattered stands at lower elevations in the northern part of the region on dry, clayey soils that are usually saline. Other plants commonly found growing with desert molly are bud sage, winterfat, and widely scattered plants of sandberg bluegrass, Indian ricegrass, and scarlet globemallow.

9. Esthetic Resources

The oil shale region is outlined by noteworthy oil shale cliffs along parts of the Piceance Creek and Uinta Basins in Colorado and Utah and by less noteworthy bluffs and escarpements in the Wyoming Basins. Some picturesque canyon lands are developed where the Green and White Rivers cut through the oil shale basins in Utah and Wyoming. The Flaming Gorge Reservoir is a varied setting. For the most part, however, the terrain within the oil shale basins offers a gently rolling hill or flat plain view that has attracted little attention aesthetically.

10. Recreational Resources

The environs adjacent to but outside of the oil shale lands contain many prime outdoor recreational opportunities. Boating and fishing are popular along the Flaming Gorge Reservoir in Wyoming, Desolation Canyon and White River in Utah. Hunting, fishing and sightseeing are also among the activities which are quite popular in these open public lands. However, the oil shale lands are located a good 10 to 100 miles from recreational lakes and streams, and therefore are not utilized for water-oriented activities. However, there is some hunting of deer, antelope and game birds within the oil shale region itself.

The public lands provide high quality outdoor recreational activities. Some of the opportunities that are available on these lands are of the following types:

(a) Water oriented activities associated with the lakes and streams of the high country and along the major streams of the lowlands of the Duchesne, Green, and White Rivers and especially the Flaming Gorge National Recreation Area;

(b) Wildlife opportunities, especially those associated with wildlife refuges, hunting mule deer, elk, moose, and bighorn sheep at the higher elevations on National Forest and Bureau of Land Management Lands;

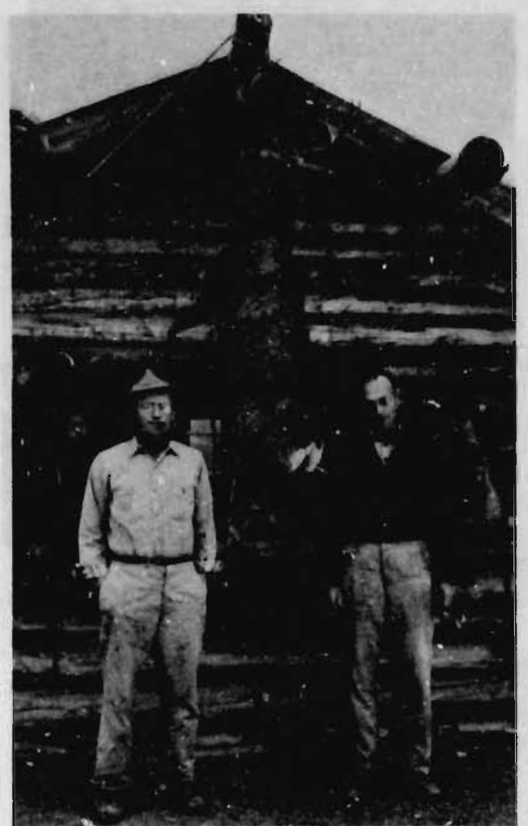
(c) Sightseeing the unique features and scenic wonders of Flaming Gorge National Recreation Area, Dinosuar National Monument, Curay Wildlife Range, Whiterocks Fish Hatchery, Desolation Canyon, and many more;

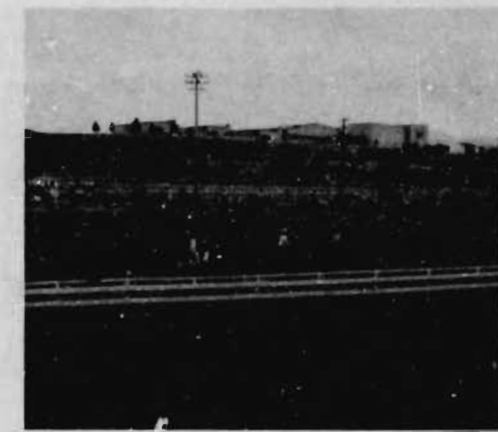
(d) Hiking and rockhounding in the backcountry of Yellowstone Creek, Rock Creek, the Badlands in the White River area, Piceance Creek, etc; and

(e) Visiting the historic areas of Old Fort Duchesne, the Uintah-Ouray Indian Reservation, Wind River Shoshone and Commanche Country, Freemont Indian Culture, etc.

The Upper Colorado River Region, which encompasses the Green River oil shale areas, also includes many prime recreational opportunities in areas near the oil shale lands (see Figures II-25, II-26, and II-27). These are described in the recreation report of the Upper Colorado Region Comprehensive Framework Study (1971). Many of the prime scenic areas are in the national monuments, national recreational areas, and national forests, including wilderness areas, ski areas, and public camp sites. Many of the larger towns near the oil shale lands have municipal or public golf courses, swimming pools, rodeo grounds, playgrounds, and other recreational facilities (See Wengert).

One common characteristic of all the recreation areas on the public lands of the oil shale region is that they have few developed urban-type facilities that may be expected by incoming populations. The region as a whole, however, does have many untapped recreation opportunities, such as those described above, within, as well as outside, the primary oil shale lands of Colorado, Utah, and Wyoming.





Rodeo parade, Meeker.

Deer taken in headwaters of Parachute Creek.

Outdoor artistry, decorative curtain across Rifle Gap, with oil shale cliffs in background.

Trout catch, Rifle Creek near the oil shale area.

FIGURE II-25.--Recreational Opportunities Near the Colorado Oil Shale Area.

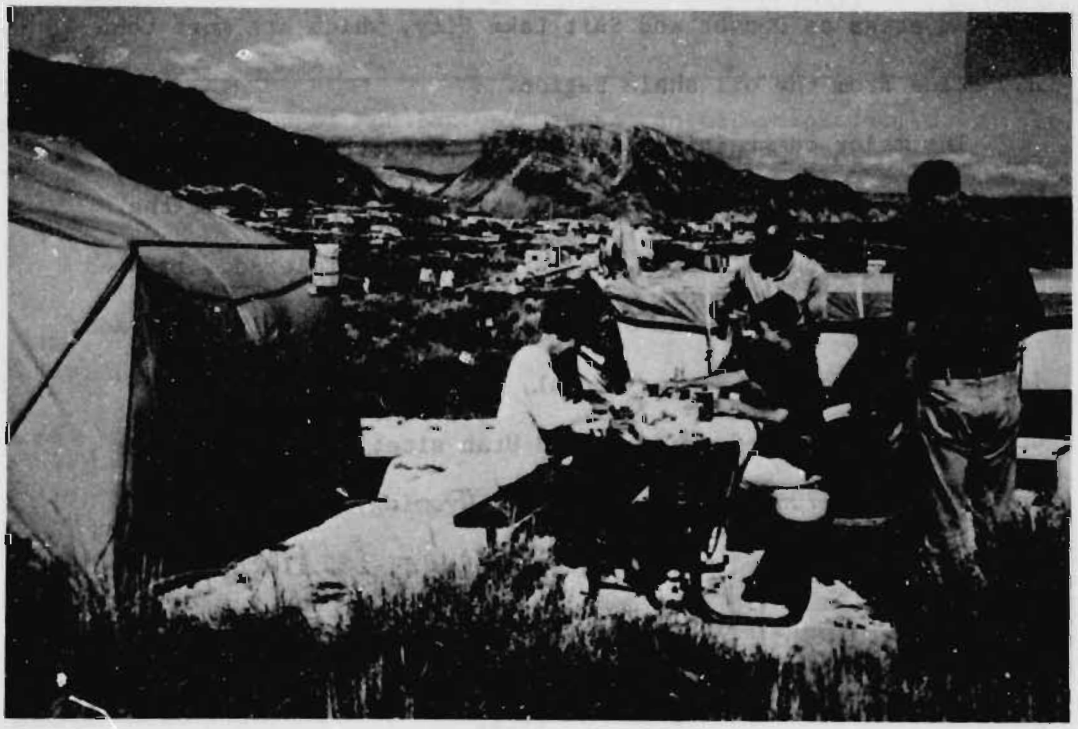
Gateway to Piceance Creek, Colo.

Fossil bone dig, Piceance Creek Basin.

Cathedral Bluffs, on the West rim of Piceance Creek Basin, Colo. The prominent oil shale cliffs above the talus slopes and hummocky landslide ground below.

FIGURE II-26.--Recreation and scenery in the Upper Colorado Region.

Winter snowmobiling, a popular recent outdoor activity of the Upper Colorado River Region.



Antelope Flat Public Campground, Flaming Gorge Reservoir.

FIGURE II-27.--Recreation in the Upper Colorado Region.

11. Socioeconomic Resources

The three-State oil shale region of Colorado, Utah, and Wyoming is sparsely populated and relatively isolated. The total population of the area under consideration was approximately 119,400 in 1970. This population indicates a net 6.5 percent increase during two previous 10-year periods. Most of this increase was in the Colorado area. Population shifts during the 1960-1970 decade for the seven counties directly involved in oil shale development are shown in Table II-15.

The average population density of the area as a whole is approximately three people per square mile. Although there are a number of small air fields located in the area, only one (in Grand Junction, Colorado) has large jet transport capabilities. All others are serviced by connecting flights to such major metropolitan areas as Denver and Salt Lake City, which are more than 200 miles from the oil shale region.

The major communities in or adjacent to the oil shale region are Grand Junction, Colorado, population 20,000, south of the Piceance Creek Basin; Rifle, Meeker and Craig, Colorado, located on the eastern edge of the oil shale beds; and Rangely, Colorado, in the center of the Basin; Vernal, Utah (population 4,000), 40 miles northeast of the selected Utah site; and Rock Springs (population 11,700), and Green River, Wyoming, both situated north of the selected areas, (See Figures II-28, II-29, and II-30).

TABLE II-15.--Population Trends in the Three-State, Oil Shale Region.

State	Population	
	1960	1970
Colorado		
Garfield	12,000	14,800
Mesa County	50,700	54,300
Rio Blanco County	5,200	4,800
Utah		
Duchesne County	7,200	7,300
Uintah County	11,600	12,700
Wyoming		
Sweetwater County	18,000	18,400
Uinta County	7,500	7,100
Total	112,200	119,400

Source: 1970 Census of Population, General Social and Economic Characteristics, U.S. Dept. of Commerce. Washington, D.C. 1972.

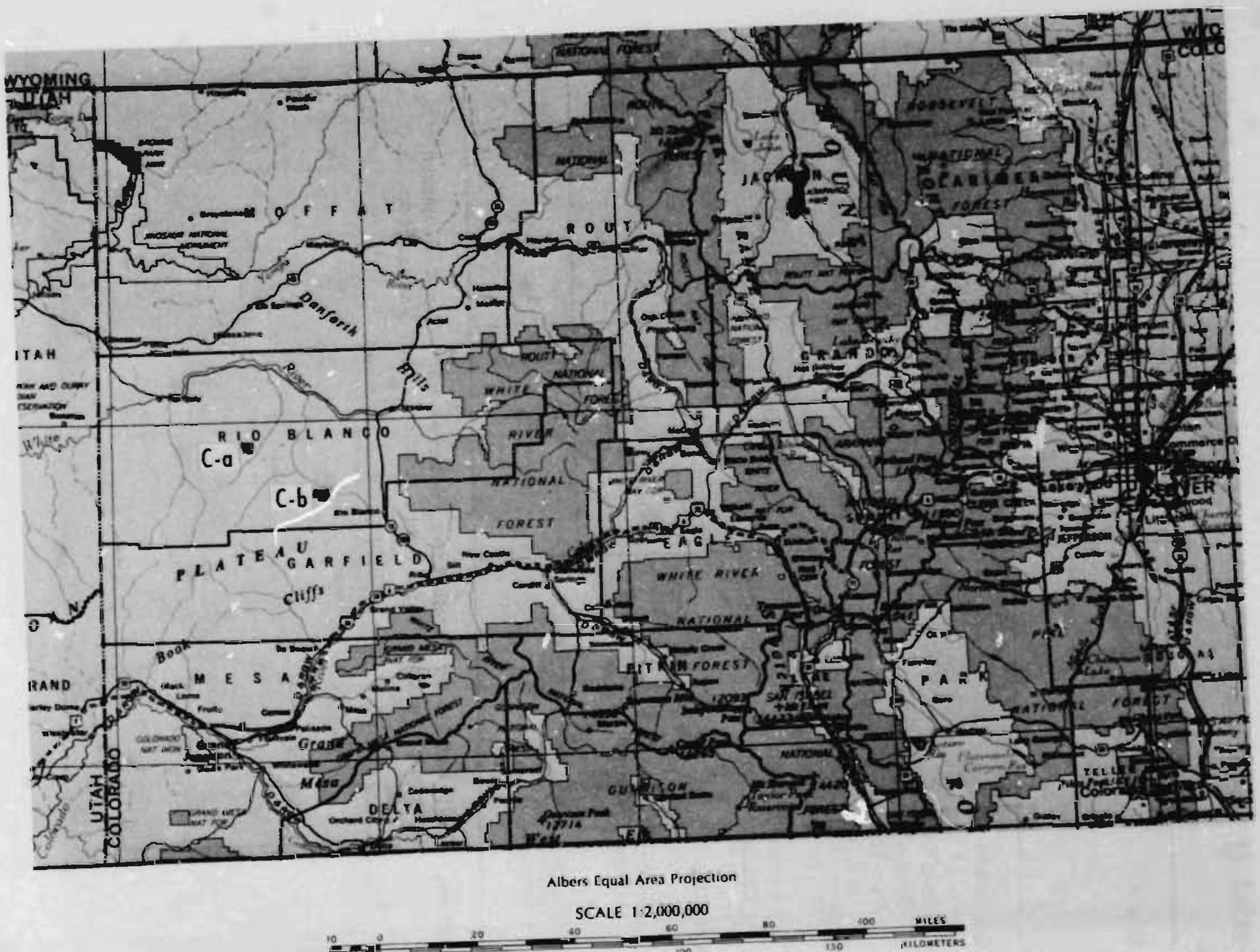
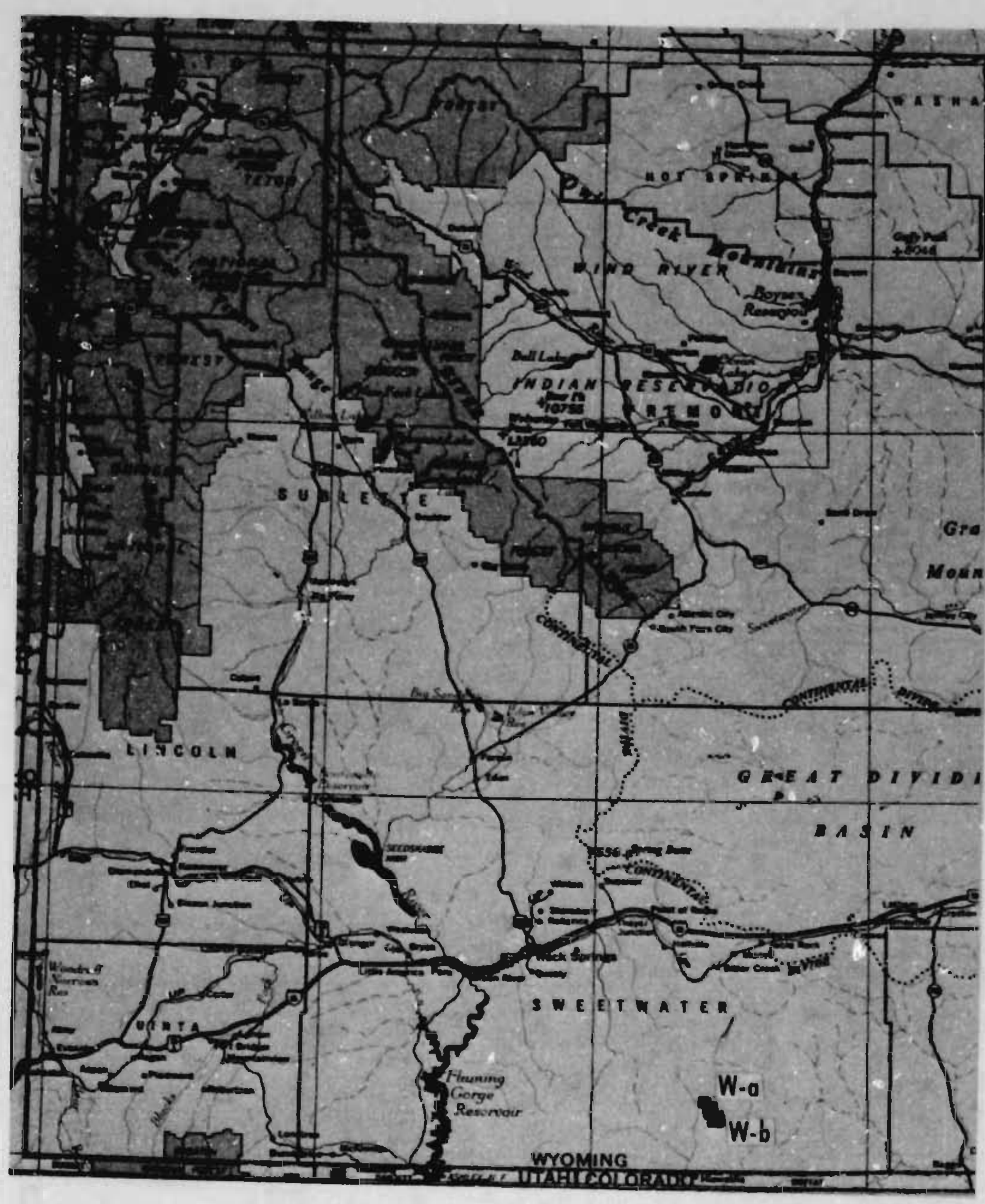


FIGURE II-28.--Map of Northwestern Colorado Showing Environs of Nominated Oil Shale Lease Tracts.

FIGURE II-29.--Map of Northeastern Utah Showing Environs of Nominated Lease Tracts.



Albers Equal Area Projection

SCALE 1:2,000,000

10 0 20 40 60 80 100 MILES

10 0 50 100 150 KILOMETERS

FIGURE II-30.--Map of Southwestern Wyoming Showing Environs of Nominated Lease Tracts.

The area is dependent upon agricultural activities, the minerals industry, and tourist and recreation for its economic support. Much of the farm land is used by ranchers for cattle and sheep. Mining activities in the area include oil and gas, limited uranium and vanadium production in Colorado and Utah, and oil, natural gas, sodium (trona), and coal production in Wyoming. The value of farm products sold annually is $54.0 million. The value of mineral products is more than $160 million annually for the total area. A more comprehensive analysis follows in Sections B, C and D.

More detailed statistics by county and in some cases by city are available from a variety of local governmental and private association sources. These data are invaluable in formulating action programs at the local level. Comprehensive data covering Garfield, Mesa, and Rio Blanco Counties and Grand Junction, Colorado, have been compiled by Colony Development Operation (see Wengert, 1972). The report covers recreations, government, city services, utilities, communications, transportation, business, employment, manufactures, and raw materials. It has been made available by Colony to the local and regional planning organizations of the areas covered for their use in formulating comprehensive local plans. It is also available at cost from Colony 1/.

1/ Write: Colony Development Operation, 1500 Security Life Building, Denver, Colorado 80202.

12. Ownership

The ownership of major land areas of the oil shale region is shown in Figure II-31. Of the more than 11 million acres of oil shale land potentially suitable for commercial development in Colorado, Utah, and Wyoming, about 72 percent are public lands administered by the Department of the Interior. These public lands contain 80 percent of the high-grade oil shale.

The areas shown in Figure II-31 as public lands supervised by the Bureau of Land Management include some privately owned land, some with minerals reserved to the United States. Part of the oil shale land has been claimed at one time or another by individuals or companies for placer claims, with oil shale, aluminum, or other prospectively recoverable mineral designated as valuable. Efforts to clarify the validity of these claims have been vigorously pursued by the Interior Department since 1965, and ownership of land and mineral for numerous claims have been resolved. The land status of the Federal Oil Shale Lands in Colorado, Utah, and Wyoming in 1968 is summarized in Tables II-16, II-17, and II-18, and is described in greater detail in Prospects for Oil Shale Development, Colorado, Utah, and Wyoming, U. S. Department of the Interior, 1968.

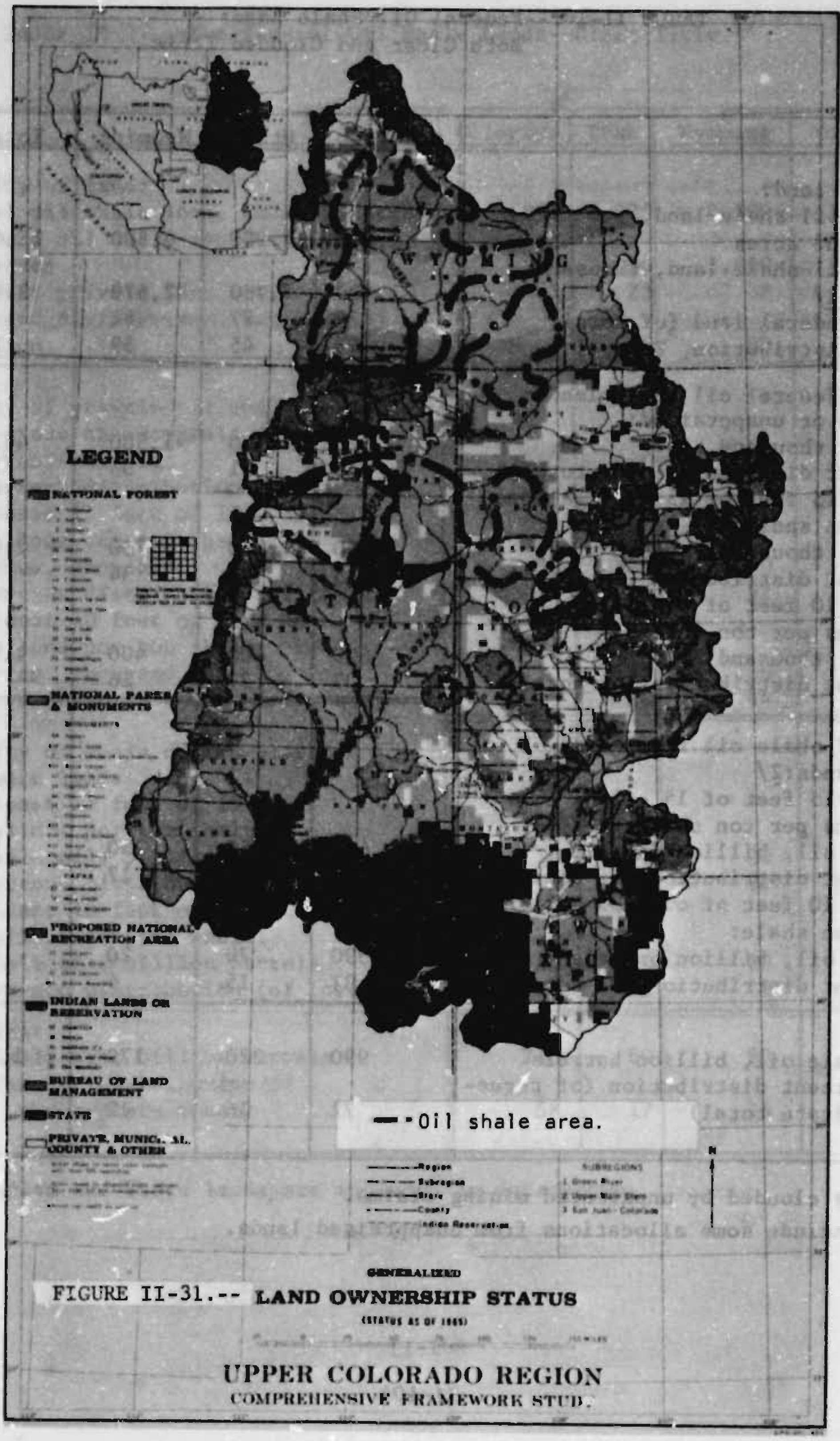


FIGURE II-31.-- LAND OWNERSHIP STATUS

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TABLE II-16.--Federal Oil Shale Lands - Both Clear and Clouded Title.

Item	Colorado	Utah	Wyoming	Total
Quantity of land:				
Total of oil shale land, thousand acres	1,800	4,900	4,300	11,000
Federal oil shale land, thousand acres 1/	1,420	3,780	2,670	7,870
Percent Federal land (of total)	79	77	62	72
Percent distribution, Federal land	16	45	39	100
Quality of Federal oil shale lands:				
Low grade or unappraised:				
Acres, thousand	570	2,130	1,500	4,200
Percent distribution (of total)	13	51	36	100
At least 15 feet of 15 - 25 gallons per ton shale:				
Acres, thousand	300	1,070	700	2,070
Percent distribution (of total)	15	51	34	100
At least 10 feet of over 25 gallons per ton shale:				
Acres, thousand	600	600	400	1,600
Percent distribution (of total)	37	37	26	100
Quantity of shale oil in place - Federal lands:2/				
At least 15 feet of 15 - 25 gallons per ton shale:				
Shale oil, billion barrels	600	150	150	900
Percent distribution (of total)	66	17	17	100
At least 10 feet of over 25 gallons per ton shale:				
Shale oil, billion barrels	390	70	20	480
Percent distribution (of total)	81	15	4	100
Total:				
Shale oil, billion barrels	990	220	170	1,380
Percent distribution (of three-State total)	72	16	12	100

1/ Largely clouded by unpatented mining claims.

2/ Data include some allocations from unappraised lands.

TABLE II-17.--Non-Federal Oil Shale Lands--Clear Title.[1/]

Item	Colorado	Utah	Wyoming	Total
Quantity of land:				
Total oil shale land, thousand acres	1,800	4,900	4,300	11,000
Private oil shale land, thousand acres	400	1,100	1,600	3,100
Percent private land (of total)	21	23	38	28
Percent distribution, non-Federal land	13	35	52	100
Quality of private oil shale lands:				
Low grade or unappraised:				
Acres, thousand	165	640	890	1,695
Percent distribution	10	38	52	100
At least 15 feet of 15 - 25 gallons per ton shale:				
Acres, thousand	80	320	440	840
Percent distribution (of total)	10	38	52	100
At least 10 feet of over 25 gallons per ton shale:				
Acres, thousand	170	170	260	600
Percent distribution (of total)	28	28	44	100
Quantity of shale oil in place--private lands:				
At least 15 feet of 15 - 25 gallons per ton shale:				
Shale oil, billion barrels	130	40	80	250
Percent distribution (of total)	52	16	32	100
At least 10 feet of over 25 gallons per ton shale:				
Shale oil, billion barrels	80	20	10	110
Percent distribution (of total)	73	18	9	100
Total:				
Shale oil, billion barrels	210	60	90	360
Percent distribution (of three-State total)	58	17	25	100

1/ Indian and State lands are included in data shown.

TABLE II-18.--Federal Oil Shale Lands--Clouded Title.

Item	Colorado	Utah	Wyoming	Total
Quantity of land:				
Total Federal lands, thousand acres	1,420	3,780	2,670	7,870
Land with unpatented mining claims:				
Old claims, prior to 1966, thousand acres	400	2,600	2,200	5,200
New claims, 1966, thousand acres	700	400	400	1,500
Total with claims, thousand acres	1,100	3,000	2,600	6,700
Percent of Federal land with claims	78 1/	79	97	85
Quality of lands with unpatented claims:				
Low grade or unappraised:				
Acres, thousand	500	1,700	1,400	3,600
Percent distribution (of total)	14	47	39	100
At least 15 feet of 15 - 25 gallons per ton shale:				
Acres, thousand	200	800	700	1,700
Percent distribution (of total)	12	47	41	100
At least 10 feet of over 25 gallons per ton shale:				
Acres, thousand	500	500	400	1,400
Percent distribution (of total)	36	36	28	100
Quantity shale oil in place, unpatented mining claims: 2/				
At least 15 feet of 15 - 25 gallons per ton shale:				
Shale oil, billion barrels	500	100	100	700
Percent distribution (of total)	72	14	14	100
At least 10 feet of over 25 gallons per ton shale:				
Shale oil, billion barrels	320	50	20	390
Percent distribution (of total)	82	13	5	100
Total:				
Shale oil, billion barrels	820	150	120	1,090
Percent distribution (of three-State total)	75	14	11	100

1/ Ninety-five percent of lands in Piceance Creek Basin, Colorado, have unpatented mining claims.

2/ Data include some allocations from unappraised lands.

Present land use and suitability of the Upper Colorado Region and projected land use through the year 2020 (from "Upper Colorado Region Comprehensive Framework Study") is shown in Table II-19. Projected land use changes by land resource groups are shown in Table II-20.

Much of the Federal oil shale land is under lease for oil and gas exploration, other areas are leased for sodium mineral extraction or sodium prospecting permits. The same lands may be leased for livestock grazing. Some accommodation between different leases will be required when the oil shale is developed.

TABLE II-19.--Land Use and Suitability Related to Regionally Interpreted OBERS, Upper Colorado Region, 1965

(Thousands of acres)

Type of use	Present land use	Land suitable and available	Projected land use			Change 1965 to 2020	
	1965	1965	1980	2000	2020	Inc +	Dec -
Irrigated cropland	1,622	7,058 1/	1,794	1,954	2,122	500	
Dry cropland	603	603	572	532	503		100
Grazing	60,442	54,624	55,958	54,691	53,380		7,062
Timber production	9,419	9,419	9,351	9,266	9,194		225

1/ Includes only potentially irrigable land.

TABLE II-20.--Land use in 1980 and 2000 for Framework Plan, Upper Colorado Region.

Land Resource Groups	Area	Cropland Irrig.	Cropland Dry	Grazing	Timber Production	Urban and Industrial	Developed Recreation	Primitive Areas (Wilderness)	Developed Mineral Production	Trans. and Utilities	Developed Fish and Wildlife	Military	Classified Watershed
	Area (Thousands of Acres)												
UPPER COLORADO REGION-1980													
Alpine	1,329		-	257	-	3	-	417	-	6	-	-	22
Forest	27,152	-	-	19,926	9,351	10	-	777	-	104	-	12	155
Range	37,050	-	-	33,944	-	11	-	156	-	151	-	101	69
Cropland	1,571	1,056	515	-	-	-	-	-	-	-	-	-	-
Pasture	1,395	738	57	600	-	-	-	-	-	-	-	-	-
Urban (Priv)	392	-	-	-	-	185	-	-	-	198	-	-	-
Water & misc.	3,268	-	-	1,231	-	147	140	64	71	169	393	1	16
Total Land	72,157	1,794	572	55,958	9,351	356	140	1,414	71	632	393	114	262
Water (areas 40 ac.)	482	-	-	-	-	-	351	-	-	-	-	-	-
TOTAL	72,639	1,794	572	55,958	9 351	356	491	1,414	71	632	393	114	262
UPPER COLORADO REGION-2000													
Alpine	1,329	-	-	172	-	3	-	417	-	6	-	-	21
Forest	26,901	-	-	19,472	9,266	18	-	777	-	128	-	12	155
Range	36,600	-	-	32,956	-	18	-	156	-	170	-	101	72
Cropland	1,589	1,110	479	-	-	-	-	-	-	-	-	-	-
Pasture	1,757	844	53	860	-	-	-	-	-	-	-	-	-
Urban (Priv)	442	-	-	-	-	196	-	-	-	210	-	-	-
Water & misc.	3,528	-	-	1,231	-	168	273	64	103	189	450	1	19
Total Land	72,146	1,954	532	54,691	9,266	403	273	1,414	103	703	450	114	268
Water (areas 40 ac.)	493	-	-	-	-	-	351	-	-	-	-	-	-
TOTAL	72,639	1,954	532	54,691	9,266	403	624	1,414	103	703	450	114	268

Note: Horizontal totals may exceed the total land area because of overlapping uses. Extensive uses such as incidental recreation, fishing, hunting and wildlife habitat are not identified in this table. Timber production acreage for economic subregions.

B. Colorado (Piceance Creek Basin)

1. Physiography

The term "Piceance Creek Basin" is sometimes used to describe a major geologic structural and sedimentary basin in Rio Blanco, Garfield, and Mesa Counties, Colorado, (Figures II-I, II-2). The portion of the Basin containing the principal oil shale deposits is a dissected plateau, known as the Roan Plateau, bounded by steep escarpments which face the Colorado River on the south, the White River on the north, the valleys of Government and Sheep Creek on the east, and Douglas Creek on the west.

Piceance Creek, Yellow Creek, and tributaries of Douglas and Sheep Creeks drain the northern part of the oil shale area and are tributaries to the White River. Parachute Creek and Roan Creek drain the southern part of the oil shale area, into the Colorado River. Most of the Federal oil shale lands are located in the stream drainage basin of Piceance Creek and Yellow Creek. Smaller deposits, in Battlement and Grand Mesa south of the Colorado River, are excluded from consideration here.

The topography of the shale-bearing area is somewhat unique. The differential resistance to erosion has produced ridges and valleys with local relief of 200 to 600 feet. They are generally oriented north and north-easterly in a nearly parallel pattern as illustrated in the aerial view (Figure II-32). Elevation varies from about 5,250 feet along the White River to a maximum of about 9,000 feet for some ridge crests on the south.

2. Climate

Annual precipitation in the Piceance Basin varies from approximately 12 inches in the extreme northwest corner to approximately 24 inches in the southwest corner. The area is generally classified as semiarid.

Slightly less than half of the precipitation occurs as snow during the period December to April. The spring precipitation is usually very small. During the latter part of the summer occasional thunderstorms, with accompanying flash floods, ranging from light to very severe occur throughout the area. Fall weather can vary from fair to infrequent rain or snow storms.

The area is subject to thermal extremes, with summer temperatures reaching 100° F and winter temperatures dropping to minus 40° F.

The frost-free season varies from 124 days at the lower elevations to 50 days at upper elevations. The dry climate and relatively short growing season permit restricted growth of small quantities of irrigated native hay, corn for silage, and some small grains along Piceance Creek, Yellow Creek, and the White River.

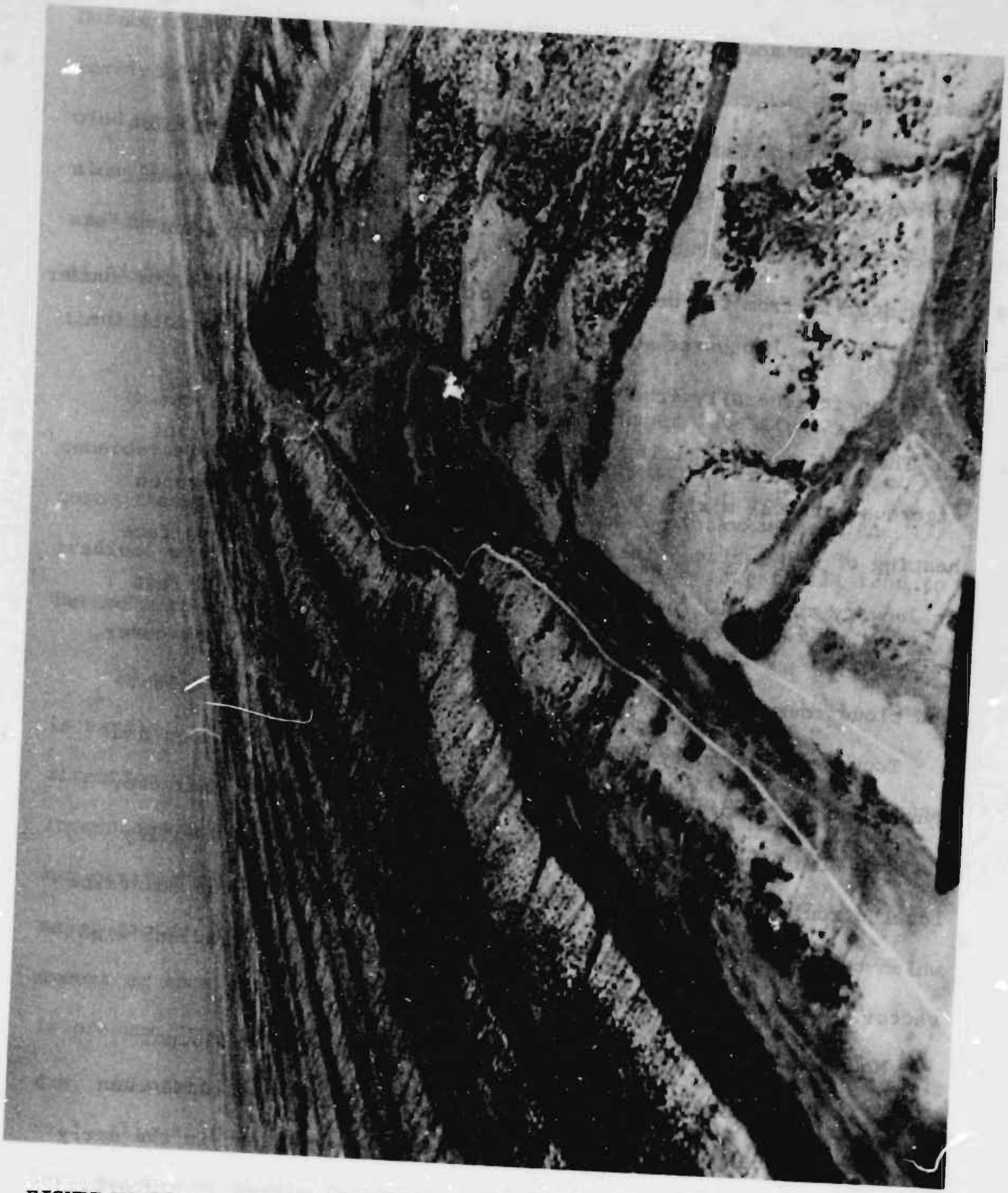

FIGURE II-32.--Aerial View Colorado Oil Shale Country in the Central Part of the Piceance Creek Basin.

Information developed for Project Rio Blanco (Project Rio Blanco Environmental Impact Evaluation, 1971) using upper air flow data measured at the National Weather Service upper air sounding station at Grand Junction, gives an indication of upper air wind speed and direction over the Piceance Basin. At 10,000 feet the mean wind for winter is from the west-southwest at about 10 knots, while for summer it is from the southwest at about 8 knots. In the spring and fall the direction is generally from the southwest at about 6 knots.

The mean maximum mixing depth (the thickness of the layer of vigorous vertical mixing due to convection arising from afternoon heating of the surface) increases from 1115 feet above the surface in January to 11,710 feet in June and then decreases to 1410 feet in December. Daily variations due to afternoon heating, snow cover, and cloud cover can cause wide fluctuations in this mixing depth.

Topography strongly influences the local wind circulations and dynamic effects which affect the transport and diffusion characteristics. The two main effects of topography are mountain - valley local circulations and the frictional effect induced by the mountains which causes observed winds to blow to the left of the gradient wind vector.

Mountain-valley local circulations are dependent on diurnal variations. Generally, wind velocities are lowest about dawn when there is little vertical thermal mixing and are greatest in the early afternoon when, due to surface heating, vertical mixing is highest.

During warm afternoons, because of lateral constriction, the vertically expanding air tends to move up the valley axis, and this wind is known as a valley wind. These generally light winds flow along the main valley and develop as anabatic (up-slope) winds, which are due to greater heating of the valley sides than of the valley floor. At night, the cold denser air at higher elevations moves into the valleys; this is known as katabatic wind.

Mountains and rough terrain modify the upper level free airflow considerably because of friction. This lowers wind velocities and turns the winds in the frictional layer counter-clockwise from the gradient wind vector, e.g., flow from the south-southwest will tend to become more southerly in the lower air layers.

In valleys with broad floors, inversions may form at night. There is hardly any transport through these inversions. Thus, the wind direction will be determined by the local downslope circulation. These inversions are usually broken by surface heating during the day but may persist for large portions of the day. During the winter the major factor in formation and persistence of these inversions is the amount of snow cover and its level of reflectance. If snow cover is present, the incoming solar radiation is reflected during the day. At night, the snow, because it does not conduct heat very well, allows little heat to come up from the ground to replace heat lost due to radiation. Therefore, the down-slope flow is enhanced, and, because snow reflects incoming radiation during the day, upslope flow is retarded. Thus, the inversion will persist.

Wind directional frequency has been determined for four recording stations associated with Project Rio Blanco. The stations show major seasonal changes in wind direction frequency due to diurnal variations and changes in the local mountain-valley circulations caused by surface heating variations, changes in mixing depth, and differences in upper air flow. For a detailed analysis, see Project Rio Blanco Environmental Impact Evaluation, 1971.

3. Geology

The geology of oil shale-bearing rocks of the Piceance Creek Basin, Colorado, has been described by Donnell in a report entitled "Tertiary Geology and Oil-Shale Resources of the Piceance Creek Basin--Northwestern Colorado.", U.S. Geological Survey Bulletin 1082-L. The reader is referred to this report for maps showing the detail of distribution of oil shale and associated rocks of the Green River Formation.

The principal oil shale unit known as the Parachute Creek Member of the Green River Formation forms the upper part of a cliff or escarpment 2,000 to 3,500 feet high around the margins of the basin. The upper part of the oil shale sequence is exposed in some deep gulches within the basin behind the escarpment. In the interior of the basin, however, the oil shale is concealed in most places by a buff-weathering sandstone and siltstone sequence known as the Evacuation Creek Member.

The general distribution of oil shale and saline minerals in, or associated therewith, in the Piceance Creek Basin is illustrated in the cross sections of Figures II-33 and II-34.

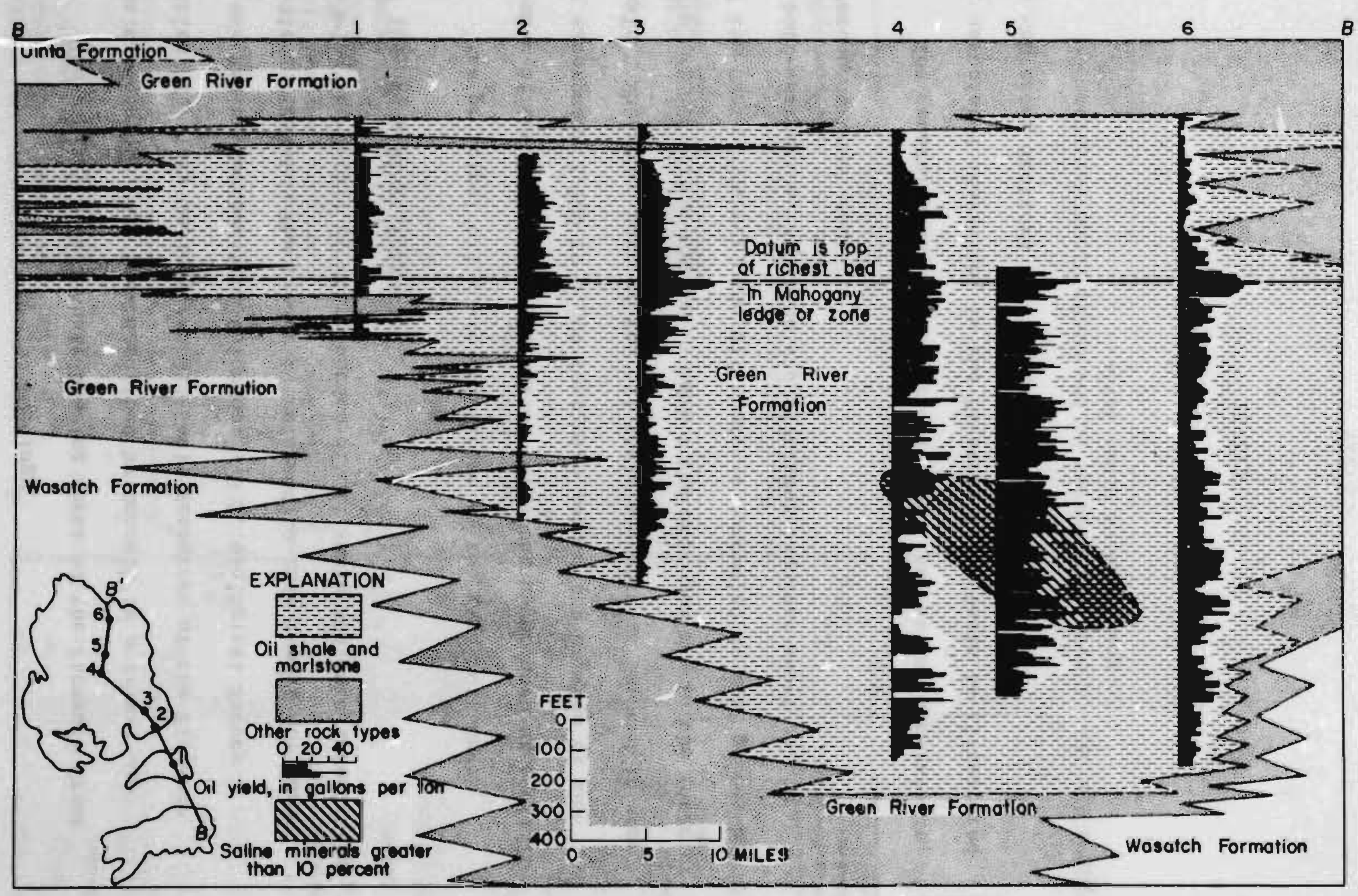

FIGURE II-33.--Cross Section of the Green River Formation in the Piceance Creek Basin.

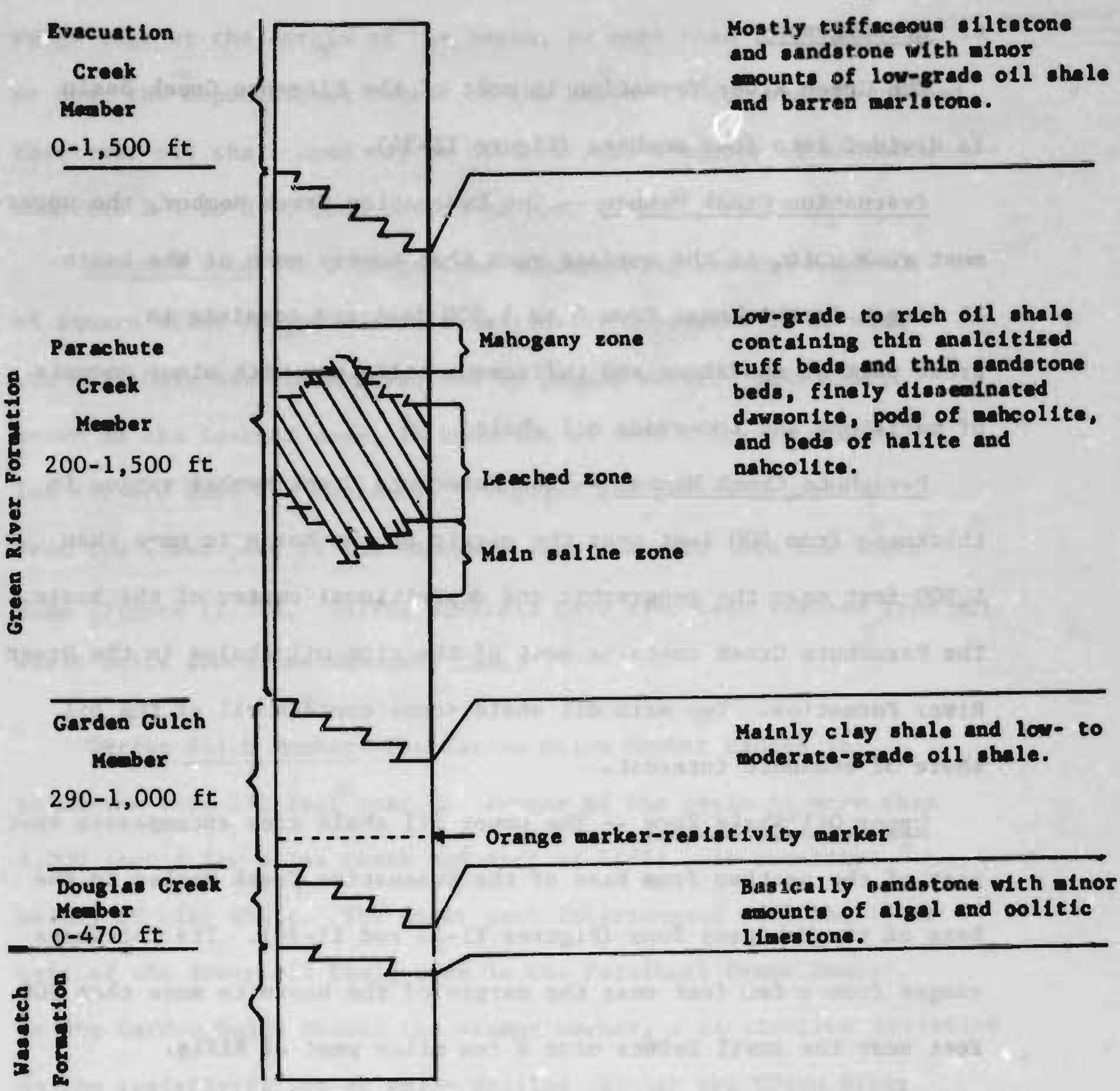

FIGURE II-34.--Generalized Section of the Green River Formation in the Piceance Creek Basin.

a. Stratigraphy

The Green River Formation in most of the Piceance Creek Basin is divided into four members (Figure II-34).

Evacuation Creek Member -- The Evacuation Creek Member, the uppermost rock unit, is the surface rock that covers much of the basin. It ranges in thickness from 0 to 1,500 feet and consists in great part of sandstone and tuffaceous siltstone with minor amounts of marlstone and low-grade oil shale.

Parachute Creek Member -- The Parachute Creek member ranges in thickness from 200 feet near the margin of the basin to more than 1,500 feet near the geographic and depositional center of the basin. The Parachute Creek contains most of the rich oil shales in the Green River Formation. Two main oil shale zones contain all of the oil shale of economic interest.

Upper Oil Shale Zone -- The upper oil shale zone encompasses that part of the section from base of the Evacuation Creek Member to the base of the Mahogany Zone (Figures II-33 and II-34). Its thickness ranges from a few feet near the margin of the basin to more than 500 feet near the Anvil Points mine a few miles west of Rifle.

Lower Oil Shale Zone -- A thin zone of low-grade oil shale, barren marlstone, sandstone, or siltstone separates the upper and lower oil shale zones. The lower zone ranges in thickness from a wedge edge at the margin of the basin, to more than 1,000 feet at or near the depositional center of the basin. Where best developed the lower oil shale zone may be divided into a number of subzones numbered R-1 to R-6, from bottom to top. (See Figure II-35).

Leached zone--In a large area encompassing several hundreds of square miles saline minerals originally deposited in or with the oil shale have been dissolved by ground water. This unit, known as the leached zone, is hundreds of feet thick in places. The top and base are extremely irregular and generally extend from the lower part of the Mahogany zone downward into the lower zone (Figure II-34). Saline minerals have also been leached from oil shale units above the Mahogany Zone.

Garden Gulch Member--The Garden Gulch Member ranges in thickness from 290 feet near the center of the basin to more than 1,000 feet a few miles north and west of Rifle. It consists mainly of clay shale. The upper part intertongues with the lower part of the lower oil shale zone in the Parachute Creek Member. In the Garden Gulch Member the orange marker, a distinctive deviation on the resistivity log of wells drilled through the Green River Formation, in general marks the base of oil shale of economic interest.

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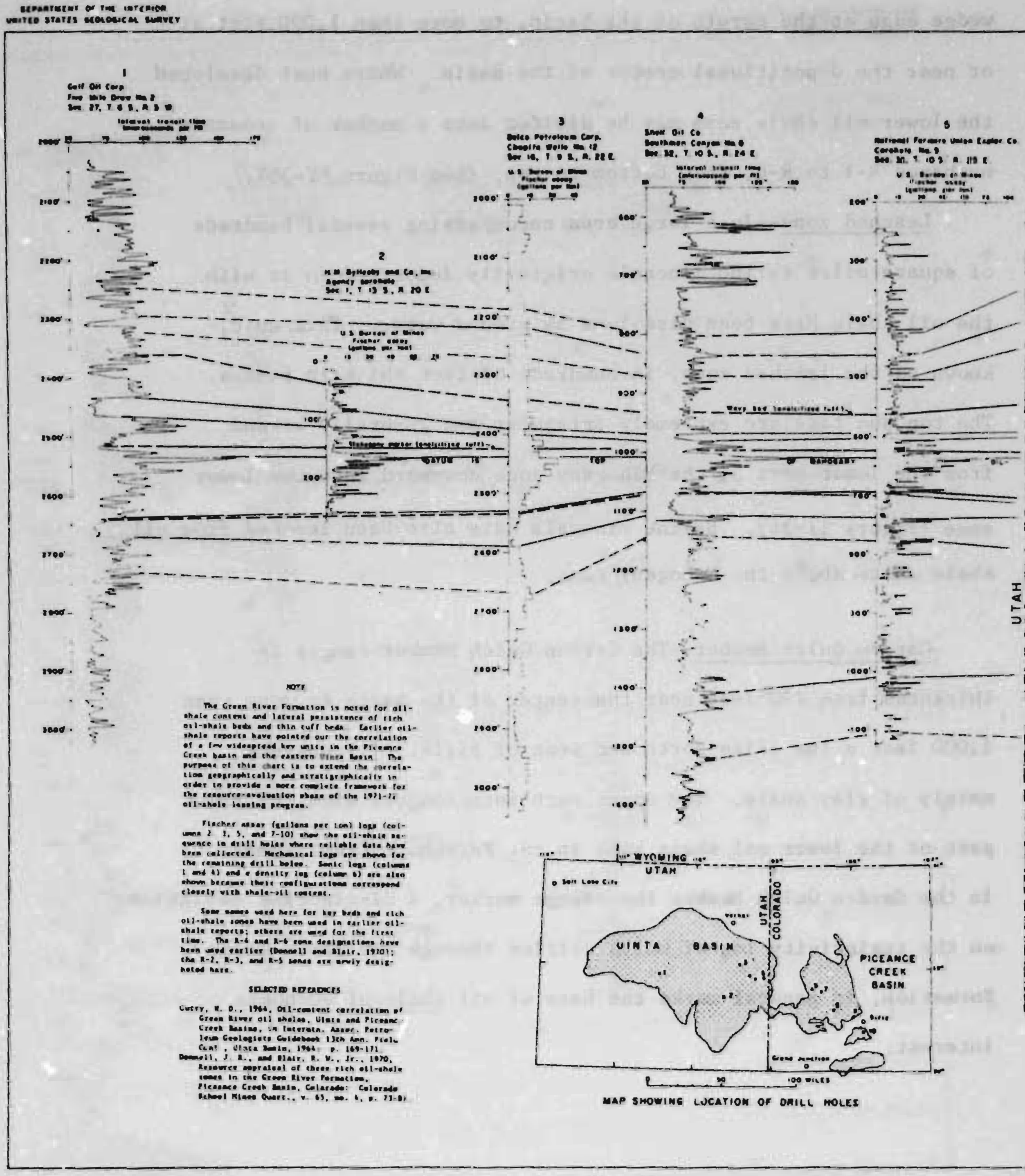


FIGURE II-35..--Chart Showing Correlation of Several Key Units in the Organic-Rich Sequence of the Green River Formation.

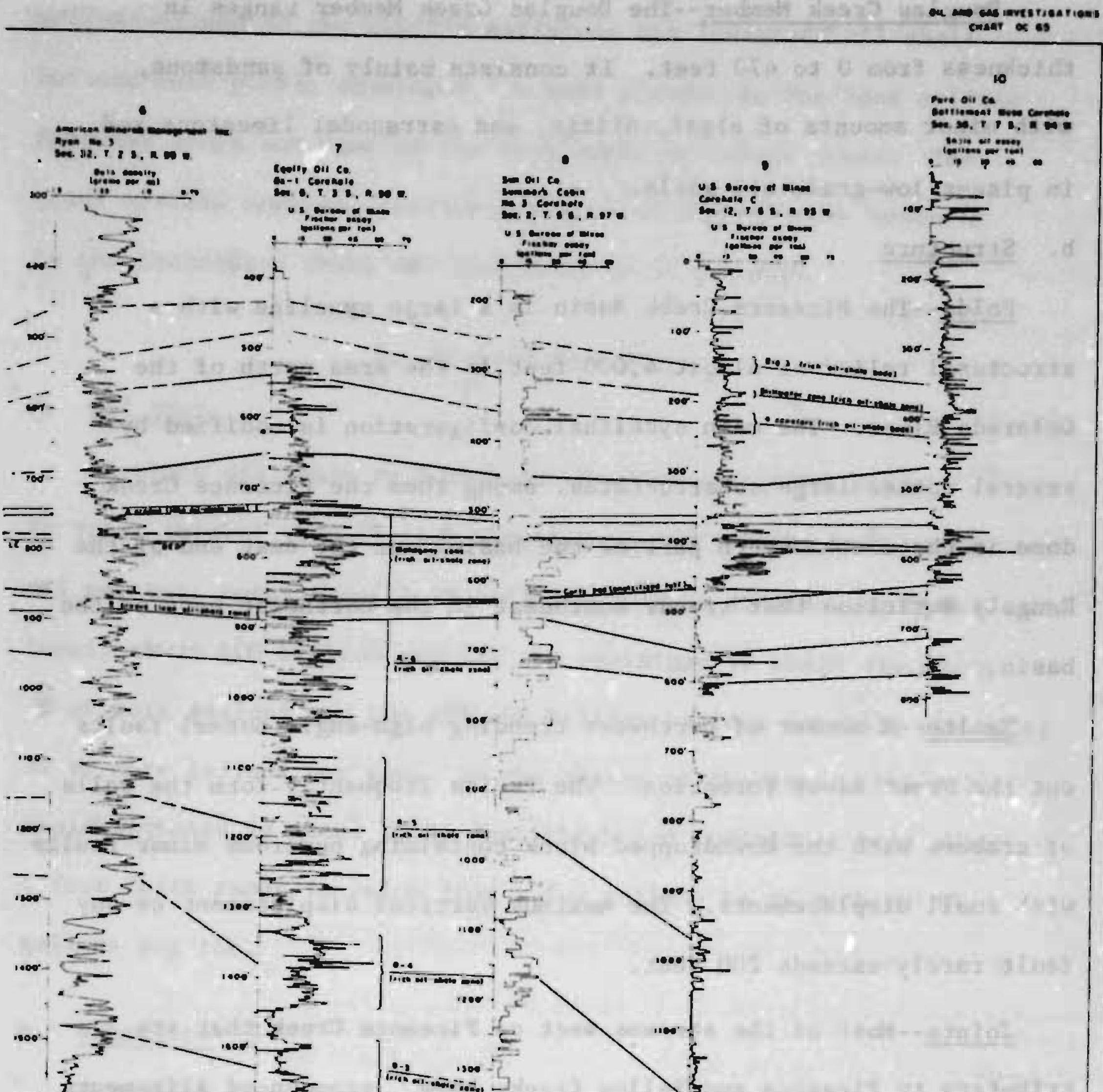


Figure II - 35 (continued)

Douglas Creek Member--The Douglas Creek Member ranges in thickness from 0 to 470 feet. It consists mainly of sandstone, with minor amounts of algal, olitic, and ostracodal limestone and in places low-grade oil shale.

b. Structure

Folds--The Piceance Creek Basin is a large syncline with a structural relief of almost 4,000 feet in the area north of the Colorado River. The main synclinal configuration is modified by several rather large substructures, among them the Piceance Creek dome in the northeastern part of the basin; and the east end of the Rangely anticline that trends southeast in the northwest part of the basin.

Faults--A number of northwest trending high-angle normal faults cut the Green River Formation. The faults frequently form the walls of grabens with the downdropped block containing numerous minor faults with small displacements. The maximum vertical displacement on any fault rarely exceeds 200 feet.

Joints--Most of the streams west of Piceance Creek that are tributary to Piceance and Yellow Creeks have pronounced alinements to the northeast. Many side gulches trend northwest, at right angles to the major stream drainages. These alinements coincide with the trend of the major joint systems. The joint systems are readily mappable along the outcrop of the oil shale. The joints are well-developed in the brittle marlstone and low-grade oil shale but are more poorly developed, in most places, in the less brittle Mahogany ledge and some of the rich lower oil shale zones. The joint systems sometime provide avenues for ground-water movement in the Evacuation Creek and Parachute Creek Members.

4. Mineral Resources

a. Oil Shale

In-place oil shale resources in the Piceance Creek Basin, in zones thicker than 15 feet that average 15 or more gallons of oil per ton, total about 1.25 trillion barrels of oil. Of this total, about 600 billion barrels are contained in shale averaging 25 or more gallons per ton and 450 billion barrels in shale averaging 30 or more gallons per ton. In the center of the basin, the oil shale sequence is about 2,000 feet thick and individual beds about 1 foot thick range in value from a few gallons to as much as 90 gallons per ton.

b. Nahcolite

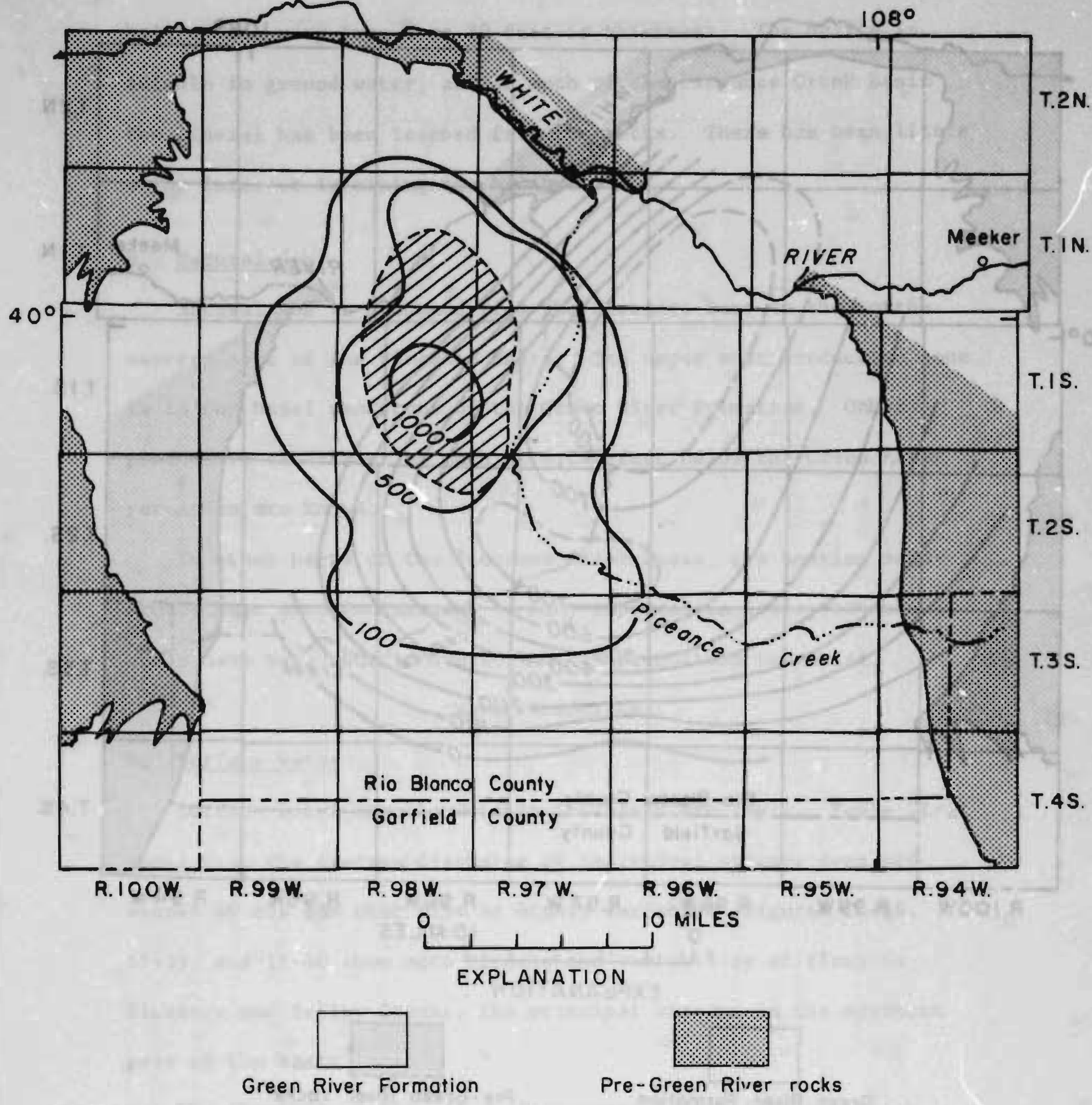
Nahcolite is sodium bicarbonate mineral ($NaHCO_3$) that occurs throughout the major part of the Parachute Creek Member. It may be present as elliptical pods that in some places are as much as several feet in diameter, or it may be present as beds that are as thick as 10 or 12 feet. In all parts of the upper oil shale zone, nahcolite probably averages less than 5 percent by weight, but, in thick sequences of the lower oil shale zone, it may average more than 30 percent by weight. Near the center of the basin where the deposits of nahcolite are best developed, resources of as much as 130 million tons of nahcolite per square mile are indicated (Dyni). Figure II-36 shows the thickness of the nahcolite-bearing oil shale in the northern part of the Piceance Creek basin in Colorado. Nahcolite is a potential source of soda ash and may also be useful for removal of sulfur from industrial stack gases.

c. Dawsonite

Dawsonite is a dihydroxy sodium aluminum carbonate mineral ($NaAl(OH)_2CO_3$) that occurs finely disseminated in the oil shale mainly in the lower oil shale zone in the part of the Piceance Creek Basin that is in Rio Blanco County. Alumina may be relatively easily extracted from dawsonite; therefore, although the percent of alumina in dawsonite is small, it may be of economic interest. A sequence of oil shale as thick as 800 feet near the center of the basin contains dawsonite in appreciable quantities. Units of mineable thickness may contain 3 percent by weight of equivalent extractable alumina. Figure II-37 shows the thickness of the dawsonite-bearing oil shale in the northern part of the Piceance Creek Basin in Colorado.

d. Halite

In the north central part of the basin an area of approximately 75 square miles is underlain by the sodium chloride mineral, halite, in the Parachute Creek Member (Figure II-36). A sequence of interbedded halite and oil shale more than 300 feet thick is present in the R-5 zone of Figure II-36 at the same localities. Individual



(The thickness, in feet, of nahcolite-bearing oil shale is shown by contour lines. The distribution of halite bearing rocks is shown by diagonal lines.)

FIGURE II-36. --Thickness of Nahcolite-Bearing Oil Shale in the Northern Part of the Piceance Creek Basin.

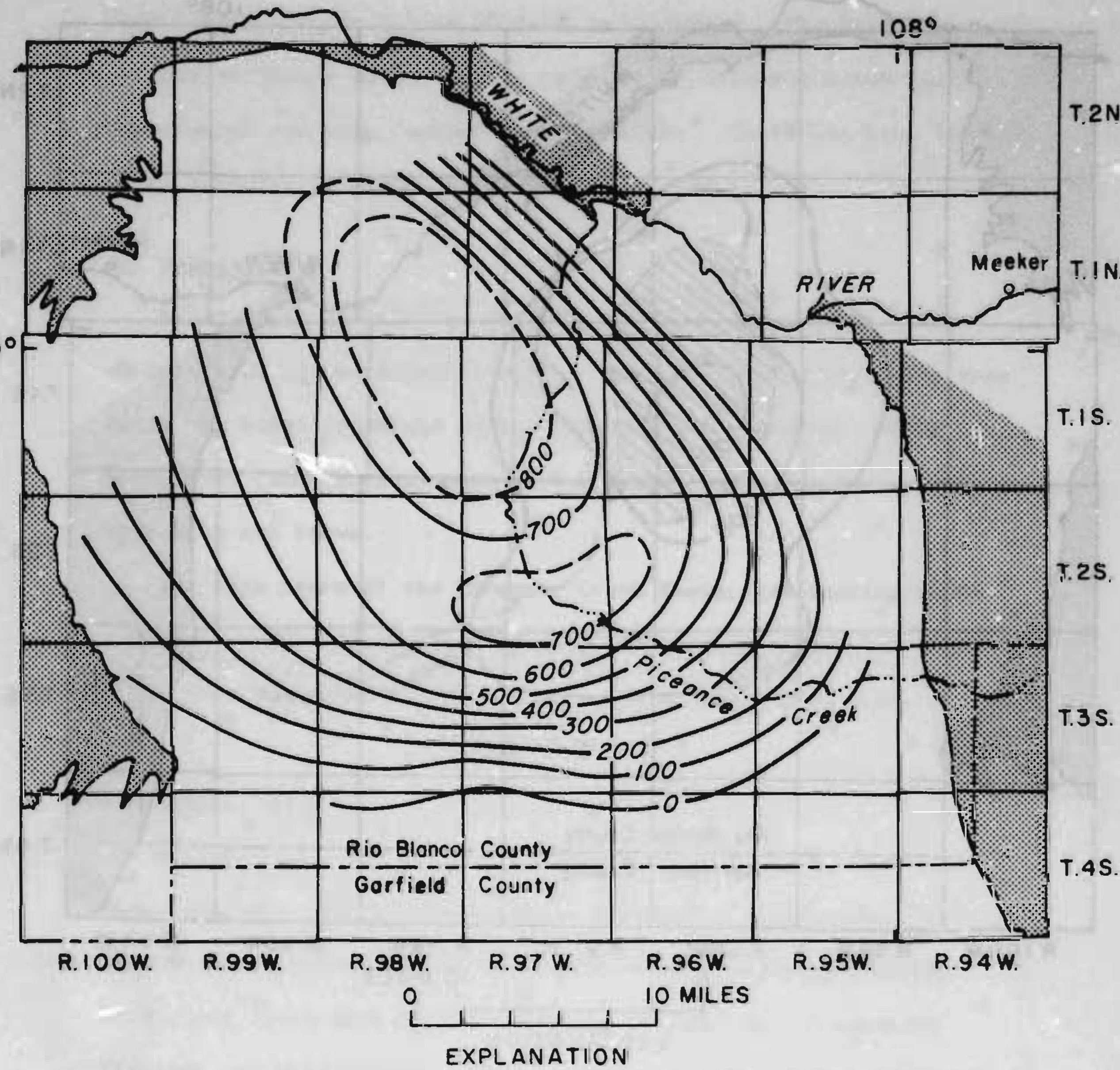


FIGURE II-37.--Thickness of Dawsonite-Bearing Oil Shale in the Northern Part of Piceance Creek Basin.

halite beds vary from 1 to 30 feet in thickness. The halite is soluble in ground water, and in much of the Piceance Creek Basin the mineral has been leached from the rocks. There has been little or no interest in mining the halite.

e. <u>Natural Gas</u>

Natural gas is produced from the Piceance Dome in the northeastern part of the Piceance Basin. The upper most productive zone is in the basal sandstone of the Green River Formation. Other productive sandstones as much as 6,000 feet below the Green River Formation are known.

In other parts of the Piceance Creek Basin, gas bearing sandstones have been encountered in many exploration wells, but the wells have been shut in due to limited production potential.

5. Water Resources

a. <u>Surface Water</u>

Surface water supplies within the basin are small. Table II-21 shows that the average discharge of individual streams does not exceed 40 cfs and that flow is highly variable. Figures II-38, II-39, and II-40 show more clearly the variability of flows in Piceance and Yellow Creeks, the principal streams in the northern part of the basin.

The chemical quality of surface water in the Piceance Creek Basin is variable, depending largely on the quality and quantity of ground water discharge to the stream. This relationship is shown graphically for Piceance Creek in Figure II-41. The

Table II-21.--SUMMARY OF STREAMFLOW RECORDS
(after Coffin and others, 1971)

[Station numbers are those used in publication of surface-water records, except prefix 9 is omitted]

Station No.	Streamflow station	Period of record	Drainage area (sq mi)	Average discharge (cfs)	Extremes of discharge (cfs)	
					Maximum	Minimum daily
0928	West Fork Parachute Creek near Grand Valley	Oct. 1957 Sept. 1962	48.1	4.37	147	0
0930	Parachute Creek near Grand Valley	Oct. 1948 Sept. 1954 Oct. 1964 Sept. 1967	144	17.7	738	0
0935	Parachute Creek at Grand Valley	Apr. 1921 Sept. 1927 Oct. 1948 Sept. 1954	200	30.3	912	0
0940	Roan Creek at Simmons Ranch	June 1935 Sept. 1935 Apr. 1936 Oct. 1936 Mar. 1937 Sept. 1937	79		142	0
0941	Carr Creek at Altenbern Ranch	June 1935 Nov. 1936 Mar. 1937 Sept. 1937	17	2.85	143	0
0942	Roan Creek above Clear Creek	Oct. 1962 Sept. 1967	151	14.8	800	1.0
0944	Clear Creek near DeBeque	July 1966 Sept. 1967	111		1,540	0
0950	Roan Creek near DeBeque	Apr. 1921 Sept. 1926 Oct. 1962 Sept. 1967	321	40.0	1,220	3.2
3055	Piceance Creek at Rio Blanco	Oct. 1952 Sept. 1957	9	1.40	23	.1
3060	Piceance Creek near Rio Blanco	Oct. 1940 Sept. 1943	153	20.3	430	.1
3062	Piceance Creek below Ryan Gulch	Oct. 1964 Sept. 1967	485	12.5	400	.80
3062.22	Piceance Creek at White River[1]	Oct. 1964 Sept. 1966	629	17.0	550	.9
3062.55	Yellow Creek near White River[1]	Oct. 1964 Sept. 1966	258	1.37	1,060	0

[1] Unpublished record.

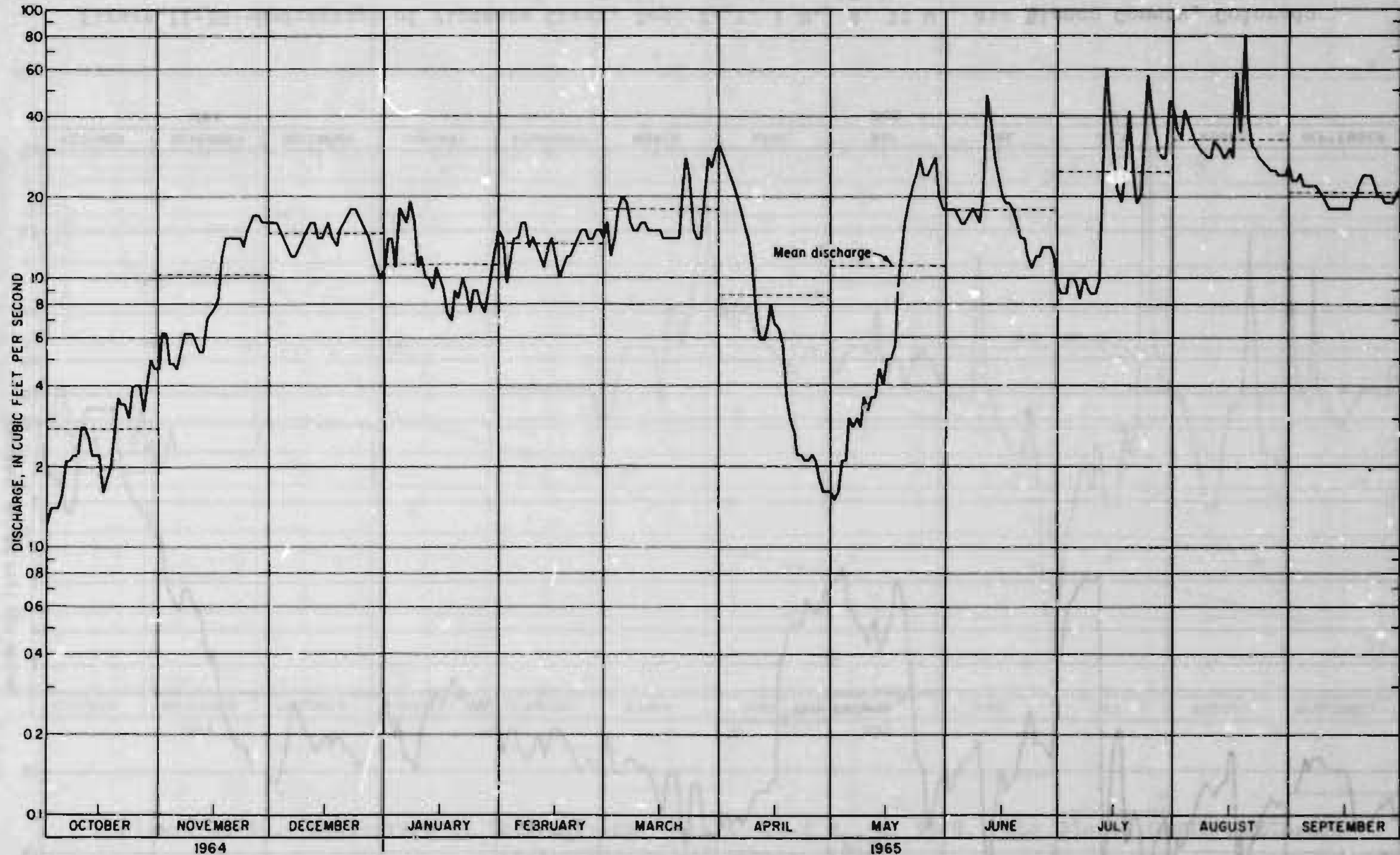


Figure II-38.--Hydrograph of Piceance Creek, Sec. 32, T. 1 S., R. 97 W., Rio Blanco County, Colorado (after Coffin and others, 1968)

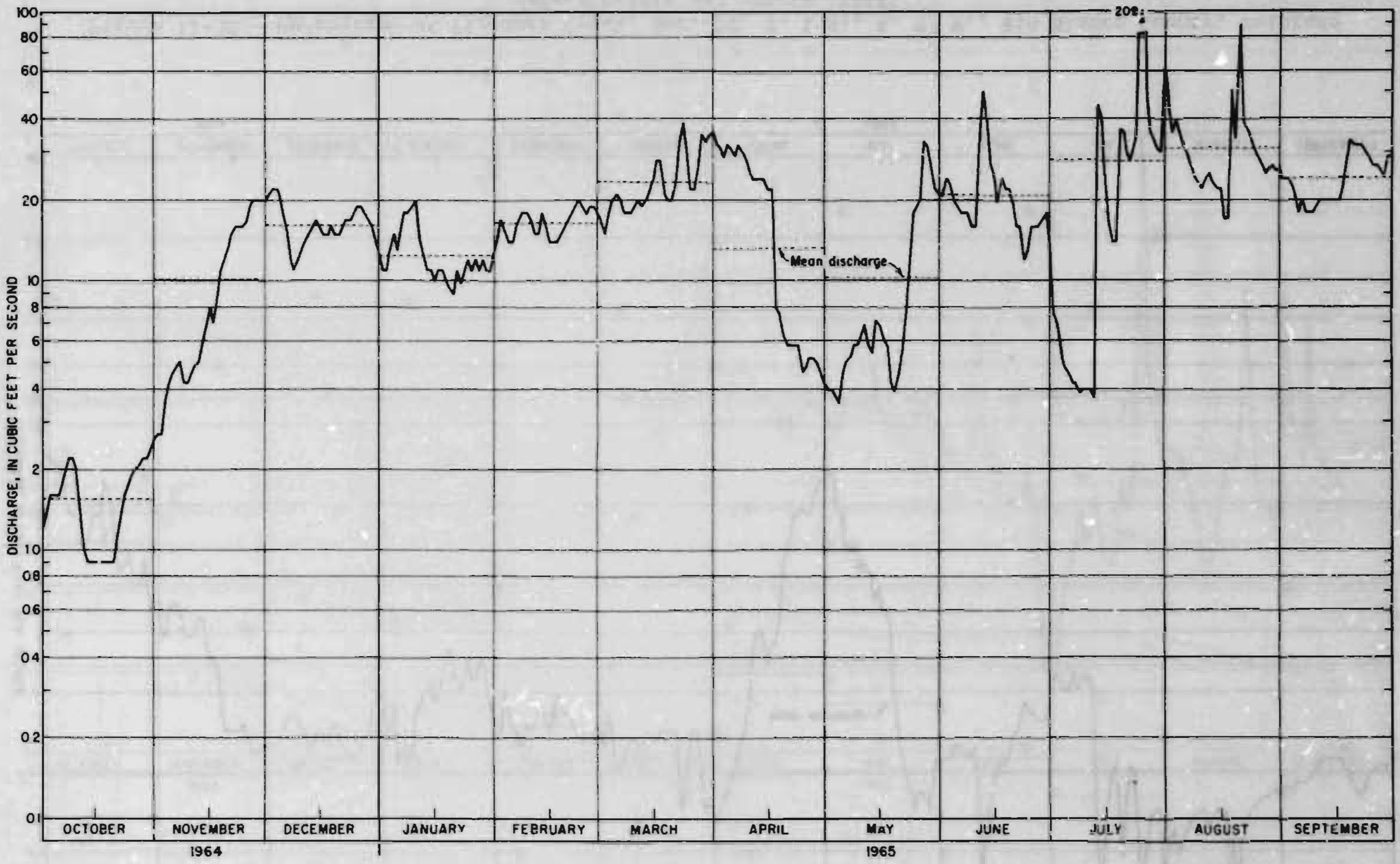


Figure II-39--Hydrograph of Piceance Creek, Sec. 2, T. 1 N., R. 97 W., Rio Blanco County, Colorado (after Coffin and others, 1968)

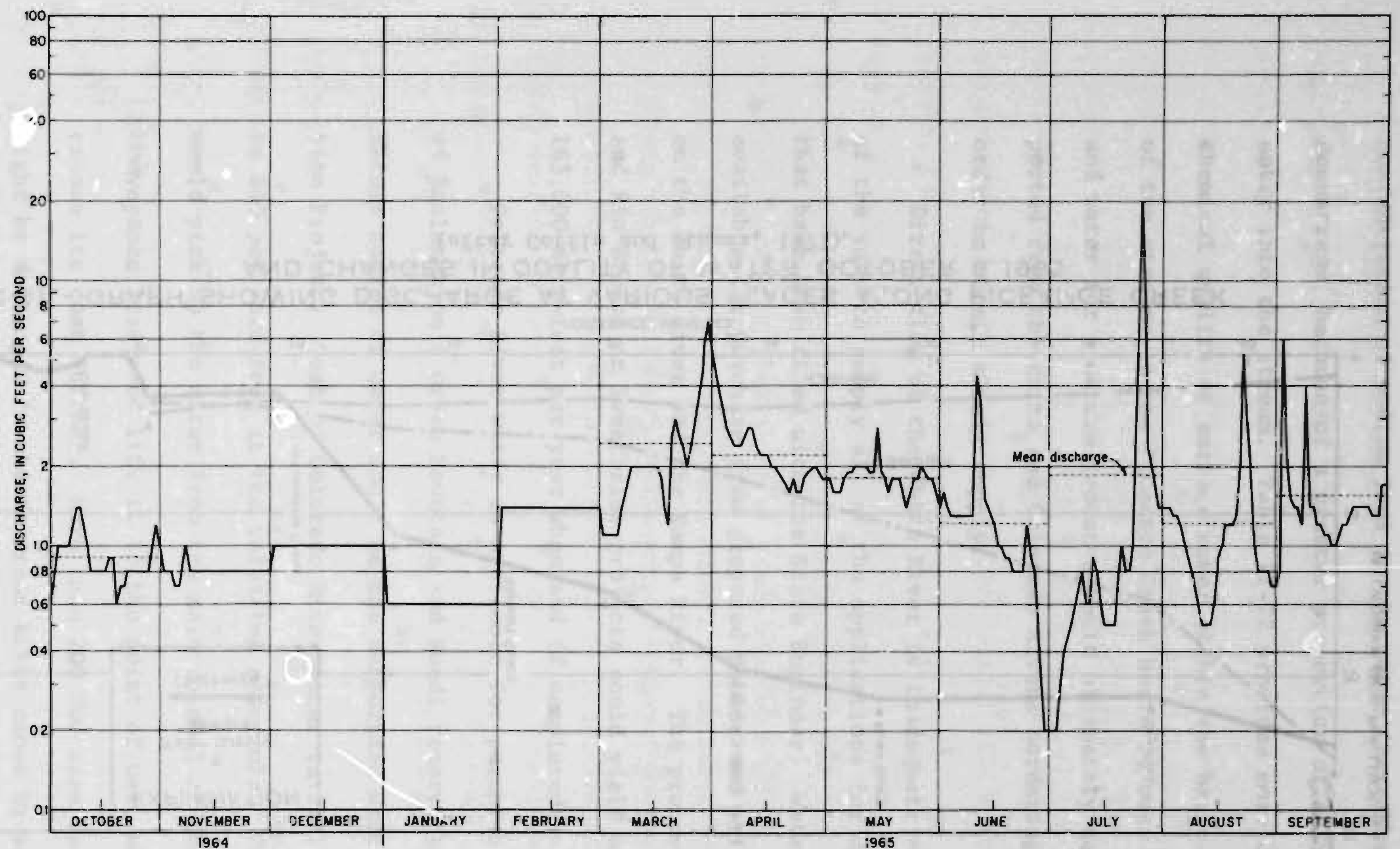


Figure II-40.--Hydrograph of Yellow Creek, Sec. 4, T. 2 N., R. 98 W., Rio Blanco County, Colorado (after Coffin and others, 1968).

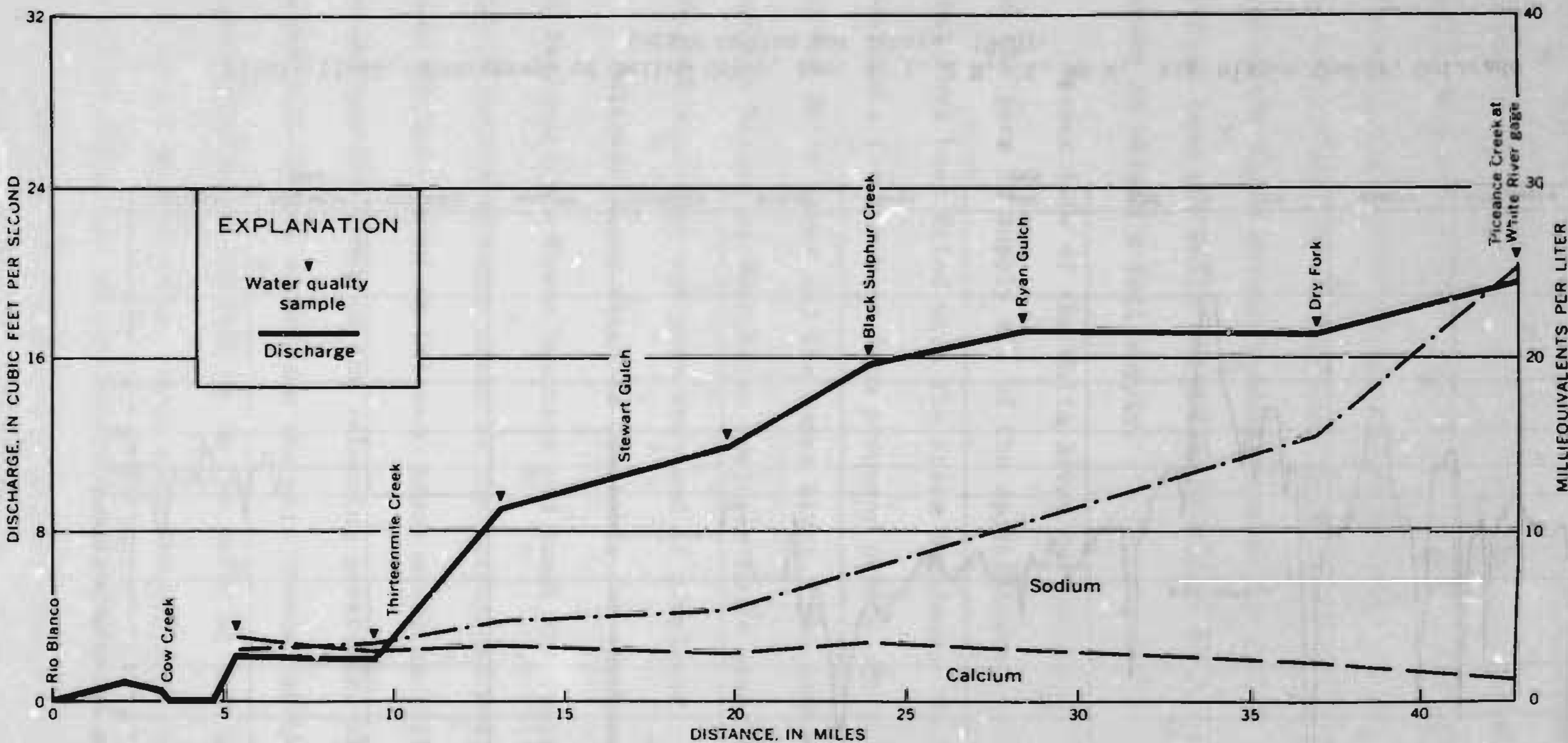


Figure II-41.--GRAPH SHOWING DISCHARGE AT VARIOUS PLACES ALONG PICEANCE CREEK AND CHANGES IN QUALITY OF WATER OCTOBER 6, 1965 (after Coffin and others, 1971).

concentration of sodium ions in the water increases significantly downstream, because of a greater proportion of saline ground water entry into the stream. Table II-22 provides more details of the chemical quality of surface water within the basin. Direct flow of the streams in the Piceance Creek Basin is over-appropriated and water for a mature industry would ultimately need to be imported from the White and Colorado Rivers bordering the basin in order to obtain a full supply.

Direct flow of the White River is inadequate several months of the year to supply all of the applications for appropriation that have been filed with the State Engineer. Water could be available for purchase from proposed public and private projects on the White River and the Yampa River. The proposed Yellow Jacket and Rio Blanco or Sweetbriar projects could yield as much as 165,000 acre-feet per year when and if completed.

Colorado River water is available for purchase from the Bureau of Reclamation's Green Mountain and Ruedi reservoirs. A possible future source of water could be the authorized West Divide Reclamation Project. Cost of Colorado River water in 1971 was from $10 to $40 per acre-foot at the releasing reservoir. The purchaser would pick up the water from the main channel of the river (minus conveyance loss) and lift it to the point of use, which will increase its cost further. More than 200,000 acre feet per year might be developed in the Colorado River above De Beque, for use in the Piceance area from existing available water (Table II-4) and proposed projects, including the purchase of existing senior water rights.

Table II-22.--Chemical analyses and related physical measurements of surface water
(after Coffin and others, 1968)

(Concentrations of dissolved constituents, dissolved solids, and hardness given in parts per million)

Location: Locations are listed in downstream order. See text for well-numbering system. Discharge (cfs): Discharge measurements given in cubic feet per second; E, estimated.

Location	Discharge (cfs)	Date of collection	Temperature (°F)	Silica (SiO_2)	Iron (Fe)	Manganese (Mn)	Calcium (Ca)	Magnesium (Mg)	Sodium (Na)	Potassium (K)	Bicarbonate (HCO_3)	Carbonate (CO_3)	Sulfate (SO_4)	Chloride (Cl)	Fluoride (F)	Nitrate (NO_3)	Boron (B)	Dissolved solids (calculated)	Hardness as $CaCO_3$	Non-carbonate hardness $CaCO_3$	Percent sodium	Sodium adsorption ratio	Specific conductance (micromhos at 25°C)	pH
										Piceance Creek														
C4-95- 1aa	. .	6- 8-65	. .	. .	. .	. .	126	33	. .	. .	328	0	. .	6	. .	. .	. .	. .	260	0	. .	. .	736	7.8
	0.55	10- 6-65	40	. .	. .	. .	75	52	. .	. .	418	0	. .	13	. .	. .	. .	. .	402	59	. .	. .	1,050	8.0
C3-95-36cc	.5E	7-17-64	. .	14	0.00	0.00	57	33	70	1.5	344	0	130	8.9	0.1	1.6	0.12	485	278	0	35	1.8	753	7.9
-26db	2.1	10- 6-65	47	. .	. .	. .	75	34	. .	. .	356	0	. .	9.5	. .	. .	. .	. .	324	32	. .	. .	812	8.0
- 9dc	2.0	10- 6-65	47	. .	. .	. .	58	39	. .	. .	324	0	. .	9.5	. .	. .	. .	. .	304	38	. .	. .	768	8.1
C3-96-11bd	9.1	10- 6-65	53	. .	. .	. .	66	47	. .	. .	484	0	. .	14	. .	. .	. .	. .	356	0	. .	. .	986	8.2
C2-97-36ba	11.9	10- 6-65	56	. .	. .	. .	59	57	. .	. .	476	0	. .	16	. .	. .	. .	. .	382	0	. .	. .	1,160	8.0
C2-96-32dd	2.5E	7-17-64	. .	15	.00	.00	40	46	149	1.9	554	0	144	23	1.3	.5	.31	693	290	0	53	3.8	1,090	8.1
C2-97-16dc	4E	7-17-64	. .	16	.00	.00	52	85	190	2.6	567	0	400	16	.5	1.0	.24	1,040	480	15	46	3.8	1,500	8.0
	. .	6- 8-65	59	. .	. .	. .	67	106	. .	. .	716	0	. .	23	. .	. .	. .	. .	602	15	. .	. .	1,900	8.2
	15.6	10- 6-65	58	. .	. .	. .	70	72	. .	. .	546	0	. .	16	. .	. .	. .	. .	472	24	. .	. .	1,350	8.0
C1-97-32ad	17	6- 8-65	65	. .	. .	. .	87	107	. .	. .	736	0	. .	18	. .	. .	. .	1,360	656	52	43	. .	1,870	8.1
B1-97-35ca	2.5E	7-17-64	. .	17	.00	.00	52	117	529	3.9	1,250	45	610	46	.4	1.3	.48	2,040	610	0	65	9.3	2,690	8.4
	. .	3-24-65	37	. .	. .	. .	64	73	. .	. .	808	0	. .	20	. .	. .	. .	a/1,150	460	0	. .	. .	1,680	8.1
	. .	4-12-65	38	. .	. .	. .	38	28	. .	. .	1,110	51	. .	39	. .	. .	. .	a/1,750	209	0	. .	. .	2,520	8.4
	. .	6- 8-65	67	. .	. .	. .	38	117	. .	. .	1,200	22	. .	46	. .	. .	. .	. .	574	0	. .	. .	2,890	9.4
	17.0	10- 6-65	60	. .	. .	. .	41	86	. .	. .	848	16	. .	30	. .	. .	. .	. .	456	0	. .	. .	2,010	8.3
B1-97- 2ab	2E	7-17-64	. .	11	. .	. .	12	95	1,240	6.4	2,540	182	479	208	2.5	2.3	.74	3,490	420	0	86	26	5,020	8.7
	32	3-24-65	36	. .	. .	. .	56	68	. .	. .	1,010	0	. .	45	. .	. .	. .	a/1,380	420	0	. .	. .	2,010	8.2
	14	4-12-65	40	. .	. .	. .	22	37	. .	. .	1,630	81	. .	94	. .	. .	. .	a/2,340	205	0	. .	. .	3,400	8.5
	18	6- 8-65	70	. .	. .	. .	24	107	. .	. .	1,430	59	. .	80	. .	. .	. .	2,370	500	0	. .	. .	3,370	8.4
	19.3	10- 6-65	64	. .	. .	. .	22	81	. .	. .	1,240	33	. .	79	. .	. .	. .	. .	386	0	. .	. .	2,680	8.5
										Black Sulphur Creek														
C2-97-20c	1E	7-17-64	. .	17	.00	.00	76	81	123	1.4	478	0	372	9.5	.3	.5	.15	916	525	133	34	2.3	1,330	7.8
										Hunter Creek														
C2-97-27ac	.5E	7-17-64	. .	19	.00	.00	92	106	157	2.2	566	0	532	9.5	.1	1.2	.16	1,200	665	201	34	2.6	1,610	8.0
										Yellow Creek														
B1-98-12bb	. .	5- 4-65	62	. .	. .	. .	60	175	. .	. .	832	20	. .	24	. .	. .	. .	a/2,020	870	155	. .	. .	2,600	8.3
B2-98-26bb	. .	5- 3-65	65	. .	. .	. .	56	165	. .	. .	832	30	. .	28	. .	. .	. .	a/1,970	820	89	. .	. .	2,540	8.4
- 9ab	5E	3-24-65	33	12	. .	. .	36	63	424		936	16	363	69	. .	3.1	. .	1,420	350	0	72	9.9	2,100	8.3
	. .	4- 8-65	50	. .	. .	. .	18	59	. .	. .	1,420	102	. .	112	. .	. .	. .	a/2,530	288	0	. .	. .	3,500	8.5
	. .	5- 4-65	65	. .	. .	. .	20	151	. .	. .	1,600	98	. .	128	. .	. .	. .	2,750	670	0	. .	. .	3,740	8.6
										Roan Creek														
C6-99-29ab	3E	10- 9-65	54	. .	. .	. .	. .	. .	. .	. .	. .	. .	146	. .	. .	. .	. .	. .	. .	. .	. .	. .	816	. .
C6-98-32bdd	2	10- 9-65	57	. .	. .	. .	. .	. .	. .	. .	. .	. .	263	. .	. .	. .	. .	. .	. .	. .	. .	. .	1,120	. .
C7-98-22ab	5	10- 9-65	51	. .	. .	. .	. .	. .	. .	. .	. .	. .	520	. .	. .	. .	. .	. .	. .	. .	. .	. .	1,630	. .
-25d	2E	10- 9-65	46	. .	. .	. .	. .	. .	. .	. .	. .	. .	809	. .	. .	. .	. .	. .	. .	. .	. .	. .	2,070	. .
C8-97-18aa	.5E	10- 9-65	62	. .	. .	. .	. .	. .	. .	. .	. .	. .	4,200	. .	. .	. .	. .	. .	. .	. .	. .	. .	7,160	. .

a/ Dissolved solids, residue on evaporation at 180°C.

Table II-23 shows the dissolved solids content of the White River at high and low flows. In general, the quality of the White River is excellent.

The quality of the Colorado River above the Cameo gaging station is also excellent. The Department of the Interior Progress Report No. 5, shows that 2,439,000 acre feet of water passed the station near Cameo, Colorado, in 1968, and had an average dissolved solids content of 439 mg/l. The average annual flow near Cameo between 1941 and 1968 was 2,758,000 acre feet having an average dissolved solids content of 406 mg/l.

Tributary inflow to the Colorado or White Rivers often contributes significant quantities of dissolved material to the main stream. For example, Meiman, in a report to industry, 1/ found that, on a long term basis, samples of water from Parachute Creek contained 850 mg/l or more of dissolved solids 50 percent of the time. Eighty percent of the time the dissolved solids concentration in Parachute Creek at Grand Valley is 680 mg/l or greater.

By way of comparison, samples of water from the Colorado River at Glenwood Springs, upstream from Parachute Creek, show that 50 percent of the time the dissolved solid concentration is 391 mg/l or greater. Downstream from Parachute Creek, 50 percent of the time the concentration of dissolved solids in the Colorado River is 625 mg/l or greater (Irons and others, 1965).

1/ Colony Development Operation Report, private communication.

TABLE II-23.--Flows and Total Dissolved Solids Concentrations for the White River in Colorado. 1/

(Milligram per liter and cubic feet per second)

	Sampling	Number of samples	Mean 2/ TDS	Extreme TDS	Average flow	Extreme flow
White River at USGS Gage near Buford, Colo.	5/8/62 9/3/64	25	162	255 104	286	1,210 110
South Fork White River at USGS Gage at Buford, Colo.	2/15/64 2/3/64	7	144	195 107	189	560 85
White River at USGS Gage below Meeker, Colo.	5/8/62 9/2/64	26	344	689 189	600	2,620 250

1/ Data from Federal Water Pollution Control Administration, 1966.

2/ Flow weighted mean.

b. Ground Water

The Green River Formation, which contains the vast deposits of oil shale, also is the principal source of ground water in the Piceance Creek Basin of Colorado. The Green River Formation has been divided into several lithologic units based on depositional history, and it can be divided as well on the basis of its water bearing properties. (See diagrammatic section, Figure II-12.)

The Garden Gulch Member, the lowermost unit, consists of marlstone and oil shale. It is as much as 900 feet thick near the center of the basin. In general, it is relatively impermeable and yields very little water.

The Parachute Creek Member, which overlies the Garden Gulch Member, is composed principally of oil shale. The lower part of the Parachute Creek Member contains some beds of unleached saline minerals. This zone is relatively impermeable and shows very high resistivity on electrical logs of wells. It commonly is termed the "high resistivity zone."

A zone characterized by low resistivity on electric logs overlies the high resistivity zone and is termed the "leached zone." Core recovery from this zone generally is poor, but, where cores have been recovered, it is oil shale containing voids and contorted bedding caused by leaching of saline minerals. Fractures are common throughout this zone. The zone is as much as 600 feet thick near the center of the basin, and it is the most extensive and most permeable aquifer in the basin.

The Mahogany Zone overlies the leached zone. It is a rich zone of oil shale containing little saline minerals. In general, the Mahogany Zone is relatively impermeable, but locally it is fractured, permitting some vertical flow of water between aquifers.

Above the Mahogany Zone, the oil shale grades upward into marlstone and fine-grained sandstone of the Evacuation Creek Member. This upper zone forms the surface rock throughout the basin and is as much as 1,500 feet thick. Below stream level, this zone is saturated and water moves vertically and laterally through fractures in the zone. The fracture permeability varies widely, but in most parts of the basin the zone is a good aquifer. This zone generally accepts recharge readily throughout the basin.

The transmissivity distribution in the leached zone was estimated from the thickness map of the zone and from aquifer tests (Coffin and others, 1968; Weir and Dinwiddie, written communication 1973). The transmissivity of the zone ranges from less than 3,000 gpd/ft (gallons per day per foot) in the margins of the basin to 20,000 gpd per ft in the center of the basin. Tests indicate that the potential yield of a well tapping the leached zone may be as much as 1,000 gpm. Yields of 300 to 600 gpm are most common. The artesian storage coefficient of the leached zone is estimated to be about 1×10^{-4}, but when not confined, the storage coefficient would be about 1×10^{-1}. Thus pumping very large quantities of water would cause water levels to decline several hundred feet to the top of the leached zone in a short time, but after water levels reached the leached zone, the decline would be much slower. Test wells penetrating the upper permeable zone yield as much as 300 gpm, but yields of 100 gpm or less are more common (Coffin and others, 1971).

According to Coffin and others (1971), the major ground water divide in the basin is approximately the same as the topographic divide between the White River and the Colorado River. Ground water movement in the Green River Formation (northern part of the Piceance Creek basin) is toward the two major drainages of the basin, Piceance and Yellow Creeks. The Green River Formation is bound on the west by Cathedral Bluffs. On the north, the divide is near the main stem of the White River.

Recharge on the margins of the basin moves downward through the Evacuation Creek Member and Mahogany Zone into the leached zone of the Parachute Creek Member. Most of the recharge water is derived from snowmelt in late spring, but some is derived from rainstorms. Data from a few wells indicate that the potentiometric head in the leached zone near the edges of the basin is lower than the head in the overlying zones. Other data indicate that near the center of the basin the head in the leached zone is higher than the head in the upper zone. The head differences between the two water bearing zones commonly are 50 to 100 feet. These head relations indicate that the direction of flow is downward in the margins of the basins, laterally toward the center and northern edge of the basin, and upward in the lower reaches of Piceance and Yellow Creeks and in the White River valley (Coffin and others, 1971). The gradient of the potentiometric surface in the basin ranges from 30 to 100 feet per mile.

In the central and northern parts of the basin, water moves upward from the leached zone through the Mahogany Zone into the upper permeable zone and discharges into the alluvium along Piceance Creek, Yellow Creek, and the White River or rises to the land surface in well-defined spring pools. The potentiometric contours indicate that about half of the northern part of the basin contributes ground water to Piceance Creek. South of the major divide, water is discharged by springs that issue from fractures near the top of Mahogany Zone. The discharge of some springs is highly seasonal, due to recharge from snowmelt, as illustrated in Figure II-42.

During a streamflow study of Piceance Creek, October 6, 1965, it was found that the flow increased 14 cfs between Thirteenmile Creek and Black Sulphur Creek. All this increase in flow was due to ground water discharge.

Coffin and other (1971) estimated that the volume of ground water in storage in the leached zone in the northern part of the Piceance Creek Basin (630 square mile area of Picenace Creek and Yellow Creek drainage) is about 2.5 million acre-feet, a very conservative estimate based on a storage coefficient of 10^{-2}. More recent work indicates that the unconfined storage coeeficient probably is closer to 10^{-1}. Weir (1970) reported that a sidewall neutron porosity log of the project Rio Blanco hole RB-D-01 indicated a total porosity in the waterbearing zones of 3.0×10^{-1} and he estimated the effective porosity to be 1.5×10^{-1}. Coffin and Bredehoeft (1969) used a storage coefficient of 1×10^{-1} in estimating the rate of ground-water flow into a hypothetical mine in the oil shale. Applying a storage coeffieient of 1×10^{-1} for estimating the volume of ground water in storage in the Green River Formation of the Piceance Creek Basin indicates about 25 million acre-feet of water in storage. Of course all of the water in storage could not be recovered for beneficial use.

The depth to water in the Green River Formation ranges from land surface, or even above land surface, in the valleys to as much as 500 feet beneath some of the ridges. Generally the depth to water does not exceed 400 feet.

Alluvium is a source of ground water in the major stream valleys although the areal extent of the alluvium is small compared to that of the bedrock aquifer, being confined to belts less than a mile wide along the creeks. The alluvium ranges from 0 to 140 feet thick and the saturated thickness may be as much as 100 feet at a few places (Coffin and others, 1968). The depth to water generally is less than 40 feet. The water flows from some wells completed in the alluvium. Initially, wells tapping the alluvium might yield as much as 2,000 gpm but would quickly deplete streamflow and decline in yeild. An aquifer test in the alluvium of Piceance Creek showed that after pumping a few hours, the hydrologic boundaries of the alluvium affected drawdowns and well

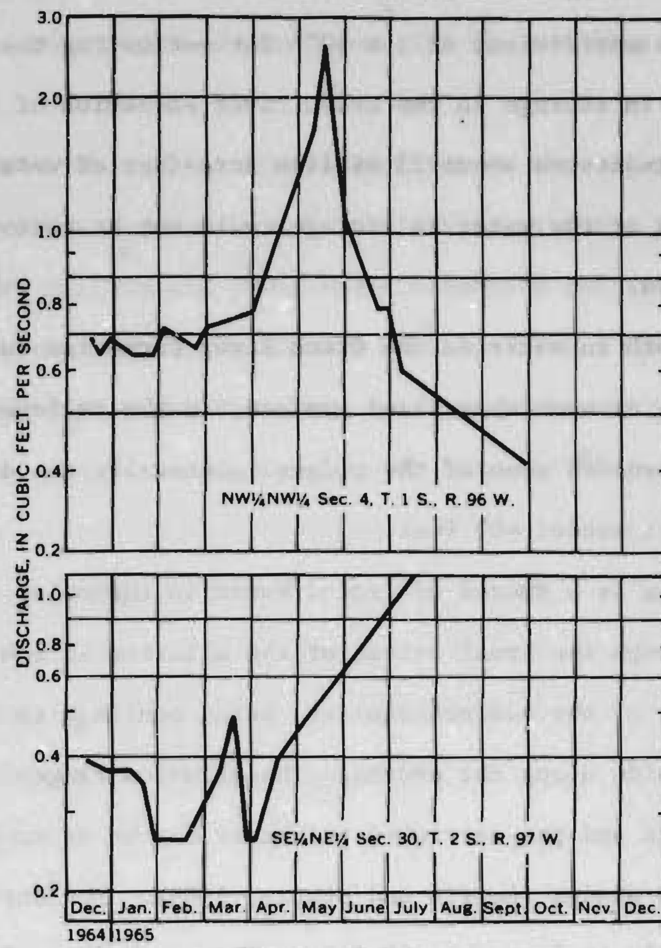


Figure II-42.--HYDROGRAPHS OF SELECTED SPRINGS
(after Coffin and others, 1971)

yields (Coffin and others, 1968). The water in storage in the alluvium could be depleted rapidly by withdrawal of water at a high rate on the sustained basis.

The storage coefficient of the alluvium probably averages about 0.20. The transmissivity generally is more than 20,000 gpd per ft.

The chemical quality of ground water in the basin differs widely from place to place and in different aquifers, ranging from 250 to 63,000 mg/l in the Green River Formation and from 250 to 25,000 mg/l in alluvium (Coffin and others, 1971). Chemical analyses of ground water from many sources are presented in Table II-24. Analyses of water samples from different intervals in a test hole at the project Rio Blanco site in sec. 14, T. 3 S., R. 98 W., are presented in Table II-25.

At the present time, ground water is used in the basin primarily for livestock and wildlife supplies. A small amount of water from the alluvium is used for irrigation.

Table II-24.--Chemical analyses and related physical measurements of ground water (after Coffin and others, 1968)

(Concentrations of dissolved constituents, dissolved solids, and hardness given in parts per million)

Location: See text for well-numbering system.

Geologic source: Tga, Anvil Points Member of the Green River Formation; Tgg, Garden Gulch Member of the Green River Formation; Tgp, Parachute Creek Member of the Green River Formation; Tge, Evacuation Creek Member of the Green River Formation; Qal, alluvium; for the description of the physical character of the water-bearing formations see table 1.

Depth of well: Depth of well given in feet below land surface; R, reported.

Iron (Fe): In solution at time of sampling.

Location	Geologic source	Depth of well (feet)	Date of collection	Temperature (°F)	Silica (SiO_2)	Iron (Fe)	Calcium (Ca)	Magnesium (Mg)	Sodium (Na)	Potassium (K)	Bicarbonate (HCO_3)	Carbonate (CO_3)	Sulfate (SO_4)	Chloride (Cl)	Fluoride (F)	Nitrate (NO_3)	Boron (B)	Dissolved solids (calculated)	Hardness as $CaCO_3$	Noncarbonate hardness $CaCO_3$	Percent sodium	Sodium adsorption ratio	Specific conductance (micromhos at 25°C)	pH
B1-97-11dc	Tgp	Spring	8-18-65	56	17	. .	42	98	516	0.8	1,030	19	640	47	2.5	0.1	0.40	1,890	508	0	69	9.9	2,690	8.4
-22ad	Qal	Spring	8-18-65	60	14	. .	0.0	24	10,100	31	23,300	1,110	155	1,660	32	55	4.9	24,600	98	0	99	444	28,800	8.5
-22da	Qal	Spring	10- 4-65	52	. .	. .	38	82	. .	. .	1,630	0	. .	88	. .	. .	. .	. .	430	0	. .	. .	2,970	8.2
-22dc	Qal	104	10-16-65	55	2.8	0.02	2.4	15	3,380	8.8	7,100	296	85	985	16	.5	1.1	8,290	66	0	99	181	12,000	8.4
-35ca	Qal(?), Tge(?)	Spring	10- 4-65	55	. .	. .	80	57	. .	. .	586	0	. .	14	. .	. .	. .	. .	436	0	. .	. .	1,230	8.0
B1-98- 8cd	Qal,Tge	183	10- 5-65	54	. .	. .	79	92	. .	. .	1,110	0	. .	14	. .	. .	. .	. .	552	0	. .	. .	2,700	7.6
-13db	Tge	2,600	6-16-65	50	15	. .	33	187	284	2.1	676	28	708	22	.4	5.8	.21	1,710	852	252	42	4.2	2,280	8.4
-18db	Qal,Tge	132	10- 5-65	54	. .	. .	127	132	. .	. .	816	0	. .	14	. .	. .	. .	. .	860	191	. .	. .	2,110	7.8
-24ac	Qal	80	10- 5-65	47	18	. .	116	156	292	1.9	748	12	854	28	.5	4.9	.27	1,850	930	297	41	4.2	2,410	8.3
B1-99- 2a	Qal,Tge	110	4- 8-65	46	18	. .	113	109	151	1.5	509	0	601	18	.6	14	.16	1,280	730	313	31	2.4	1,680	8.0
- 2a	Qal,Tge	110	10- 5-65	52	. .	. .	112	101	. .	. .	498	0	. .	18	. .	. .	. .	. .	694	286	. .	. .	1,650	8.0
- 4da	Tge,Tgp	171	4- 9-65	50	18	. .	101	92	125	1.0	443	0	492	18	1.0	11	.14	1,080	628	264	30	2.2	1,450	7.8
- 9cd	Qal,Tge(?)	. .	10- 5-65	52	. .	. .	56	46	. .	. .	446	0	. .	14	. .	. .	. .	. .	300	0	. .	. .	1,240	7.9
-20b	Tgp(?)	Spring	10- 5-65	52	. .	. .	144	95	. .	. .	570	0	. .	20	. .	. .	. .	. .	752	284	. .	. .	1,870	7.9
-26dd	Tge(?)	1,300R	10- 5-55	55	. .	. .	110	109	. .	. .	826	0	. .	12	. .	. .	. .	. .	725	48	. .	. .	2,040	7.6
B1-100-24b	Qal,Tgp	Spring	8-19-65	54	17	. .	73	90	119	.5	534	0	320	14	.7	25	1.1	923	552	114	32	2.2	1,380	8.1
B2-98-22cb	Tge,Tgp	Spring	9-23-64	53	15	.04	.0	99	3,910	8.8	1,260	4,150	65	746	6.9	14	2.1	9,630	408	0	95	84	12,800	8.5
-22ac2	Qal	45	6-22-65	50	17	. .	46	16.5	437	3.2	1,010	13	804	38	1.1	.1	.35	2,020	792	0	54	6.8	2,760	8.3
C1-96-10bd	Qal,Tge(?)	14	10- 9-64	49	17	.00	67	45	101	1.4	470	0	149	8.0	.3	9.3	.10	629	354	0	38	2.3	947	7.8
-10da	Tgp	3,000	8-17-65	80	12	. .	.0	7.1	246	.4	570	0	47	9.6	5.1	.2	.66	608	29	0	95	2.0	969	8.2
C1-97-11acd	Qal	68	10-25-65	52	18	. .	23	56	240	1.1	552	0	309	25	1.0	1.9	.11	946	290	0	64	6.1	1,380	8.2
-15db	Tge,Tgp	Spring	10- 8-65	50	. .	. .	32	56	. .	. .	1,090	49	. .	44	. .	. .	. .	. .	312	0	. .	. .	2,120	8.6
-28ab	Tgp	1,051	10-12-64	70	12	.04	.0	9.5	7,540	19	9.880	4,320	15	542	30	2.3	2.6	17,400	40	0	100	522	20,700	8.7
C1-99- 4bc	Qal	115	10- 7-65	51	1.1	. .	17	47	108	1.3	104	0	339	13	.0	.6	.04	578	234	149	50	3.1	999	7.5
- 4bc	Qal	115	10- 7-65	51	. .	. .	139	89	. .	. .	540	0	. .	16	. .	. .	. .	. .	702	259	. .	. .	1,570	7.7
- 6bc	Tge	Spring	10- 7-65	49	. .	. .	115	94	. .	. .	696	0	. .	18	. .	. .	. .	. .	674	103	. .	. .	1,580	8.0
-11aa	Qal	. .	10- 7-65	52	. .	. .	127	117	. .	. .	632	0	. .	17	. .	. .	. .	. .	796	278	. .	. .	1,870	7.7
C2-94-19c	Qal,Tga	58	8-27-65	50	31	. .	248	164	39	1.6	518	0	879	17	.5	1.0	.06	1,840	1,300	870	6	.5	1,980	7.5
-30c	Tga	205	6-27-65	48	14	. .	112	154	133	1.3	416	0	770	11	.7	.1	.08	1,400	910	569	24	1.9	1,330	7.6
C2-95-12d	Tga	203	8-27-65	49	40	. .	208	163	125	1.3	632	0	858	14	.3	4.1	.02	1,720	1,190	672	19	1.6	2,160	7.4
-23d	Tgp	75	8-27-65	48	27	. .	84	71	60	1.2	431	0	232	5.0	.7	4.4	.08	697	500	147	21	1.2	1,010	8.0
C2-96- 4cb	Tge	Spring	10- 8-65	47	. .	. .	59	29	. .	. .	376	0	. .	10	. .	. .	. .	. .	266	0	. .	. .	701	8.0
- 9cb	Tge	413	10- 8-65	. .	20	. .	46	19	55	1.3	324	0	34	10	.1	.8	.03	345	194	0	38	1.7	[illegible]	8.2
C2-97-27c	Qal(?), Tge(?)	Spring	8-17-65	47	. .	. .	111	109	. .	. .	556	0	. .	9.0	. .	. .	. .	. .	734	278	. .	. .	1,610	7.8
-30ad	Tge	Spring	10-13-64	45	15	.05	80	88	149	1.0	526	0	451	6.6	.1	.3	.12	1,050	562	131	37	2.7	1,450	7.9
C2-98- 9da	Tge	37	10- 8-65	48	16	. .	98	126	243	1.4	682	0	703	17	.3	3.4	.21	1,540	765	206	41	3.8	2,100	8.0
-10db	Qal,Tge(?)	Spring	10- 8-65	48	. .	. .	104	132	. .	. .	694	0	. .	20	. .	. .	. .	. .	804	235	. .	. .	2,100	7.8
-19ca	Qal(?), Tge(?)	Spring	8-17-65	47	. .	. .	98	110	. .	. .	540	0	. .	11	. .	. .	. .	. .	696	253	. .	. .	1,670	7.7
-28dd	Qal(?),Tge	Spring	8-20-65	47	16	.00	43	92	78	1.0	486	0	220	6.5	.4	6.3	.07	702	485	86	26	1.5	1,080	8.1
C2-99- 4cc	Tge(?), Tgp(?)	Spring	10- 7-65	47	17	. .	87	74	100	1.0	446	0	337	15	.2	3.6	.07	854	522	156	29	1.5	1,240	8.0
-12ac	Qal	Spring	10- 7-65	46	. .	. .	115	90	. .	. .	520	0	. .	14	. .	. .	. .	. .	658	231	. .	. .	1,530	7.7
-15dc	Qal	. .	10- 7-65	48	. .	.02	80	76	. .	. .	411	0	. .	14	. .	. .	. .	. .	512	98	. .	. .	1,280	7.9

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Table II-24.--Chemical analyses and related physical measurements of ground water--Continued

Location	Geologic source	Depth of well (feet)	Date of collection	Temperature (°F)	Silica (SiO_2)	Iron (Fe)	Calcium (Ca)	Magnesium (Mg)	Sodium (Na)	Potassium (K)	Bicarbonate (HCO_3)	Carbonate (CO_3)	Sulfate (SO_4)	Chloride (Cl)	Fluoride (F)	Nitrate (NO_3)	Boron (B)	Dissolved solids (calculated)	Hardness as $CaCO_3$	Noncarbonate hardness $CaCO_3$	Percent sodium	Sodium adsorption ratio	Specific conductance (micromhos at 25°C)	pH
C3-95-18ab	Tge	Spring	10- 5-65	49	13	. .	51	54	119	2.4	508	0	154	12	1.3	0.9	0.23	658	346	0	43	2.8	1,030	8.1
-31cc	Qal,Tge(?)	. .	9- 1-65	53	. .	. .	67	37	. .	. .	366	16	. .	7.5	. .	. .	. .	. .	322	0	. .	. .	850	8.4
C3-96- 5aa	Tge	Spring	10- 8-65	47	11	. .	94	78	117	1.2	500	0	365	16	.3	5.6	.09	928	555	145	31	2.2	1,330	8.1
-11ba	Tgp	1,000R	5- 7-62	70	13	0.01	8.0	3.4	684	1.2	1,610	63	4.1	30	30	.4	.92	1,630	34	0	98	51	2,500	9.3
-11ba	Tgp	1,000R	4-13-65	70	11	. .	4.0	3.4	. .	. .	1,510	112	10	28	26	1.3	. .	1,640	24	0	98	6[illegible]	2,470	8.4
-11bb	Tgp	1,300	9-29-65	76	. .	. .	15	4.4	. .	. .	1,489	24	. .	106	. .	. .	. .	. .	56	0	. .	. .	2,530	8.3
C3-97-14cb	Qal(?),Tge	Spring	8-18-65	47	. .	. .	101	79	. .	. .	542	0	. .	9.0	. .	. .	. .	. .	578	133	. .	. .	1,360	8.0
-27cd	Qal(?),Tge	Spring	8-18-65	46	. .	. .	104	74	. .	. .	498	0	. .	8.0	. .	. .	. .	. .	566	158	. .	. .	1,240	7.8
C3-98-22db	Qal(?),Tge	Spring	8-17-65	46	. .	. .	123	66	. .	. .	460	0	. .	6.0	. .	. .	. .	. .	578	201	. .	. .	1,300	7.7
C4-94-34b	Qal,Tga	Spring	8- -65	45	. .	. .	73	38	. .	. .	422	0	. .	3.0	. .	. .	. .	. .	340	0	. .	. .	687	7.8
C4-95- 3ba	Qal(?),Tge(?), Tgp(?)	74	8-30 65	48	12	. .	53	28	66	.3	255	0	161	14	.8	.3	.04	460	248	39	37	1.8	703	8.1
- 8bb	Tge(?),Tgp(?)	39	8-31-65	48	23	. .	88	49	90	.0	408	0	244	6.4	.8	3.9	.08	706	420	85	32	1.9	1,040	7.7
-19cc	Qal,Tge	128	10-11-65	45	11	.00	29	34	125	.5	384	0	141	5.2	.1	.6	.05	535	210	0	56	3.8	892	8.1
C4-97-12db	Qal,Tge,Tgp	80	8-30-65	48	15	. .	112	75	106	.4	464	0	393	5.8	.7	4.8	.08	940	588	208	28	1.9	1,310	7.9
-31bd	Tge	Spring	8-18-65	43	. .	. .	59	33	. .	. .	332	0	. .	3.0	. .	. .	. .	. .	282	10	. .	. .	600	7.9
-33ca	Tge	Spring	9-18-65	45	. .	. .	75	38	. .	. .	380	0	. .	4.0	. .	. .	. .	. .	344	32	. .	. .	730	7.8
-33cb2	Qal	Spring	8-18-65	57	. .	. .	103	55	. .	. .	510	0	. .	6.0	. .	. .	. .	. .	486	68	. .	. .	1,020	7.5
C4-98-14cc	Tge(?)	Spring	8-17-65	45	. .	. .	95	81	. .	. .	396	0	. .	6.0	. .	. .	. .	. .	570	245	. .	. .	1,210	0.0
-17cb	Tge(?)	Spring	8-28-65	46	. .	. .	73	41	. .	. .	350	26	. .	6.5	. .	. .	. .	. .	352	22	. .	. .	836	8.4
-36aa	Tge	Spring	8-18-65	44	. .	. .	76	47	. .	. .	388	0	. .	3.0	. .	. .	. .	. .	382	64	. .	. .	850	8.1
C4-99-10ac	Tgp	Spring	10-12-64	45	18	.02	69	29	35	.4	374	0	80	2.0	.0	1.8	.05	419	294	0	21	.9	668	7.7
-10ac	Tgp	Spring	8-16-65	46	. .	. .	74	29	. .	. .	354	0	60	2.0	. .	. .	. .	. .	304	14	. .	. .	639	8.1
C5-94-14ab	Tge	Spring	8- -65	49	. .	. .	57	21	. .	. .	308	0	. .	2.0	. .	. .	. .	. .	228	0	. .	. .	505	7.5
C5-95-30c	Qal(?)	Spring	8-16-65	48	16	. .	51	38	41	1.5	345	0	64	4.8	.6	3.4	.06	390	282	0	24	1.1	629	7.9
C5-96- 1bd	Tge	Spring	8-27-65	46	. .	. .	51	33	. .	. .	310	0	. .	5.0	. .	. .	. .	. .	262	8	. .	. .	662	8.0
- 1bd2	Qal	Spring	8-27-65	51	. .	. .	39	33	. .	. .	266	0	. .	6.0	. .	. .	. .	. .	232	14	. .	. .	596	8.2
-36aaa	Qal	50R	8-13-65	53	. .	. .	70	50	. .	. .	400	0	. .	8.0	. .	. .	. .	. .	378	50	. .	. .	862	7.9
C5-97- 1c	Tgp	. .	8- -65	55	. .	. .	47	33	. .	. .	344	0	. .	5.0	. .	. .	. .	. .	254	0	. .	. .	679	8.0
-23bb	Tge	Spring	8- -65	55	. .	. .	58	18	. .	. .	332	0	. .	3.0	. .	. .	. .	. .	218	0	. .	. .	521	7.6
C5-98- 2ac	Tgp	Spring	8-30-65	43	. .	. .	59	30	. .	. .	324	0	. .	4.0	. .	. .	. .	. .	270	4	. .	. .	650	7.5
C6-95-12ba	Tgp	Spring	8-26-65	46	. .	. .	87	31	. .	. .	416	0	. .	2.0	. .	. .	. .	. .	344	3	. .	. .	621	7.7
C6-96-29da	Qal	33	10-12-65	55	21	. .	124	73	92	16	700	0	267	10	1.2	10	.17	958	610	36	24	1.6	1,410	7.8
C6-98-16aa	Qal	68R	10-13-65	. .	16	. .	63	52	75	2.5	446	0	141	11	.9	5.4	.16	586	372	6	30	1.7	918	7.9
-34cd	Qal	70R	10-13-65	57	18	. .	100	79	117	3.1	616	0	252	12	1.2	52	.23	918	575	70	31	2.1	1,370	7.9
C7-96-11aa	Qal	50R	10-12-65	. .	19	. .	170	122	198	5.2	656	0	793	18	.9	.4	.20	1,650	925	387	32	2.8	2,180	7.9
C7-97- 5ba	Qal(?)	Spring	10-11-65	50	6.8	. .	44	69	67	3.4	484	0	129	6.0	.6	1.5	.11	565	392	0	27	1.5	1,000	8.0
C7-98- 4ba	Qal	61R	10- 9-65	52	15	. .	96	90	149	2.3	598	0	424	10	.7	6.6	.22	1,090	610	120	35	2.6	1,530	8.0
- 8ab	Tgp(?), Tgg(?)	Spring	10- 9-65	. .	. .	. .	48	94	. .	. .	689	0	. .	14	. .	. .	. .	. .	506	0	. .	. .	1,840	8.1
-14ca	Qal	68R	10- 9-65	54	15	.15	144	170	396	3.8	737	0	1,220	35	.6	.7	.57	2,350	1,060	456	45	5.3	3,010	8.0
C7-99-26cc	Qal(?), Tgg(?)	Spring	10-11-65	50	. .	. .	91	73	. .	. .	512	0	. .	10	. .	. .	. .	. .	528	108	. .	. .	1,410	7.7
-27bd	Qal(?), Tgg(?)	Spring	10-11-65	47	16	. .	50	86	110	1.9	494	0	287	5.4	.3	.5	.10	800	478	73	33	2.2	1,220	8.1
C7-100-25db	Qal	Spring	10-11-65	48	. .	. .	86	57	. .	. .	496	0	. .	5.0	. .	. .	. .	. .	448	41	. .	. .	1,050	7.8
-35bb	Qal	Spring	10-11-65	51	. .	. .	72	57	. .	. .	424	0	. .	5.0	. .	. .	. .	. .	416	68	. .	. .	894	7.8
C8- 97- 7ab	Qal	759	10- 9-65	54	16	. .	164	148	293	3.3	692	0	1,040	18	.8	5.5	.31	2,030	1,020	453	38	4.0	2,630	7.9

Table II-25.--Chemical analyses of water from hole RB-D-01, Project Rio Blanco, Colorado
(after Weir, 1972)
(Analyses by U.S. Geological Survey. Constituents in milligrams per liter unless otherwise noted.)

Constituents	Intervals sampled, in feet below land surface		
	244 to 845 ft; October 16, 1971	244 to 1,651 ft; October 19, 1971	882 to 1,651 ft; October 23, 1971
Silica (SiO_2)	12	12	14
Aluminum (Al)	<.01	.01	.04
Iron (Fe)	<.01	<.01	<.01
Manganese (Mn)	<.01	<.01	<.01
Calcium (Ca)	3.6	5.2	3.6
Magnesium (Mg)	5.3	5.7	9.1
Strontium (Sr)	.76	.70	.39
Sodium (Na)	250	530	1,200
Potassium (K)	.2	1.1	4.6
Lithium (Li)	.03	.20	.52
Bicarbonate (HCO_3)	579	1,080	2,300
Carbonate (CO_3)	8	79	210
Sulfate (SO_4)	28	74	220
Chloride (Cl)	10	44	120
Fluoride (F)	20	27	39
Nitrate (NO_3)	.2	.2	.3
Phosphate (PO_4)	<.01	<.01	<.01
Dissolved solids			
Res. on evap. at 180°C	663	1,320	2,850
Calculated	623	1,310	2,950
Hardness as $CaCO_3$			
Total	32	38	47
Non-carbonate	0	0	0
Specific conductance (micromhos per cm at 25°C)	997	2,050	4,130
pH	8.5	9.1	9.2

6. Fauna

a. General

The Colorado Division of Wildlife has compiled a significant amount of information on birds and mammals of the Piceance Basin. It is from this source (Colorado Department of Natural Resources, Wildlife Management Unit No. 22, 1971) that most of the following materials have been drawn. Information on fish and aquatic invertebrates was drawn principally from a thesis by May (1970). Over 300 species of birds, mammals, reptiles, and amphibians have been documented or are believed to exist in the 805,000 acre Piceance Creek Basin, many of which use the Basin on a migratory or transient basis. These species are presented in Table II-26.

b. Mammals

The Piceance Basin constitutes Colorado's most important mule deer range. It is the principal wintering ground for the migratory White River herd, believed to be one of the largest migratory herds in North America. The estimated size of this herd in recent years has ranged from 30,000 to 60,000 head (USDA, 1968).

The herd uses high elevation summer range of the White River National Forest and the Bluffs-Roan Divide area and moves to the historic winter range at the lower elevation of the Piceance Basin. The northeastern corner of the Basin normally supports the highest winter concentrations. An estimated density of 52 deer per square mile was found in the Yellow Creek area in 1968. In addition, there is a year-round population and every square mile of the Basin is considered to be deer summer range.

TABLE II-26.-Bird and Mammal Species of Wildlife Management Unit 22, Piceance Creek Basin, Colo. (Colorado Game, Fish and Parks Division, 1971).

Big game mammals 1/

Black bear (Ursus americanus)
Buffalo (bison) (Bison bison)
Elk (Cervus canadensis)
Mountain lion (Felis concolor)
Mule deer (Odocoileus hemionus)

Small game mammals 1/

Cottontail rabbit (Sylvilagus audubonii; S. nuttallii)
Pine (red) squirrel (Tamiasciurus hudsonicus)
Snowshoe hare (Lepus americanus)

Game birds 2/

Migratory waterfowl and shorebirds

Great Basin Canada goose (Branta canadensis moffitti)
Black brant (Branta nigricans) 3/
White-fronted goose (Anser albifrons frontalis) 3/
Snow goose (Chen hyperborea hyperborea) 3/
Mallard (Anas platyrnynchos platyrhynchos)
Gadwall (Anas atrepera)
Pintail (Anas acuta)
Green-winged teal (Anas carolinensis)
Blue-winged teal (Anas discors discors)
Cinnamon teal (Anas cyanoptera septentrionalium)
American widgeon (Mareca americana)
Shoveler (Spatula clypeata)
Wood duck (Aix sponsa) 3/
Redhead (Aythya americana)
Ring-necked duck (Aythya collaris)
Canvasback (Aythya valisineria)
Greater scaup (Aythya marila nearctica) 3/
Lesser scaup (Aythya affinis)
Common golden-eye (Bucephala clangula americana)
Barrow's golden-eye (Bucephala islandica) 3/
Bufflehead (Bucephala albeola)
Ruddy Duck (Oxyura jamaicensis rubida)
Hooded merganser (Lophodytes cucullatus)
Common merganser (Mergus merganser americanus)
Red-breasted merganser (Mergus serrator serrator) 3/
American coot (Fulica americana americana)
Common (Wilson's) snipe (Capella gallinago delicata)

Table II-26 - Continued

Upland game birds:

Blue grouse (Dendragapus obscurus obscurus)
Sage grouse (Centrocercus urophasianus urophasianus)
Ring-necked pheasant (Phasianus colchicus)
Chukar (Alectoris graeca)
Band-tailed pigeon (Columba fasciata fasciata)
Mourning dove (Zenaidura macroura marginella)

1/ Nomenclature according to Lechleitner, R. R. 1969. Wild mammals of Colorado. Pruett Publishing Co., Boulder. 254 pp.

2/ Nomenclature according to Baily, A. M., and R. J. Neidrach. 1967. Pictorial checklist of Colorado birds. Denver Mus. Nat. Hist. 168 pp.

3/ Unverified in hunters' bag checks but possible rare migrant and legal game in 1970-71.

Table II-26 - continued

OTHER MAMMALIAN SPECIES 1/ - WILDLIFE MANAGEMENT UNIT 22

Furbearers 2/

Beaver (Castor canadensis)
Muskrat (Ondatra zibethicus)
Ringtail (Bassariscus astutus)
Weasels (Mustela erminea; M. frenata)
Mink (Mustela vison)

Nongame mammals 2/ 3/

White-tailed jack rabbit (Lepus townsendii)
Black-tailed jack rabbit (Lepus californicus)
Yellow-bellied marmot (Marmota flaviventris)
White-tailed prairie dog (Cynomys leucurus)
Richardson's ground squirrel (Spermophilus richardsonii)
Thirteen-lined ground squirrel (Spermophilus tridecemlineatus)
Rock squirrel (Spermophilus variegatus)
Golden-mantled ground squirrel (Spermophilus lateralis)
White-tailed antelope squirrel (Ammospermophilus leucurus)
Least chipmunk (Eutamias minimus)
Colorado chipmunk (Eutamias quadrivittatus)
Uinta chipmunk (Eutamias umbrinus)
Coyote (Canis latrans)
Red fox (Vulpes fulva)
Kit (swift) fox (Vulpes velox)
Gray fox (Urocyon cinereoargenteus)
Raccoon (Procyon lotor)
American badger (Taxidea taxus)
Spotted skunk (Spilogale putorius)
Striped skunk (Mephitis mephitis)
Bobcat (wildcat)(Lynx rufus)

1/ These species, grouped separately as "Furbearers" and "Nongame mammals" and outside of "game" categories, follow Chapter 62, Colo. Rev. Statutes 1963 As Amended, in Colo. Game, Fish and Parks Div. Laws and Regulations Hdbk., 1970. (Art. 1, Item 3, Definitions, p. 327)

2/ Nomenclature according to Lechleitner, R. R. 1969. Wild mammals of Colorado. Pruett Publishing Co., Boulder, Colo. 254 pp.

3/ Although not included in the above list, wild horses also inhabit the basin (K. Roberts, pers. obs.).

Table II-26 - continued

OTHER AVIAN SPECIES 1/ - WILDLIFE MANAGEMENT UNIT 22

Nongame birds: 2/

Common loon (Gavia immer) Rare migrant.
Horned grebe (Podiceps auritus cornutus) Possible rare migrant.
Eared grebe (Podiceps caspicus californicus) Possible common migrant and occasional summer resident.
Western grebe (Aechmophorus occidentalis) Possible rare migrant.
Pied-billed grebe (Podilymbus podiceps podiceps) Uncommon migrant and rare summer resident.
Double-crested cormorant (Phalacrocorax auritus auritus) Possible rare migrant.
Great blue heron (Ardea herodias treganzai) Common summer resident 3/.
Snowy egret (Leucophoyx thula brewsteri) Possible uncommon summer resident.
Black-crowned night heron (Nycticorax nycticorax hoactli) Common summer resident.
Least bittern (Ixobrychus exilis exilis) Possible rare summer migrant.
American bittern (Botaurus lentiginosus)Rare summer migrant.
White-faced ibis (Plegadis chihi) Possible rare migrant.
Whistling swan (Olor columbianus) Uncommon migrant.
Sharp-tailed grouse (Pedioecetes phasianellus columbianus) Resident 3/, 4/, 10/
Sandhill crane (Grus canadensis canadensis; G. c. tabida) Regular migrant.
Virginia rail (Rallus limicola limicola) Possible uncommon summer resident.
Sora (Porzana carolina) Possible uncommon summer resident.
Semipalmated plover (Charadrius semipalmatus)Possible rare migrant.
Killdeer (Charadrius vociferus vociferus) Common summer resident 3/ and rare winter resident.
Mountain plover (Eupoda montana) Possible rare migrant, 10/
Black-bellied plover (Squatarola squatarola) Possible uncommon migrant.
Long-billed curlew (Numenius americanus americanus) Rare migrant, 10/
Spotted sandpiper (Actitis macularia) Common summer resident.
Solitary sandpiper (Tringa solitaria cinnamomea) Common migrant and occasional summer resident 3/.
Willet (Catoptrophorus semipalmatus inornatus) Possible rare migrant.

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Nongame birds: (continued)

Greater yellowlegs (Totanus melanoleucus) Possible common migrant.
Lesser yellowlegs (Totanus flavipes) Possible uncommon migrant.
Knot (Calidris canutus rufa) Possible rare migrant.
Pectoral sandpiper (Erolia melanotos) Possible rare migrant.
Baird's sandpiper (Erolia bairdii) Possible common migrant.
Least sandpiper (Erolia minutilla) Possible common migrant.
Long-billed dowitcher (Limnodromus scolopaceus) Possible uncommon migrant.
Stilt sandpiper (Micropalama himantopus) Possible rare migrant.
Semipalmated sandpiper (Ereunetes pusillus) Possible rare migrant.
Western sandpiper (Ereunetes mauri) Possible uncommon migrant.
Marbled godwit (Limosa fedoa) Possible rare spring migrant.
Sanderling (Crocethia alba) Possible rare migrant.
American avocet (Recurvirostra americana) Possible rare migrant.
Black-necked stilt (Himantopus mexicanus) Possible rare migrant.
Wilson's phalarope (Steganopus tricolor) Common migrant and uncommon summer resident.
Northern phalarope (Lobipes lobatus) Possible uncommon migrant.
Pomarine jaeger (Stercorarius pomarinus) Possible rare migrant.
Herring gull (Larus argentatus smithsonianus) Possible uncommon migrant.
California gull (Larus californicus) Possible rare migrant.
Ring-billed gull (Larus delawarensis) Possible uncommon migrant.
Franklin's gull (Larus pipixcan) Possible uncommon migrant.
Bonaparte's gull (Larus philadelphia) Possible rare migrant.
Sabine's gull (Xema sabini sabini) Possible rare migrant.
Forster's tern (Sterna forsteri) Possible rare migrant.
Common tern (Sterna hirundo hirundo) Rare migrant.
Least tern (Sterna albifrons athalassos) Possible rare migrant.
Black tern (Chlidonias niger surinamensis) Possible rare migrant.
Rock dove (Columba livia) Possible common resident.
White-winged dove (Zenaida asiatica mearnsi) Possible rare migrant.
Yellow-billed cuckoo (Coccyzus americanus americanus) Possible uncommon summer resident.
Poor-will (Phalaenoptilus nuttallii nuttallii) Common summer resident 5/.
Common nighthawk (Chordeiles minor hesperis; C. m. howelli) Common summer resident 3/.
White-throated swift (Aeronautes saxatalis sclateri) Common summer resident.
Black-chinned hummingbird (Archilochus alexandri) Common summer resident.
Broad-tailed hummingbird (Selasphorus platycercus platycercus) Common summer resident 3/, 5/.

Table II-26- continued

Nongame birds: (continued)

Rufous hummingbird (Selasphorus rufus)Possible common late summer migrant.
Calliope hummingbird (Stellula calliope) Possible rare migrant and summer resident.
Rivoli's hummingbird (Eugenes fulgens aureoviridis) Possible rare summer migrant.
Belted kingfisher (Megaceryle alcyon alcyon) Common resident.
Yellow-shafted flicker (Colaptes auratus luteus) Possible rare migrant.
Red-shafted flicker (Colaptes cater collaris) Common resident 3/, 5/.
Lewis' woodpecker (Asyndesmus lewis) Possible common summer resident.
Yellow-bellied sapsucker (Sphyrapicus varius nuchalis) Common Common summer 3/, 5/ and occasional winter resident.
Williamson's sapsucker (Sphyrapicus thyroideus nataliae) Possible common summer resident.
Hairy woodpecker (Dendrocopos villosus monticola) Possible uncommon resident.
Downy woodpecker (Dendrocopos pubescens leucurus) Uncommon
Northern three-toed woodpecker (Picoides tridactylus dorsalis) Possible rare resident.
Eastern kingbird (Tyrannus tyrannus) Possible uncommon summer resident.
Western kingbird (Tyrannus verticalis) Common summer resident 3/.
Cassin's kingbird (Tyrannus vociferans vociferans) Possible uncommon summer resident.
Ash-throated flycatcher (Myiarchus cinerascens cinerascens) Common summer resident 3/.
Say's phoebe (Sayornis saya saya) Common summer 3/ and occasional winter resident.
Traill's flycatcher (Empidonax traillii)Possible uncommon summer resident.
Hammond's flycatcher (Empidonax hammondii) Possible migrant.
Dusky flycatcher (Empidonax oberholseri) Possible summer resident.
Gray flycatcher (Empidonax wrightii) Possible summer resident.
Western flycatcher (Empidonax difficilis hellmayri) Common summer resident 3/.
Western wood peewee (Contopus sordidulus veliei)Common summer resident 5/.
Olive-sided flycatcher (Nuttallornis borealis) Possible uncommon summer resident.
Horned lark (Eremophila alpestris leucolaema) Common resident 5/.

Table II-26- continued

Nongame birds: (continued)

Violet-green swallow (Tachycineta thalassins lepida) Common summer resident 3/, 5/.
Tree swallow (Iridoprocne bicolor) Possible common migrant and uncommon summer resident.
Bank swallow (Riparia riparia riparia) Possible uncommon migrant and uncommon summer resident.
Rough-winged swallow (Stelgidopteryx ruficollis serripennis) Uncommon migrant and summer resident 3/.
Barn Swallow (Hirundo rustica erythrogaster) Common migrant and summer resident 3/.
Purple martin (Progne subis subis) Possible rare summer migrant.
Gray jay (Perisoreus canadensis capitalis) Possible uncommon resident.
Steller's jay (Cyanocitta stelleri macrolopha) Common resident 3/, 5/.
Scrub jay (Aphelocoma coerulescens woodhouseii) Common resident 3/, 6/.
Black-billed magpie (Pica pica hudsonis) Common resident 3/, 5/.
Common raven (Gorvus corax sinuatus) Common resident 3/, 5//
Common crow (Corvus Brachyrhynchos brachyrhynchos) Uncommon resident.
Pinyon jay (Gymnorhinus cyancephalue) Common summer resident 3/ and possible uncommon winter resident.
Clark's nutcracker (Nucifraga columbiana) Common resident 3/, 5//
Black-capped chickadee (Parus atricapillus garrinus) Common resident 3, 5/.
Mountain chickadee (Parus gambeli gambeli) Common resident 3/, 5/.
Plain titmouse (Parus inornatus ridgwayi) Common resident 3/.
Common bushtit (Psaltriparus minimus plumbeus) Possible common resident.
White-breasted nuthatch (Sitta carolinensis nelsoni) Uncommon resident 3/.
Red-breasted nuthatch (Sitta canadensis) Rare resident 3/, 5/, 6/.
Pygmy nuthatch (Sitta pygmaea melanotis) Possible uncommon resident.
Brown-creeper (Certhia familiaris montana) Possible uncommon resident and common migrant.
Dipper (Cinclus mexicanus unicolor) Common resident 5/.
House wren (Troglodytes aedon parkmanii) Common summer resident 3/, 5/
Bewick's wren (Thryomanes bewickii eremophillus) Possible common summer resident and rare winter resident.
Long-billed marsh wren (Telmatodytes palustris plesius) Possible rare winter resident.

Nongame birds: (continued)

Violet-green swallow (Tachycineta thalassina lepida) Common summer resident 3/, 5/.

Tree swallow (Iridoprocne bicolor) Possible common migrant and uncommon summer resident.

Bank swallow (Riparia riparia riparia) Possible uncommon migrant and uncommon summer resident.

Rough-winged swallow (Stelgidopteryx ruficollis serripennis) Uncommon migrant and summer resident 3/.

Barn swallow (Hirundo rustica erythrogaster) Common migrant and summer resident 3/.

Cliff swallow (Petrochelidon pyrrhonota pyrrhonota) Common summer resident 3/, 5/.

Purple martin (Progne subis subis) Possible rare summer migrant.

Gray jay (Perisoreus canadensis capitalis) Possible uncommon resident.

Steller's jay (Cyanocitta stelleri macrolopha) Common resident 3/, 5/.

Scrub jay (Aphelocoma coerulescens woodhouseii) Common resident 3/, 6/.

Black-billed magpie (Pica pica hudsonia) Common resident 3/, 5/.

Common raven (Corvus corax sinuatus) Common resident 3/, 5/.

Common crow (Corvus brachyrhynchos brachyrhynchos) Uncommon resident.

Pinyon jay (Gymnorhinus cyanocephalus) Common summer resident 3/ and possible uncommon winter resident.

Clark's nutcracker (Nucifraga columbiana) Common resident 3/, 5/.

Black-capped chickadee (Parus atricapillus garrinus) Common residenc 3, 5/.

Mountain chickadee (Parus gambeli gambeli) Common resident 3/, 5/.

Plain titmouse (Parus inornatus ridgwayi) Common resident 3/.

Common bushtit (Psaltriparus minimus plumbeus) Possible common resident.

White-breasted nuthatch (Sitta carolinensis nelsoni) Uncommon resident 3/.

Red-breasted nuthatch (Sitta canadensis) Rare resident 3/, 5/, 6/.

Pygmy nuthatch (Sitta pygmaea melanotis) Possible uncommon resident.

Brown-creeper (Certhia familiaris montana) Possible uncommon resident and common migrant.

Dipper (Cinclus mexicanus unicolor) Common resident 5/.

House wren (Troglodytes aedon parkmanii) Common summer resident 3/, 5/.

Bewick's wren (Thryomanes bewickii eremophillus) Possible common summer resident and rare winter resident.

Long-billed marsh wren (Telmatodytes palustris plesius) Possible rare winter resident.

Table II- 26 - continued

Nongame birds: (continued)

Canyon wren (Salpinctes mexicanus conspersus) Uncommon summer resident 3/.
Rock wren (Salpinctes obsoletus obsoletus) Common summer 3/ and possible rare winter resident.
Mockingbird (Mimus polyglottos leucopterus) Uncommon summer resident 3/.
Catbird (Dumetella carolinensis) Rare summer resident.
Sage thrasher (Oreoscoptes montanus) Common summer resident 3/,6/.
Robin (Turdus migratorius propinquus) Common summer resident 3/, 5/.
Hermit thrush (Hylocichla guttata auduboni) Common summer resident 5/.
Swainson's thrush (Hylocichla ustulata almae) Possible common migrant.
Veery (Hylocichla fuscescens salicicola) Possible common migrant and uncommon summer resident.
Western bluebird (Sialia mexicana bairdi) Possible common migrant and uncommon summer resident 3/.
Mountain bluebird (Sialia currucoides) Common migrant and summer resident 3/, 5/ and occasional winter resident.
Townsend's solitaire (Myadestes townsendi townsendi) Uncommon resident 5/.
Blue-gray gnatcatcher (Polioptila caerulea amoenissima) Common summer resident 3/.
Golden-crowned kinglet (Regulus satrapa amoenus) Possible uncommon migrant and rare summer resident.
Ruby-crowned kinglet (Regulus calendula cineraceus) Possible common migrant.
Bohemian waxwing (Bombycilla garrulus pallidiceps) Possible irregular winter migrant.
Cedar waxwing (Bombycilla cedrorum) Possible uncommon and irregular resident.
Northern shrike (Lanius excubitor invictus) Possible common winter resident.
Loggerhead shrike (Lanius ludovicianus excubitorides) Uncommon summer 3/ and common winter resident.
Starling (Sturnus vulgaris vulgaris) Possible common resident.
Gray vireo (Vireo vicinior) Possible uncommon summer resident.
Solitary vireo (Vireo solitarius plumbeus) Possible common summer resident.
Red-eyed vireo (Vireo olivaceus) Rare summer resident 3/.
Warbling vireo (Vireo gilvus swainsonii) Possible common summer resident.
Tennessee warbler (Vermivora peregrina) Possible rare but regular migrant.

Table II-26 - continued

Nongame birds[1] (continued)

Orange-crowned warbler (Vermivora celata orestera) Possible uncommon migrant and summer resident.
Nashville warbler (Vermivora ruficapilla ridgwayi) Possible rare migrant.
Virginia warbler (Vermivora virginiae) Possible common summer resident.
Yellow warbler (Dendroica petechia aestiva) Common summer resident 3/, 5/.
Myrtle warbler (Dendroica coronata coronata) Possible common migrant.
Audubon's warbler (Dendroica auduboni memorabilis) Common summer resident 3/, 6/.
Black-throated gray warbler (Dendroica nigrescens) Common summer resident 3/.
Townsend's warbler (Dencroica townsendi) Possible uncommon fall migrant.
MacGillibray's warbler (Oporornis tolmiei moncicola) Common migrant and uncommon summer resident 5/.
Yellowthroat (Geothlypis trichas occidentalis: G. t. campicola) Possible uncommon summer resident.
Yellow-breasted chat (Icteria virens auricollis) Possible common summer resident.
Wilson's warbler (Wilsonia pusilla pileolata) Possible common migrant.
American redstart (Setophaga ruticilla tricolora) Possible rare migrant.
House sparrow (Passer domesticus domesticus) Common resident 3/.
Bobolink (Dolichonyx oryzivorus) Possible rare summer migrant.
Western meadowlark (Sturnella neglecta neglecta) Common summer 3/ and uncommon winter resident.
Yellow-headed blackbird (Xanthocephalus xanthocephalus) Common summer resident.
Red-winged blackbird (Agelaius phoeniceus fortis) Common resident 3/.
Rusty blackbird (Euphagus carolinus carolinus) Possible rare winter migrant.
Brewer's blackbird (Euphagus cyanocephalus) Common resident 3/.
Brown-headed cowbird (Molothrus ater artemisiae) Common summer resident 3/.
Western tanager (Piranga ludoviciana) Possible common migrant and summer resident.
Scarlet tanager (Piranga olivacea) Possible rare summer migrant.
Black-headed grosbeak (Pheucticus melanocephalus melanocephalus) Common summer resident 5/.

Nongame birds: (continued)

Blue grosbeak (Guiraca caerulea interfusa) Possible uncommon summer resident.
Lazuli bunting (Passerina amoena) Uncommon summer resident 3/.
Evening grosbeak (Hesperiphona vespertina brooksi) Irregular resident.
Cassin's finch (Carpodacus cassinii) Possible common resident.
House finch (Carpodacus mexicanus frontalis) Common summer 3/, 5/ and possible uncommon winter resident.
Pine grosbeak (Pinicola enucleator montana) Possible uncommon resident.
Gray-crowned rosy finch (Leucosticte tephrocotis tephrocotis; L. t. littoralis) Possible common winter migrant.
Black rosy finch (Leucosticte atrata) Possible common winter migrant.
Brown-capped rosy finch (Leucosticte australis) Possible common winter migrant.
Common redpoll (Acanthis flammea flammea) Possible rare winter migrant.
Pine siskin (Spinus pinus pinus) Common resident 3/, 5/.
American goldfinch (Spinus tristis tristis; S. t. pallidus) Common summer 3/ and possible uncommon winter resident.
Lesser goldfinch (Spinus psaltria psaltria) Possible uncommon summer and rare winter resident.
Red crossbill (Loxia curvirostra) Possible rare resident.
White-winged crossbill (Loxia leucoptera leucoptera) Possible rare winter migrant.
Green-tailed towhee (Chlorura chlorura) Common summer resident 3/, 5/, and possible rare winter resident.
Rufous-sided towhee (Pipilo erythrophthalmus montanus) Uncommon summer and rare winter resident.
Lark bunting (Calamospiza melanocorys) Uncommon summer resident.
Savannah sparrow (Passerculus sandwichensis nevadensis; P. s. anthinus) Possible uncommon migrant and summer resident.
Grasshopper sparrow (Ammodramus savannarum perpallidus) Uncommon summer resident 5/.
Vesper sparrow (Pooecetes gramineus confinis) Common migrant and summer resident 5/.
Lark sparrow (Chondestes grammacus strigatus) Possible common migrant and summer resident.
Black-throated sparrow (Amphispiza bilineata deserticola) Possible common summer resident.
Sage sparrow (Amphispiza belli nevadensis) Common summer resident 3/.
White-winged junco (Junco aikeni) Possible rare winter migrant.

Table II-26 - continued

Nongame birds: (continued)

Slate-colored junco (Junco hyemalis hyemalis; J. h. cismontanus) Possible rare winter resident.
Oregon junco (Junco oreganus) Common winter resident.
Gray-headed junco (Junco caniceps caniceps) Common summer 5/ and winter resident.
Tree sparrow (Spizella arborea ochracea) Possible uncommon winter migrant.
Chipping sparrow (Spizella passerina boreophila) Common summer resident 3/.
Brewer's sparrow (Spizella breweri breweri) Common summer resident 3/, 6/.
Harris' sparrow (Zonotrichia querula) Possible rare winter resident.
White-crowned sparrow (Zonotrichia leucophrys) Common resident 3/, 5/.
Fox sparrow (Passerella iliaca schistacea) Rare summer resident 5/.
Lincoln's sparrow (Melospiza lincolnii alticola) Common migrant and summer resident 3/.
Song sparrow (Melospiza melodia) Common summer 3/ and possible uncommon winter resident.
Lapland longspur (Calcarius lapponicus alascensis) Possible rare winter migrant.
White-throated sparrow (Zonotrichia albicollis) Possible rare migrant.

Raptors: 2/

Turkey vulture (Cathartes aura meridionalis) Common summer 3/, 5/ and rare winter resident.
Goshawk (Accipiter gentilis atricapillus) Rare resident.
Sharp-shinned hawk (Accipiter striatus velox) Possible rare summer and common winter resident.
Cooper's hawk (Accipiter cooperii) Uncommon summer 3/, 5/, and common winter resident.
Red-tailed hawk (Buteo jamaicensis calurus) Common resident 3/,5/.
Swainson's hawk (Buteo swainsoni) Uncommon summer 5/ and rare winter resident.
Rough-legged hawk (Buteo lagopus s. johannis) Rare summer 3/ and uncommon winter resident or migrant.
Ferruginous hawk (Buteo regalis) Rare summer and common winter resident 10/.
Golden eagle (Aquila chrysaetos canadensis) Common resident 3/, 7/.
Bald eagle (Haliaeetus leucocephalus alascanus) Common winter resident 7/.
Marsh hawk (Circus cyaneus hudsonius) Common summer 3/, 5/, and winter resident.
Osprey (Pandion haliaetus carolinensis) Possible rare migrant 10/
Prairie falcon (Falco mexicanus) Rare resident 3/, 9/.
Peregrine falcon (Falco peregrinus anatum) Possible rare migrant 8/.
Pigeon hawk (Falco columbarius) Possible rare winter migrant 10/.
Sparrow hawk (Falco sparverius sparverius) Common summer 3/, 5/ and uncommon winter resident.
Screech owl (Otus asio) Possible uncommon resident.
Flammulated owl (Otus flammeolus flammeolus) Possible rare summer resident.
Great horned owl (Bubo virginianus) Common resident 3/, 5/.
Pygmy owl (Glaucidium gnoma californicum) Possible rare resident.
Burrowing owl (Speotyto cunicularia hypugaea) Common summer 5/, 10/ and possible rare winter resident.
Long-eared owl (Asio otus wilsonianus) Uncommon resident 5/.
Short-eared owl (Asio flammeus flammeus) Possible uncommon winter migrant.
Saw-whet owl (Aegolius acadicus acadicus) Possible uncommon resident.

Table II-26 continued

1/ These species, grouped separately as "Nongame birds" and "Raptors" and outside of "game" categories, follow Chapter 62, Colo. Rev. Statutes 1963 As Amended, in Colo. Game, Fish and Parks Div. Laws and Regulations Hdbk., 1970. (Art. 1, item 3, Definitions, p. 327).

2/ Nomenclature from Bailey, A. M., and N. J. Neidrach. 1967. Pictorial checklist of Colorado birds. Denver Mus. Nat. Hist. 168 pp. Information on occurrence, in employing term "possible," is adapted from foregoing reference and notes in Davis, W. A. 1969. Birds in western Colorado. Colo. Field Ornithologists. 61 pp. Where adjective "possible" is absent, actual sighting(s) have been reported verbally by anyone or more of Division personnel W. McKean, C. Reichert, G. Gore, S. Steinert, and R. Bartmann, or qualified by additional footnotes that follow.

3/ Sight records given in unpublished checklists of birds of the Little Hills Game Exp. Station by R. A. Ryder, I. R. Gabrielson, D. Charbonneau, C. White, and R. Lauridson, 1947 and 1948.

4/ Technically a game bird, but comparative rarity makes occurence in Unit 22 questionable. Species is cited here to avoid its complete omission, since chances appear good enough for it to occur in the unit some time.

5/ Sight record given in unpublished checklist of birds of Naval Oil Shale Reserve, 1969-70, by L. M. Stephens.

6/ Specimens collected and cited in checklists of the Little Hills Exp. Station.

7/ Golden and bald eagle specifically excluded from statutes defining "Raptor" as cited in footnote 1/ but herein listed to avoid omission.

8/ Endangered species.

9/ Species likely to become endangered.

10/ Undetermined status.

Table II-26 - Addendum

Other Mamalian Species 1/ - Western Rio Blanco County

Little brown bat (Myotis lucifugus)

Long-eared myotis (Myotis evotis)

Long-legged myotis (Myotis volans)

Small-footed myotis (Myotis leibii)

Big brown bat (Eptesicus fuscus)

Townsend's big-eared bat (Plecotus townsendii)

Northern pocket gopher (Thomomys talpoides)

Ord's kangaroo rat (Dipodomys ordii)

Western harvest mouse (Reithrodontomys megalotis)

Canyon mouse (Peromyscus crinitus)

Deer mouse (Peromyscus maniculatus)

Pinon mouse (Peromyscus truei)

White-throated woodrat (Neotoma albigula)

Bushy-tailed woodrat (Neotoma cinerea)

Montane vole (Microtus montanus)

Long-tailed vole (Microtus longicaudus)

Sagebrush vole (Lagurus curtatus)

Western jumping mouse (Zapus princeps)

Porcupine (Erethizon dorsatum)

Black-footed ferret (Mustela nigripes) (endangered species)

1/ These species are reported as occurring in Rio Blance County in the area from Meeker to the west, by Armstrong.

Table II-26 - Addendum

Reptiles and Amphibians [2] - Western Rio Blanco County

Sagebrush lizard (*Sceloporus graciosus*)

Eastern fence lizard (*Sceloporus undulatus*)

Tree lizard (*Urosaurus ornatus*)

Side-blotched lizard (*Uta stansburiana*)

Short-horned lizard (*Phrynosoma douglassi*)

Western garter snake (*Thamnophis elegans*)

Red-sided garter snake (*Thamnophis sirtalis*)

Gopher snake (*Pituophis catenifer*)

Western rattlesnake (*Crotalus viridis*)

Tiger salamander (*Ambystoma tigrinum*)

Rocky Mountain toad (*Bufo woodhousei*)

Chorus frog (*Pseudacris nigrita*)

Leopard frog (*Rana pipiens*)

2/ These species are reported as occuring in Rio Blanco County in the area from Meeker to the west, by Maslin.

The sagebrush type, which covers about 35 percent of the Piceance Basin, is undoubtedly important as mule deer habitat. Unpublished data from Little Hills investigation show, by stomach analysis, four browse species (serviceberry, big sagebrush, snowberry, and pinyon pine) comprise 71 percent of the stomach content.

It appears that the best deer forage in the sagebrush type occurs in open stands where there is a variety of grasses, forbs, and shrubs. Sagebrush range affords good cover for deer especially where it intermingles with the rough breaks of the pinyon-juniper and the thickets of the mountain shrub type.

Heavy use of grass species by the Piceance Creek deer herd in early spring is common. Trend counts by the Colorado Division of Wildlife are made in the spring when hundreds of deer descend each evening to feed on the grass meadows of the creek bottoms. Ranchers report heavy deer use in the spring on crested and intermediate wheatgrass pastures. This use continues only while the grasses are green and succulent. Little foraging on grass occurs in other seasons. Carhart conducted studies of the food habits of the White River deer herd from 1938 to 1941, based on about ten stomach samples per month. These studies showed that grasses constituted less than one percent of the diet in summer, fall, and winter. In spring, grasses and herbs comprised about one-eighth and one-tenth of the diet, respectively.

Carhart showed that deer secured over 93 percent of their winter food from six browse species which comprised only 75 percent of the total forage available. In order of decreasing importance, these species are big sagebrush, pinyon pine, juniper, rabbitbrush, serviceberry, and mountain mahogany. Similarly, six forage categories (big sagebrush, serviceberry, grasses, herbs, snowberry, and pinyon pine) provided over 84 percent of the spring diet. During summer, four categories (serviceberry, black chokeberry, scrub oak, and herbs) provided almost 92 percent of the diet. In the fall, six browse species (serviceberry, big sagebrush, mountain mahogany, rabbitbrush, aspen, and pinyon pine) provided almost 68 percent of the diet.

The Division of Wildlife reports (1971) that a total of 258,949 big game hunting licenses valued at \$6.9 million were sold state-wide in 1970. Most licences were sold for mule deer hunting, since 70,254 of the 93,673 animals reported harvested were mule deer. State-wide, big game hunters are estimated to have spent \$77,192,831 on gross hunting expenditures in 1970. Although specific expenditures cannot be itemized, the Piceance Basin is perhaps the single most important mule deer hunting area in Colorado. Harvest statistics indicated that 6.7 percent (4,737) of the total state harvest occurred in the Piceance Basin and that mule deer kill per square mile was the highest in the State (4.70 deer harvested per square mile). Hunting pressure (7.07 hunters per square mile) was second only to the Coal Creek area (8.04 hunters per square mile). It is also significant to note that 66 percent of the reported deer kill in the basin was by nonresident hunters, as reported against 45 percent for the entire state.

Deer-auto collisions on main highways bounding Unit 22 have been recorded. On a 20-mile section of highway south of Meeker, a minimum loss of 118 deer was reported in 1968-69, and 109 deer in 1969-70. Fifty-one deer were reported killed on Highway 64 between Meeker and the Piceance Creek turnoff during April 1960 to March 31, 1961.

Antelope are restricted mainly to the northern edge of the Basin.

Limited numbers of elk utilize the general Piceance Basin area, with the center of activity found at higher elevations of the Roan Plateau. Winter movement to lower ranges carries some elk use into the central portion of the basin. Total elk harvests from this population during 1965-69 were 17, 4, 21, 8, and 20 animals. Elk are mainly grazers of open areas at higher elevations in aspen and conifer type habitat. Sagebrush areas are also utilized as calving areas and sources of grass forage.

An estimated population of 5 to 15 mountain lions roam over the Piceance Basin, being particularly influenced by deer migrations and movement of sheep bands. Incidences of mountain lion predation were recorded in the northern half of the Basin during 1958-68.

Black bear occur at higher elevations in the southern part of the Basin, although they are few in number. Statistics for 1970 show that one bear was reported as harvested in the Piceance Basin (Myers, et. al., 1971), although the average reported harvest for 1955-69 was three bears per year (Colorado Game, Fish and Parks, 1971).

Coyotes and bobcats are regarded as abundant in the Basin although no population estimate is available. It has been estimated that over 1,000 domestic sheep are annually lost to coyote predation (Environmental Resources Center, 1971).

Extrapolation of data from other areas indicates that cottontail rabbits in the Piceance Basin may be present at a density of 150 to 200 animals per square mile. Both the snowshoe hare and the pine squirrel are believed to be distributed coincidentally with Douglas fir on the Roan Plateau between Cow Creek and Black Sulphur Creek. Directly applicable statistics on rabbit harvest by hunters are not available, but a substantial number of rabbits are known to be harvested annually in the Basin.

The Colorado Division of Wildlife has established a small captive herd of buffalo and is conducting research studies on Rocky Mountain Bighorn Sheep at the Little Hills Experiment Station in the Dry Fork drainage.

Other mammals have been recorded and can be found listed in Table II- 26. These include yellow bellied marmots, prairie dogs, ground squirrels, porcupine, chipmunks, red fox, raccoon, and others.

Wild horses are present in the Piceance Basin with current estimates ranging from 150 to 250 head. On occasion, a small band of 10 to 15 horses have been observed on and in the immediate vicinity of Tract C-a.

c. Birds

Sage grouse have been frequently observed at various sites throughout the Piceance Basin including important habitat areas on the

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Cathedral Bluffs, the divide between Douglas and Yellow Creeks, and the Gas Well area east and north of Piceance Creek at the head of Collins Gulch. Density appears to be about 1-10 birds per square mile.

Blue grouse occur in Douglas fir and aspen types of the Roan Plateau and Cathedral Bluffs area, as well as other places in the Basin.

Chukar partridge have been stocked and are known to exist in small numbers on and near main Piceance Creek between Steward and Story Gulches.

A small population of ringneck pheasants is known to exist in some low quality habitat along the White River bottoms and agricultural land from the river bridge on Highway 64 to about the Thomas Ranch.

An estimated population of 300 mallards, green-winged teal, common golden-eye, and common nerganser are knwon to winter along the White River and on warm spring-fed waters of Piceance Creek and its tributaries. In addition, gadwalls, cinnamon and blue-winged teal, along with the winter resident, breed in these same areas. The summer population consists of perhaps 1,000 birds.

All of the Piceance Basin is in mourning dove breeding range. Bank-tailed pigeons occasionally traverse the basin, although no records of breeding and wintering are known. There is no population density data for either of these species.

Golden eagles are year-long residents of the Piceance Creek area and the stretch of the White River between Meeker and Rangely is a wintering area for bald eagles. Active golden eagle nest sites as 1970 included: east Piceance Creek Road near Dudley Gulch (T1S, R97W);

Dry Fork of Dark Canyon (T1S, R96W); mouth of Dry Fork Piceance Creek (T1N, R97W); and Kendall Gulch (T1N, R95W).

Many other species of migratory waterfowl, shorebirds, song birds, hawks, eagles, and other vultures winter, breed, summer, or migrate through the Piceance Basin. Their abundance ranges from abundant to rare. Table II-26 lists all species which have been documented.

d. Aquatic Organisms

Aquatic habitats exist at Stake Springs, 84 Springs, Yellow Creek, and the trout pond on the Violet Place on Yellow Creek, as well as in the White River and intermittent Yellow Creek. Fish species include trout, suckers, and minnows.

A survey of aquatic organisms in the White River, Yellow Creek, and Piceance Creek was done by May (1970). These data may be indicative of the fauna that exists downstream from Tract C-a and C-b. Fish populations in the studied streams were limited to two species. Fluctuating flows were found to be a major influence on the vertebrates and chemical composition of the water. Bottom composition of Piceance Creek was found to be comprised mostly of fine gravel (shale) with a few large rocks.

Bottom samples from the three streams yielded 10,505 organisms, with peak abundance occurring during June. Mean monthly numbers of organisms ranged from 140 organisms per inch in April 1969, to 1,466 organisms per inch in June 1969. May flies and midges were most numerous, while beetles, caddis flies, and stone flies were also present. Non-insect aquatic invertebrates included oligochoetes.

e. Threatened Species

As shown in Table II-14, 19 threatened species of birds, mammals, and fish are believed to exist in the three-State oil shale region. Although all of these probably do not exist in the Piceance Basin, it is probably that at least the more mobile species use the habitat of the Basin. Table II-26 lists a number of other threatened species as possible migrants.

Golden and bald eagles, not designated endangered, but protected by Federal legislation, winter in the area. The rare prairie falcon is known to exist in the area. There are still a few prairie dog towns in the basin and the endangered black-footed ferret is dependent on such habitats. The black-footed ferret has not been verified by actual specimen from northwest Colorado since 1942, but one sighting in the early sixties in Moffat County and a more recent sighting in nearby Uintah County, Utah indicates that they still exist in the oil shale region.

Although not nationally threatened ar endangered, the ringtail (Bassariscus astutus) is reported ot occur in limited numbers near Douglas Creek. This species is rather scarce in western Colorado (Environmental Resources Center, 1971).

7. Soils

Soils of the Piceance Creek Basin vary from very thin or none on the steep slopes and cliffs to thick alluvial soils on the wider valley floors. Upland areas may be covered by thin soils or high-level, thick, alluvial soil.

The alluvial valley land supports good hay crops where irrigated, otherwise sagebruch or greasewood. The upland allvium supports sagebrush predominantly, with some grass. The thin upland soils generally support pinyon-juniper.

Soils of the Piceance Creek Basin consist primarily of Haplorthents, Haplargids, Argiustolls, and the Haplustolls on the uplands. Many of these soils are lithic or shallow to bedrock. Deep alluvial soils such as Haplustolls, and Haplaquolls occur in valley bottoms and drainageways. Land types such as rock outcrops, rough gullied land and shale badlands occur as small areas throughout the Basin. The west slope of Cathedral Bluffs is an example of the outcrop land type.

A generalized map of the soils of the White River Basin, Colorado, which includes the Piceance Creek Basin is shown in Figure II-43. Soils contained within the Piceance Creek Basin are described as follows:

Soil Mapping Unit 3: Shallow rocky and deep moderately dark colored soils of the uplands

Landscape: The landscape is highly dissected by creeks and their intermittent tributaries. There is a repeating pattern of narrow alluvial valleys along creeks flanked by canyons or very steep rocky slopes which rise to higher lying uplands. Narrow bands of rolling upland or mesas form divides between upper reaches of creek tributaries.

Slopes: Slope gradients usually range between 10 and 60 percent. Those of less than 10 percent are confined to alluvial valleys, mesas, and uplands.

Climate: For the most part, elevations range between 6,000 and 7,000 feet. Climate is more favorable for plant growth than in the desert areas around Rangely. Annual precipitation is 12 to 15 inches and mean annual temperature is a little less than 47 degrees F. The frost-free period is about 100 days.

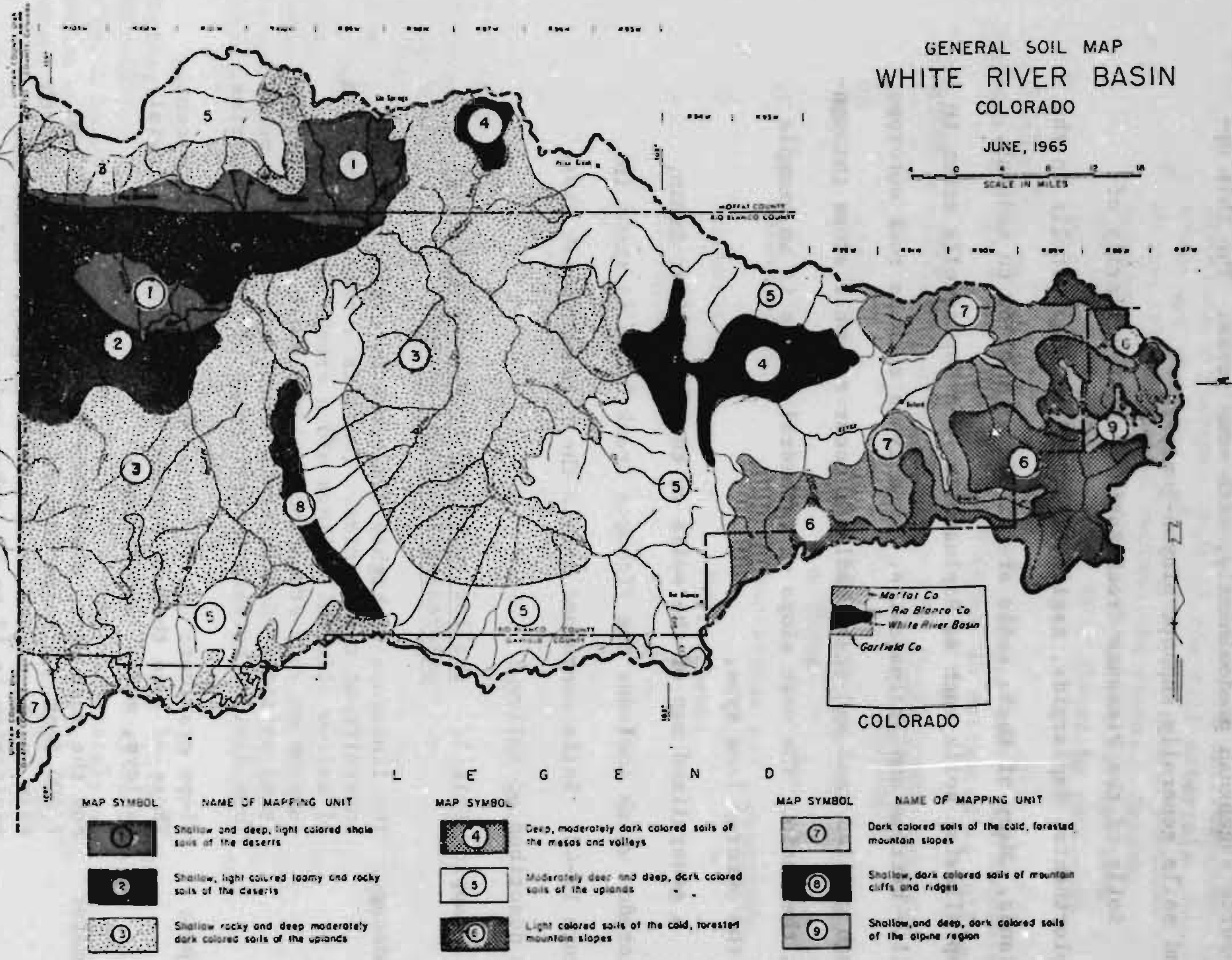

FIGURE II-43.--General Soil Map of the White River Basin.

Soil parent materials: Soil parent materials are mainly limy sandstones and shales along with reworked valley fill derived from sandstone and shale. Much of the fill materials is stony and gravelly. Eolian deposits mantle portions of the rolling upland between the creeks. Recent alluvium is of minor extent. Alluvial valleys have been markedly influenced at many places by sediments and colluvium from nearby slopes.

Composition map unit 3 by Great Soil Groups, except for Regosols included with the Brown soils and land types, is estimated as follows:

Percent	1949 Great Soil Group	1965 Great Group, Subgroup or Family
60	Lithosols	Haplorthents (Lithic and Thin)
25	Brown soils	Haplargids and Camborthids
5	Alluvial soils	Haplorthents
2	Solonetz soils	Natrargids
8	Land types: Rock outcrop 3% Rough gullied land 3% Shale badlands 2%	Land types: Rock outcrop 3% Rock gullied land 3% Shale badlands 2%

One of the most extensive components of unit 3 is the light colored, shallow, stony soils that are intermingled with large sandstone boulders and rock outcrops. They overlie sandstone or shale at depths of less than 20 inches, and are usually calcareous. Stony soils are extensive near narrow valleys and canyons that dissect the unit. At many locations soft sandstone is penetrated by tree roots. Closely associated with rocky soils are deeper soils with weak horizonation that have high proportions of coarse fragments in the subsoil. Deeper soils are in footslope positions below and within the complex patterns of shallow soils.

Medium depth soils occupy lower portions of many narrow mesa divides. They have formed in local wind deposited sandy materials derived for the most part from sandstone. Deep, moderately dark colored loamy soils which are noncalcareous to depths of 6 to 24 inches occupy smoother slopes on the divides. Often they have formed in calcareous wind-blown deposits of loamy texture.

Accelerated erosion is chiefly confined to rolling upland divides and stream valleys. Water erosion on rocky, gravelly pinyon-juniper slopes is principally along roads and hunting trails. Trails and roads along steep upper slopes have had a striking effect in concentrating runoff water. Deep gullying and destructive bank cutting is visible along all intermittent creeks and head cutting is common on side drains. Summer storms frequently wash out many bridges and creek crossings within this unit. Detrimental flood deposits are left on alluvial fans and bottomlands that formerly supported good stands of grass.

Soil Mapping Unit 5: <u>Moderately deep and deep, dark colored soils of the uplands</u>.

Landscape: The unit consists of steep lower mountain slopes of rugged relief dissected by narrow valleys and streams. The sharp ridges of the Grand Hogback are representative of portions of this unit.

Slopes: Steep slopes with gradients between 10 and 60 percent are most common. Gradients of less than 10 percent are generally limited to colluvial slopes, swales, fans and alluvial bottom-lands.

Climate: Most of the unit is at elevations between 7,000 and 8,000 feet but there are extremes from 6,400 to 8,800 feet. Soil moisture conditions are more favorable for plant growth due to higher precipitation and lower evaporation associated with higher elevations. Data from the Marvine station show a mean annual precipitation of about 20 inches, a mean annual temperature of nearly 40° F., and a frost-free period of 47 days. Since unit 5 extends west to the State line, a range of from 15 to 20 inches in annual precipitation and 45 to 100 days in length of frost-free period can be expected.

Soil parent materials: Parent materials consist of mixed alluvium, colluvium, and outwash deposits along streams and valleys. Gravelly and stony valley fill is extensive along the lower mountain slopes. Parent rocks are chiefly sandstones, quartzites, shales and basalt. They have furnished the source for much reworked material in which soils have formed.

The approximate composition of the unit by Great Soil Groups follows. Estimates were not made for Regosols as they are included within the zonal soils:

Percent	1949 Great Soil Group	1965 Great Group, Subgroup or Family
45	Chernozem soils	Argiudolls and Argiborolls Hapludolls and Haploborolls
35	Chestnut soils	Argiustolls and Haplustolls
15	Lithosols	Haplustolls and Hapludolls (Lithic)
3	Alluvial soils	Haplustolls and Haplaquolls
2	Land types: Rock outcrop	Land types: Rock outcrop

Dominate soils of this unit have dark gray or dark grayish brown surface layers that are high in organic matter content. Surface layers are loamy with sandy textures being most common. On steep colluvial slopes coarse fragments from higher lying rock ledges and outcrops are usually scattered over the surface soil. Subsoils are more clayey and may be sandy clay loam to clay in texture. Many subsoils contain gravel, stone, and rock fragments. Lime is usually leached to depths of 40 to 60 inches.

Moderately deep and deep soils are intermingled within this unit. At depths between 20 and 40 inches there is usually sandstone, shale or basalt under moderately deep soils. Deep soils have formed in valley fill and may have dark colored buried soils within the upper four feet of the profile. Some dark surface soils are unusually thick and extend to depths of 20 to 30 inches.

Erosion is slight to moderate. Most evident is that in cultivated fields where runoff water has concentrated and resulted in rilling and gullying. Under native cover, erosion has been limited to washing along stock trails and minor gullying along drainageways.

Soil Mapping Unit 8: Shallow dark colored soils of mountain cliffs and ridges.

Landscape: This unit extends as a narrow band above Spring Creek across the west side of Cathedral Bluffs and southeast nearly to the Garfield County line. Large oil shale sequence sections in the Green River Formation are exposed along the west face of Cathedral Bluffs.

Conspicuous features of the landscape are light colored cliffs and escarpments. The white, light gray to very pale brown exposed shale, marl, sandstone and limestone beds extend along an irregular, jagged strip seldom more than a mile or two wide. Above the cliffs are sharp rolling windswept ridge crests which form a divide between the Douglas Creek and Piceance Creek drainage basins, while below are very steep talus slopes. Included in the landscape are highly dissected uplands forming headwaters of intermittent drains that flow west and north into Douglas Creek.

Slopes: Slopes are irregular and broken. They usually extend for only short distances before changing in aspect. Slope gradients on rolling ridge crests above the cliffs are 5 to 25 percent. Between and below vertical cliff faces slopes range from 25 to 75 percent

Climate: Most of unit 8 is at an elevation between 8,000 and 8,500 feet but extreme limits are 7,000 to 8,700. Mean annual precipitation is 16 to 20 inches. The frost-free period and mean annual temperature is similar to that of unit 7. A striking difference characterizing unit 8 is that much of the annual precipitation is lost by evaporation and runoff on bare exposures and windswept ridges. Consequently, a smaller portion of total precipitation is available for plant growth than within unit 7.

Soil parent materials: Soil parent materials have been mainly calcareous shales and fine grained sandstones. Marly deposits and limestone beds are also common. There has been much local reworking of materials from residual beds. Many of the colluvial slopes contain high proportions of gravel and stone.

Composition of unit 8 by Great Soil Groups is estimated as follows:

Percent	1949 Great Soil Group	1965 Great Group, Subgroup or Family
65	Lithosols	Lithic Haploborolls Lithic Haplustolls Lithic Haplorthents
25	Regosols	Haploborolls Haplustolls
10	Land Types: Rock outcrop	Land Types: Rock outcrop

Soils of this unit are predominantly shallow. Usually underlying shales or fine grained sandstones are at depths of 6 to 20 inches. Soil depth changes frequently within short distances. Deeper soils with underlying parent beds at depths of 20 to 40 inches occupy about 25 percent of the unit. Plant roots enter most of the residual beds and most shales can be readily penetrated with digging tools.

On west and south facing slopes surface soils are lighter colored and limy. Shaly loams and gravelly sandy loams are the common surface soil textures on steep upper slopes. Deep soils containing high proportions of shale and stone occupy some lower colluvial slopes.

Erosion within this unit is mainly geologic in character. Parent rocks, steep slopes and strong winds slow the rate of soil formation. In addition, much weathered material moves down slope as colluvium. Accelerated erosion is principally by wind on ridge crests where overgrazing had denuded shallow loamy soils. Gullying is limited to narrow drainageways occupied by deep, friable soils.

8. Vegetation

Vegetative types or aspects occurring in the Piceance Creek Basin and surrounding area may be placed in seven major categories: Saltbush, Greasewood, Pinyon-Juniper, Sagebrush, Mountain Shrub, Aspen, and Conifers. These generally occur in relation to elevation as they are listed above with saltbush at the lowest elevations and conifers at the highest.

a. Saltbush

This vegetative type is limited to the lowest elevations on moderately saline soils. It occurs sparsely in the Piceance Creek Basin as low lying parks and valley alluviums and is usually surrounded by Pinyon-Juniper breaks.

The dominant vegetation is an association of salt tolerant low growing shrubs including shadscale, four-winged saltbush, nuttall saltbush, horsebrush, spiny hopsage, winterfat, black sage, low yellow brush, and greasewood.

Grasses found in the potential saltbush plant community include Indian ricegrass, squirreltail, galleta, perennial ryegrasses, and small amounts of native annuals.

Forbs common in the association are desert mallow, wild buckwheat, Indian wheat, stick seed, loco, and cactus.

Because of high summer temperatures and low summer rainfall, livestock use by sheep and cattle is generally limited to the winter months. Primary livestock use is by sheep. Many of the shrubs common to the plant community are palatable and provide good winter forage. Sheep also utilize the moderate snowfall that occurs during the winter months in lieu of water facilities.

Big game use of the saltbush type is limited to winter use by migratory mule deer. The principal winter range of the mule deer herd is the pinyon-juniper and lower sagebrush communities. Species in the saltbush community preferred by deer are four-winged saltbush, low yellow brush, and winterfat. The saltbush type in the Piceance Creek Basin is relatively insignificant as mule deer habitat.

The saltbush type supports a variety of small animal species. The principal species is the cottontail rabbit which utilizes most plant species in the plant community. This animal is able to obtain its water requirements from plants, including prickly pear cactus.

Predators that prey primarily upon the rodent population include various species of raptors, bobcats, and coyotes.

Grazing by livestock is the primary man caused activity influencing the successional stage of the plant community. In its potential condition, the plant community is sparse and provides only about 15 percent ground cover. While proper winter use is not generally detrimental to the physiology of the plants, soil disturbances caused by trampling tends to accelerate erosion. Areas of heavy livestock concentrations such as bed grounds revert quickly to lower plant successional stages.

As the plant community regresses, perennial grasses and shrubs are replaced by cactus, and annual plants including cheat grass, kochia, halogeton, Russian thistle, mustards, and six-weeks fescue.

b. Greasewood

This type includes areas where greasewood (Sarcobatus) is the predominant vegetation or gives a characteristic aspect. Usually this type occupies valley floors subject to overflow during flood periods or areas underlain with ground water where the soil is more or less saline.

It is a common vegetative type in the drainage bottoms and adjacent benches of Piceance Creek tributaries and occurs from the upper reaches of the watersheds to the White River.

Because of its valley bottom occurrence, the site is commonly subjected to heavy grazing use by livestock. In areas where grazing use has historically been moderate, the greasewood frequently forms open stands with dense cover of perennial grasses.

Principal grass species are western wheatgrass, squirreltail, basin wildrye, slender wheatgrass, and Kentucky bluegrass.

Forbs include wild onion, dock, wild buckwheat, tansy mustard, milkvetch, primrose, gilia, and stickseed.

Other shrubs commonly found in the association are tall rabbitbrush, four-winged saltbush, and big sagebrush.

At present, many of the greasewood bottoms contain deep active gullies, an apparent result of vegetative cover loss on the watersheds. The deepening gullies result in drainage and lowering of the water table in the valley bottoms. Greasewood is a strong phreatophyte capable of extending its root system to depths of over 30 feet to utilize the receding watertable. As the watertable recedes, understory plants tend to decrease and practically pure stands of greasewood result.

The migratory mule deer herd finds little palatable forage in the greasewood bottoms, but may utilize the areas for cover during spring, fall, and winter.

The greasewood type affords excellent habitat for small game animals, including cottontail rabbits and chukar partridges.

Cattle find good grazing in the type when it is near potential with a good grass understory. As the site regresses to pure stands of greasewood, primary use by cattle is for protection from inclement weather.

c. Pinyon-Juniper

This vegetative type comprises about 35 percent of the Piceance Creek Basin. It is dominated by a tree cover of juniper and pinyon pine. The type occurs on a wide variety of soils and slopes from steep rocky breaks to high flat mesas and ridgetops. It occupies elevations between 5,000 and 6,500 feet and is generally intermingled with the sagebrush type.

Stand form of the pinyon-juniper varies considerably. On some sites, juniper grows alone in open stands. On others, various mixtures of the two occur with equal proportions or one or the other dominant. Dense stands of even age trees are common and may dominate a site so that the soil surface is largely barren of understory plants. Young stands can be found throughout the type where young trees appear to be invading grassland openings or adjacent sagebrush type.

Most ecologists agree that fire is an important factor in the ecological processes of the pinyon-juniper type. Natural fires from lightning tend to burn off ridge tops and mesas, creating parts and open areas which revert to grasslands. In recent years, ranchers have burnt off large areas of pinyon-juniper to improve grazing conditions for livestock. Chaining by ranchers and government agencies has also created large grassland areas within the pinyon-juniper type.

Leopold (1924) considers grassland openings within the pinyon-juniper to be temporary communities that will ultimately be reinvaded by pinyon and junipers to form the potential plant community. Others contend that the grassland communities are climax and invasion occurs with disturbance to the grassland. This contention is supported by the fact that soils in the grassland parks are of a type that evolves with grassland vegetation.

In any event, when the pinyon and juniper trees are removed, the resulting grassland vegetation persists for many years.

There is considerable variation in associated understory plants in the pinyon-juniper type. As previously stated, mature even-age stands contain practically no understory vegetation. Maximum forage production occurs generally in the grassland parks and in open areas within the type.

Possibly because the Piceance Creek Basin represents the northern most range of the pinyon-juniper type, plant succession from bare ground following destruction of the trees to a perennial grass-shrub association is rather rapid.

A dense ground cover of annuals such as cheatgrass and Russian thistle in association with Indian ricegrass, an aggressive perennial bunchgrass, commonly establishes the first year following destruction of the trees. Within 3 or 4 years, with protection from grazing, the invading annuals diminish and a mixed stand of perennial grasses, forbs, and shrubs forms the stable long lasting open parks of the pinyon-juniper type.

Periods of drought or grazing pressure may prolong the successional process and may also affect the resulting composition of the plant community. Variations will also result from site factors such as elevation, aspect, and soil conditions.

In the final stages of succession in the pinyon-juniper parks, dominant plants include Indian ricegrass, beardless bluebunch wheatgrass, beardless wildrye, Sandbergs bluegrass, and junegrass.

Shrubs include bitterbrush, mountain mahogany, low rabbit-brush, serviceberry, and big sagebrush.

Forbs are generally not abundant but may include scarlet globemallow, hairy goldaster, fleabane, goldenweed, gumweed, and gilia.

In open stands of pinyon-juniper, a great variety of local understory plant communities occur. Shrub communities of bitter-

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brush and mountain mahogany are common along ridgetops and open slope areas.

Perennial grasses including Indian ricegrass, beardless bluebunch wheatgrass, and Sandberg bluegrass form stands throughout the type where they are able to avoid the inhibiting influences of the trees. Forbs are also scattered throughout the stand where local environmental factors are favorable.

The pinyon-juniper type of the Piceance Creek Basin provides ideal winter range for the White River migratory mule deer herd. The broken rough country and dense stands of pinyon and junipers provide cover and protection. Beneficial "edge effect" is prominent where dense stands of trees meet the open parks and ridges. High quality browse plants used for winter forage are relatively abundant in parks and open areas. These include bitterbrush, mountain mahogany, and serviceberry.

In the spring before migration to the mountain shrub country, the deer feed heavily on the early greening native bluegrasses of the pinyon-juniper slopes.

The pinyon-juniper type also provides excellent habitat for a variety of small animals including rabbits, squirrels, rodents, birds, and various predators. The small animals feed upon pinyon nuts, juniper berries, plant seeds, and a variety of plants.

d. Sagebrush

This type comprises about 35 percent of the Piceance Creek Basin and includes all land having an aspect dominated by big sagebrush and related species and subspecies.

Because of the wide environmental adaptability of big sagebrush and its low palatability factor for livestock, it occurs as a dominating aspect species on a variety of sites from the lowest elevations to the coniferous forest.

The Soil Conservation Service describes 10 major plant communities in the Basin having distinctive soils and plant associations that may at some stage of plant succession present a dominating sagebrush aspect.

The sagebrush type is most prevalent on deep medium textured soils on benches, mesas, and valley alluviums. It intermingles throughout the region with the pinyon-juniper and mountain shrub types.

Associated plant communities vary widely in species composition and forage production capability. Major factors determining associated communities are soil type, elevation, and past grazing use.

In the lower elevations on medium textured soils, Indian ricegrass, squirreltail, Sandberg bluegrass and blue grama may dominate the association. At the same elevation on heavier soils, western wheatgrass frequently dominates. On those sites, air dry forage production may reach 600 lb/acre.

At the intermediate elevations, a wider variety of grasses and forbs are found. Needle-and-thread grass, sand dropseed, and several native bluegrasses may dominate the light textured soils. On medium textured soils, dryland sedges, slender wheatgrass, muttongrass, Junegrass and bluegrasses mix with a variety of forbs including balsamroot, lupine, yarrow, geranium, buckwheat, etc. Dense stands of western wheatgrass are common on fine textured soils. On these sites, air dry forage production may reach 1500 lb/acre.

At the higher elevations, big sagebrush may be replaced by silver sage (Artemisia cana). Grass species include mountain brome, Idaho fescue, Thurbers fescue, Columbia needlegrass, slender wheatgrass, Kentucky bluegrass, and timothy. Forbs from the intermediate zones persist at the higher elevations. Forage production may exceed 2,000 lb/acre air dry.

Because of the high forage yields of grass from sites within the sagebrush type, it has been a favored type for livestock grazing. Early grazing is known to have been exceedingly heavy. Selective grazing by cattle has greatly diminished the climax perennial grasses over much of the type. As the grasses diminish, big sagebrush rapidly replaces them. Many sites supporting no more than 5 to 15 percent sagebrush in the potential plant community now contain up to 75 percent big sagebrush.

In the lower elevations, early successional stages are commonly dominated by annuals such as cheatgrass and Russian thistle and undesirable perennials including snakeweed, fringed sage, and various forbs. These occur in an open stand of sagebrush.

As the type approaches the lower stages of plant succession, sheet and gully erosion accelerate at all elevations.

In recent years, some areas of the sagebrush type have been sprayed with the selective herbicide 2,4-D to control big sagebrush. Kills of 85 to 90 percent are common if applications are correctly applied. Recovery of the perennial grasses and forbs after release from the sagebrush competition is impressive. Forage production is commonly increased by 200 to 300 percent. The reestablishment of sagebrush following spraying depends upon the degree of grazing use. With proper grazing, big sagebrush increases in percentage of the plant community composition only to the climax community level. With heavy grazing, the site is soon reinvaded by dense stands of big sagebrush. See section 6, "Fauna of the Piceance Creek Basin," for description of mule deer use of the sagebrush types.

Small animals, including rabbits, rodents, and upland game birds, make good use of the sagebrush type. It affords the primary habitat for sage grouse which utilizes sagebrush for food, mating grounds, and nesting areas.

e. Mountain Shrub

This type comprises about 20 percent of the Piceance Creek Basin. It includes about five identifiable subtypes all characterized by the dominance of woody shrub species.

Mixed communities are most common in the Basin. These communities contain open to dense stands of serviceberry, mountain mahogany, snowberry, rose, and bitterbursh in various combinations.

A large variety of grasses and forbs occur in the understory. Grasses include needlegrasses, bromes, wheatgrasses, and bluegrasses. Common forbs are balsamroot, lupine, yarrow, buckwheat, geranium, cinquefoil, and penstemon.

Ecologically, the brush communities are rather stable. Grazing by livestock, browsing by mule deer, and fire are the major factors causing successional changes in vegetation.

Fire is an important factor primarily in the thicket type stands of Gambel oak. These stands have historically been subjected to natural fires, fires set by Indians to facilitate hunting, and fires set by livestock interests to improve understory forage production.

Following fire, there is an increase in grasses and forbs released from the oak competition but sprouting rootstocks soon reestablish the oak thickets.

Livestock grazing, if excessive, produces a pronounced change in understory vegetation. Palatable perennial grasses decrease and are replaced by forbs and grasses of lower palatability.

High deer populations have contributed to the present plant community situation. Heavy browsing of selected species, including mountain mahogany, serviceberry, and bitterbrush, has kept these species hedged to a low growth form, decreased seed production, and reduced seedling establishment.

The type occurs on moderate to steep slopes on a variety of soils but usually on stony or gravelly soils that are well-drained.

It is generally limited to elevations of 6,500 to 7,500 feet in the Piceance Creek Basin. It forms an erratic pattern in the upper reaches of the subwatersheds where it intermingles with the sagebrush type and upper pinyon-juniper. At its upper limits, it borders the aspen and coniferous forests.

Major shrub species that occur as single species stands or in a variety of mixtures include mountain mahogany, serviceberry, bitterbrush, snowberry, rose, and Gambel oak.

Where Gambel oak dominates, it may form dense thickets, open stands, or a clump aspect. Elk sedge is commonly the dominant understory plant. Grasses include slender wheatgrass, western wheatgrass, native bromes, and needlegrasses. Common forbs include aspen peavine, fleabane, yarrow, lupine, and American vetch.

Brush communities dominated by serviceberry are also common in the Piceance Creek Basin. These vary from open stands of low growth form to mature stands where serviceberry plants may reach heights of 10 feet or more.

In the mature stands, understory vegetation is generally sparse because of competition from the serviceberry. Chokeberry sometimes occurs in these stands. Understory communities that occur are similar to those of the Gambel oak stands.

Communities dominated by mountain mahogany occur as open or moderately dense stands but are generally not large.

These influences, particularly in the mixed stands, have caused changes in relative plant composition. More grasses and forbs appear or there is an increase in the less palatable shrubs such as snowberry, rose, and sagebrush.

This vegetative type is extremely important as mule deer habitat. It is used heavily by migrating deer leaving the lower winter range in the spring and again as they return in the fall. In the higher mountain shrub sites, deer utilization may occur throughout the summer. Lower sites may be utilized throughout the winter. The degree and range of winter use is generally dependent upon the amount and distribution of snowfall.

Species preferred by deer are mountain mahogany, serviceberry, and bitterbrush, but other associated shrub species are also browsed. Some utilization is also made of grass and forb species in the understory.

The mountain shrub type also affords excellent cover for deer. This is important since deer are commonly in this type during their migration to the winter range at the hunting season.

The type also provides year-round habitat for a variety of small animals including cottontail rabbits, small rodents, and birds.

f. Aspen

This vegetative type is readily identifiable by the dominance of aspen trees (Populus tremuloides). It occurs only at the higher elevations of the Piceance Creek Basin, primarily along the ridges of the Book Cliffs and Cathedral Bluffs in the southern portion of the Basin. It intermingles with the coniferous forest type at elevations above 7,000 feet. It comprises less than 5 percent of the total Basin area.

Ecologically the aspen community is generally considered a transition type that occupies coniferous forest sites temporarily following fire. It is also found on soils that are more chernozenic than forest types where it appears to be able to maintain itself and withstand invasion of conifers.

Aspen trees are generally found on north and east exposures. They are intolerant of shade and reproduce primarily from rhizonatous rootstocks. On the deep soil sites, a dense understory of grasses and forbs may produce over 3,500 lb of air dry forage per acre.

On the shallow mineral soils where it is a succe- -onal stage reverting to conifers the understory may contain understory plants found in the coniferous forest and a mixture of other grasses and forbs. Here total forage production is much less than on the deep soil sites.

Most of the aspen type found in the Basin is the successional type. Within this type, during its dominance, successional stages occur in the understory vegetation. The primary factor affecting understory vegetation is grazing by cattle.

Where grazing has been light or moderate the understory will contain plants from the coniferous type and perennial native grasses including mountain bromes, blue wildrye, Thurbers fescue, oatgrasses, and needlegrasses.

Heavy use by cattle generally causes a decrease in these species. A lower successional plant association results dominated by plants unpalatable to cattle or with the ability to withstand grazing. These include Kentucky bluegrass, smooth brome, orchard grass, dandelion, yarrow, pusseytoes, fringed sage, and Oregon grape.

Because of its high elevational range, grazing use by livestock and wildlife is limited to the summer months. Primary use is by cattle that seek the palatable understory vegetation and shade. Most of the Piceance Creek migratory mule deer summer outside the Piceance Creek Basin; however, some spend the summer in the aspen and coniferous forest sites.

A small herd of elk also utilizes the Piceance Creek summer range at the higher elevations.

Small game utilizing the aspen type include varying hares, marmots, and several species of upland grouse. The type also provides habitat for a variety of rodents and birds and associated predators.

g. Conifers

This type includes several subtypes where the dominant vegetation is coniferous trees other than pinyon-juniper. It also comprises less than 5 percent of the Basin area and is limited to elevations above 7,500 feet.

Douglas fir communities are common on north and east facing slopes and in high narrow canyons. In its lower and intermediate elevations, it is associated with Ponderosa pine and aspen. In the upper elevations it will be associated with Engleman spruce, and subalpine fir. It is seldom a pure type, but will vary from 40 to 90 percent of the overstory.

Engleman spruce and subalpine fir are found only at the highest elevations in the basin, usually at 8,500 feet. They may associate with stands of lodgepole pine, Douglas fir, and aspen. Open grassland parks are common in this subtype.

Understory vegetation varies from practically none in dense timber stands to high density grass-forb associations in the open parks.

Species commonly found in the forest understory include Kinnikinnick, boxleaf myrtel, common juniper, Oregon grape, snowberry, mountain muhly, Thurbers fescue, Fendlers bluegrass, and elk sedge.

In the open parks, grass species include Idaho fescue, Thurbers fescue, native bluegrasses, bromes, and needlegrasses. Forbs include cinquefoil, geranium, golden pea, strawberry, etc.

The coniferous forest type affords summer habitat for a limited number of mule deer and elk.

Small game animals include the varying hare, marmot, and several species of upland grouse. Several species of small tree squirrels and rodents utilize the type. A variety of songbirds and raptors are also found in the type.

Table II-27 indicates the occurrence of plant species in the above described vegetative types.

Table II - 27 --- Major Vascular Plant Species of the Piceance Basin

Scientific Name	Common Name	Saltbush	Greasewood	Pinyon-Juniper	Sagebrush	Mountain Shrub	Aspen	Conifers
		Occurrence in Vegetative Types						
Grasses:								
Agropyron inerme	Bluebunch wheatgrass	X	X	X	X			
Agropyron smithii	Western wheatgrass		X	X	X	X		
Agropyron subsecundum	Bearded whatgrass					X	X	X
Agropyron trachycaulum	Slender wheatgrass					X	X	X
Bouteloua gracilia	Blue grama			X	X			
Bromus anomalous*	Nodding brome					X	X	X
Bromus tectorum	Cheatgrass	X	X	X	X			
Elymus cinereus	Basin wildrye	X	X	X	X			
Elymus salinus*	Salina wildrye	X	X					
Festuca idahoensis	Idaho fescue					X	X	X
Festuca thurberi	Thurber's fescue						X	X
Hilaria Jamesii	Galleta	X	X	X	X			
Hordeum jubatum	Foxtail barley	X	X					
Koeleria cristata	Junegrass				X	X	X	
Oryzopsis hymenoides	Indian ricegrass							
Phileum pratense	Timothy						X	X
Poa fendleriana	Mutton grass			X		X	X	
Poa pratensis	Kentucky bluegrass				X	X	X	X
Poa secunda*	Sandberg bluegrass	X	X	X	X	X		
Sitanion hystrix	Squirrel tail	X	X	X	X	X		
Sporobolus cryptandrus	Sand dropseed	X						
Stipa comata*	Needle and thread	X	X	X	X			
Grasslike								
carex geyeri*	Elk sedge				X	X	X	X
Juncus balticus**	Baltic rush				X	X	X	X

Table II - 27---Major Vascular Plant Species of the Piceance Basin(continued)

Scientific Name	Common Name	Saltbush	Greasewood	Pinyon-Juniper	Sagebrush	Mountain Shrub	Aspen	Conifers
		Occurrence in Vegetative Types						
Forbs								
Archilea lanulosa	Yarrow					X	X	X
Allium textile*	Onion	X	X					
Antennaria rosea	Pussey toes			X	X	X		
Artemisia ludoviciana*	Louisiana sagewort							
Astragalus bisulcatus*	Two-grooved milkvetch							
Balsamorhiza saggitata	Arrowleaf balsamroot			X	X			
berberis repens	Oregon grape						X	X
Chrysopsis villosa	Hairy goldaster			X	X			
Catilleja chronosa*	Indian paintbrush			X	X	X		
Crepis acuminata	Tapertip hawksbeard			X	X			
Erigeron flagellaris*	Trailing daisy-fleabane			X	X	X	X	
Erioganum subalpinum*	Sulphur buckwheat				X	X	X	X
Generanium fremontii*	Fremont geranium				X	X	X	
Gilia aggregata	Scarlet gilia		X	X	X			
Grindelia squarrosa	Curleycup gumweed		X	X				
Halogeton glomeratus	Halogeton	X	X					
Happolopappus acaulis*	Stemless goldenweed			X	X			
Heracleum lanatum	Cow parsnip						X	
Iris missouriensis**	Iris	X	X	X	X	X	X	
Lappula redowski	Stickseed	X	X	X				
Lathyrus leucanthus	Aspen peavine						X	
Ligusticum porteri	Wild celery							
Lithospermum ruderale	Stoneseed				X	X		
Lupinus argenteus*	Silvery lupine							
Oenothera nudicaulis	Evening primrose		X	X				
Penstenon secundiflorus*	Sidebells penstemon			X	X			
Phlox hoodii*	Hood's phlox	X	X	X				
Polygonum douglasii	Douglas knotweed		X	X	X	X	X	X
Rumex crispus**	Curley dock	X	X					
Salsola kali	Russian thistle	X	X	X	X			
Senecio fendleri*	Fendler's groundsel		X	X	X	X		
Sisymbrium altissimum*	Tumbling mustard	X	X	X	X			
Spaeralcea coccinia	Scarlet globemallow	X	X	X	X			
Thermopsis montana	Golden pea					X	X	X
Trifolium gymnocarpon*	Hollyleaf clover		X	X	X			
Zygadenus gramineus	Death camas		X	X	X			

Table II - 27---Major Vascular Plant Species of the Piceance Basin(continued)

Scientific Name	Common Name	Saltbush	Greasewood	Pinyon-Juniper	Sagebrush	Mountain Shrub	Aspen	Conifers
		Occurrrence in Vegetative Types						
Amelanchier utahensis	Service berry			X	X	X		
Artemisia frigida	Fringed sagebrush	X		X	X			
Artemisia cana	Silver sagebrush						X	X
Artemisia tridentata*	Big sagebrush	X	X	X	X	X		
Atriplex canescens	Four-wing saltbush	X	X	X	X			
Atriplex confertifolia	Shadscale	X	X					
Atriplex nuttallii*	Gardner saltbush	X	X					
Cercocarpus montanus	Mountain mahogany			X	X	X		
Chrysothamnus nauseosus	Rubber rabbitbrush	X	X	X	X			
Chrysothamnus viscidiflorus	Douglas rabbitbrush	X		X	X			
Eurotia lanata	Winterfat	X	X	X	X			
Grayia spinosa	Spiny hopsage	X						
Gutierrezia sarothrae	Snakeweed	X	X	X	X			
Opuntia polyacantha*	Prickly pear							
Plantage purshii	Indianwheat							
Potentilla fruticosa	Shrubby cinquefoil					X	X	X
Prunus virginiana demissa	Western chokecherry					X		
Purshia tridentata	Antelope bitterbrush			X	X			
Rosa nutkana	Rose					X	X	X
Sympnoricarpos oreophilus	Mountain snowberry					X	X	X
Sarcobatus vermiculatus	Greasewood							
Tetradymia canescens*	Snooth horsebrush		X	X	X			

* "and others", the listed species is typical; others may also occur in the area, but are not listed.

** Occurs in intrazonal locations

9. Recreation Resources

The hunting of mule deer during October and November is the major annual recreational use of the Basin. The Colorado Fish, Wildlife and Parks Division records show that over 5,000 hunters spend approximately 40,800 hunter days during the hunting season and harvest an average of 5,500 deer. A few elk and black bears are also taken each year.

Nonresidents, 29,400 in 1969, constitute a large portion of the Piceance Creek hunters. Many utilize trailers or campers brought from their home states. Developed facilities for recreational activities in the Basin are generally lacking. Local ranchers commonly guide out-of-state hunters from their ranch headquarters for a fee.

The Piceance Creek Basin is sparsely populated but is generally accessible to motor vehicles. The area is visited sparingly by tourists at times other than during the big game hunting season. This is probably because of the proximity of the area to more desirable country with high recreation values.

Fishing in the basin is limited to several man-made ponds in the major drainage bottoms and in the headwater of several small live streams.

There are no commercial recreation facilities within the Basin other than ranch headquarters. Recreational access to some public land is impaired as a result of private ownership of adjacent lands. Service centers utilized by hunters and local recreationists are the towns of Rifle, Meeker, and Rangely, each about 20 miles from the Basin perimeter. These communities also serve fishermen, hunters, winter sports participants, and campers utilizing the high quality recreation facilities of the White River National Forest and surrounding area.

In the environs around, but somewhat distant from the Piceance Creek Basin, there are many other recreational activities and opportunities. Some of the more spectacular scenic areas in the region surrounding the oil shale lands include Dinosaur, Arches, Canyonlands and Black Canyon National Monuments, Colorado, and numerous scenic areas and campgrounds of the National Forest, such as the White River and Uncompahgre National Forest. These prime scenic areas are within 100 miles of the oil shale lands. Some of the country's better ski areas are located near Snowmass, Aspen, and Vail, Colorado, less than 100 miles from the oil shale areas. Municipal or club golf courses, swimming pools and rodeo grounds are available to the public in most of the larger towns near the oil shale lands.

The quality and type of outdoor recreation, like most uses of the land, are primarily controlled by the landscape and its attending components of soil, climate, relief, water, vegetation and wildlife. In the Piceance Creek Basin the primary outdoor recreation activities are oriented around hunting, fishing, and camping. The 800,000 odd acres of the Basin are located mostly in the central third of Rio Blanco County, with a small portion lapping over into Garfield County. Rio Blanco and Garfield Counties along with Moffat County to the north make up the Northwest Colorado Recreation Region (R6). 1/ All three counties contribute a significant portion to the hunting, fishing, and camping resources of Colorado.

Recreation inventories 2-3/ for Rio Blanco County reveal that outside of the Piceance Creek oil shale area there are approximately 25 private ranches that cater to hunting and fishing clientele: and 16 resort operators who specialize in providing hunting, fishing, and rural living accommodations. In addition to these accommodations there are 78 ranches in the county, most all of which are outside of the shale area, which provide hunting on a fee basis. The average size of these ranches is 500 acres, with 20 hunters per ranch. Hunting outfitters in the county total 27.

1/ 1970--Colorado Comprehensive Outdoor Recreation Plan.
2/ 1965--Bureau of Outdoor Recreation Survey of Public Areas and Facilities, USDI.
3/ 1971--An Appraisal of Outdoor Recreation in Rio Blanco County, Colorado, USDA, SCS.

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Public recreation in Rio Blanco County is located mostly on National Forest lands in the eastern third of the county and on Bureau of Land Management lands in the western half of the county. Major recreation areas, called recreation complexes, administered by the BLM within or around the perimeter of the Piceance Creek Basin include: Douglas Creek (400,000 acres), Piceance (268,476 acres), Strawberry (40,000 acres), and Yellow Creek (343,468). Visitation to these areas in 1965 totaled approximately 30,000 visitor days.

Potentials in Rio Blanco County are as follows: high for camping, pack trips, cold water fishing, big and small game hunting, and vacation ranches; low for warm water fishing; and medium for water sport areas, and waterfowl hunting. At present, however, big and small game hunting is the principal recreational activity.

Rio Blanco County includes important natural, scenic or historic areas. Approximately twenty areas have been inventoried.4/ The most notable are the Flat Tops Wilderness Area, Douglas Creek and Missouri-Texas Creeks, Moon Canyon, Cathedral Bluffs, Raven Ridge, and Piceance Creek. White River Road-U.S. Highway 40, which traverses east to west just north of Piceance Creek Basin, is being considered as a potential scenic highway. Personal communications

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4/ 1971--An Appraisal of Outdoor Recreation in Rio Blanco County, Colorado, USDA, SCS.

with a member of the Colorado Grotto of the National Speleological Society reveals that there are numerous caves in the limestone formations between Meeker on the north and Glenwood Springs on the south. One of these is located on the South Fork campgrounds area of the White River National Forest.

10. Archaeological and Historical Values

There are no historic sites listed for Rio Blanco County, Colorado, in the National Register of Historic Places.

Rio Blanco County has identified the Ryan Gulch School as a local historic site. In addition, the Rio Blanco County Historical Society has just finished compiling a book on Rio Blanco history.[5/]

There are indications in the Piceance Basin that campsites of presently unknown nomadic hunting peoples, possibly Ute and older, may be found on the ridges above the valleys, in select caves, and near water sources.

Farming activity along the main drainages precludes any surface indications of Indian activity. Gully erosion of some bottom land may expose evidence of early peoples.

5/ Gitchel, Ron. Meeker, Colorado, Meeker Town Planning Commission, Meeker, Chamber of Commerce (page 90 G-J Hearings, Friday, October 13, 1972) Lines 17-25.

Archaeological study of the oil shale areas has been very limited. The Midwest Archaeological Center, National Park Service, Lincoln, Nebraska; Colorado Historical Society, Denver, Colorado; and Department of Anthropology, Colorado University, Boulder, Colorado, have no record of known archaeological sites occuring on or near the public oil shale areas being considered for development. The Colorado Historical Society lists the Meeker Massacre Site and Thornburg Battle Site in Rio Blanco County as potential historical sites. These are both outside, although adjacent to,the oil shale areas.

11. Socioeconomic Resources

The Piceance Creek Basin is located on the "Western Slope" of Colorado, at some distance from any major population center. Access routes include U. S. Highway 6 along the Colorado River, Colorado Highway 64 along the White River, and Colorado Highway 13 on the east and 139 on the west (Figure II-28). Many unsurfaced roads and rough trails lead into and across the area from the main access routes. A paved county road traverses the area along Piceance Creek. The shale area, approximately 1200 square miles, is sparsely settled, with 150 people living in the Basin itself. The inhabitants are generally widely dispersed and are engaged in the livestock, mineral, oil and gas industries, or in farming.

The principal oil shale areas of the Piceance Creek Basin are in Garfield and Rio Blanco Counties. Mesa County also contains a minor amount of oil shale.

A description of the principal supply centers and facilities (socioeconomic resources) of the communities in the surrounding areas is as follows:

Grand Junction (population 20,200), the county seat of Mesa County and the largest community of western Colorado, is a transportation hub with rail, truck, and highway communication with western Colorado and more distant points and with frequent jet air service, principally to Denver and Salt Lake City. Grand Junction is also a commercial and medical center for the region, with a number of wholesale supply firms and services, as well as educational and other professional services (See also Wengert).

The town of Rifle (population 2,500), situated in Garfield County on the Colorado River at the southeastern corner of the Piceance Creek Basin, has been oriented toward both industrial activity while acting as an agricultural supply center. It is the site of a Union Carbide vanadium-uranium mill which is now being closed and is the nearest community to the Bureau of Mines' research facility at Anvil Points. The Denver and Rio Grande Railroad has made it a shipping point for livestock from the Piceance Creek Basin.

Glenwood Springs (population 4,100) the county seat of Garfield County, is situated at the junction of the Roaring Fork and Colorado Rivers. This community has become the focal point of distribution of goods and services to the very large areas drained above it by the, Colorado, Eagle, Roaring Fork, Frying Pan and Crystal Rivers.

Meeker, the county seat of Rio Blanco County, is situated on the White River northeast of the oil shale area. It is mainly an agricultural supply center. The town population is about 1,500.

The town of Rangely, in Rio Blanco County, is situated on the White River, northwest of the Piceance Creek Basin. It is an operation center for the Rangely oil field, and the site of a western Colorado junior college. The town population is also about 1,500.

In 1970, Garfield County had a population of 15,000. The total number of employed persons during that same year was 6,000, with an unemployment rate of 4.9 percent. Retail trade provided the greatest amount of income to the community in 1967, with sales totaling over $27 million. The agricultural sector, which is considered one of the primary sources of income for the area, provided employment for 483 persons in 1970. The value of the farm products sold in 1969 (including livestock) was $6.7 million. Total revenue to the county government in Garfield County in 1967 was $5.2 million and total expenditures were $5.4 million. (See Table II-30 for a breakdown of expenditures by purpose.)

Mesa County, located south of the Piceance Basin, has the largest population of the three counties. In 1970, the population of Mesa County was 54,000. Grand Junction, located in Mesa County, had a population of 20,100. Slightly less than one-half of Grand Junction's employed persons are either blue collar or service workers. This is also true of the county as a whole. Approximately one-third of the county's total number of employed persons are located in Grand Junction.

Mesa County government revenue received was $20.6 million in 1967. Expenditures during that year were close to $22 million, of which $13.6 million were spent on the local school systems. (See Table II-30 for other expenditure items.) The major source of income to the community was from retail trade in 1967 (sales totaled $81.5 million). Commercial income from the agricultural sector (valued at $81.1 million) was 22 percent of retail trade.

Rio Blanco County will be most directly affected by the oil shale development because of its location, which includes a major portion of the Piceance Basin. In 1970, the total county population was 5,000. Meeker, the county seat, and Rangely, are principal towns of the county.

Rio Blanco County has the highest per capita property tax receipts ($452, compared with $149 for Mesa County and $163 for Garfield County) of the three counties. However, the amount of revenue collected in 1967 was the least of the three. In 1967, Rio Blanco County government revenue was $3.4 million, less than one-quarter of the revenue collected by the Mesa County government.

Rio Blanco County expended $1.4 million in 1967 for educational purposes, which was more than one-third of its total annual revenues. The towns of Rangely and Meeker are considered to have excellent school systems. Each community has a hospital with at least 20 beds and in 1967 $.5 million were expended by the county for health and hospital services. The county had 12 resident physicians, dentists, and/or medical practitioners in 1970.

The value of the farm products sold in Rio Blanco county in 1969 ($5.6 million) was the same as the total sales from retail trade ($5.6 million). It is estimated that hunters spend $4 million in the county annually during the deer hunting season. The county had an unemployment rate of 2.1% in 1970, which was below both the national average and the rate for the other two counties. The total number of employed persons in 1970 was 2,000 of which 40% were employed in white collar occupations, 45% in blue collar and service related industries and 15% in the agricultural sector.

Total employment in the minerals sector in the three counties was 1,143 in 1970 (Garfield County 395 persons, Mesa County 468, and Rio Blanco County 280). The value of production in Garfield County was $3.4 million, consisting mainly of vanadium, uranium, and sand and gravel. Rio Blanco County's mineral production was almost totally petroleum and natural gas and was valued at $41.3 million in 1970.

Pertinent economic and social parameters for the three counties are shown in Tables II-28, II-29, II-30 and II-31.

TABLE II-28.--County and City Social Characteristics, for Colorado, 1970.
(Thousands, unless otherwise indicated)

County and City	Population	No. of households	School enrollment Primary-High School		Median school years completed (25 years and over)
Garfield	14.8	5 0	2.7	1.2	12.2
Mesa	54.4	17.6	9.5	4.1	12.3
Rio Blanco	4.8	1.5	.9	.5	12.4
Total	74.0	24.1	13.1	5.8	12.3
City of Grand Junction (Mesa)	20.1	7.2	3.0	1.3	12.3

Source: 1970 Census of Population, General Social and Economic Characteristics -- Colorado. U.S. Department of Commerce, Washington, D.C., 1972

TABLE II-29.--County and City Economic Characteristics for Colorado, 1970.
(Thousands, unless otherwise indicated)

County and City	Employment				Unemployed (percent)	Median family income
	Total employed 16 yrs. and over	White collar	Blue collar	Agricultural		
Garfield..........	5.9	2.5	2.9	.5	4.9%	$8,380
Mesa..............	20.1	9.9	8.9	1.3	5.4%	8,065
Rio Blanco........	2.0	.8	.9	.3	2.1%	8,010
Total.......	28.0	13.2	12.7	2.1	5.3%	$8,122
City of Grand Junction (Mesa)	7.7	4.2	3.4	.1	6.1%	8,092

Source: 1970 census of Population, General Social and Economic Characteristics--Colorado. U. S. Department of Commerce, Washington, D.C., 1972.

Table II-30 - - County Economic Indicators for Colorado - - Government
(Thousand dollars unless otherwise indicated)

Total government finances 1/	County			Total
	Garfield	Mesa	Rio Blanco	
Revenue:				
Total	5,280	20,620	3,430	29,330
Property tax per capita (dollars)	163	149	452	171
Expenditures:				
Total	5,396	22,297	3,385	31,078
Education	2,929	13,642	1,351	17,922
Highways	735	1,471	690	2,896
Public Welfare	619	2,955	143	3,717
Hospitals	-	-	454	454
Health	21	163	2/	184
Police protection	121	392	71	584
Fire protection	9	269	3	281
Sewerage	111	211	48	370
Sanitation other than sewerage	65	166	-	231
Parks and recreation	52	260	69	381
Natural resources	31	437	34	502
Housing and urban renewal	-	-	-	-
Correction	7	32	4	43
Libraries	29	75	6	110
Financial administration	66	256	43	365
General control	182	474	96	752
General public buildings	200	175	35	410
Interest on general debts	71	330	198	599
Other and unallocable	149	988	139	1,276

1/ Fiscal years ending between July 1, 1966 and June 30, 1967.
2/ Less than ½ unit.

Source: U.S. Bureau of the Census, Census of Governments, 1967, Volume 7: State Reports, No. 6: Colorado. U.S. Government Printing Office, Washington, D. C.; 1970.

TABLE II-31.--County Economic Indicators for Colorado--Private Sector
(Million dollars, unless otherwise indicated)

County	Retail trade 1/		Services 1/		Agriculture 2/		
	Total establishments	All sales	Total establishments	All receipts	Acreage farmed (thousand)	Total commercial farms	Value of farm products sold
Garfield	200	27.7	174	4.1	457	309	6.7
Mesa	525	81.5	418	12.2	524	812	18.1
Rio Blanco ...	57	5.6	66	1.6	557	149	5.6
Total ...	782	114.8	658	17.9	1538	1270	30.4

1/ 1967
2/ 1969

Source: U.S. Bureau of the Census, Census of Business, 1967. Volume II, Retail Trade - Area Statistics. Part I, U.S. Summary and Alabama to Indiana. U.S. Government Printing Office, Washington, D.C., 1970. U.S. Bureau of the Census, Census of Business, 1967. Volume V, Selected Services - Area Statistics. Part I, U.S. Summary and Alabama to Indiana. U.S. Government Printing Office, Washington, D.C., 1970.

U.S. Bureau of the Census, Census of Agriculture, 1969. Volume I, Area Reports, Part 41, Colorado. U.S. Government Printing Office, Washington, D.C., 1972

12. Land Use

Public lands in the Piceance Creek Basin serve primarily as livestock forage areas, wildlife habitats, limited natural gas and natural gas liquids production, a watershed, and for outdoor recreation. These uses have not changed appreciably in recent years. The public domain lands are all included in two Grazing Districts administered under the Taylor Grazing Act. About 60,000 authorized animal unit months of forage use are distributed among 45 permittees.

Gas wells, pipelines, and a gas liquids plant of the Piceance dome are on public lands of the Piceance Creek Basin.

Numerous other oil and gas test wells in the Basin are shut in. Some marginal gas wells are being considered for future commercial development if they can be stimulated by fracture techniques.

The privately owned lands are used mostly for farming and livestock grazing. A number of hunting camp-buildings on private land are used during deer hunting season.

13. Land Status

Total land area in the two Bureau of Land Management (BLM) planning units of major significance is 805,420 acres. Land ownership in the two units is as follows:

BLM Planning Unit	Federal (percent)	Public land (acres)	State (acres)	Private (acres)
Piceance Basin	61	264,580	11,526	97,780
Yellow Creek	79	343,989	18,823	68,719

C. Utah (Uinta Basin)

1. Physiography

The Uinta Basin, a broad structural and physiographic basin, is a depression bounded on the east by the cliffs west of the Douglas Creek Arch, the Uintah Mountains on the north, the Wasatch Mountains on the west, and the Roan Cliffs on the south. The richest and thickest deposits of oil shale lie mostly in the Uintah County portion of the basin, which is thus the area of primary concern.

The topography consists of rough mountain terrain and flat valleys, sharply dissected by deep gulleys with adjoining rock capped ridges. Oil shale crops out in cliffs and ledges on the south and east sides of the Basin. Elevations vary from 4,600 to more than 8,000 feet. An aerial view of a typical oil shale exposure is shown in Figure II-44. The area drains into the White and Green River systems and eventually into the Colorado River.

The Green River is the main flowing body of water in the area cutting through the best oil shale deposits in a northeast to southwest direction. The other source of water is the westward-flowing White River, which empties into the Green within the bounds of the Uinta-Ouray Indian Reservation. The Duchesne and Uinta Rivers enter the Green River from the west.

FIGURE II-44.--Aerial View of Green River Formation Escarpment in West Wall of Hell's Hole Canyon, Utah.

2. Climate

This area is semi-arid, characterized by low relative humidity and a wide range of daily temperatures. Summer daytime temperatures reach the 80's and 90's, and at night drop to the low 50's. Winters are cold, with day temperatures ranging from 20°F to 28°F during January. Mean annual temperature is 45°F.

Growing seasons vary greatly, with records showing annual frost-free periods of 90 days to 218 days. The average growing season is about 4 months, from late May to late September.

Precipitation averages about 7 inches at the lower elevations and 15 inches at the higher levels. Records show that about 55% of the precipitation falls as rain during the growing season and the remaining 45% falls as winter snow. Most rainfall comes from thunderstorms, which are short-lived, but of high intensity. As a result, most of the moisture is lost through rapid runoff and evaporation. Snowfall is light, averaging 30 inches per year. However, snow melt in the spring is slow, allowing the soil to absorb most of the snow moisture.

Winds are irregular and light, except when associated with local thunderstorms. Although there is little wind erosion, winds affect the vegetation of the area by evaporating moisture from the soils before it becomes available for plant use.

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3. Geology

The Uinta Basin is a sedimentary, structural, and topographic basin.

Oil shale of the Green River Formation is exposed along the south and east margins of the Basin, and is concealed by younger sediments in the central and northern parts of the Basin. From available drilling information, the thicker, richer oil shale is in the eastern half of the Basin, mostly concealed by younger rocks of the Uinta Formation. Geologic maps and description of the oil shale in the southeastern part of the Uinta Basin are shown by Cashion's USGS Professional Paper 548. The reader is referred to his report for details of distribution of the rock units, oil shale, gilsonite, bituminous rock, and petroleum in the Green River Formation of the area.

a. Stratigraphy

Surface rocks within the area presently considered for development are, for the most part, beds of the Uinta Formation that are composed of brown and gray sandstone, siltstone, and shale. The Green River Formation is exposed in a relatively small part of the total area of the tracts.

The upper part of the Green River Formation is composed chiefly of light-gray to dark-gray beds of marlstone, low-grade oil shale, and some tuff. Saline minerals are found in these upper layers in the form of very thin lenses or beds and small pods. Underlying the upper sequence is a middle sequence composed of dark-gray oil-shale beds. This sequence includes the Mahogany zone and beds above and below it. The lower sequence, that part of the formation below the oil shales is composed principally of interbedded brown and gray sandstone and limestone, in the southeastern part of the Uinta Basin.

The stratigraphic relationships of the oil shale and associated rocks of the Basin are shown in Figure II-45.

b. Geologic Structures

The Uinta Basin is a broad asymmetric synclinal basin. Along the southern flank of the basin the oil shale beds dip gently northward 100 to 200 feet per mile. The trough or axis extends east-west near the north margin of the Basin, and the north flank of the Basin is steeply tilted toward the axis.

A northwest trending series of graben faults offset the oil shale and related rock in several parts of the Uinta Basin. The displacements are generally presumed to be small.

4. Mineral Resources

a. Oil Shale

The lower grade oil shale in the Uinta Basin as known from exploration and as reported in Cashion's Professional Paper 548 underlies about 2,500 square miles of the Basin and contains 320 billion barrels of oil equivalent. The higher grade shale

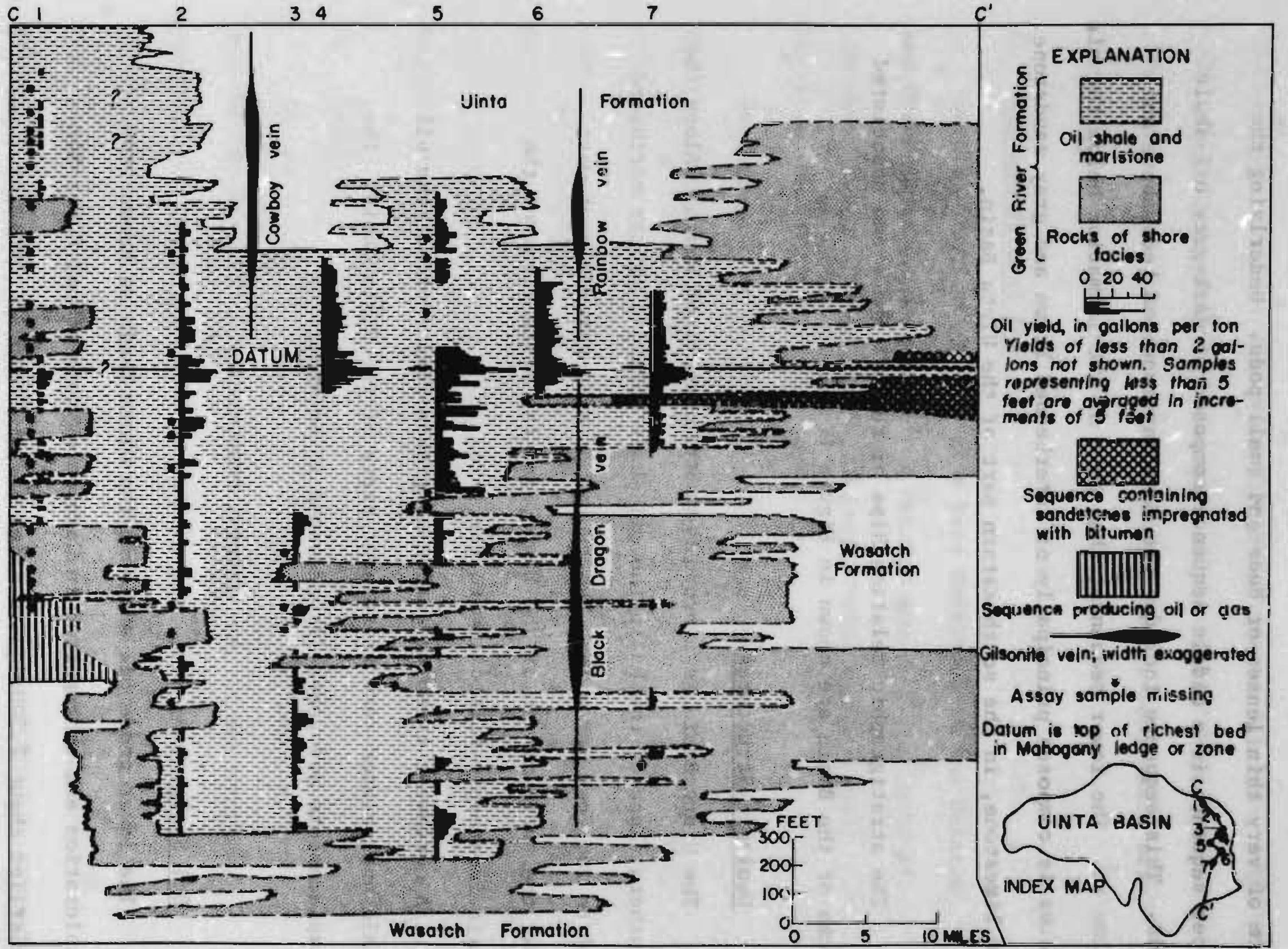

FIGURE II-45.--Cross-Section C-C' of Green River Formation in Uinta Basin, Utah.

of the Basin contains approximately 80 billion barrels in a 1,000 square-mile area of the eastern part of the Basin, where thicknesses of 15 feet or more of rich (30-gallon-per-ton) shale are reported.

b. Oil and Natural Gas

Several large oil fields have been developed in the Wasatch and Green River Formations in the central and northern parts of the Uinta Basin (Figure II-6). The oil fields are situated north of the richer oil shale areas.

Several gas fields have been developed in reservoirs below the oil shale bearing rocks within the rich oil shale areas. The reserves in selected reservoirs are not reported by the producing companies. The Uinta Basin has been only partly explored for oil and gas. Exploration has tested only the upper part of the total sedimentary rock sequence. The sediments below the presently explored deposits may contain undiscovered oil and gas accumulations.

c. Tar Sands

Tar sand deposits (Figure II-8) exist in the Green River and Wasatch Formations of the Uinta Basin. Two of the principal deposits, at Sunnyside and near Vernal, Utah, lie marginal to the area of oil shale interest. A third deposit, known as P.R. Springs, is in the sandstone beds of the Green River Formation, situated 20 to 100 feet below the rich oil shale of the

Mahogany Zone in the southeastern outcrop areas of the Uinta Basin. The tar sands are estimated to contain about 7 billion barrels of bitumen.

d. Gilsonite

Gilsonite and similar solid hydrocarbon veins are numerous in the richer oil shale areas. The gilsonite veins are generally in rocks above the oil shale. They contain about 36-40 million tons of hydrocarbon and have been mined for many years; the wider veins are partly mined out.

e. Other Minerals

Nahcolite ($NaHCO_3$) occurs as very thin lenses or beds and small pods in the upper part of the Green River Formation, mostly in an interval extending from 300 to 600 feet above the Mahogany Zone. The quality is probably not good enough to allow profitable recovery.

There are minor occurrences of uranium in the lower part of the Uinta Formation and the upper part of the Green River Formation of the eastern Uinta Basin. None has been noted in the proposed oil shale tracts.

5. Water Resources

a. Surface Water

Streams in the Uinta Basin, which are within the area of the oil shale deposits, drain relatively low-elevation watersheds that receive small amounts of precipitation each year, therefore, local streamflow is very limited in amount. As shown in Section A.5.a of this Chapter, some 107,000 acre-feet of water annually is potentially available from the Green, White and Yampa Rivers for developemnt of oil shale in the Uinta Basin. This could be made available from the existing Flaming Gorge Reservoir on the Green River and potential reservoir sites on the White and Yampa Rivers. The Utah Division of Water Resources holds a pending application to appropriate 350 cubic feet per second, plus 250,000 acre-feet of water from White River, its tributaries, and ground water. Utilization of water from the White and Yampa Rivers would require construction of dams and reservoirs. Additional water in the area could be made available by purchasing and changing the nature of use and point of diversion of existing senior water rights.

Streamflow records for the White River near Watson, Utah, show a 47-year mean discharge of 702 cubic feet per second. Dissolved solids concentration (20 years of record) ranged from 209 to 2,380 mg/1; and the discharge-weighted mean for 1969 was 408 mg/1.

Records for the streamflow station on the Green River near Jensen, Utah, show a mean flow of 4,307 cubic feet per second. The dissolved solids concentration was 391 mg/1 in 1969.

The streamflow at the gaging station on the Colorado River near Cisco, Utah, has a mean discharge (59 years) of 7,711 cubic feet per second. Dissolved solids concentrations ranged (in 42 years) between 202 and 2,670 mg/1. The mean concentration in 1969 was 631 mg/1.

b. Ground Water

The underground sources of water in the oil shale area of Utah are not well defined. Hydrologic data are not available for many of the formations in the Uinta Basin, mainly because few water wells have been drilled to test the quantity or quality, although some data have been collected during oil and gas exploration. Data are least available in the northwestern part of the basin where oil and gas exploration has not been extensive and water wells have not been drilled deep enough to penetrate all potential aquifers (Feltis, 1966).

According to Feltis (1966) chemical analyses of water from springs, water wells, and oil and gas wells show that parts of the following formations contain fresh water; Madison Limestone, Morgan Formation, Weber Sandstone, Phosphoria and Park City Formations, Navajo and Entrada Santstones, Frontier Sandstone Member of the Mancos Shale, Mesaverde Group, and the Wasatch, Green River, Uinta, and Duchesne River Formations. The areal extent of the fresh water in each formation is not fully known because of the scarcity of points at which samples could be obtained. For most of the formations, fresh water probably is limited to narrow bands in and near the outcrops around the margins of the basin.

In the northeastern part of the basin, outside the oil shale area, warm springs issue from near the top of the Madison Limestone, or possibly at the base of the Morgan Formation, in T. 4 S. R. 24 E. and flow into the Green River. In September 1948, the discharge of the springs above river level was estimated to be 6 cfs and an equal amount or more was believed to discharge directly into the river (Thomas, 1952, p.12). The source of water for the springs is probably from the south flank of the Uinta Mountains where the Madison and Morgan Formations crop out. These formations could also be a partial source of the water produced in the Ashley Valley oil field.

The Morgan Formation, Madison Limestone, and other limestones of Mississippian age crop out over a wide area along the south flank of the Uinta Mountains, and they all should be considered potential fresh-water aquifers along the north edge of the basin. These formations have not been explored in the oil shale areas because of their great depth, but presumably they do underlie the area and are permeable. The overlying Weber Sandstone is another good aquifer near outcrops along the north side of the basin but lies at great depth beneath the oil shale area.

Feltis (1966) reported that the yield of water from the Green River Formation in the Uinta Basin, as indicated by 17 oil and gas wells, ranges from 0.5 gpm to 200 gpm. Two gas wells in sec. 35, T. 10 S., R. 20 E. and sec. 17, T. 10 S., R. 22 E. were converted to water wells; and in 1964 they flowed at rates of 80 and 10 gpm, respectively. The largest reported yield of water from the Green River Formation is from an oil well which produced 220 gpm. Flowing wells are common throughout the interior of the basin.

The Uinta Formation, which overlies the Green River Formation, yields as much as 225 gpm of water through springs. A well in T. 7. S., R. 24 E. yielded 110 gpm of water from the Uinta and another oil well in T. 4 S., R. 5 W. (USM) yielded 30 gpm of water. Wells that could produce as much water as the springs probably could be developed in some areas.

Other formations in the basin are poor aquifers and do not warrant further considerations.

Recharge to bedrock aquifers of the Uinta Basin occurs mostly along the north flank of the basin and to a lesser extent on the areas of highest elevations on the south flank of the basin. Along the north flank runoff from the Uinta Mountains, Split Mountain, and Blue Mountain Plateau percolates into the upturned outcrops of formations that dip steeply into the basin. Precipitation directly on these outcrops also is a source of recharge. Because numerous formations are exposed to recharge, fresh or slightly saline water should be expected in most permeable formations near the north edge of the basin. On the south flank of the basin, most recharge is in the areas of highest altitude where precipitation is greatest. However, because of the low dip of the south flank, few formations except the Green River Formation are exposed to recharge. Wells drilled below the formation that crops out seldom yield fresh or even slightly saline water (Feltis, 1966). Ground-water discharge is along the valley of the Green River and the lower parts of its tributaries. Thomas (1952) reported that ground-water inflow to the Green River in the Uinta Basin is about 240 cfs (about 175,000 acre-feet per year).

Selected hydrogeologic and chemical data on water wells and springs in the Uinta Basin are presented in Table II-32. Most of the formations in the basin are represented in the tabulation, but the small sampling may not be a good indication of the general conditions in the formations.

The Western Oil Shale Corporation drilled a special test hole (WOSCO exploratory hole Ex. 1) in Section 36, T. 9 S., R. 20 E., about 25 miles northwest of site U-a, to obtain detailed information on the oil shale and ground water. The results of the water tests are given in Table II-33. Chemical analyses of water from the intervals tested in the WOSCO exploratory hole Ex. 1 are presented in Table II-34. This test hole flowed only 5 gpm at the land surface.

The dissolved solids content of water from the Green River Formation ranges from 348 to 72,700 mg/l. Feltis (1966) reported that most of the fresh and slightly saline water in the Green River Formation came from wells on the southern flank of the Uinta Basin. He reported that analyses of 73 water samples from 51 wells and 1 spring indicate 4 were fresh, 18 were slightly saline, and the remainder were moderately saline to briny.

The Uinta Formation yields water that ranges in quality from fresh to briny, 237 to 81,200 ppm disolved solids (Feltis, 1966).

Table II-32.--Selected hydrogeologic data from water wells and springs in the Uinta Basin, Utah

Location: Township	Location: Range	Location: Section	Aquifer	Depth to top of formation (ft)	Interval Sampled (ft)	Yield (gpm)	Method or Point of Collection	Date of Collection	Dissolved Solids 1/ ppm
1 N	1 W2/	34	Duchesne River Formation	-	-	<10	Flow	7-6-58	306
*1 N	7 W2/	31	Navajo Sandstone	0	-	40	"	7-4-58	148
1 S	2 W2/	22	Duchesne River Formation	0	60-810	1.8	"	10-6-64	234
1 S	5 W2/	13	" " "	33	199-367	-	Storage tank	10-20-59	380
*1 S	8 W2/	12	Mancos Shale	0	-	1	-	7-4-58	786
*1 S	8 W2/	36	Uinta Formation	0	-	50	From pipeline ½ mile from spring	10-20-54	237
2 S	1 W2/	15	Duchesne River Formation	36	158-557	5	Flow	10-6-64	328
2 S	1 W2/	21	" " "	18	520-540	2.5	"	7-6-58	443
2 S	5 W2/	34	Uinta Formation	-	-	-	-	7-5-58	439
3 S	3 W2/	8	" "	-	106-175	20	Flow	7-5-58	779
3 S	8 W2/	19	" "	0	-	-	-	7-7-58	4,430
*4 S	7 W2/	14	" "	0	-	20	Flow	5-15-60	7,320
*5 S	6 W2/	1	" "	0	-	200	"	5-15-60	1,840
*5 S	7 W2/	12	" "	0	-	225	"	5-15-60	2,710
*2 S	22 E	31	Park City Formation	0	-	1,350	"	8-8-50	228
3 S	21 E	28	Weber Sandstone	1575	1575-2552	140	"	5-25-34	386
3 S	21 E	30	" "	-	At 2660	210	"	10-8-58	432
*4 S	23 E	25	" "	0	-	2	"	11-18-58	712
*4 S	23 E	26	Entrada Sandstone	0	-	2	"	7-12-58	363
*4 S	23 E	27	Navajo Sandstone	0	-	2	"	7-12-58	342
*4 S	23 E	27	Mancos Shale	0	-	1	"	7-12-58	2,620
*4 S	24 E	20	Madison Limestone and Morgan Formation	0	-	5,400±	"	9-19-48	942
*5 S	24 E	32	Weber Sandstone	0	-	10	-	9-13-58	1,960
6 S	23 E	1	" "	2447	2527-2650	1,000	Well head	6-25-57	1,870
*6 S	24 E	5	" "	0	-	10	Flow	7-13-58	911
10 S	20 E	35	Green River Formation	750	-	140	"	7-24-64	2,070
10 S	22 E	17	" " "	1100	2311-3405	10	"	11-30-64	10,500
*15 S	23 E	36	" " "	0	-	1	"	9-17-64	381
*16 S	17 E	3	Wasatch Formation	0	-	225	-	9-25-48	596
*17 S	17 E	20	Mesaverde Group	0	-	-	-	9-25-48	707
*20 S	20 E	17	" "	0	-	-	-	10-20-33	660
*20 S	20 E	27	" "	0	-	-	-	2-24-41	1,090 3/

1/ Dissolved solids calculated from determined constituents except as noted.
2/ Uinta special Meridian.
3/ Residue at 180°C.
* Springs
Source of data: Feltis, 1966

Table II-33.--Summary of hydraulic testing data for WOSCO exploratory hole Ex. 1, Uintah County, Utah, July 1969

Test number and dates	Interval open during test (feet below land surface)	Method	Average discharge (gpm)	Temperature (°C)	pH	Specific conductance (micromhos/cm at 25°C)	Approximate drawdown at end of test[1/] (feet)	Specific capacity (rounded) (gpm per ft drawdown)	Approximate transmissivity[2/] (gpd per ft)	Remarks
1 7/28-29/69	1,900-2,959	Air jetting from 579.1 m (1,900 ft)	8	23	8.6	82,000	1,500	0.005	10	Production from two zones: 2,729-2,809 feet and 2,901-2,929 feet below land surface. Sampled for general chemical, radiochemical, and tritium analyses.
2 7/30/69	1,900-324	do.	16	25	8.7	48,000	1,790	.009	18	Production from three zones: 2,729-2,809 feet 2,901-2,929 feet; and 3,115-3,154 feet below land surface. Sampled for general chemical radiochemical, and tritium analyses.
2a 7/30-31/69	1,900-3,234	Flow	5	23	8.4	54,000	--	--	--	Production from three zones: 2,729-2,809 feet; 2,901-2,929 feet; and 3,115-3,154 feet below land surface. Sampled for general chemical, minor elements, and radiochemical analyses.

Source of data: Weir, 1970

Table II-33.--Summary of hydraulic testing data for WOSCO exploratory hole Ex. 1, Uintah County, Utah, July 1969 continued

Test number and dates	Interval open during test (feet below land surface)	Method	Average discharge (gpm)	Temperature (°C)	pH	Specific conductance (micromhos/cm at 25°C)	Approximate drawdown at end of test 1/ (feet)	Specific capacity (rounded) (gpm per ft drawdown)	Approximate transmissivity 2/ (gpd per ft)	Remarks
3	1,900-2,822	Air jetting from 850.4± m (2,790± ft)	9	28	9.4	85,000	2,750	.003	6	Production from one zone: 2,729-2,809 feet below land surface. Sampled for general chemical, minor elements, radio-chemical, tritium, and carbon-14 analyses

1/ Based on downhole pressure recordings.

2/ Based on specific capacity x 2,000, an approximate method of calculating transmissivity (Brown, 1963, p. 338. and Theis, 1963, p. 334).
Source of data: Weir, 1970

Table II-34.--**Analyses of water from the Green River Formation, WOSCO exploratory hole Ex. 1 July 1969** (After Weir, 1970)

(Analyses by U.S. Geological Survey.[1] Date below sample number is date of collection. Unless otherwise noted, data are in milligrams per liter.)

Element	Sample numbers (1) 7-29-69	(2) 7-30-69	(3) 7-31-69	(4) 7-31-69
Silica (SiO_2)	9.2	8.6	12	9.2
Aluminum (Al)	<.10	<.10	.80	.80
Iron (Fe)	.71	.40	.33	1.1
Manganese (Mn)	.13	.09	.06	.15
Calcium (Ca)	4.1	4.1	2.0	2.8
Magnesium (Mg)	1.2	1.2	1.2	.8
Strontium (Sr)	.70	.44	.70	730
Sodium (Na)	28,000	14,600	16,600	28,500
Potassium (K)	104	53	62	102
Lithium (Li)	.71	.59	.65	.74
Boron (B)	640	300	360	620
Copper (Cu)	.11	.08	.06	.08
Selenium (Se)	<.001	.002	.007	<.001
Zinc (Zn)	.02	.02	.04	.01
Bicarbonate (HCO_3)	5,710	3,830	5,940	5,910
Carbonate (CO_3)	832	856	319	1,230
Sulfate (SO_4)	917	35	400	464
Chloride (Cl)	37,100	18,600	21,500	37,500
Fluoride (F)	60	54	46	70
Nitrate (NO_3)	<.1	<.1	<.1	<.1
Phosphate (PO_4)	.88	.30	.18	.88
Dissolved solids				
Residue on evap. at 180°C	72,200	37,000	41,800	72,700
Hardness as $CaCO_3$				
Total	16	16	11	12
Non-carbonate	0	0	0	0
Specific conductance				
(µmhos/cm at 25°C)	82,000	48,000	54,000	85,000
pH	8.8	8.9	8.6	8.9
Temperature (°C)	23.0	24.5	23.5	27.5

1/ Analyst: O. J. Feist, Jr.

< Less than figure shown.

(1) Interval sampled 1,900-2,959 feet below land surface; sample from zones 1 and 2.

(2) Interval sampled 1,900-3,234 feet below land surface; sample from zones 1, 2, and 3.

(3) Interval sampled 1,900-3,234 feet below land surface; (flow); sample from zones 1, 2, and 3.

(4) Interval sampled 1,900-2,822 feet below land surface; sample from zone 1.

Ground water is not used extensively in the Uinta Basin. Present use is limited to livestock and wildlife supplies and some domestic and small town supplies.

The supply of ground water in the Uinta Basin is not adequate to support a large oil shale industry, unless large supplies could be obtained from the Madison Limestone through deep wells. However, small supplies of fresh or slightly saline water could be obtained to support a small oil shale industry on the south flank of the Uinta Basin.

6. Fauna

Major drainage in the vicinity of the oil shale deposits of Utah are the Green River and White River systems which pass through deep escarpments. Geologic processes have created rugged, dissected terrain that is difficult to traverse, resulting in land forms of great scenic beauty remaining in a state approaching primitive isolation. Within this setting, the Uinta Basin oil shale area provides a combination of vegetative, climatic, physiographic, and cultural conditions which constitutes ideal natural faunal habitat. Many forms of game, as well as non-game birds, and mammals, are present in significant numbers. In their natural association, they constitute a major aesthetic, recreational and economic resource.

Utah's Uinta Basin area provides 1,355,000 acres of important mule deer winter range of which 250,000 acres are considered critical as winter feeding areas (see Figure II-15). An average annual harvest of 8,000 mule deer has been recorded in this area. Small numbers of elk are present in restricted areas (see Figure II-16). Transplanted antelope have become established and are increasing in numbers (Figure II-16). Additional transplants into the area are planned by the Utah Fish and Game Division.

Bears have been reported in the area but are considered scarce. Mountain lions exist in the area, but the population status is uncertain.

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Bears have been reported in the area but considered scarce. Mountain lions exist in the area, but the population is uncertain.

Coyotes, porcupines, bobcats, muskrat, beaver, mink, jack rabbits, cottontails, and many other small mammal species exist in the area. The cottontail is the most important small game species with an annual harvest varying from 10,000 to 15,000. Bureau of Land Management estimates indicate that a herd of about 130 wild horses inhabit the Utah oil shale lands.

Many bird species, including waterfowl (See Figure II-19), wild turkey (See Figure II-18) doves, chukar partridge, numerous song birds, eagles, prairie falcons, golden eagles, bald eagles reside or migrate through the area. Sage grouse occur in limited numbers with restricted distribution (See Figure II-18). The chukar partridge has been introduced to the area, and the population is increasing. Over 1,000 chukars are harvested annually, and more transplants are anticipated.

Headwater drainages throughout the Uinta Basin possess considerable trout fishing potential (See Table II-13 and Figure II-17). Soil surfaces in this area are highly erodable. Heavy siltation and accompanying degradation of water qualities, i.e., blanketing of spawning and nursery habitat and reduction of light penetration has created a generally depleted fishery environment in lower reaches of the major river systems.

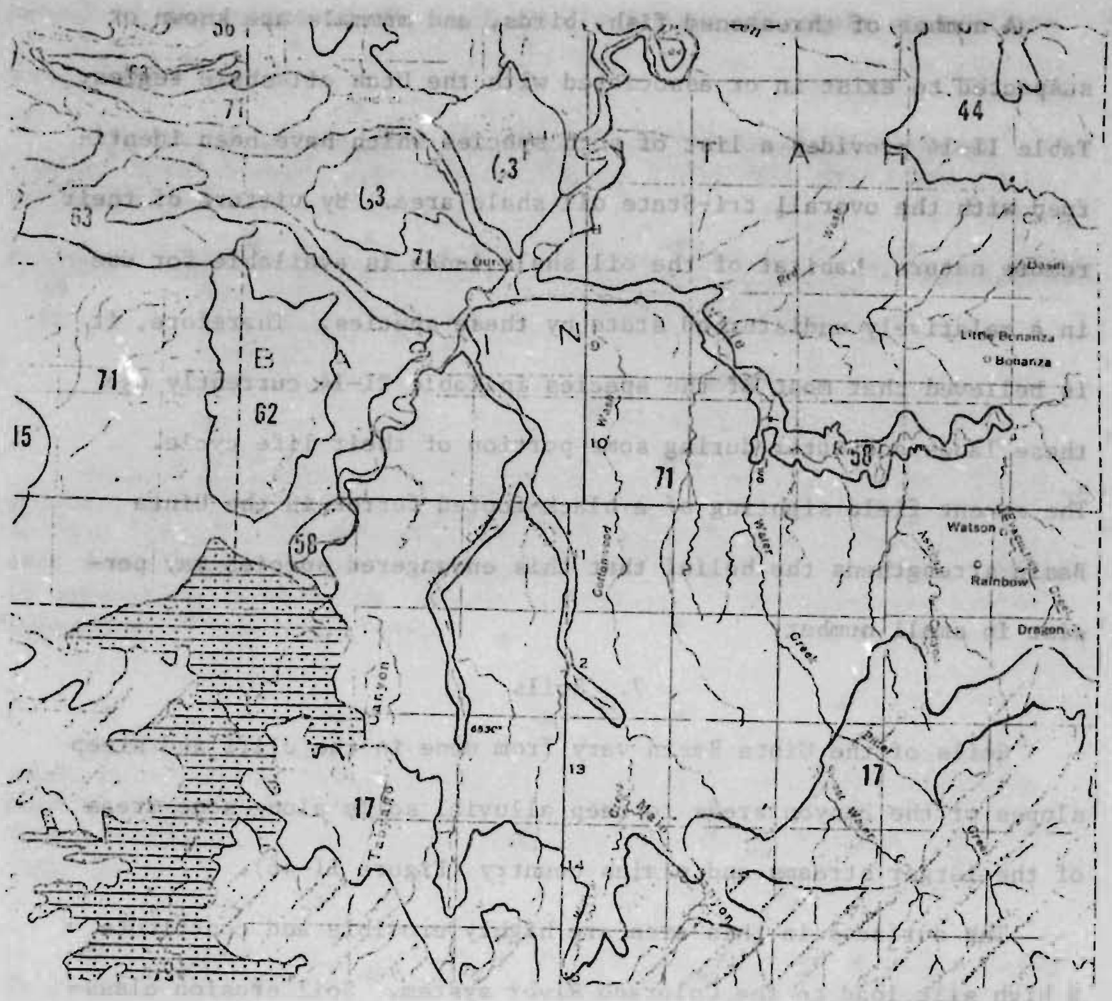
A number of threatened fish, birds, and mammals are known or suspected to exist in or associated with the Utah oil shale region. Table II-14 provides a list of such species which have been identifued with the overall tri-State oil shale area. By virture of their remote nature, habitat of the oil shale lands is available for use in a relatively undisturbed state by these species. Therefore, it is believed that most of the species in Table II-14 currently use these lands and water during some portion of their life cycle. The recent field sighting of a black-footed ferret in the Uinta Basin strengthens the belief that this endangered species may persist in small number.

7. Soils

Soils of the Uinta Basin vary from none in the cliff and steep slopes of the canyon areas to deep alluvial soils along some areas of the larger streams and plains country (Figure II-46).

The surfaces in this area are highly erodible and contribute a high silt load to the Colorado River system. Soil erosion classifications on the three units containing 875,000 acres of public lands are shown below:

	Erosion classifications (Percent of area)			
	Slight	Moderate	Critical	Severe
Bonanza (337,000acres)	--	9	64	27
Rainbow (299,000 acres)	1	45	54	--
Book Cliffs (240,000 acres)	15	77	8	--



Scale: 1 inch equals approximately 8 miles. Prepared by Soil Conservation Service.

FIGURE II-46.--Soil Association Map, Utah.

Technical discussion of the soils of the better oil shale area of the Uinta Basin follows:

Composition of map unit 71 (Fig. II-46) by Great Soil Groups (1949); Great Groups, Subgroup, or Family (1965) and land types is estimated as follows:

Percent	1949 Great Soil Group	1965 Great Group, Subgroup or Family
50	Red Desert	Typic Torriorthents
25	Rendzinas	Lithic Calciorthids
	Lithosols	
	(Solonetz)	(with inclusions of Lithic Natrargids and Badlands)

Typic Torriorthents are shallow soils over weathered soft marine shales. They have thin light yellowish brown calcareous fine loamy or fine silty surface horizons and fine silty or clay subsoils. The soft shale bedrock usually is at depths of less than 20 inches. Relief is undulating to rolling. Chipeta and Persayo Soil Series are representative of this sub-group.

Lithic Calciorthids are shallow over sandstone or interbedded sandstone or shale bedrock. The soils are light colored; calcareous sand or coarse loamy surface horizons; underlain by a loam or stony loam accumulation zone. No soil Series has been established for this sub-group.

All of these soils are well drained; permeability is slow; runoff is rapid and sediment production is high especially from intense summer storms.

Native vegetation is shadscale, greasewood, saltbush, galleta grass and Indian ricegrass.

These soils are in Hydrologic Group D.

Composition of map unit 58 by Great Soil Groups (1949); Great Group, Subgroup or Family (1965); is estimated as follows:

Percent	1949 Great Soil Group	1965 Great Group, Subgroup or Family
25	Alluvial	Aquic Xerofluvents
30	Alluvial	Aquic Ustifluvents
20	Alluvial	Typic Torrifluvents (with
	(Solonetz)	inclusion of Typic Natrargids and Vertic Fluvaquents)

This association occurs along recent flood plains and low terraces adjacent to major rivers (White River). Relief is smooth to gently undulating.

The Aquic Xerofluvents are deep soils that have gray, calcareous loamy or silty surface horizons underlain by stratified subsoil that ranges in texture from coarse loamy or course silty to fine sandy loamy or fine silty. Mottling is common below 10 inches. The Abraham Soil series is representative of this subgroup.

The Aquic Ustifluvents are deep soils with brown to pale brown, moderately calcareous, loamy surface horizon. Underlain by stratified coarse loamy to fine loamy subsoils. They are mottled below depths of 20 inches. Water table ranges between 20 to 40 inches. The Green River Soil Series is representative of the subgroup.

Typic Torrifluvents are deep soils with light colored calcareous loamy or silty surface, coarse silty, fine loamy or fine silty subsoils. The Ravola Soil Series is typical of this subgroup.

Permeability is moderate for all of these soils except for the Natragids which have slow permeability. Runoff is medium to rapid and sediment production is high because of stream cutting during periods of high stream flow.

Native vegetation is cottonwood trees, willows, salt cedar, greasewood and associated grasses and forbs.

These soils are in Hydrologic Group B and D.

8. Vegetation

That portion of the Uinta Basin containing oil shale deposits includes four major vegetative types: Desert Shrub, Salt Desert Shrub, Pinyon-Juniper, and Sagebrush.

The higher elevation types of the Uinta Basin occur to the west of areas of potential oil shale development and will not be described here.

In general, the Uinta Basin types fit the descriptions given for the Piceance Creek Basin of Colorado. Because of lower elevations, the sites are more xeric and are similar to the lower extremes of the Colorado sites.

The Saltbush type described in the Colorado description has been divided into Desert Shrub and Salt Desert Shrub because they are more easily identified in the Uinta Basin.

a. Desert Shrub

This type comprises about 60 percent of the oil shale area of the Uinta Basin. The vegetation of the Saltbush type described for the Piceance Creek Basin of Colorado adequately describes this type in the Uinta Basin.

About two-thirds of the type area is in the lower elevational range of the type on sandy soils. Vegetation on these sites is extremely sparse. Horsebrush (Tetradymia) and rabbitbrush (Chrysothamnus) are the dominant species.

b. Salt Desert Shrub

This type comprises about 15 percent of the area. Soils are finer textured and contain more salt than in the Desert Shrub type.

The vegetative aspect is one of bare shale with very little soil development, containing a sparse stand of low-growing saltbushes. Dominant species are mat saltbush (Atriplex corrugata) and Nuttall saltbush (Atriplex nuttallii). Annuals include cheatgrass, Russian thistle, dock, and halogeton.

Streambottoms within the type many contain cottonwood trees, greasewood associations, and rocky lands devoid of vegetation.

c. Pinyon-Juniper Type

In the Uinta Basin this type is primarily juniper with pinyon pines occurring only in a few higher elevation locations. The type comprises about 10 percent of the oil shale area.

The description of the Pinyon-Juniper type in the Piceance Creek Basin of Colorado adequately describes the type as found in the Uinta Basin.

d. Sagebrush

This type comprises about 10 percent of the oil shale area. The sagebrush type description for the Piceance Creek Basin of Colorado is generally adequate for describing the type in the Uinta Basin.

In Utah, the sagebrush type extends into lower elevational ranges than in Colorado. As it blends into the Desert shrub type, black sage (Artemisis nova) creates the sagebrush aspect rather than big sage (Artemisia tridentata).

Grazing use in the oil shale area of the Uinta Basin is primarily by sheep in the winter. Some cattle are also grazed in the area during the winter months.

There are several poisonous plants in the area, but only locoweed and halogeton cause serious problems with livestock. After a wet, warm fall locoweed becomes a serious problem; livestock must be kept off the area to prevent considerable loss. Halogeton is scattered throughout the unit, and in some disturbed areas forms dense patches. This plant has not caused serious problems in the past, but sheep herds must be managed to avoid it.

The locoweeds and halogeton have their greatest concentrations within the mixed desert shrub areas on the fringes of the pinyon-juniper. Major losses of sheep occurred on the locoweeds during the winter grazing seasons of 1957-58 and 1965-66.

Death camas (Zygadenus sp.) is scattered generally over the entire unit. There are no known concentrations of any consequence within the unit.

Wildlife use of this portion of the Uinta Basin is similar to that described for the same types in the Piceance Creek Basin of Colorado.

According to the Utah Fish and Game Division, the following wildlife species utilize this area: antelope, mule deer, cottontail and jack rabbits, chukar partridge, sage grouse, pheasants, Hungarian partridge, California valley quail, mourning doves, and a variety of water fowl including ducks, geese, and swans.

In addition, the area supports song birds and rodents which utilize some vegetation.

The dominant plant species for each of the four major vegetative types are as follows:

		Common Name	Scientific Name
Pinyon-Juniper Type:	Grasses:	Western wheatgrass	Agropyron smithii
		Wheatgrass	Agropyron spp.
		Curly grass	Hilaria jamesii
		Indian rice grass	Oryzopsis hymenoides
		Needle-and-and Thread grass	Stipa comata
	Forbs:	Russian thistle	Salsola kali
		Stickseed	Lappula spp.
		Buckwheat	Eriogonum spp.
		Lupine	Lupinus spp.
		Loco weed	Astragalus spp.
	Shrubs:	Black sage brush	Artemisia nova
		Big sage	Artemisia tridentata
		Snake weed	Gutierrezia sarothrae
		Low yellowbrush	Chrysothamnus viscidiflorus
	Trees:	Utah juniper	Juniperus osteosperma
		Pinyon pine	Pimis edulis
Sagebrush Type:	Grasses:	Curly grass	Hilaria jamesii
		Indian rice grass	Oryzopsis hymenoides
		Western wheatgrass	Agropyron smithii
		Wheatgrass	Agropyron spp.
	Forbs:	Russian thistle	Salsola kali
		Stickseed	Lappula spp.
		Mustard	Lepidium spp.

	Common Name	Scientific Name
	Shrubs:	
Sagebrush Type: (Continued)	Big sage	Artemisia tridentata
	Black sage	Artemisia nova
	Shadscale	Artiplex confertifolia
	Snakeweed	Gutierrezia sarothrae
	Low yellowbrush	Chrysothamnus viscidiflorus
Desert Shrub Type	Grasses:	
	Galleta	Hilaria jamesii
	Indian ricegrass	Orysopsis hymenoides
	Needle-&-thread grass	Stipa comata
	Cheatgrass	Bromus tectorum
	Forbs:	
	Russian thistle	Salsola kali
	Halogeton	Halogeton glomeratus
	Cactus	Opuntia spp.
	Desert mallow	Sphaeralcea spp.
	Shrubs:	
	Black sage	Artemisia nova
	Shadscale	Artiplex confertifolia
	Low yellowbrush	Chrysothmanus viscidiflorus
	Big sage	Artemisia tridentata
	Horsebrush	Tetradymia spp.
	Greasewood	Sarcobatus vermiculatus
	Nuttall saltbush	Atriplex nuttallii
	Snakeweed	Gutierrezia sarothrae
	White sage (winterfat)	Eurotia lanata
	Spiny hopsage	Grayia spinosa
Salt Desert: Shrub Type	Grasses	
	Galleta	Hilaria jamesii
	Indian ricegrass	Oryzopsis hymenoides
	Squirreltail	Sitanion hystrix
	Cheatgrass	Bromus tectorum
	Six-week fescue	Festuca octiflora

	Common Name	Scientific Name
Salt Desert Shrub: Type (Continue)	Forbs:	
	Indian wheat	Plantago spp.
	Russian thistle	Salsola kali
	Stickseed	Lappula spp.
	Halogeton	Halogeton glomeratus
	Cactus	Opuntia spp.
	Desert mallow	Sphaeralcea spp.
	Buckwheat	Eriogonum spp.
	Shrubs:	
	Nuttall saltbush	Atriplex nuttalli
	Shadscale	Atriplex confertifolia
	Mat saltbush	Atriplex corrugata
	Black sage	Artemisia nova
	Shortspine horsebush	Tetradymia spinosa
	Big sage	Artemisia tridentata
	White sage (winterfat)	Eurotia lanata
	Mormon tea	Ephedra spp.

All of the major vegetative types in the area provide good winter forage for sheep or cattle, except that:

(a) Much of the pinyon-juniper has very few forage plants growing underneath.

(b) Some of the big sage brush is in dense, nearly pure stands, which livestock will only use lightly.

(c) The sparse cover on some of the bare shale in the desert shrub and salt desert shrub types provides little, if any, forage.

The vegetation along the Green River and the White River is mainly annuals, desert saltgrass (Dictichlis stricta), alkali sacaton (Sporobolus airoides), tamerix (Tamarix gallica), willows (Salix spp.), and squaw bush (Rhus trilobata). This type is used mostly by cattle in summer.

The pinyon-juniper type produces a few cedar posts and some firewood.

9. Recreational Resources

The oil shale areas of the Uinta Basin are extensively used for hunting during a fall hunting season. Small game animals and birds are also hunted. The canyon lands of the Green River are occasionally used for adventurous boating excursions. Fishing potential along the White and Green Rivers where they cross the oil shale land is good but little used.

The oil shale areas of the Uinta Basin are generally seldom used for other recreational purposes. The more attractive recreational areas which are utilized are in the nearby Uinta Mountains and in Dinosaur National Monument north of the arid flat land of the oil shale area.

The recreation resources in the environs of the Uinta Basin, mostly outside of the oil shale area, consist of many high-quality recreational opportunities of the following types:

(a) Water oriented activities associated with the lakes, ponds, and streams of the Uintah Mountains along the basin's northern boundary, the Tavaput Plateau on the southern boundary, and the Green and Duchesne Rivers of the lowlands, and 138 lakes, ponds, and rivers;

(b) Backpacking opportunities of Yellowstone Creek, Rock Creek, and the Badlands in the White River area;

(c) Wildlife opportunities, especially those associated with Ouray Wildlife Refuge along the Green River winter deer range, and the deer on 10 major hunting units in the basin. Average yield harvests of 8,000 deer annually are common in the basin;

(d) Winter sports in the Grizzly Ridge Ski and Winter Recreation Area 25 miles north of Vernal;

(e) Sightseeing of unique features and scenic wonders of the Flaming Gorge, Book Cliffs, Sheep Creek Canyon, Whiterocks Fish Hatchery, Grays and Desolation Canyons, and the valley country of the Green and Duchesne Rivers.

(f) Cultural and historic sites: Old Fort Duchesne, the Uintah-Ouray Indian Reservation, Desolation Canyon, Sheep Creek Geological Area, Dinosaur National Monument, Indian Petroglyphs in Dry Fork Canyon, and Fort Robideaux.

For recreation planning purposes the State Outdoor Recreation Plan of Utah has designated the counties of Duchesne, Daggett and Uintah as the Uinta Basin Planning District--Planning District VII.6/ The Bureau of Land Management has designated this same area as the "Vernal District." BLM administers 1,673,000 acres, or 31 percent, of the Uinta Basin's 5.4 million acres. Most of the public lands are located in Uintah County which contains most of the potential high-yielding oil shale lands, 768,000 acres. National Forest lands of the basin are located outside of the primary oil shale lands area. Lands of the Uintah and Ouray Indian Reservation are located immediately adjacent to the primary oil shale lands.

All lands under the administration of the Bureau of Land Management and the Forest Service are generally considered for multiple use, including outdoor recreation. The total acres of designated,

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6/ Outdoor recreation in Utah, 1970.

developed, recreation sites on all Federal and State lands in the basin is less than 15,000 acres; the potential is estimated to be 4.2 million if only Federal lands under multiple use are considered. The total acreage set aside as recreation sites in the basin is less than 16,000 acres. Ninety percent of the site acres occur on Federal lands and 6 percent on private lands.

Half of the recreation visitors to northeastern Utah are sightseers or tourists. Fishing and hunting combined account for 24 percent of the visitors followed by camping and picnicking at 16 percent. Deer hunting is known to be the primary type of hunting with 8,000 deer being harvested annually in the Basin. Rock hunting is considered to be a fast growing activity in the Basin. Water sports account for only one percent of the visitors. However, the potential for water oriented activities is high with almost 75 percent of the feature oriented sites in the Basin being related to water, 48 percent are related to streams or rivers, and 30 percent to lakes and/or reservoirs.

In 1968 the estimated outdoor recreation visitor-day use in northeastern Utah was estimated to be 1.2 million days or 15 percent of the State total of 7.8 million visitor days. Dagget County, the smallest county by far with only 461,400 acres, accounted for almost half of the Basin's visitor days. However, most of these were to the highly developed Flaming Gorge Natural Recreation Area in the Ashley National Forest, and the Dinosaur

National Monument administered by the National Park Service. Uintah County accounted for 35 percent of the basin's visitors. Duchesne County was far behind with 17 percent.

Applying State of Utah economic day use values of 10 and 15 dollars the estimated 1968 returns to local and State economics of the basin for outdoor recreation were 11.7 and 17.1 million dollars, respectively. For public lands in Daggett and Uintah Counties the estimated visitor days and dollars to the local economy was 112,875 days and $1,128,770; hunting and fishing accounted for 70 percent of the visitor days and monies. Land ownership, outdoor recreation site ownership, and visitor day use are tabulated in Tables II-35 and II-36.

10. Socioeconomic Resources

Access to Uinta Basin oil shale area is gained, from the north, by U.S. Highway 40, and from the south, by U.S. Highway 6 and 50 (Figure II-29) Gravel surface State and county roads cross the basin in a general north-south direction. Jeep trails and seismic and oil exploration roads crisscross the basin in a random manner. Population within the three principal BLM planning units is approximately 470.

The better oil shale area of the Uinta Basin is sparsely populated. A small gilsonite mining community, Bonanza, and a small Indian village, Ouray, lie within the rich oil shale lands. A few gas field development buildings and personnel occupy installations in the oil shale area. Major oil field developments and installations are situated north of the oil shale area.

TABLE II-35.—Land Ownership and Outdoor Recreation Site Ownership Within the Uinta Basin, 1972.

Agency and owner	Total lands		Recreation sites	
	Acres	Percent	Acres	Percent
Federal	4,050,000	75	14,217	90
State	270,000	5	155	1
Local	....	...	379	2
Quasipublic	....	...	80	1
Private	1,080,000	20	890	6
Total.......	5,400,000	100	15,729	100

Source: Bureau of Land Management Analysis Plan 1972.

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TABLE II-36.--Estimated Outdoor Recreation on Federal and State Lands in and near Uinta Basin, 1968.

	Approximate land area, acres	Visitor day use	
		Days	Percent
County:			
Daggett 1/....	461,440	550,000	48
Duchesne	2,086,400	210,000	17
Uintah	2,856,320	410,000	35
Total...	5,404,160	1,170,000	100
State..............	52,696,960	7,770,000	

1/ Daggett County, Utah, is situated north of the oil-shale region of the Uinta Basin and south of the oil-shale region of Green River Basin, Wyoming.

The land surface of the oil shale area is used mostly for wildlife range, wildlife refuge, and seasonal livestock grazing.

Vernal, Utah, a town of approximately 4,000 people is in the center of the Ashley Valley, north of the oil shale area. The Valley is 48 square miles in area and supports a population of 9 to 10 thousand. The primary industries in the Vernal area are oil and mining, agriculture, and tourism. The community has a dependable water supply from Ashley Creek and Ashley Springs, and supplies water to the entire Valley through a pipeline system. Vernal is the service center for the Rangely oil field, Ashley oil field and newly developing oil fields in adjacent Duchesne County. It is also the center for a phosphate mining enterprise 12 miles from the town and the Gilsonite mines at Bonanza, Utah.

Vernal and Uintah County maintain a planning commission, which has developed a planning and zoning program for the entire County. The community has an adequate school system. The city maintains a 30-bed hospital, which is being enlarged to 50 beds. There is presently an acute shortage of physicians in the town. Vernal is located on U.S. Highway 40, a major east-west artery. It has no railroad but maintains an airport facility with a 6,000 foot runway. Frontier Airlines provides service principally to Denver, Salt Lake City, and Grand Junction.

The town has many tourist attractions, including the nearby Dinosaur National Monument, an outstanding geological museum, and excellent fishing, hunting, and camping facilities in nearby national forests and the Flaming Gorge Reservoir Recreation Area. Nearby agricultural enterprises are primarily large livestock ranches with small acreages of irrigated hay and pasture lands in the drainage bottoms.

The counties in Utah in the Uinta Basin which will be most directly affected by oil shale development are Duchesne and Uintah.

The Uinta Basin and its surrounding counties has the least population of the three oil shale regions. The population of the two counties was just 20,000 in 1970. Uintah County accounted for 60 percent of the total, and Vernal's population of 4,000 accounted for one-third of the Uintah County total in the same year. Median family income for the two counties in 1970 was \$7,893, and \$9,242 for Vernal. Both median income and the median number of school years completed were higher in the city (See Tables II-37 and II-38).

In 1967, the local governments of Uintah and Duchesne Counties expended a combined total of \$6.9 million including \$4.7 million for educational purposes, \$0.6 million for highway maintenance and construction, and \$0.05 million for hospital services. Total revenue of the combined area in the same year was \$6.3 million.

Social and economic parameters of the two counties are set forth in Tables II-37, II-38, II-39, and II-40.

TABLE II- 37 --County and City Social Characteristics for Utah, 1970.
(Thousands unless otherwise indicated)

County and City	Population	No. of households	School enrollment Primary-High School		Median school years completed (25 years and over)
Duchesne.........	7.3	2.0	1.6	0.8	12.1
Uintah..........	12.7	3.4	3.0	1.1	12.3
Total......	20.0	5.4	4.6	1.9	12.2
City of Vernal (Uintah)	4.0	1.2	.9 1/	.4 1/	12.6

1/ Estimated

Source: 1970 Census of Population, General Social and Economic Characteristics--Utah, U. S. Department of Commerce, Washington, D.C., 1972

TABLE II-38 --County and City Economic Characteristics, for Utah, 1970.

(Thousand, unless otherwise indicated)

County and City	Employment				Unemployed percent	Median family income
	Total employed 16 years and over	White collar and service	Blue collar and service	Agri-cultural		
Duchesne	2.4	1.1	0.9	0.4	4.6	$7,572
Uintah	4.0	1.6	2.0	.4	7.0	8,082
Total	6.4	2.7	2.9	.8	6.1	7,893
City of Vernal (Uintah)	1.4	.8	.6	(1/)	6.0	9,242

1/ Less than 50.

Source: 1970 Census of Population, General Social and Economic Characteristics-Utah, U.S. Department of Commerce, Washington, D.C., 1972.

Table II-39 - - County Economic Indicators for Utah - - Government
(Thousand dollars unless otherwise indicated)

Local government finances 1/	County		
	Duchesne	Uintah	Total
Revenue:			
Total	2,407	3,934	6,341
Property tax per capita (dollars)	135	151	145
Expenditures:			
Total	2,801	4,133	6,934
Education	1,907	2,847	4,754
Highways	236	370	606
Public welfare	2	3	5
Hospitals	-	-	-
Health	8	40	48
Police protection	36	79	115
Fire protection	4	9	13
Sewerage	334	35	369
Sanitation other than sewerage	3	50	53
Parks and recreation	25	30	55
Natural resources	19	102	121
Housing and urban renewal	-	-	-
Correction	4	9	13
Libraries	1	30	31
Financial administration	35	57	92
General control	48	75	123
General public buildings	16	20	36
Interest on general debt	60	12	72
Other and unallocable	64	366	430

1/ Fiscal years ending between July 1, 1966 and June 30, 1967.

Source: U.S. Bureau of the Census, Census of Governments, 1967 Volume 7: State Reports, No. 44: Utah. U.S. Government Printing Office, Washington, D. C., 1970.

TABLE II-40 --County Economic Indicators for Utah, Private Sector.
(Million dollars, unless otherwise indicated)

County	Retail Trade 1/		Services 1/		Agriculture 2/		
	Total establishments	All sales	Total establishments	All receipts	Acreage farmed (Thousand)	Total commercial farms	Value of farm products sold
Duchesne	95	8.7	50	.8	408	428	6.3
Uintah	118	16.1	89	2.5	1443	337	6.4
TOTAL	213	24.8	139	3.3	1851	765	12.7

1/ 1967.
2/ 1969.

Source: U. S. Bureau of the Census, Census of Business 1967. Volume II Retail Trade - Area Statistics. Part 3, North Dakota to Wyoming, Guam, and Virgin Islands, U. S. Government Printing Office, Washington, D. C., 1970.
U.S. Bureau of the Census, Census of Business, 1967. Volume V, Selected Services - Area Statistics. Part 3, North Dakota to Wyoming, Guam, and Virgin Islands. U.S. Government Printing Office, Washington, D.C., 1970.

U.S. Bureau of the Census, Census of Agriculture, 1969. Volume Area Reports, Part 44, Utah. U.S. Government Printing Office, Washington, D. C., 1972.

Revenue collected by the Uintah County Government was almost two-thirds of the two-county total, $3.9 million.

Uintah County, which has twice the population of Duchesne County, is also twice as large in the categories of total employment and retail sales. In value of petroleum production Uintah is three times as large as Duchesne. In value of farm products sold, however, Duchesne County nearly equals Uintah with only one-third as many acres utilized (See Table II-40).

The major portion of both Duchesne's and Uintah County's mineral production is oil production. In 1970 the value of petroleum produced in Duchesne County was $5.3 million and the industry employed 86 people. The oil industry in Uintah County employed 715 people, and production was valued at $17.6 million which was just under two thirds of the county's total mineral production value.

11. Archaeological and Historical Values

There are no historic sites listed for Uintah County, Utah, in the National Register of Historic Places.

The Colorado Historical Society recognizes the historic significance of the abandoned Uintah Railroad and related sites located along the Colorado - Utah State Line.

The White River area in Utah has the highest values. Two rock overhangs with evidence of the Fremont culture, a farming group of Indians dating in the 11th Century A.D., were found within one-half mile of the White River at the County Bridge crossing and others may be expected along with possibly some pithouse village sites in the rest of the main canyon and near the mouths of the watered side canyons emptying into the White River.

Historical sites of importance are also present in the White River vicinity in the area immediately adjacent to the proposed use area. These are at the road crossing of the White River (Ignacio Stage Stop and Old Bridge) and in the gilsonite mining area. The ghost towns of Rainbow and Watson, the remains of the narrow gauge Uintah Railroad which served the area until 1938, and the remains of many abandoned old gilsonite mines, an interesting relic of a rare mineral activity, are all adjacent to the south boundary of the potential development area.

12. Land Use

The generally semiarid and severe climatic nature of the area limits any cultivation of new lands for crop production. Most of the lands having agricultural potential are along the stream valleys and are already in private ownership. Vernal is the nearest population and community center. Any expansion of population and accompanying development is expected to take place in Vernal or other established communities.

13. Land Status

The total land area in the three principal BLM planning units involved is 1,091,959 acres. Land ownership in the three units is as follows:

BLM Planning Unit	Federal (percent)	Public Land (acres)	State (acres)	Private (acres)
Bonanza	82.5	337,518	46,295	19,278
Rainbow	77	299,424	52,259	37,874
Book Cliff	82	239,971	36,652	17,112

D. Wyoming (Green River and Washakie Basins)

1. Physiography

The Wyoming oil shale deposit areas are bounded on the west by the Wasatch Mountains; on the north by the Wind River Range, the Green Mountains, and Seminoe Mountains; on the east by the Medicine Bow Range; and on the south by the Uintah Mountains. This area of southwestern Wyoming includes all of Sweetwater, and part of Lincoln, Sublette, and Carbon Counties. The area of principal concern, however, is that portion of Sweetwater County that contains the richest and thickest deposits of oil shale. The best oil shale lies within the Green River structural basin. Good quality oil shale also underlies the western part of the Washakie Basin (See Figures II-1 and II-2).

The best deposit of oil shale (Green River Basin) is cut west to east by Interstate Highway 80 and north to south by U.S. Highway 187 (Figure II-30). Jeep trails and mineral exploration roads in the area are numerous.

The Green River is the principal flowing water source in the immediate area, with the Big Sandy furnishing the only other source of live water. Drainage of the area flows into these two streams.

Topography is structurally controlled, varying from synclinal valleys to monoclinal slopes, with hills and ridges having a steep face on one side and a gently sloping face on the other side. This is illustrated in Figure II-47, an aerial view of of the Kinney Rim area. Elevations range from about 5,000 to 8,000 feet. Badlands are common in some of the soft mudstone of the area's Bridger Formation.

The area is generally underlain by soft shales and fine grained sandstone of Cretaceous and Tertiary age. Weathering of these beds and stream transport of material have filled the valleys along major streams with alluvium.

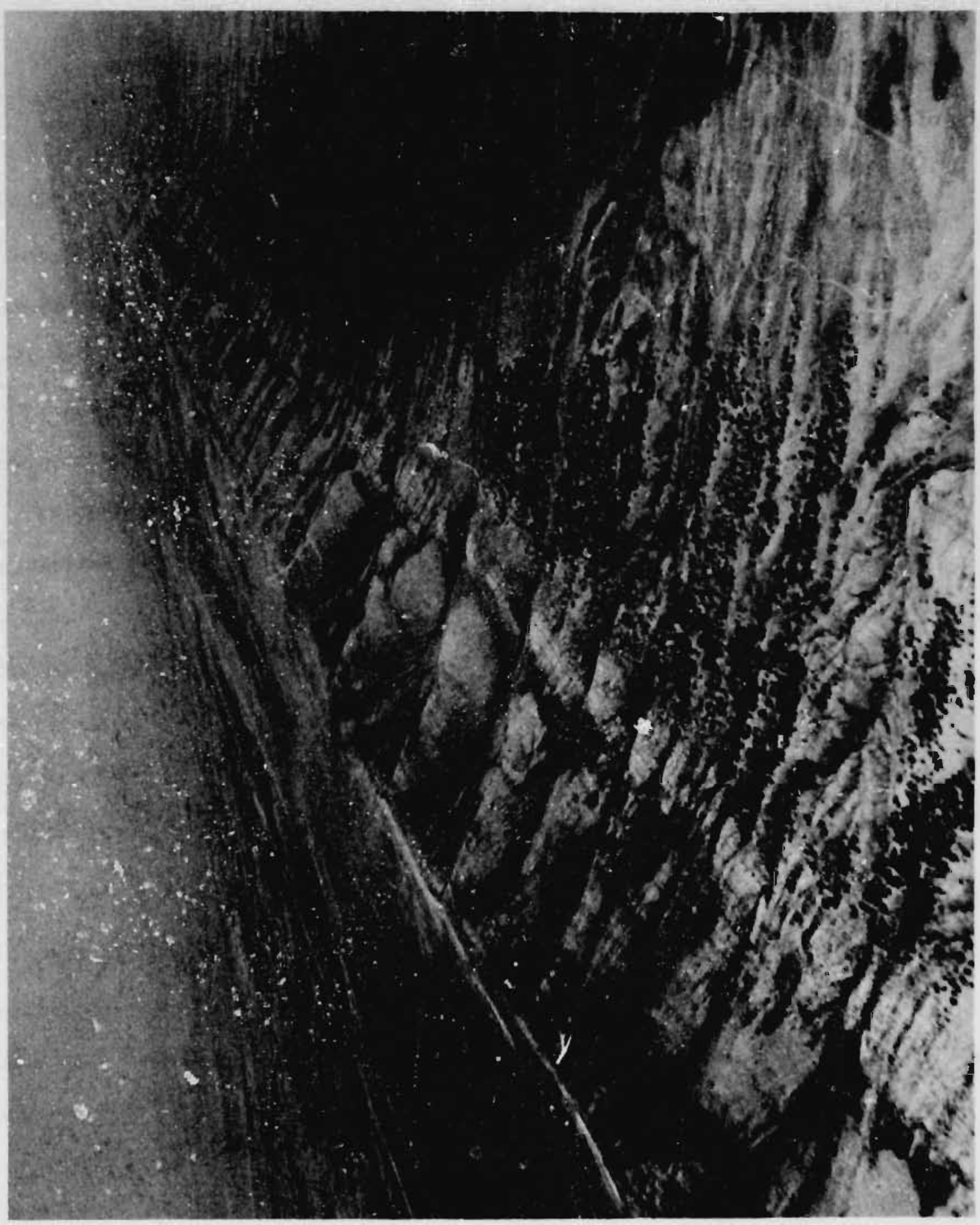

FIGURE II-47.--Aerial View of Oil Shale Exposure in Kinney Rim, Washakie Basin, Wyo.

2. Climate

Annual precipitation in the Wyoming oil shale area varies from approximately 7 to 21 inches, considerably less than surrounding highlands; consequently the area is considered semiarid.

Seasonal distribution of precipitation is variable, but the annual total precipitation changes little from year to year. Winters are cold; summers, short and hot. Most of the precipitation comes as snow. The relatively dry summers have occasional thunderstorms with rapid runoff.

The temperature range in the area is extreme. Summer temperatures may reach 90°F. and winter temperatures can drop to -40°F. July is usually the hottest month, and January, the coldest. Temperatures within the area vary considerably. The frost-free season varies from 50 days to 120 days.

Winds are relatively strong over the areas, which is typical of semiarid regions.

3. Geology

The principal oil shale leasing areas underlying 6,700 square miles in southwestern Wyoming are in the Green River Basin and Washakie Basin. Oil shale beds are exposed in ledges and low escarpments along the eastern margin of the Green River Basin and along the western margin of the Washakie Basin. The oil shale zones in the Green River Formation extend below surface to depths as much as 3,000 feet or more.

Several members of the Green River Formation intertongue with sandstone-mudstone members of the Wasatch Formation. In the central parts of the basins the oil shale bearing rocks are overlain by the Bridger Formation. The details of distribution of the oil shale and related rocks are shown in maps by Bradley, Culbertson, and Roehler. The reader is referred to their reports for maps, cross sections and discussion of details of the deposits.

The general stratigraphic distribution of oil shale and sodium minerals of the Green River Basin are shown in Figure II-48. The distribution and character of rocks in the Washakie Basin are shown in Figures II-49 and II-50.

More than 20,000 feet of older sedimentary rocks underlie the Green River Formation in the Green River Basin. These older sediments locally contain oil and gas reservoirs which are produced in the Church Buttes, and Big Piney gas fields. Other smaller fields are shown in Figure II-6.

Coal bearing rocks are also deeply buried beneath the Green River Formation (Figure II-7).

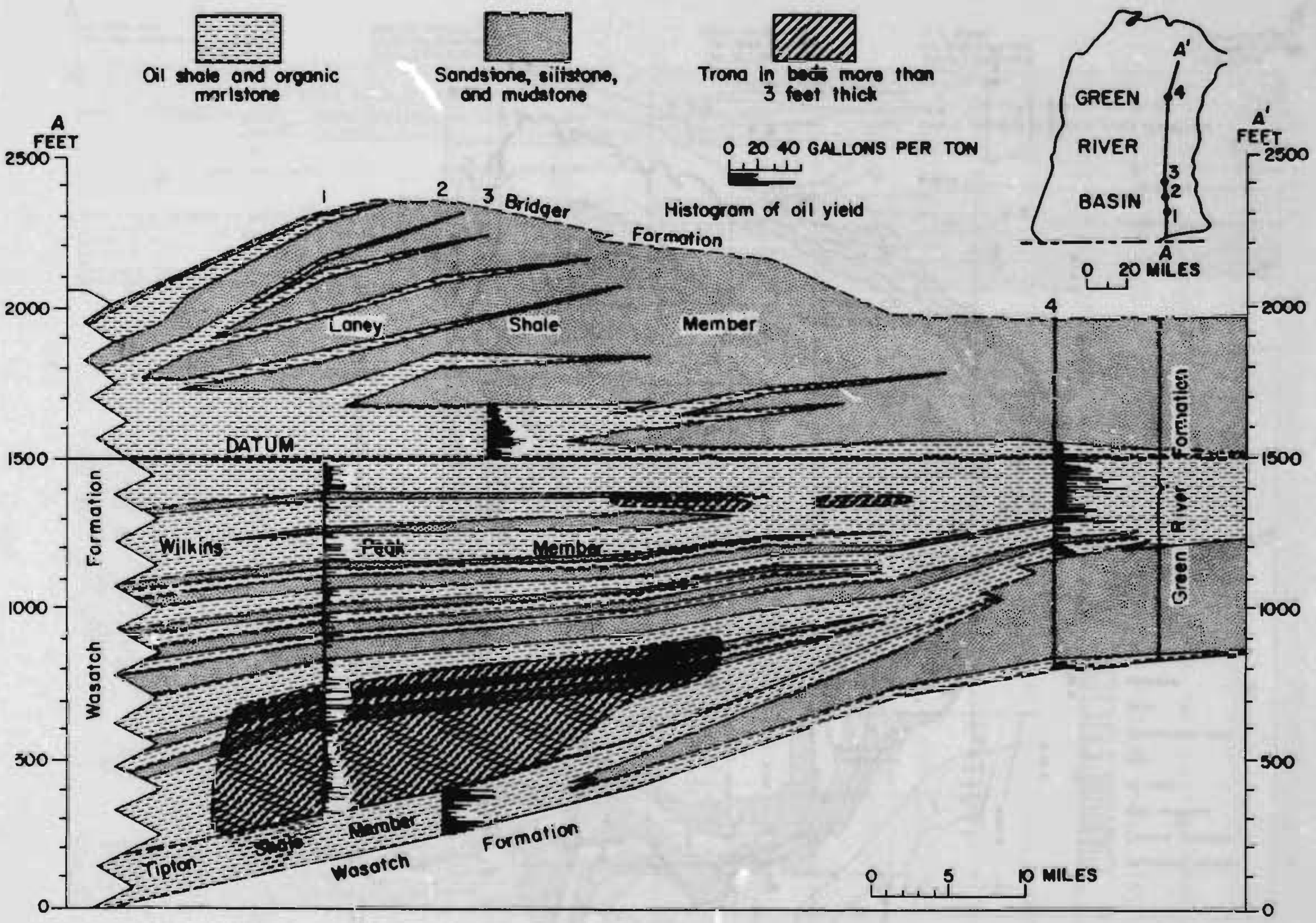

FIGURE II-48.--Cross-Section of Green River Formation in Green River Basin, Wyo.

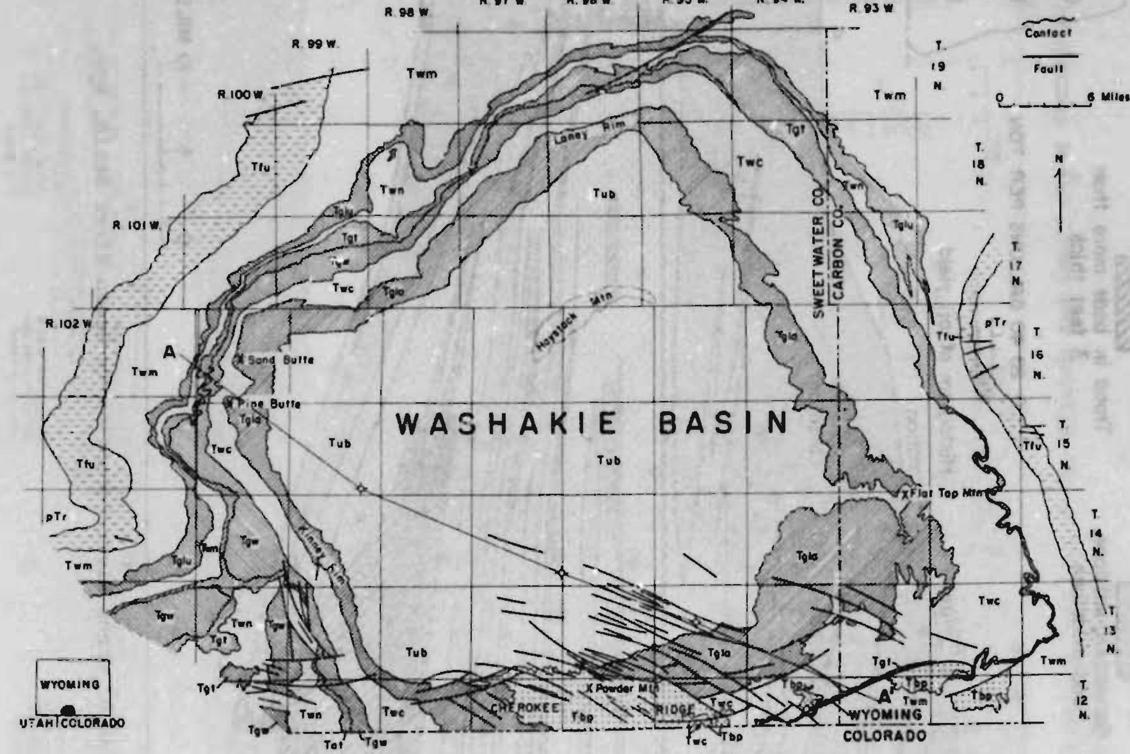

FIGURE II-49.--Geologic Map of the Washakie Basin, Wyo.

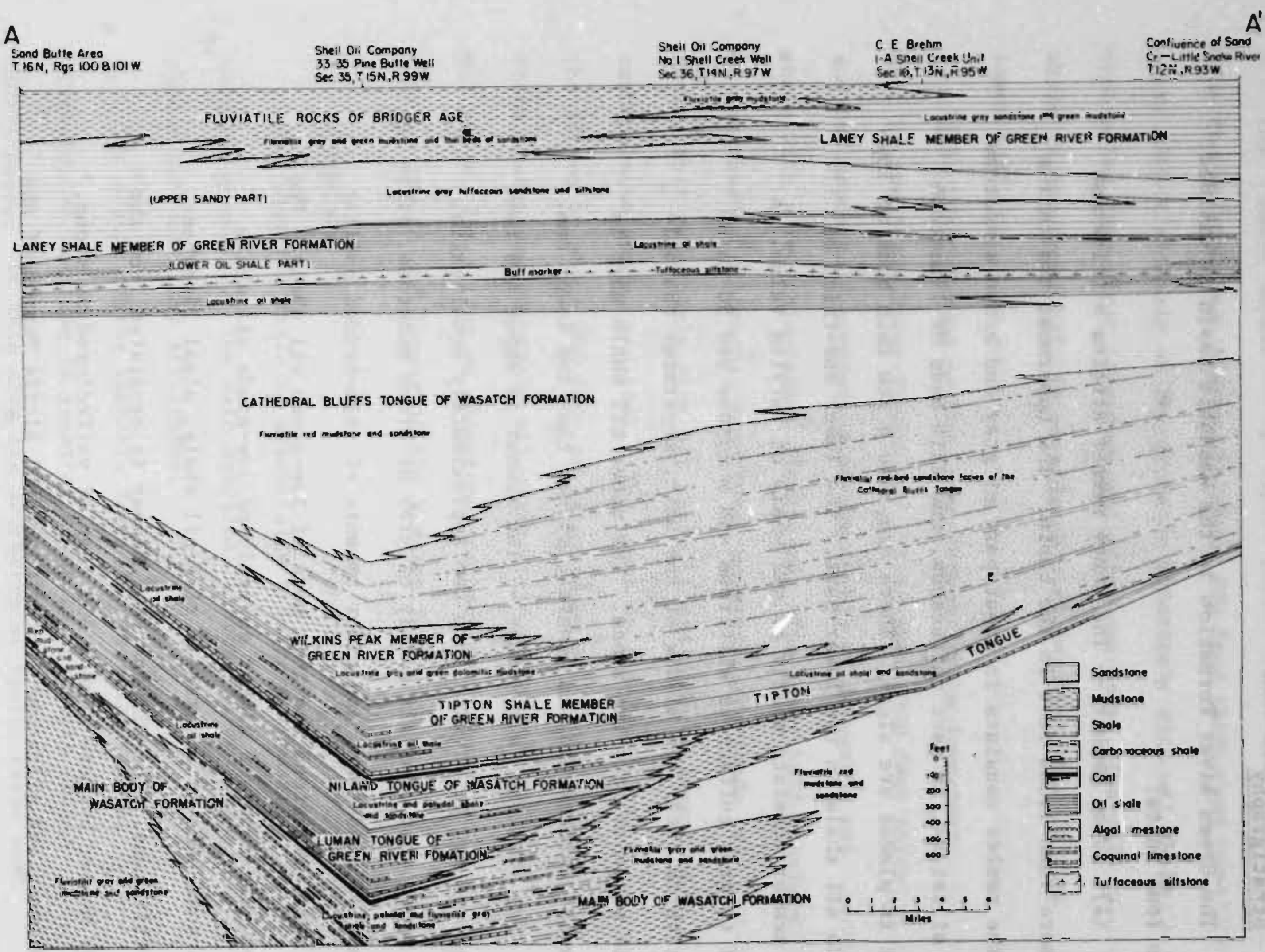

FIGURE II-50.--Simplified Restored Section of the Wasatch and Green River Formations in the Washakie Basin, Wyo.

a. Stratigraphy

The Green River Formation in the Washakie basin is divided into four units:

(1) Laney Member -- The Laney Member attains a thickness of more than 1,300 feet in the basin. The uppermost two-thirds of the member consists in great part of gray and brown sandstone and siltstone, in part tuffaceous, and thin beds of limestone that in places are algal. There are also a few thin beds of low-grade oil shale in the lower part. The lower one-third of the member consists mostly of oil shale of varying value. A buff to gray tuffaceous siltstone and mudstone bed 50 to 60 feet thick, near the middle of the unit, separates the oil-shale sequence into two zones. The upper oil shale unit is somewhat thicker and, in general, richer than the lower one.

(2) Wilkins Peak Member -- The member is about 400 feet thick and may be divided into two approximately equal units. The upper unit consists mainly of gray or brown mudstone, siltstone, or sandstone, and minor amounts of thin-bedded oolitic and algal limestone and thin beds of low-grade oil shale. The lower unit consists almost entirely of low-grade oil shale with some beds of moderately rich oil shale, algal limestone, and siltstone. The Wilkins Peak Member is separated from the Laney Member by more than 1,500 feet of varicolored mudstone, sandstone, and siltstone in the Cathedral Bluffs Tongue of the Wasatch Formation.

(3) Tipton Member -- The Tipton Member immediately underlies the Wilkins Peak Member, is about 200 feet thick, and consists almost entirely of low-grade to moderately rich oil shale with a few thin algal limestone and siltstone beds. The oil shale in the upper half is considerably richer than that in the lower half.

(4) Luman Tongue -- The Luman Tongue is the lowermost unit in the Green River Formation. It is about 300 feet thick and the upper half consists almost entirely of low-grade oil shale with a few thin-bedded limestones. The lower half consists of interbedded siltstone, sandstone, mudstone, low-grade oil shale, thin moderately rich oil shale, fossiliferous limestone. carbonaceous shale, and coal. The Luman is separated from the Tipton by about 200 feet of interbedded siltstone, sandstone, mudstone, low-grade oil shale, thin moderately rich oil shale, fossiliferous limestone, carbonaceous shale, and coal in the Niland Tongue of the Wasatch Formation.

b. <u>Structure</u>

The Washakie Basin is essentially a large northeast-trending syncline. The main synclinal feature is modified in places by subsidiary structures.

The center of the Washakie Basin is essentially fault free. Intensity of faulting is greatest along the southern margin of the basin. In this area the southernmost faults trend west parallel to Cherokee Ridge, a structural high that bounds the Washakie Basin on the south. North of the west-trending faults are a series of northwest-trending normal faults as much as 10 miles in length that extend from the Wasatch Formation outcropping on the southern margin into the lowermost part of the rock sequence overlying the Green River Formation that outcrops near the center of the basin. The west margin of the basin is less heavily faulted; however, there are some north to northwest-trending normal faults along the west margin that are less than 6 miles in length. The northwestern, northern, and northeastern parts of the basin are essentially fault free.

4. Mineral Resources

a. <u>Oil Shale</u>

Recently the U.S. Bureau of Mines drilled two core holes near the western margin of the Washakie Basin. This is the only core assay information publicly available from the Washakie Basin and was deemed to be insufficient for a reliable estimate of the oil-shale resources of the entire Washakie Basin.

b. <u>Other Minerals</u>

Thus far, sodium minerals in or associated with the oil shale deposits in other basins have not been found in or with the oil shales in the Washakie Basin. Both oil and gas, in commercial quantities, have been produced from the Wasatch, Fort Union, and Mesaverde Formations in fields surrounding the

Washakie Basin. These producing formations underlie the Basin. The producing zones in the Fort Union and Mesaverde Formations are several thousand feet below the lowermost oil shales in the Green River Formation.

Coal deposits also are present below the oil shale bearing rocks. They are so deep they are not considered usable in the forseeable future.

5. Water Resources

a. Surface Water

The Green River is the principal surface water resource of the Green River Basin. Records from the stream flow station on the Green River near Green River, Wyoming, show a 19-year mean discharge of 1,620 cubic feet per second. Dissolved solids concentration (18 years of record) ranged from 156 to 855 mg/l, with a discharge--weighted mean of 303 mg/l.

Streams draining the oil shale land in the Green River and Washakie Basins receive very little precipitation each year and flow only intermittently. It is doubtful whether much local surface water could be developed within the area. Up to 67,000 acre-feet of water annually is potentially available from the Green River for development of oil shale in the Green River and Washakie Basins. This could be made available from the existing Fontenelle and Flaming Gorge Reservoirs. Additional water in the areas could be made available by purchasing and changing the nature of use and point of diversion of existing senior water rights.

b. Ground Water

In the oil shale area of the Washakie Basin, the Laney Shale Member of the Green River Formation and the Wasatch Formation yield fresh water to wells.

The Laney Shale Member consists of marlstone, shale, oil shale, muddy sandstone, tuffaceous sandstone, and algal limestone. Welder and McGreevy (1966) reported that 10 wells which tap this member yield from 0 to 200 gpm and that the maximum potential yield probably is not much greater than 200 gpm.

The Wasatch Formation in the Washakie Basin consists of alternating beds of claystone, siltstone, sandstone, and shale. The beds of sandstone contain water under artesian pressure, except where they crop out. These beds are very irregular in thickness but have enough interconnection to form moderately good aquifers. Welder and McGreevy (1966) reported that 20 wells tap the Wasatch Formation in the vicinity of the outcrops. The yield of these wells ranges from 1 to 67 gpm. The maximum potential yield of wells in the Wasatch Formation probably does not exceed 400 gpm. Water in the Wasatch probably is under sufficient artesian pressure to produce flow at the land surface in the lower areas.

The aquifers in the Washakie Basin are recharged in outcrop areas by infiltration directly from precipitation and from streamflow. Most of the streams in the area are above the water table, and flows occur for only short periods of time after rainfall or melting of snow. Discharge of ground water is by underflow to perennial streams outside the study area.

Chemical analyses of water for two wells and three springs in the Laney Shale Member show a range in dissolved solids content of 562 to 3,450 mg/l. Analyses of water from 20 wells that tap the Wasatch Formation range in dissolved solids content from 455 to 3,590 mg/l. Most samples contained between 500 and 1,500 mg/l of dissolved solids (Welder and McGreevy, 1966).

The predominant use of ground water in the Washakie Basin is for stock watering. Small amounts are used for domestic supplies, oil well drilling and coal mining operations.

The supply of ground water in the Washakie Basin is not adequate to support a large oil shale industry for a prolonged time.

In the Green River Basin, the principal aquifers are beds of sandstone in the Bridger, Green River, Wasatch, and Fort Union Formations. Welder (1968) reported that existing wells yield 1 to 500 gpm, but yields of most wells range from 10 to 100 gpm. Yields greater than 500 gpm probably could be obtained from deep wells that penetrate all the water-bearing beds to the base of the Fort Union Formation in some localities.

The depth to water generally is less than 200 feet below land surface and artesian flow can be expected in the lower areas.

Recharge to the aquifers in the Green River Basin is mainly by seepage from precipitation and streams in the outcrop areas. The water moves down dip to areas of discharge along major streams. Some water moves from one formation to another by vertical flow.

The chemical quality of ground water varies widely. The dissolved solids content of water from four wells in the Bridger Formation ranges from 563 to 4,910 mg/l; the dissolved solids content in water from 27 wells in the Green River Formation ranged from 555 to 7,020 mg/l; and the dissolved solids in water from 32 wells in the Wasatch Formation ranged from 215 to 1,780 mg/l. More than half of all the ground water sampled contained less than 1,000 mg/l of dissolved solids, and 72 percent of the water samples from the Wasatch Formation contained less than 1,000 mg/l of dissolved solids (Welder, 1966).

The predominant use of ground water in the Green River Basin is for livestock and domestic supplies. Small amounts are used for public supplies and for water flooding and drilling in the oil fields.

Ground water may be a nuisance to oil shale mining in both the Washakie and Green River Basins, as some beds in the Green River Formation are water-bearing.

6. Fauna

a. General

The Green River Basin oil shale lands (including the Washakie Basin) possess significant fish and wildlife values. High-quality game habitats consisting of varied associations of browse and grass species provide forage and cover requirements for populations of deer, elk, antelope, moose, and black bear. In addition, the area contains populations of blue grouse, sage grouse, chukars, doves, rabbits, coyotes, bobcats, as well as various species of water-fowl, raptors, and numerous other small bird and mammal forms expected in an ecologically healthy high-desert range area. Wild horses are quite numerous throughout general range areas, and a number of species intolerant of human activity, including the mountain lion, bald eagle, and golden eagle, are found within the basin. Table II-41 presents a list of over 300 species of birds and mammals found in the basin.

b. Mammals

Mule deer habitat exists across most of the Wyoming oil shale lands and the deer are the most abundant big game species. (See Figure II-15.) A winter population of 39,650 mule deer was estimated to exist in 1969 in Game Division District 4. From 1960-69 an estimated average of 7,215 deer were harvested annually in District 4.[1/] Of resident hunters, 72% were successful in getting a deer, while 86% of non-residents were successful. While summer range habitat is generally adequate, winter range is limited and most available browse is over-

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1/ Game Division District 4, Wyoming Game and Fish Commission, (1971).

Table II-41. -- Partial List of Bird, Mammal, Reptile and Amphibian Species of the Green River Basin, Wyoming. [1/]

Common Name	Scientific Name
Big Game Animals [2/]	
Elk	Cervus canadensis, common resident
Mule Deer	Odocoileus hemionus, common resident
White-tailed Deer	Odocoileus virginianus, rare resident
Pronghorn	Antilocapra americana, common resident
Trophy Game Animals	
Mountain Lion	Felis concolor, uncommon resident
Small Game Animals	
Red Squirrel	Tamiasciurus hudsonicus, common resident
Cottontail Rabbit	Sylvilagus nuttalli, Sylvilagus audubonii, common resident
Furbearers	
Mink	Mustela vison, common resident
Badger	Taxidea texus, common resident
Beaver	Castor canadensis, common resident
Muskrat	Ondatra zibethicus, common resident
Protected Animals	
Otter	Lutra canadensis, rare resident

Table II-41.--Con't.

Common Name	Scientific Name
Predatory Animals	
Raccoon	Procyon lotor, uncommon resident
Weasel	Mustela erminea, Mustela frenata, common resident
Spotted Skunk	Spilogale putorius, common resident
Striped Skunk	Mephitis mephitis, common resident
Coyote	Canis latrans, common resident
Red Fox	Vulpes fulva, uncommon resident
Bobcat	Lynx rufus, common resident
Porcupine	Ezethizon dorsatum, common resident
White-tailed Jackrabbit	Lepus townsendi, common resident
Nongame Mammals	
Wild Horse	Equus caballus, common resident
Masked Shrew	Sorex cinereus, status unknown
Merriam Shrew	Sorex merriami, status unknown
Vagrant Shrew	Sorex vagrans, status unknown
Dusky Shrew	Sorex obscurus, status unknown
Dwarf Shrew	Sorex nanus, status unknown
Northern Water Shrew	Sorex palustris, status unknown
Little Brown Myotis	Myotis lucifugus, status unknown
Yuma Myotis	Myotis yumanensis, status unknown
Long-eared Myotis	Myotis evotis, status unknown
Fringed Myotis	Myotis thysanodes, status unknown
Long-legged Myotis	Myotis volans, status unknown
Small-footed Myotis	Myotis subulatus, status unknown
Silver-haired Bat	Lasionycteris noctivagans, status unknown
Big Brown Bat	Eptesicus fuscus, status unknown
Hoary Bat	Lasiurus cinereus, status unknown
Spotted Bat	Euderma maculata, status unknown [3/]
Western Big-eared Bat	Plecotus townsendi, status unknown
Ringtail	Bassariscus astutus, rare resident

Table II-41.--Con't.

Common Name	Scientific Name
Nongame Mammals	
Yellowbellied Marmot	Marmota flaviventris, uncommon resident
White-tailed Prairie Dog	Cynomys gunnisoni, common resident
Richardson Ground Squirrel	Citellus richardsoni, common resident
Uinta Ground Squirrel	Citellus armatus, common resident
Thirteen-lined Ground Squirrel	Citellus tridecemlineatus, common resident
Golden-mantled Squirrel	Citellus lateralis, common resident
Least Chipmunk	Eutamias minimus, common resident
Cliff Chipmunk	Eutamias dorsalis, status unknown
Uinta Chipmunk	Eutamias umbrinus, status unknown
Northern Flying Squirrel	Glaucomys sabrinus, status unknown
Northern Pocket Gopher	Thomomys talpoides, status unknown
Wyoming Pocket Mouse	Perognathus fasciatus, status unknown
Great Basin Pocket Mouse	Perognathus parvus, status unknown
Ord Kangaroo Rat	Dipodomys ordi, status unknown
Canyon Mouse	Peromyscus crinitus, status unknown
Deer Mouse	Peromyscus maniculatus, common resident
Northern Grasshopper Mouse	Onychomys leucogaster, status unknown
Bushytail Woodrat	Neotoma cinerea, common resident
Mountain Phenacomys	Phenacomys intermedius, status unknown
Boreal Redback Vole	Clethrionomys gapperi, status unknown
Mountain Vole	Microtus montanus, status unknown
Longtail Vole	Microtus longicaudus, status unknown
Richardson Vole	Microtus richardsoni, status unknown
Sagebrush Vole	Lagurus curtatus, common resident
Western Jumping Mouse	Zapus princeps, common resident
Game Birds	
Migratory Waterfowl and Shorebirds	
Canada Goose	Branta canadensis, common spring, summer, fall, winter resident and migrant
White-fronted Goose	Anser albifrons, uncommon fall migrant
Lesser Snow Goose	Chen hyperborea hyperborea, uncommon fall migrant
Mallard	Anas platyrhynchos, common spring, summer, fall, winter resident and migrant
Pintail	Anas acuta, common spring, summer, fall, winter resident and migrant
Gadwall	Anas strepera, common spring, summer, fall, winter resident and migrant
American Widgeon	Mareca americana, common spring, summer, fall resident and migrant
Shovelar	Spatula clypeata, common spring, summer, fall resident and migrant

Table II-41.--Con't.

Common Name	Scientific Name
Game Birds	
Migratory Waterfowl and Shorebirds	
Blue-winged Teal	Anas discors, common spring, summer, fall resident and migrant
Cinnamon Teal	Anas cyanoptera, common spring, summer, fall resident and migrant
Green-winged Teal	Anas carolinensis, common spring, summer, fall resident and migrant
Wood Duck	Aix sponsa, rare spring, fall migrant
Redhead	Aythya americana, common spring, summer, fall resident and migrant
Canvasback	Aythya valisineria, uncommon spring, summer, fall resident and migrant
Ring-necked Duck	Aythya collaris, uncommon spring, summer, fall resident and migrant
Greater Scaup	Aythya marila, common spring, fall migrant
Lesser Scaup	Aythya affinis, common spring, summer, fall, winter resident and migrant
Common Goldeneye	Bucephala clangula, common spring, summer, fall, winter resident and migrant
Barrow's Goldeneye	Bucephala islandica, uncommon spring, fall migrant
Bufflehead	Bucephala albeola, common spring, summer, fall resident and migrant
Oldsquaw	Clangula hyemalis, rare winter migrant
White-winged Scoter	Melanitta deglandi, rare fall, winter migrant
Ruddy Duck	Oxyura jamaicensis, common spring, summer, fall resident
Common Merganser	Mergus merganser, common spring, summer, fall, winter resident and migrant
Red-breasted Meganser	Morgus serrator, uncommon spring migrant
Hood Meganser	Lophodytes cucullatus, rare fall, winter migrant
American Coot	Fulica americana, common spring, summer, fall resident and migrant
Wilson's Snipe	Capella gallinago, common spring, summer, fall resident and migrant
Upland Game Birds	
Merriam's Turkey	Meleagris gallopavo merriami, rare resident
Sage Grouse	Centrocercus urophasianus urophasianus, common resident
Chukar Partridge	Alectoris graeca, common resident
Mourning Dove	Zenaidura macroura, common spring, summer, fall resident and migrant

Table II-41 --Con't.

Common Name	Scientific Name
Predacious Birds	
Black-billed Magpie	Pica pica, common resident
Common Crow	Corus brachyrhynchos, common spring, summer, fall resident and migrant
Starling	Sturnus vulgaris, common resident
House Sparrow	Passer domesticus, common resident
Nongame Birds	
Common Loon	Gavia immer, common spring, fall migrant
West Grebe	Aectimophorus occidentalis, common spring, summer, fall migrant
Horned Grebe	Podiceps auritus, uncommon spring, fall migrant
Eared Grebe	Podiceps caspicus, common spring, summer, fall resident and migrant
Pied-billed Grebe	Podilymbus podiceps, common spring, summer, fall resident and migrant
White Pelican	Pelecanus erythrorhynchos, common spring, fall migrant
Double-crested Cormorant	Phalacrocorax auritus, uncommon spring, fall migrant
Turkey Vulture	Cathartes aura, common summer resident and migrant
Goshawk	Accipiter gentilis, common resident
Cooper's Hawk	Accipiter cooperi, uncommon summer resident and migrant
Sharp-shinned Hawk	Accipiter striatus, common spring, summer, fall resident and migrant
Marsh Hawk	Circus cyaneus, common resident and migrant
Rough-legged Hawk	Buteo lagopus, common resident and migrant
Ferruginous Hawk	Buteo regalis, common resident 4/
Red-tailed Hawk	Buteo jamaicensis, common spring, summer, fall resident and migrant
Swainson's Hawk	Buteo swainsoni, common spring, summer, fall resident and migrant
Harlan's Hawk	Buteo harlani, rare spring, fall migrant
Golden Eagle	Aquila chrysaetos, common resident and migrant
Bald Eagle	Haliaeetus leucocephalus, common spring, fall, winter resident and migrant
Osprey	Pandion haliaetus, common spring and fall migrant 4/
Gyrfalcon	Falco rusticolus, rare winter migrant
Prairie Falcon	Falco mexicanus, common resident and migrant 3/
Peregrine Falcon	Falco peregrinus, uncommon spring, summer, fall resident and migrant 2/

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Table II-41.--Con't.

Common Name	Scientific Name
Nongame Birds	
Pigeon Hawk	Falco columbarius, uncommon spring, summer, fall resident and migrant. This area is also included in the range of the Prairie Pigeon Hawk (Subspecies richardsonii) 4/
Sparrow Hawk	Falco sparverius, common spring, summer, fall resident and migrant
Snowy Egret	Leucophoyx thula, common spring, summer, fall resident and migrant
Great Blue Heron	Ardea herodias, common spring, summer, fall resident and migrant
Black-crowned Night Heron	Nycticorax nycticorax, common spring, summer, fall resident and migrant
American Bittern	Botaurus lentiginosus, common spring, summer, fall resident and migrant
White-faced Ibis	Plegadis chihi, common spring, summer, fall resident and migrant
Greater Sandhill Crane	Grus candensis tabida, common spring, fall migrant
Virginia Rail	Rallus limicola, uncommon spring, summer, fall resident and migrant
Sora	Porzana carolina, common spring, summer, fall resident and migrant
Yellow Rail	Coturnicops novoboracensis, rare spring, fall migrant
Common Gallinule	Gallinula chloropus, rare spring migrant
American Avocet	Recurvirostra americana, common spring, summer, fall resident and migrant
Mountain Plover	Eupoda montana, uncommon spring, fall migrant 4/
Black-bellied Plover	Squatarola squatarola, rare spring, fall, migrant
Snowy Plover	Charadrius alexandrinus, rare spring, fall migrant 4/
Killdeer	Charadrius vociferus, common spring, summer, fall resident and migrant
Long-billed Curlew	Numenius americanus, common spring, summer, fall resident and migrant 4/
Marbled Godwit	Limosa fedoa, common spring, summer, fall resident and migrant
Upland Plover	Bartramia longicauda, rare spring migrant
Solitary Sandpiper	Tringa solitaria, common spring, summer fall resident and migrant
Spotted Sandpiper	Actitis macularia, common spring, summer. fall resident and migrant
Willet	Catoptrophorus semipalmatus, common spring, summer, fall resident and migrant

Table II-41.--Con't.

Common Name	Scientific Name
Nongame Birds	
Greater Yellowlegs	Totanus melanoleucus, common spring, fall resident and migrant
Lesser Yellowlegs	Totanus flavipes, uncommon spring, fall migrant
Long-billed Dowitcher	Limnodromus scolopaceus, uncommon spring, summer, fall migrant
Pectoral Sandpiper	Erolia melanotos, uncommon spring, fall migrant
Knot	Calidris canutus, rare spring migrant
Sanderling	Crocethia alba, common spring, fall migrant
Baird's Sandpiper	Erolia bairdii, uncommon spring, fall migrant
Least Sandpiper	Erolia minutilla, common spring, fall migrant
Semipalmated Sandpiper	Erounetes pusillus, common spring, fall migrant
Western Sandpiper	Ereunetes mauri, common spring, fall migrant
Wilson Phalarope	Steganopus tricolor, common spring, summer, fall resident migrant
Northern Phalarope	Lobipes lobatus, uncommon spring, fall migrant
Herring Gull	Larus argentatus, uncommon spring, summer, fall resident and migrant
California Gull	Lurus californicus, uncommon spring, fall migrant
Ring-billed Gull	Larus delawarenis, common spring, summer, fall resident and migrant
Franklin's Gull	Larus pipixcan, common spring, summer, fall resident and migrant
Bonaparte's Gull	Larus philadelphia, common spring, fall migrant
Forster's Tern	Sterna forsteri, common spring, fall migrant
Caspian Tern	Hydroprogne caspia, common spring, fall migrant
Black Tern	Chlidonias niger, common spring, summer, fall resident and migrant
Rock Dove	Columba livia, uncommon resident
Yellow-billed Cuckoo	Coccyzus americanus, uncommon summer resident and migrant
Screech Owl	Otus asio, common resident
Great Horned Owl	Bubo virginianus, common resident
Long-eared Owl	Asio otus, uncommon resident
Short-eared Owl	Asio flammeus, common resident
Snowy Owl	Nyctea scandiaca, rare winter migrant
Creat Gray Owl	Strix nebulosa, rare winter migrant
Western Burrowing Owl	Speotyto cunicularia hypugaea, uncommon spring, summer, fall resident and migrant

Table II-41.--Con't.

Common Name	Scientific Name
Nongame Birds	
Saw-whet Owl	Aegolius acadicus, uncommon resident
Flammulated Owl	Otus flammeolus, rare summer migrant
Pygmy Owl	Glaucidium gnoma, rare resident
Poor-will	Phalaenoptilus nuttallii, common summer resident and migrant
Common Nighhawk	Chordeiles minor, common summer resident and migrant
White-throated Swift	Aeronautes saxatalis, uncommon summer resident and migrant
Broad-tailed Hummingbird	Selasphorus platycercus, common summer resident and migrant
Rufous Hummingbird	Selasphorus rufus, common fall migrant
Belted Kingfisher	Megaceryle alcyon, common spring, summer, fall, winter resident and migrant
Red-shafted Flicker	Colaptes cafer, common resident
Red-headed Woodpecker	Melanerpes erythrocephalus, rare summer migrant
Lewis Woodpecker	Asyndesmus lewis, uncommon summer resident and migrant
Yellow-bellies Sapsucker	Sphyrapicus varius, common spring, summer, fall resident and migrant
Williamson's Sapsucker	Sphyrapicus thyroideus, uncommon summer migrant
Hairy Woodpecker	Dendrocopos villosus, common resident
Downy Woodpecker	Dendrocopos pubescens, uncommon resident
Northern Three-toed Woodpecker	Picoides tridactylus, uncommon resident
Eastern Kingbird	Tyrannus tyrannus, common spring, summer, fall resident and migrant
Western Kingbird	Tyrannus verticalis, common spring, summer, fall resident and migrant
Ash-throated Flycatcher	Myiarchus cinerascens, rare summer migrant
Say's Phoebe	Sayornis saya, common spring, summer, fall resident and migrant
Traill's Flycatcher	Empidonax traillii, uncommon spring, summer, fall resident and migrant
Hammond's Flycatcher	Empidonax hammondii, uncommon spring, summer, fall resident and migrant
Gray Flycatcher	Empidonax wrightii, uncommon spring, summer, fall resident and migrant
Western Flycatcher	Empidonax difficilis, common spring, summer, fall resident and migrant
Western Wood Pewee	Contopus sordidulus, uncommon spring, summer, fall resident and migrant
Olive-sided Flycatcher	Nuttallornis borealis, uncommon spring, summer, fall resident and migrant
Horned Lark	Eremophila alpestris, common resident

Table II-41.--Con't.

Common Name	Scientific Name
Nongame Birds	
Barn Swallow	Hirundo rustica, common spring, summer, fall resident and migrant
Violet-green Swallow	Tachycineta thalassina, common spring, summer, fall resident and migrant
Tree Swallow	Iridoprocne bicolor, common spring, summer, fall resident and migrant
Bank Swallow	Riparia riparia, common spring, summer, fall resident and migrant
Rough-winged Swallow	Stelgidopteryx ruficollis, common spring, summer, fall resident and migrant
Purple Martin	Progne subis, rare summer migrant
Pinyon Jay	Gymnorhinus cyanocephalus, common spring, summer, fall resident
Gray Jay	Perisoreus canadensis, uncommon spring, summer, fall resident
Clark's Nutcracker	Nucifraga columbiana, uncommon spring, summer, fall resident
Common Raven	Corvus corax, uncommon resident
Black-capped Chickadee	Parus atricapillus, common resident
Mountain Chickadee	Parus gambeli, uncommon resident
Plain Titmouse	Parus inornatus, uncommon resident
Common Bushtit	Psaltriparus minimus, common resident
White-breasted Nuthatch	Sitta earolinensis, common resident
Red-breasted Nuthatch	Sitta canadensis, common spring, fall, winter resident
Pygmy Nuthatch	Sitta pygmaea, common fall, winter resident
Brown Creeper	Certhia familiaris, uncommon resident
House Wren	Troglodytes aedon, common spring, summer resident and migrant
Bewick's Wren	Thryomanes bewickii, uncommon resident
Rock Wren	Salpinctes obsoletus, common summer resident and migrant
Canyon Wren	Catherpes mexicanus, common resident
Long-billed Marsh Wren	Telmatodytes palustris, common spring, summer, fall resident and migrant
Mockingbird	Mimus polyglottos, uncommon resident
Catbird	Dumetella carolinensis, common spring, summer, fall resident and migrant
Sage Thrasher	Oreoscoptes montanus, common spring, summer, fall resident and migrant
Robin	Turdus migratorius, common resident
Townsend's Solitaire	Myadestes townsendi, uncommon spring, fall, winter resident
Hermit Thrush	Hylocichla guttata, common summer resident and migrant
Swainson's Thrush	Hylocichla ustulata, common summer resident and migrant

Table II-41.--Con't.

Common Name	Scientific Name
Nongame Birds	
Veery	Hylocichla fuscescens, uncommon spring, summer resident and migrant
Western Bluebird	Sialia mexicana, rare summer migrant
Mountain Bluebird	Sialia currucoides, common spring, summer, fall resident and migrant
Golden-crowned Kinglet	Regulus satrapa, common spring, summer, fall migrant
Ruby-crowned Kinglet	Regulus calendula, common spring, summer, fall migrant
Water Pipit	Anthus spinoletta, common spring, summer, fall migrant
Sprague's Pipit	Anthus spagueii, uncommon spring, fall migrant
Bohemian Waxwing	Bombycilla garrulus, common winter resident and migrant
Cedar Waxwing	Bombycilla cedrorum, common spring, fall, winter resident and migrant
Northern Shrike	Lanius excubitor, common winter resident and migrant
Loggerhead Shrike	Lanius ludovicianus, common spring, summer, fall resident and migrant
Solitary Vireo	Vireo solitarius, common spring, summer resident and migrant
Warbling Vireo	Vireo gilvus, common summer resident
Orange-crowned Warbler	Vermivera celata, common summer resident and migrant
Yellow Warbler	Dendroica petechia, common spring, summer, fall resident and migrant
Myrtle Warbler	Dendroica coronota, common spring, fall migrant
Audubon's Warbler	Dendroica auduboni, common spring, summer, fall resident and migrant
Townsend's Warbler	Dendroica townsendi, uncommon fall migrant
Northern Waterthrush	Seiurus noveboracensis, rare spring, fall migrant
Yellowthroat	Geothlypis trichas, uncommon summer resident and migrant
Yellow-breasted Chat	Icteria virens, uncommon spring, summer, fall resident and migrant
MacGillivray's Warbler	Oporornis tolmiei, uncommon spring, summer, fall resident and migrant
Wilson's Warbler	Wilsonia pusilla, uncommon spring, summer, fall migrant
American Redstart	Setophaga ruticilla, rare spring, summer, fall migrant
Bobolink	Dolichonyx oryzivorus, rare spring, fall migrant
Western Meadowlark	Sturnella neglecta, common spring, summer, fall resident and migrant

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Table II-41.--Con't.

Common Name	Scientific Name
Nongame Birds	
Yellow-headed Blackbird	*Xanthocephalus xanthocephalus*, common spring, summer, fall resident and migrant
Red-winged Blackbird	*Agelaius phoeniceus*, common spring, summer, fall resident and migrant
Brewer's Blackbird	*Euphagus cyanocephalus*, common spring, summer, fall resident and migrant
Brown-headed Cowbird	*Molothrus ater*, common spring, summer, fall resident and migrant
Bullock's Oriole	*Icterus bullockii*, common summer resident and migrant
Western Tanager	*Piranga ludoviciana*, uncommon summer migrant
Black-headed Grosheak	*Pheucticus melanocephalus*, uncommon spring, summer, fall resident and migrant
Evening Grosbeak	*Hosperiphona vespertina*, common resident
Lazuli Bunting	*Passerina amoena*, rare summer resident and migrant
Purple Finch	*Carpodacus purpureus*, common spring, fall winter resident and migrant
Cassin's Finch	*Carpodacus cassinii*, uncommon resident
House Finch	*Carpodacus mexicanus*, common resident
Pine Grosbeak	*Pinicola enucleator*, uncommon resident
Gray-cowned Rosy Finch	*Leucosticte tephrocotis*, common winter resident and migrant
Black Rosy Finch	*Leucosticte atrata*, common winter resident and migrant
Brown-capped Rosy Finch	*Leucosticte australis*, rare winter resident and migrant
Common Redpoll	*Acanthis flammea*, uncommon winter resident and migrant
Pine Siskin	*Spinus pinus*, uncommon spring, summer, fall resident and migrant
American Goldfinch	*Spinus tristis*, common spring, summer, fall resident and migrant
Lesser Goldfinch	*Spinus psaltria*, uncommon summer resident and migrant
Red Crossbill	*Loxia curvirostra*, uncommon resident
White-winged Crossbill	*Loxia leucoptera*, rare winter migrant
Green-tailed Towhee	*Chlorura chlorura*, uncommon summer resident and migrant
Rufous-sided Towhee	*Pipilo erythrophthalmus*, uncommon resident
Savannah Sparrow	*Passerculus sandwichensis*, common spring, summer, fall resident and migrant
Grasshopper Sparrow	*Ammodramus savannarum*, common summer resident and migrant

Table II-41.--Con't.

Common Name	Scientific Name
Small Game Birds	
Baird's Sparrow	*Ammodramus Bairdii*, rare spring, fall migrant
Lark Bunting	*Calamospiza melanocorys*, common spring, summer, fall resident and migrant
Vesper Sparrow	*Pooecetes graminius*, common spring, summer, fall resident and migrant
Lark Sparrow	*Chondestes grammacus*, common spring, summer, fall resident and migrant
Sage Sparrow	*Amphispiza belli*, common summer resident and migrant
Slate-colored Junco	*Junco hyemalis*, common winter resident and migrant
Oregon Junco	*Junco oreganus*, common winter resident and migrant
Gray-headed Junco	*Junco caniceps*, common spring, summer, fall, winter resident and migrant
Tree Sparrow	*Spizella arborea*, common winter resident and migrant
Chipping Sparrow	*Spizella passerina*, common spring, summer, fall resident and migrant
Clay-colored Sparrow	*Spizella pallida*, rare summer resident and migrant
Brewer's Sparrow	*Spizella breweri*, common summer resident and migrant
Harris Sparrow	*Zonotrichia querula*, rare spring, fall migrant
White-crowned Sparrow	*Zonotrichia leucophrys*, common resident
White-throated Sparrow	*Zonotrichia albicollis*, uncommon spring, fall migrant
Fox Sparrow	*Passerella iliaca*, uncommon spring, summer, fall resident and migrant
Lincoln's Sparrow	*Melospiza lincolnii*, common spring, summer, fall resident
Song Sparrow	*Melospiza melodia*, common resident
McCown's Longspur	*Rhynchophanes mccownii*, uncommon spring, fall migrant
Chestnut-collared Longspur	*Calcarius ornatus*, uncommon spring, fall migrant
Lapland Longspur	*Calcarius Lapponicus*, rare winter resident and migrant
Snow Bunting	*Plectrophenaz nivalis*, rare winter migrant
Salamanders	
Utah Tiger Salamander	*Ambystoma tigrinum utahensis*
Blotched Tiger Salamander	*Ambystoma tigrinum melanostictum*

Table II-41.--con't.

Common Name	Scientific Name
Frogs and Toads	
Great Basin Spadefoot	*Scaphiopus intermontanus*
Boreal Toad	*Bufo boreas boreas*
Boreal Chorus Frog	*Pseudacris triseriata maculata*
Leopard Frog	*Rana pipiens*
Lizards	
Northern Plateau Lizard	*Sceloporus undulatus elongatus*
Sagebrush Lizard	*Sceloporus graciosus*
Tree Lizard	*Urosaurus ornatus*
Northern Side-blotched Lizard	*Uta stansburiana stansburiana*
Eastern Short-horned Lizard	*Phrynosoma douglassi brevirostre*
Snakes	
Western Yellow-bellied Racer	*Coluber constrictor*
Great Basin Gopher Snake	*Pituophis melanoleucus deserticola*
Wandering Garter Snake	*Thamnophis elegans vagrans*
Midget Faded Rattlesnake	*Crotalus viridis concolor*
Prairie Rattlesnake	*Crotalus viridis viridis*

1/ Species occurring in the Flaming Gorge Bird Management Area, Southwestern Bird Management Unit. Wyoming Game & Fish Commission, Game Division, District IV.

2/ Categories of animals (i.e., game, predatory, etc.) defined by Wyoming Game Laws, Section 23.1-1.

3/ Endangered species.

4/ Likely to become endangered.

5/ Status undetermined.

grazed by the deer. Statistics indicate that on a statewide basis the deer are on a downward trend, and the Wyoming Game and Fish Commission (1971) attributes this decline in District 4 primarily to hunting pressure from non-resident hunters.

A winter population of 3,950 elk was estimated to exist in District 4 during 1969, and several small herds of elk (probably 30-35 animals) are known to exist in the oil shale areas themselves including: one in the sand dune area east of Eden; one of the Pilot Butte area; and one in the southern portion of the Pine and Little Mountain area (see Figure II-16). This species ranges over portions of the tri-State area, and hunting seasons are held in all three States. There are important elk range areas, north, west, and south of Kemmerer, Wyoming. Summer range for this species is regarded as generally ample, and, as with mule deer, carrying capacity is determined by the quantity and quality of winter range. Most elk summer range is used jointly with cattle and domestic sheep. From 1960-69 an estimated average of 601 elk were harvested annually within District 4. Hunter success in shooting an elk ranged from 36% for residents to 56% for non-residents in 1969. Elk habitat in the Washakie Basin is limited.

An estimated 1,251,542 acres of moose range exist in District 4, most of which is found in the river and creek bottoms where the animals are found in association with abundant willow (Salix) growths. (See Figure II-20.) The existing population is believed to number about 450 animals. Although generally limited to bottom lands, moose are reported to be found in increasing numbers in pine and aspen plant communities. From 1960-69 an estimated average annual harvest of 28 moose occured within District 4. Harvest has been permitted to increase along with the expanding herd, and 35 animals were harvested in 1969. The species is expected to continue increasing under the present management program. Little or no moose range exists in the Washakie Basin.

Black bear is found in mountainous areas in the Western portion of District 4. Range for the species is estimated at about 945,000 acres and an estimated population for winter 1969 was 740 animals. Bears are hunted during spring and fall seasons, and some are taken each year as predators. The average animal hunting harvest from 1960-69 was 5 animals, although 8 were taken in 1969.

Mountain lions are known to occur in a rather even density over the Wyoming oil shale lands. No data are available on the existing number of this species.

Wyoming's Green River Basin includes some of the state's important antelope habitat area, supporting a high density population. The Washakie Basin contains important antelope range.

Substantial numbers of wild horses range widely over the Washakie Basin--Kinney Rim to Flaming Gorge area. Recent censuses indicate approximately 1,200 horses in Washakie Basin and approximately 2,500 horses and burros in the area between Kinney Rim and the Utah line (Wyoming State Director, BLM, 1972). Prevailing winds generally drift most of the snow off major portions of the area lying along and immediately east from Kinney Rim, including

Tracts W-a and W-b. Consequently, the area is utilized by wild horses during periods of heavy snow accumulation.

The cottontail rabbit, coyote, and fox are regarded as common. Cottontail habitat extends throughout the oil shale lands. The most outstanding cover is the northern desert sagebrush and saltbush vegetation community. The average annual cottontail hunting harvest over the period 1966-69 was estimated to be 27,400 rabbits.

c. Birds

Sage grouse populations are found in sagebrush-saltbush areas below 8,500 feet elevation (See Figure II-18). Although this species is generally very abundant across an estimated 8.3 million acres of habitat, sagebrush control programs, development, and other land-use changes have significantly reduced the habitat in many areas. The Eden-Farson area exhibits one of the highest densities of this species known to exist. Hunting harvests are excellent and sage grouse are hunted more than any other game bird. From 1960-69 an average annual harvest of 17,732 birds has been estimated.

Blue, ruffed, and sharptail grouse and ptarmigan habitat also exists in District 4. Blue grouse are found in forest lands and foothill areas of Uinta and Carbon Counties. Ruffed grouse are found in the same general areas but are more confined to mountain valleys and drainages. Sharptail grouse are found in sagebrush-grassland and aspen areas in the Little Snake River Valley of Carbon County. Ptarmigan habitat is good but confined to timberline regions of mountains in Sublette County. Habitat of all these species has been adversely affected by livestock activity, timber cutting, sagebrush, and brush control programs. Estimated average annual harvest of blue and ruffed grouse in District 4 from 1960-69 was 1,956 birds. Any of these four species would be scarce at best in the Washakie Basin.

Chukar partridge habitat is limited and is found in Uinta, Carbon, and Sweetwater Counties. Better habitat is found in the semidesert, badland, and juniper vegetation-type areas of Sweetwater County. These habitat types are extensive in the Washakie Basin. This bird has become established and it is becoming more popular as a hunting species. The estimated average harvest of chukar partridge from 1962-69 was 383 birds per year.

Some marginal wild turkey habitat exists on the lower Green River Basin in southern Sweetwater County (See Figure II-18). Introduced in 1957, this species is believed to be limited by a lack of adequate winter feed and cover. The population has not approached huntable numbers.

Introduced in the 1940's and 1960's, ringneck pheasants exist in limited numbers on some very marginal habitat in the Bear River Valley of Lincoln County, the Eden-Farson area of Sweetwater County, and the Little Snake River Valley in Carbon County. Lack of adequate winter food and cover are believed to be limiting factors for these populations. Average annual hunter harvest over the period 1960-69 was estimated to be 417 birds.

It is estimated that about 8,000 ducks and 795 geese were bagged in the limited available habitat along the Green River in 1969 (See Figure II-19).

d. Fish

The Flaming Gorge Reservoir and the Green River are the major sport fisheries areas in the oil shale lands of Wyoming. Flaming Gorge Reservoir is considered to provide excellent angling, and in 1970 it was reported to provide 232,000 anglers with 367,000 fish. The Green River provides fair to good trout fishery. The section from Big Island to Fontenelle Reservoir provided an estimated 4,700 trout in 1970, while the section from Big Island to the Kincaid Ranch provided an additional 3,525. The Bear, Hams Fork, and Little Snake Rivers are considered to vary from fair to poor in angling quality. The Little Snake River from Baggs to Savory is fair with good potential for improvement. The upper reaches of the Little Snake River have been dedicated to the dedicated to the preservation of the Colorado River cutthroat trout (See Table II-12).

Although little data exist on the sport fishery resource in the smaller streams, some of the better trout habitats exist in the oil shale area.

e. Threatened Species

A number of threatened fish, birds, and mammals are known to or suspected to exist in or associated with the oil shale area of Wyoming. Table II-14 provides a list of these species which have been identified with the overall tri-State oil shale area. By virtue of the remote nature of the oil shale lands, habitat there is available for use in a relatively undisturbed state by these species. It is believed that most of the species in Table II-14 currently use these lands and waters during some portion of their cycle.

7. Soils

The soils of the Washakie Basin (Figure II-51) are classified as Haplargids, Torriorthents, and Salorthids. They are developed on the high, dissected plateaus of the Green River, Bridger, and Wasatch Formations. Slopes range from nearly level, moderately sloping (75 percent of the basin) to steeply sloping (20 percent of the basin). Soil textures vary from sandy, loamy to clayey.

Sixty percent of the soils in the basin are estimated to be shallow, less than 20 inches to bedrock; the remainder of the soils are moderately deep to deep. Erosion hazards are generally moderate to high. Wind erosion is more of a problem than water erosion because of the low rainfall, 10 to 14 inches. Soil reaction is commonly alkaline to strongly alkaline. Land types such as shale badlands and sand dunes also occur in the basin.

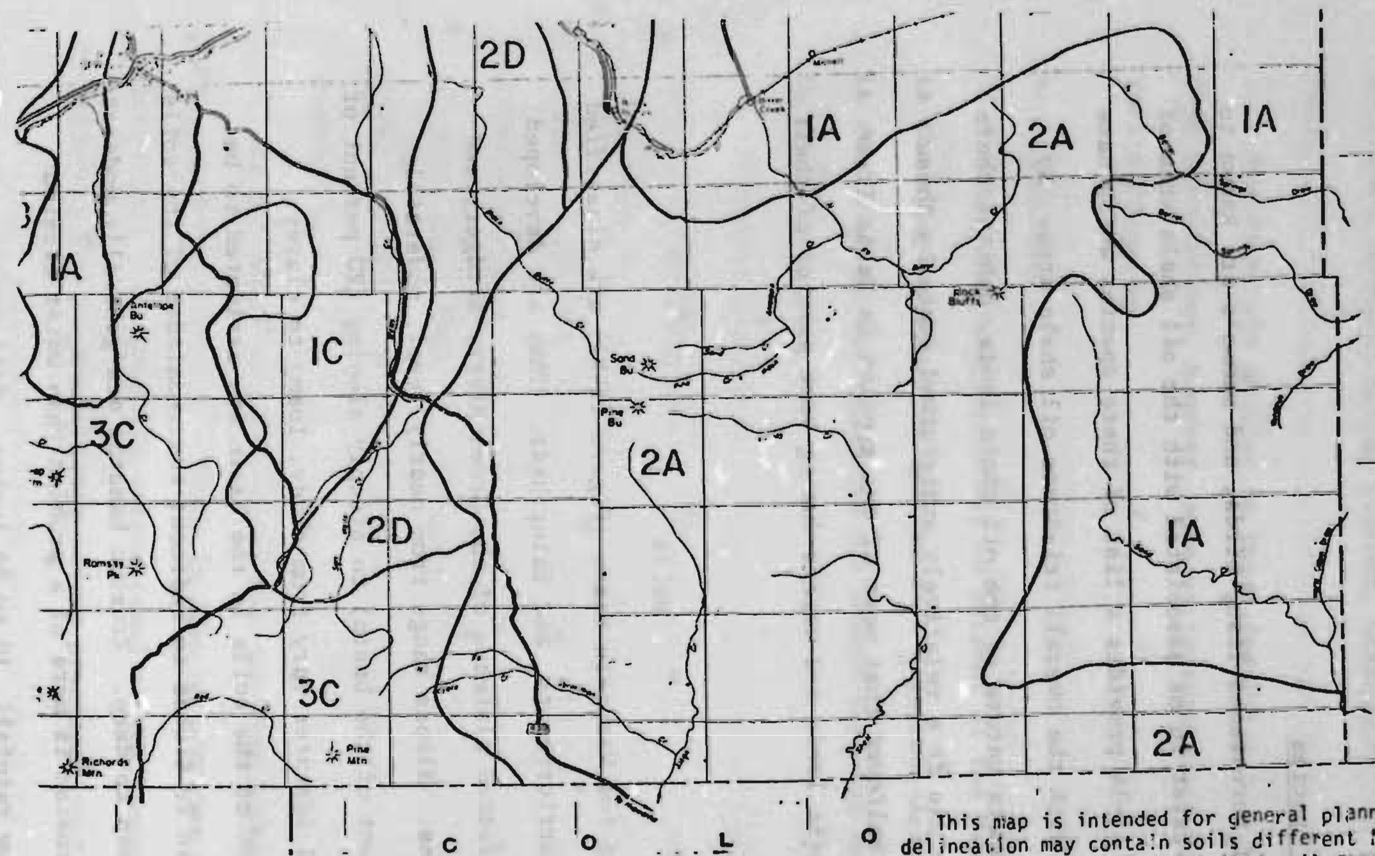

FIGURE II-51.--General Soil Map, Sweetwater County, Wyo. (Portion - Oil Shale Tracts).

This map is intended for general planning. Each delineation may contain soils different from those shown on the map. Use detailed soil maps for operational planning, and on site inspection for more detailed decisions.

Soils of Residual Uplands: Elevation 7,000 to 9,000 feet: Precipitation 10 to 14 inches

2A Washakie Basin, Delaney and Kenney Rims
2B Pilot Butte-White Mountain-Fire Hole Canyon
2C Lost Soldier-Twin Buttes
2D Black Buttes
2E . [illegible]-Bison Basin

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8. Vegetation of the Washakie Basin

The Washakie Basin contains five major vegetative types: Sagebrush, Mountain Shrub, Juniper, Greasewood, and Salt Desert Shrub.

The types are similar to those described in the Colorado and Utah descriptions, however, some variations occur because of latitudinal differences.

a. Sagebrush

This type comprises about 78 percent of the Washakie Basin. It is the type described by Kuchler as a Sagebrush-Agropyron Steppe. It is dominated by big sagebrush but favors the cool season wheatgrasses in the understory.

Principal wheatgrass species include thickspike wheatgrass (*Agropyron dasystachylum*), beardless bluebunch wheatgrass (*Agropyron inerme*), bearded bluebunch wheatgrass (*Agropyron spicatum*), and western wheatgrass (*Agropyron smithii*). Other grasses include native bluegrasses, junegrass, and on lighter textured soils, needle-and-thread grass. Common forbs include phlox, buckwheat, aster, and pussytoes. Tall and low rabbitbrush is also present in the composition.

In the lower successional stages the wheatgrasses decrease and big sagebrush increases. There is also an increase in forbs and rabbitbrush. In the early successional stages, annuals such as cheatgrass and Russian thistle become prominent.

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b. Mountain shrub

This type is described in the Piceance Creek Basin descriptions. In the Washakie Basin, it is primarily a mixed shrub association of serviceberry, mountain mahogany, bitterbrush, and snowberry.

It comprises only 5 percent of the basin and occurs primarily on the higher north and east facing slopes.

Understory plants are similar to those described in the Colorado-type description.

c. Salt Desert Shrub

This type comprises only 3 percent of the basin and is a northern extension of the type as described in the Uinta Basin descriptions.

d. Greasewood

This type is found in the drainage bottoms throughout the Washakie Basin. It comprises about 12 percent of the total area. It is described in the Piceance Creek Basin descriptions.

e. Juniper

Except for the absence of pinyon pine, this type is described in the Piceance Creek Basin descriptions. In the Washakie Basin, it comprises only 2 percent of the area and occurs primarily on rocky breaks. The dominant species is Utah juniper. Understory plants are the same as described in the Pinyon-Juniper type description for the Piceance Creek Basin.

Grazing use of the Washakie Basin is primarily by sheep in the winter and fall. Some cattle also use the area, and there is a sizable herd of wild horses in the area all year.

Primary game use is by antelope all year and by mule deer in the winter. During the winter months a few elk are seen in the vicinity of Baggs, Wyoming, southeast of the Washakie Basin.

Small animals living in the area include jack and cottontail rabbits, sage grouse, rodents, songbirds, and associated predators.

The prominent plant species are as follows:

Sagebrush Type

Technical Name	Common Name
Grasses	
Agropyron smithii	Western wheatgrass
Stipa comata	Needle-and-thread grass
Poa secunda	Sandberg bluegrass
Oryzopsis hymenoides	Indian ricegrass
Forbs	
Erigonum spp.	Eriogonum
Penstemon spp.	Penstemons
Phlox spp.	Phlox
Shrubs	
Artemisia tridentata	Big sage
Artemisia nova	Black sage
Chrysothamnus	Rabbitbrush
Atriplex nuttallii	Gardner's saltbush

Mountain Shrub Type

Technical name	Common Name
Grasses	
Agropyron spicatum	Bluebunch wheatgrass
Stipa spp.	Needlegrass

Mountain Shrub Type

Technical Name	Common Name
Grasses	
Koeleria cristata	Junegrass
Poa fendleriana	Muttongrass
Forbs	
Achillea lanulosa	Western yarrow
Antennaria rosea	Pusseytoes
Eriogonum pulcherrimus	Fleabane
Castilleja chromosa	Indian paintbrush
Shrubs	
Amelanchier utahensis	Serviceberry
Symphoricarpos oreophilus	Snowberry
Cercocarpus montanus	Mountain mahogany
Rosa nutkana	Rose

Pinyon-Juniper Type

Technical Name	Common Name
Grasses	
Agropyron smithii	Western Wheatgrass
Oryzopsis hymenoides	Indian ricegrass
Poa secunda	Sandberg bluegrass
Stipa comata	Needle-and-thread grass
Sitanion hystrica	Squirrel tail
Forbs	
Astragulus bisulcatus	Milkvetch
Castilleja	Indian paintbrush
Eriogonum app.	Eriogonum
Zygadenus elegans	Death camus
Shrubs	
Cercocarpus montanus	Mountain mahogany
Artemesia tridentata	Big sage
Purshia Tridentata	Bitterbrush
Amelanchier (utahensis)	Serviceberry
Trees	
Juniperus osteosperma	Utah juniper

Saltbush Greasewood Type

Technical Name	Common Name
Grasses	
Agropyron smithii	Western wheatgrass
Distichlis strica	Inland saltgrass
Blymus cinereus	Basin wildrye
Poa app.	Bluegrass
Carex app.	Sedges
Forbs	
Muhlenbergia	Alkali muhly
Oxytropis lambertii	Pointvetch
Iva axillaris	Poverty weed
Zygadenus elegans	Death camus
Shrubs	
Sarcobatus vermiculatus	Greasewood
Artiplex nuttallii	Gardner's saltbush
Chrysothamnus app.	Rabbitbrush
Atriplex canescens	Four-wing saltbush

Salt Desert Shrub

Technical Name	Common Name
Grasses	
Agropyron smithii	Western wheatgrass
Distichlis strica	Inland saltgrass
Sporobolus airoides	Alkali sacaton
Oryzopsis hymenoides	Indian ricegrass
Forbs	
Iva axillaris	Poverty weed
Muhlenbergia asperifolia	Alkali muhly
Muhlenbergia Richardsonis	Mat muhly
Oxytropis lambertii	Point vetch
Shrubs	
Atriplex nuttallii	Gardner's saltbush
Chrysothamnus app.	Rabbitbrush
Atriplex canescens	Fourwinged saltbush
Rhus trilobeta	Skunkbrush

9. Recreational Resources

In the oil shale area of the Washakie Basin the primary outdoor recreation activities are oriented towards fall hunting mostly antelope, deer, and game birds.

In the environs of the oil shale land there are other recreational opportunities. The State Outdoor Recreation Plan for Wyoming has designated all of Sweetwater County as part of the State's Recreation Region 7 (R7).1/ Other counties in R7 include Sublette, Lincoln, and Uinta. All of these counties contain potential oil shale lands which could have an effect on outdoor recreation.

Recreation inventories of Sweetwater County show that the potential for outdoor recreation activities such as big- and small-game hunting, camping, natural and scenic areas, cold-water fishing, and vacation ranches is high; for warm-water fishing, winter sports, and pack trips, it is low; while for water sports, picnicking, and water fowl, it is medium.2/ Of the 6.7 million acres in Sweetwater County, Federal agencies administer 4.5 million acres, or 68 percent of the recreational potential of the county; State and local agencies, 346,280 acres, or 5 percent; and private owners, 1.8 million acres, or 27 percent.

Of the 13 Federal recreation areas reported to the Bureau of Outdoor Recreation in the 1965 inventory of designated public

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1/ An outdoor Recreation Plan for Wyoming--1970.
2/ Outdoor Recreation Potential, Wyoming--1969, USDA, SCS.

recreation areas for Sweetwater County, 12 are administered by BLM and one (Flaming Gorge Recreation Area) by the National Park Service. The State of Wyoming reported one State park area. 1/

Hunting, fishing, and camping were the activities most often sought after by the 700,000 who visited these public lands in 1965 (Table II-42). Approximately 125,000 visits were made to the Pine Mountain, Bitter Creek, and Burntfork recreation complexes which are the closest to the Washakie Basin; 18,000 of these visits were campers.

Private outdoor recreation enterprises in Sweetwater County consist of six entrepreneurs on only 1,153 acres; two operate camping grounds, one provides natural and scenic facilities, one operates a vacation ranch, and the other two are urban oriented.

1/ Bureau of Outdoor Recreation Survey of Public Areas and Facilities, 1965.

TABLE II-42.--Attendance at Public Outdoor Recreation Areas in Sweetwater County, Wyo., in 1965.

Federal Agency	Visits	
	Day	Night
National Park Service:		
Flaming Gorge Recreation Area	149,946	19,830
Bureau of Land Management:		
Bitter Creek	85,000	15,000
Burntfork	22,000	3,000
Flaming Gorge	325,000	75,000
Granger	8,000	2,000
Leucite Hills	45,000	5,000
Little Colorado	27,000	3,000
Northeast	175,000	25,000
Pilot Butte	17,000	3,000
Pine Mountain	175	25
Red Desert	1,800	200
Seven Lakes	900	100
Total	706,875	131,325
State: Big Sandy Reservoir Area	9,880	1,490

Source: Bureau of Outdoor Recreation, Survey of Public Areas and Facilities 1965.

10. Socioeconomic Resources

The oil shale area of the Washakie Basin is essentially uninhabited except by temporary users of the area. The basin is situated southeast of Rock Springs in Sweetwater County and is accessible by several unimproved dirt roads.

The 1970 population of Sweetwater and Uinta Counties was 25,400 (Table II-43). Sweetwater, the larger of the two, had nearly 75 percent of that total. Rock Springs, with a population of 11,700, accounted for 63 percent of Sweetwater County's total population. The two-county area had a total of 7,900 households with 49 percent (or 3,900) located in Rock Springs. The median family income for the area was $9,064 during 1970.

Rock Springs is the largest community in the two-county area, located approximately 40 miles northwest of the nominated tracts. Access to the community is provided by Interstate 80, a major east-west artery, the Union Pacific Railroad, and Frontier Airlines.

Though the area is considered rural and isolated by national standards, agriculture is not its economic mainstay. Of the region's 9,700 employed persons, only 5 percent were employed in the agricultural sector. A little more than one-half of the area's total employed persons are blue-collar and service workers.

The economic structures of the counties and city appear to be relatively stable (Table II-44 to II-46). In 1967 general revenue for the Sweetwater County government was $6.8 million. Almost one-half of the expenditures were for the local school system. At present, the school system is considered

TABLE II-43.--County and City Social Characteristics for Wyoming, 1970.
(Thousands, unless otherwise indicated)

County and city	Population	No. of House-holds	School enrollment Primary	High school	Median school years completed (25 years and over)
Sweetwater	18.3	5.9	3.5	1.3	12.2
Uinta	7.1	2.0	1.3	.6	12.2
Total	25.4	7.9	4.8	1.9	12.2
City of Rock Springs (Sweetwater)	11.7	3.9	2.1	.8	12.2

Source: 1970 Census of Population, General Social and Economic Characteristics - Wyoming, U. S. Department of Commerce, Washington, D. C., 1972.

Table II-44.--County and City Economic Characteristics for Wyoming, 1970.
(Thousands)

County and city	Employment: Total employed (16 years and over)	Employment: White-collar and service	Employment: Blue-collar and service	Employment: Agricultural	Unemployed (Percent)	Median family income
Sweetwater	7.0	2.9	3.9	0.2	4.4	$9,077
Uinta	2.7	1.0	1.4	.3	4.6	9,025
Total	9.7	3.9	5.3	.5	4.4	$9,064
City of Rock Springs (Sweetwater)	4.5	2.1	2.3	.1	4.4	8,970

Source: 1970 Census of Population, General Social and Economic Characteristics--Wyoming, U.S. Department of Commerce, Washington, D. C., 1972.

Table II-45.--County Economic Indicators for Wyoming--Government.
(Thousand dollars, unless otherwise indicated)

Local government finances 1/	County		
	Sweetwater	Uinta	Total
Revenue:			
Total	6,843	2,251	9,094
Property tax per capita (dollars)	215	165	380
Expenditures:			
Total	6,220	2,097	8,317
Education	3,048	1,189	4,237
Highways	529	121	650
Public welfare	351	95	446
Hospitals	910	215	1,125
Health	22	2	24
Police protection	204	69	273
Fire protection	80	2	82
Sewerage	35	38	73
Sanitation other than sewerage	141	17	158
Parks and recreation	49	12	61
Natural resources	67	34	101
Housing and urban renewal	-	-	-
Correction	-	1	1
Libraries	86	19	105
Financial administration	82	40	122
General control	146	46	192
General public buildings	89	16	105
Interest on general debt	147	90	237
Other and unallocable	235	89	324

1/ Fiscal years ending between July 1, 1966 and June 30, 1967.

Source: U.S. Bureau of the Census, Census of Governments, 1967. Volume 7: State Reports, No. 50; Wyoming. U.S. Government Printing Office, Washington, D. C., 1970.

Table II-46.--County Economic Indicators for Wyoming, Private Sector.
(million dollars, unless otherwise indicated)

County	Retail Trade 1/		Services 1/		Agriculture 2/		
	Total establishments	All sales	Total establishments	All receipts	Acreage farmed (thousand)	Total commercial farms	Value of farm products sold
Sweetwater	239	30.1	139	10.0	1958	114	5.1
Uinta	124	13.3	63	1.5	883	237	5.8
Total	363	43.4	202	11.5	2841	351	10.9

1/ 1967.

2/ 1969.

Source: U.S. Bureau of the Census, Census of Business, 1967, Volume II, Retail Trade - Area Statistics, Part 3, North Dakota to Wyoming, Guam, and Virgin Islands. U.S. Government Printing Office, Washington, D.C., 1970.

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adequate to meet present needs. Rock Springs has a 2-year community college. In 1967, the county also expended $0.9 million for health and hospital services. The community has a 100-bed hospital.

The economic base of the area is agriculture (large, livestock ranches), mineral extraction, and tourism and recreation. Present development includes a 300,000 kilowatt steam electric plant being constructed by the Pacific Power and Light Company. The plant is expected to add 1,200 people to the community of Rock Springs.

Sweetwater County is more heavily dependent upon the minerals sector for economic support than Uinta County. The value of mineral production in Sweetwater County is fifteen times as great as the value of farm products, while in Uinta County mining values are less than half those of agricultural sales.

11. Land Ownership

In Sweetwater County, including most of the oil shale land, ownership is as follows:

County	Federal (Percent)	Public Land (Grazing Dist.) Acres	Reserved Public Lands	State Acres (Approx.)	Private Acres (Approx.)
Sweetwater	69	2,130,328	2,244,302	140,200	1,687,000

12. Land Use

The dry climate and limited growing season permit only the growth of alfalfa hay, native hay, and some small grains along some of the major drainages and at the Eden Reclamation Project.

The area is grazed by livestock for most of the year. Cattle graze the area primarily in the spring, summer, and fall, and sheep, primarily in the fall, winter, and spring. Antelope and deer also use the area throughout the year.

Some of the public oil shale lands are also leased for oil and gas exploration and development and for trona production. Some accommodation between different lessees will be required when the oil shale is developed.

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III. ENVIRONMENTAL IMPACT

A. Introduction

An evolving oil shale industry would produce both direct and indirect changes in the environment of the oil shale region in each of the three States of Colorado, Utah, and Wyoming, where commercial quantities of oil shale resources exist. Many of the environmental changes would be of local significance, while others would be of an expanding nature and have cumulative impact. These major regional changes will conflict with other physical resources and uses of the land and water involved. Impacts would include those on the land itself, the water resources, the air quality, on fish and wildlife habitat, on grazing and agricultural activities, on recreation and esthetic values, and on the existing social and economic patterns (Table III-1). These environmental impacts are individually assessed for their anticipated direct, indirect, and cumulative environmental effects in the sections that follow.

The rate at which oil shale may be developed provides the framework within which these evaluations may be made. Although the following analysis is based on the assumption that a 1-million-barrel-per-day industry will be reached by 1985, it is impossible at this time to determine precisely what combination of public and private lands would be included.

Prototype leasing of public lands is expected to stimulate commercial development, but the rate at which oil shale may be developed depends on a number of constraints whose relation to

TABLE III-1.--Major Impacts of Oil Shale Development.

Major impacts	Nature of effect: Direct	Nature of effect: Indirect
Physical resources:		
Land:		
Surface disturbance	x	
Erosion	x	
Spent shale	x	
Chemical waste	x	
Trash and other	x	
Soil	x	
Forage	x	
Timber	x	
Other minerals	x	
Landscape, esthetics	x	
Water:		
Water quality	x	x
Water supply and aquifers	x	
Subsidence effects		x
Air:		
Dust	x	
Plant emissions	x	
Recreation:		
Disturb use		x
Wilderness		x
Fish and Wildlife:		
Habitat	x	x
Fishing		x
Hunting		x

TABLE III-1.--Major Impacts of Oil Shale Development (continued).

Major impacts	Nature of effect	
	Direct	Indirect
Socioeconomic:		
Cultural:		
Historic sites		x
Archeological sites	x	
Social living patterns		x
Population:		
Immigration		x
Concentration		x
Economic:		
Jobs	x	
Income	x	
Capital flow	x	
Health and safety:		
Plant hazard	x	
Other accident	x	
Pipeline and transportation	x	
Government:		
Services	x	
Taxes	x	
Title conflicts		x
State and other		x

each other will change over time. Key factors which must be considered are (1) technology, and the cost of shale oil production as compared to alternative energy supplies, (2) resource availability, (3) water availability, and (4) environmental considerations.

Technology for mining and surface processing of oil shale has been advanced to the 1,000 ton per day prototype stage of operations (described in Chapter I). The next logical step is the scale-up to commercial operations with each retort in the complex capable of processing about 10,000 tons of oil shale per day. A minimum-sized commercial complex would produce 50,000 to 100,000 barrels per day of shale oil. At these production rates, the total capital required would range from $250 million to $500 million. Since the return on this investment is only marginally attractive at 10 to 13 percent on a discounted cash flow basis, 1/ the initial development of this industry will depend on the availability of large amounts of venture capital that can be expected to yield only a minimum acceptable rate of return on the investment.

The economics of oil shale processing will probably not limit the ultimate size of the industry but will undoubtedly affect the rate at which a mature industry will develop. Certainly, low profit expectations have been a fundamental reason why oil shale has not been commercially developed to date. Future expectations concerning production costs, oil prices, the general state of the economy, and the availability of capital will establish the economic parameters. If, in combination, these are judged favorable by private enterprise, the actual schedule of development would be set by other limitations;

1/ Assumes a present market value of $3.90 per barrel (1).

the logistics of construction; local, State, and Federal regulations; and the operational and environmental experience and costs of the first commercial units. For the development schedule given below, it was assumed that each surface plant would require 3 years for construction and that construction would be limited to the start of no more than two plants at any one time. This assumption is based on factors related to construction that would limit development: (1) plant design, (2) engineering and construction, and (3) capability to supply heavy, mine and plant equipment. For example, operating personnel must be hired and trained, supporting housing constructed, and heavy equipment purchased and delivered from distant supply centers. These manpower, equipment, and logistical considerations will limit the rate of growth as discussed above.

A second major constraint on any fuel development is the availability of the resource. Estimates of the total oil shale reserves (see Chapter II of this volume) would indicate that no apparent resource limitation exists. However, since the majority of the high-grade oil shale resources are found on public lands (72 percent), the availability of public lands is a constraint on the rate of industry development. This is related to a restraint on private development of oil shale due to the lack of a Federal policy concerning the administration of the public lands. Without such a policy, private firms have been, and most likely will continue to be, reluctant to invest in development of private properties. This fact is noted in the National Petroleum Council report (2) to the Secretary of the Interior, which states that:

> On the assumption that no Federal leases will be available, production of the syncrude from oil shale reserves on private lands is expected to be limited to 100 MB/CD by 1985, even providing that economics and environmental attitudes were favorable.

The potential production from private lands is believed to be higher and could reach a maximum of 400,000 barrels per day by 1985, but this "...development would be unlikely without the leasing of Federal lands..." (2).

For purposes of the present discussion, it is assumed that private lands would support no more than 400,000 barrels per day and that the six prototype tracts would support a total of 250,000 barrels per day. The combined output from private and public holdings would then reach 650,000 barrels daily by 1985. Additional public lands would be required to increase the production rate above this level. Even if suitable lands are available, the rate of development will be determined by the logistics of plant construction and by manpower constraints. Under these constraints, the Department of the Interior estimates the maximum 1985 production to be 1 million barrels per day. Even at this rate of production, only about 9 percent of the 80 billion barrels of prime commercial interest would be produced by the year 2000. The ultimate size of the oil shale industry will most likely not be determined by the magnitude of the oil shale resource base but will probably be limited by other factors such as the availability of water, for example.

As discussed in Chapter II of this volume, ample water is available to support a 1-million-barrel-per-day production rate. A greater rate of production, however, is quite dependent on evolving technology. For example, successful development of in situ production technology will significantly lower water requirements by eliminating the use of water in spent shale disposal. Improved retorting technology may also eliminate the need to upgrade the crude shale oil produced from surface retorts for transportation purposes. Thus less water would be required for hydrogen production and related processing, such as cooling. Such potential future developments make the ultimate size of any future development highly speculative at the present time. Present estimates of the ultimate production from a mature industry range from 3 to 5 million barrels of shale oil per day.

As discussed above, the industry probably cannot develop beyond the 650,000-barrel level without additional public lands. These additional public lands will not be made available without the preparation of another environmental impact statement that relates specifically to this larger development. Results from the proposed prototype development will provide the firm data upon which to assess the potential impacts of any enlarged program.

For the purpose of the present analysis, estimates of the environmental impact of a mature industry have been made using the following assumptions:

1. The size of the industry could be no more than 1-million barrels per day by 1985.

2. Production above 650,000 barrels per day would require public lands in addition to those anticipated under the proposed prototype leasing program.

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3. Additional public lands will not be offered for development without a thorough analysis of the expected impact based upon the knowledge gained from prototype development and research, and without the preparation of an environmental statement as required by the National Environment Policy Act.

4. Detailed calculations given for unit-size processing plants in Volume III, Chapter II, are applicable to the larger development.

5. A combined production capacity of 400,000 barrels per day will be constructed on private and public lands during 1973 to 1981.

6. Productive capacity will increase at the rate of 150,000 barrels per year at yet unknown locations during 1982 to 1985.

7. The technology mix is as given in Table III-2.

Under the above assumptions, a possible development schedule was postulated and is presented in Table III-2. The subsequent sections of this environmental impact chapter relate the expected impacts to the development schedule as given in Table III-2.

Different assumptions would lead to different schedules of development resulting in changes in magnitude of environmental impacts and the time when these would occur. However, as long as a 1-million barrel-per-day industry is still assumed, it is not likely that the type and magnitude of the impacts would be significantly different than those described in this chapter.

B. Surface Disturbance of Land

Oil shale development will require land for core drilling, mine development, overburden disposal, storage of low-grade oil shale, construction of surface facilities, and off-site requirements such as access roads, waterlines, gas, and oil pipelines, etc. The amount of land surface required will vary depending upon the type of mining and processing option used. This section of this

Table III-2.--Projected Possible Development Pattern for Oil Shale - Cumulative Shale Oil Production.

(Thousands of Barrels Per Day)

Year	Colorado		Utah	Wyoming	Technology Assumed 1/	Total Oil (Cum.)
	Public Land	Private Land	Public Land	Public Land		
1973	--	--	--	--	--	--
1974	--	--	--	--	--	--
1975	--	--	--	--	--	--
1976	--	50	--	--	1-U	50
1977	--	--	--	--	--	50
1978	50	50	--	--	2-U	150
1979	100	--	--	--	1-S	250
1980	--	--	50	--	1-U	300
1981	--	50	--	50	1-U, 1-I	400
1982					2-U, 1-I	550
1983					3-U	700
1984					$1\text{-}S_1$	850
1985					1-U, 2-I	1,000

1/ Legend

17 total Plants

1-U = one 50,000 bbl/day underground mine
1-S = one 100,000 bbl/day surface mine
1-I = one 50,000 bbl/day in situ mine
$1\text{-}S_1$ = one 150,000 bbl/day surface mine
2-U = two 50,000 bbl/day underground mines
2-I = two 50,000 bbl/day in situ mines
3-U = three 50,000 bbl/day underground mines

Environmental Statement lists and discusses the land requirements for core drilling and then for three mining and processing options. In addition, land requirements for facilities and off-site operations are discussed. For these areas, the vegetative cover is assumed to be destroyed although much of the area may later be reclaimed. The cumulative land requirements for a 1-million-barrel-per-day shale oil industry concludes this section. The secondary impacts of this development on water quality, fauna, esthetics and recreation, and loss in grazing capacity are considered in subsequent sections of this Chapter.

1. Land Requirements for Core Drilling

Core drilling is frequently a necessary preleasing step to aid in resource evaluation and may be a post lease-issuance activity as well. A core drilling site may temporarily disturb from 3 to 15 acres of surface depending on the size of the equipment involved. To date, about 360 core samples of oil shale have been obtained from 242 test holes in Colorado, 73 in Utah, and 45 in Wyoming. Equipment capabilities, personnel, and the amount of surface areas required for typical coring operations in the three-State area are as follows:

	Large rig	Small rig
Equipment depth capabilities, feet	To 8,000	To 4,000
Personnel required, number	10 - 15	4 - 6
Amount of surface area disturbed, acres	10 - 15	3 - 5

The diameter of the core ranges from 1 7/8 inch for the small rig to 4 - 7 1/2 inches for the large rig. Length of the core section ranges from 10 to 60 feet. Air is usually preferred as the coring fluid, but water and/or drilling mud is also used.

Most environmental impacts of core drilling are of a temporary nature. After drilling and before they are plugged and abandoned, these wells, however, could provide communication between various aquifers, thus possibly mixing saline and fresh waters. Construction of access roads to the location and leveling of the site involve removal of surface vegetation, mainly sagebrush. Though the area is seeded after the core drilling operations are completed, some impacts on the area cannot be totally erased. Construction of roads and use of them by heavy equipment produces some soil compaction; in some areas, surface grades are changed that can have an effect on drainage patterns; some vegetation is removed that requires many years to replace (e.g., sagebrush, small trees, and small bushes); and new patterns of erosion are generally established by alteration of the land surface.

2. Land Requirements for Oil Shale Development

The degree to which the development of the oil shale resources on any given tract in any of the three States will affect the land on and adjacent to that tract is a function of the location of the tract; the size, type, and combination of the processing technologies involved; and the duration of operations of the lease. The land requirements for two levels of an oil shale operation are given in Table III-3. For an operation involving surface mining, a production level of 50,000 barrels per day is the "unit" tract

TABLE III-3.--Land Requirements for Oil Shale Processing.

Function	Land Required (Acres)
Mining and waste disposal:	
Surface Mine1/2/ (100,000 bbl/day):	
Mine development	30 to 85 per year
Permanent disposal; overburden	1,000 (total)
Temporary storage; low-grade shale	100 to 200 (total)
Permanent disposal; processed shale	140 to 150 per year
Surface facilities 3/	200 (total)
Off-site requirements5/	180 to 600 (total)
Underground Mine2/ (50,000 bbl/day):	
Mine development (Surface facilities)	10 (total)
Permanent disposal:	
All processed shale on surface	70 to 75 per year
60-percent return of processed shale underground	28 to 30 per year
Surface facilities3/	140 (total)
Off-site requirements	180 to 225 (total)
In situ processing (50,000 bbl/day):	
Surface facilities 3/	50 (total)
Active well area and restoration area4/	110 to 900
Off-site requirements	180 to 600 (total)

1/ Area required is dependent upon the thicknesses of the overburden and oil shale at the site. Acres shown are for a Piceance Creek Basin site, with 550 ft. of overburden and 450 ft. of 30 gallon/ton shale (approximately 900,000 bbl/acre).

2/ Assumes 30 gallons per ton oil shale and a disposal height of 250 ft.

3/ Facilities include shale crushing, storage and retorting (excluded for in situ processing), oil upgrading and storage, and related parking, office, and shop facilities.

4/ See Volume III, Figure III-10, for conceptual view of surface utilization.

5/ Includes access roads, power and transmission facilities, water lines, natural gas and oil pipelines; actual requirements depend on site location. A 60-ft. right-of-way for roads requires a surface area of about 8 acres per mile. Utility and pipeline corridors 20 ft. in width require 2.4 acres per mile.

from which subsequent calculations have been made. For surface mining, a production level of 100,000 barrels per day has been used. The land requirements for these two operations including two modes of mining, processing, and processed shale disposal are shown in the table. The amount of land surface disturbed would be a function of the total duration of operations on a given lease.

The overall magnitude of the land impact is given in the analysis below for a basic 20-year period with a possible extension of the activities to a 30-year period. On most tracts, this period would include an initial 5 years of preproduction activity followed by 15 to 25 years of actual, full-scale production.

a. Land Requirements for Surface Mining

Surface mining would have the greatest initial disturbance of land surfaces and topography, soils, and vegetation. The land surface disturbed in developing the open pit mine itself, for a 100,000-barrel-per-day operation in Colorado (Table III-3), would be 30 to 85 acres per year and would be expanded to about 1,100 acres over 20 years of continuous operation.

During the early years of an open-pit development, permanent disposal of overburden would be off site. After 10 to 20 years of full-scale production, it should be possible to begin disposing of part of the overburden and processed shale into mined-out positions of the pit. Mining of 30 gallons per ton oil shale sufficient to support a 100,000-barrel-per-day open pit operation (Colorado) would require off-site disposal of up to 250 million cubic yards of overburden before pit return could begin. The land area used for disposal would be about 1,000 acres.

During full-scale operation, 148,000 tons per day of processed spent shale would be produced at a typical plant and such a plant could cause about 140-150 acres per year to be covered with spent shale if a canyon in the shale area were filled to a depth of 250 feet. The actual area affected would depend upon the thickness of the overburden and oil shale, the mining plan, and the rate of development and restoration as detailed in Volume III, Chapter III, for a hypothetical surface mine in Colorado.

The results of that analysis referenced above are shown in Figure III-1 for a 30-year development period. Total land required for all activities (including processing facilities) is a maximum of 6,650 acres at the end of 30 years. Restoration is assumed to proceed as soon as the ultimate height of the waste disposal pile has been reached for a specific canyon. Three years thereafter, the area is assumed to have been revegetated.[1/] These data indicate that the total land not usable is similar for an operation that uses all surface disposal (3,400 acres) as compared to one that uses backfilling (2,700 acres). If surface disposal is used, six typical canyons would be affected. If backfilling operations are employed,

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1/ Revegetation success in covering large areas to retard erosion and provide forage for wildlife and cattle over sustained periods of time still requires research. Reestablishment of climax forest-type vegetation is not likely except over long time periods. See Chapter I, section D.1.

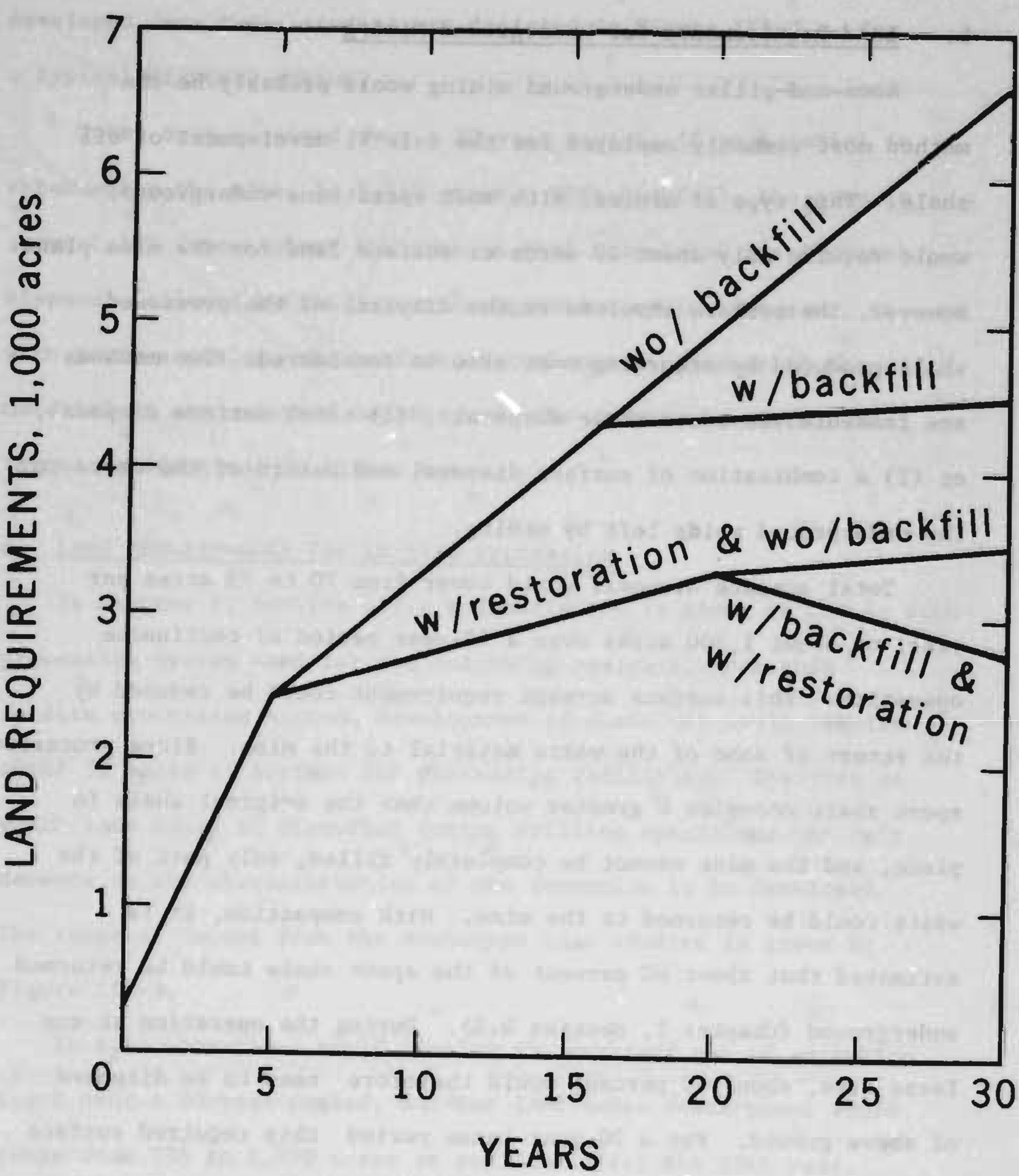

Figure III-1.--Land Requirements for a 100,000-Barrel-Per-Day Surface Mine for a 30-Year Development Period.

three typical canyons would be needed. Details of these possible options are given in Volume III, Chapter II.

b. Land Requirements for Underground Mining

Room-and-pillar underground mining would probably be the method most commonly employed for the initial development of oil shale. This type of mining, with most operations underground, would require only about 10 acres of surface land for the mine plant. However, the surface involved in the disposal of the processed shale produced by retorting must also be considered. Two methods are feasible for waste shale disposal: (1) total surface disposal, or (2) a combination of surface disposal and return of the waste to the underground voids left by mining.

Total surface disposal would cover from 70 to 75 acres per year, or about 1,500 acres over a 20-year period of continuous operation. This surface acreage requirement could be reduced by the return of some of the waste material to the mine. Since processed spent shale occupies a greater volume than the original shale in place, and the mine cannot be completely filled, only part of the waste could be returned to the mine. With compaction, it is estimated that about 60 percent of the spent shale could be returned underground (Chapter I, Section D.2). During the operation at any lease site, about 40 percent would therefore need to be disposed of above ground. For a 20-year lease period this required surface disposal area would be approximately 450 acres.

Three underground developments (two in Colorado and one in Utah) are detailed in Volume III of the Environmental Statement. Data developed from these studies are depicted in Figure III-2 for a typical disposal option.

Total area required over a 30-year period, if no material is returned to the mine, is 2,210 acres. With backfill, the area is about 1,100 acres--about the same as that calculated for surface disposal followed by the 3-year revegetation cycle. However, as with surface mining, the surface disturbance is greater if the material is not returned underground; the amount of usable land is nearly identical in either case.

c. Land Requirements For In Situ Processing

In Chapter I, Section C.2., a description is given of the in situ processing system used for the following analysis. For this in situ processing system, development of shale oil would require about 50 acres of surface for processing facilities. The rate at which land would be disturbed during drilling operations entirely depends on the characteristics of the formation to be developed. The range of impact from the prototype case studies is given in Figure III-3.

In situ operations could involve the eventual use of an entire tract over a 30-year period, but the land under development would range from 775 to 1,790 acres at any time after the 10th year. Impacts on land would be similar to those previously described under coring operations, that topography of the surface following processing would not be significantly altered.

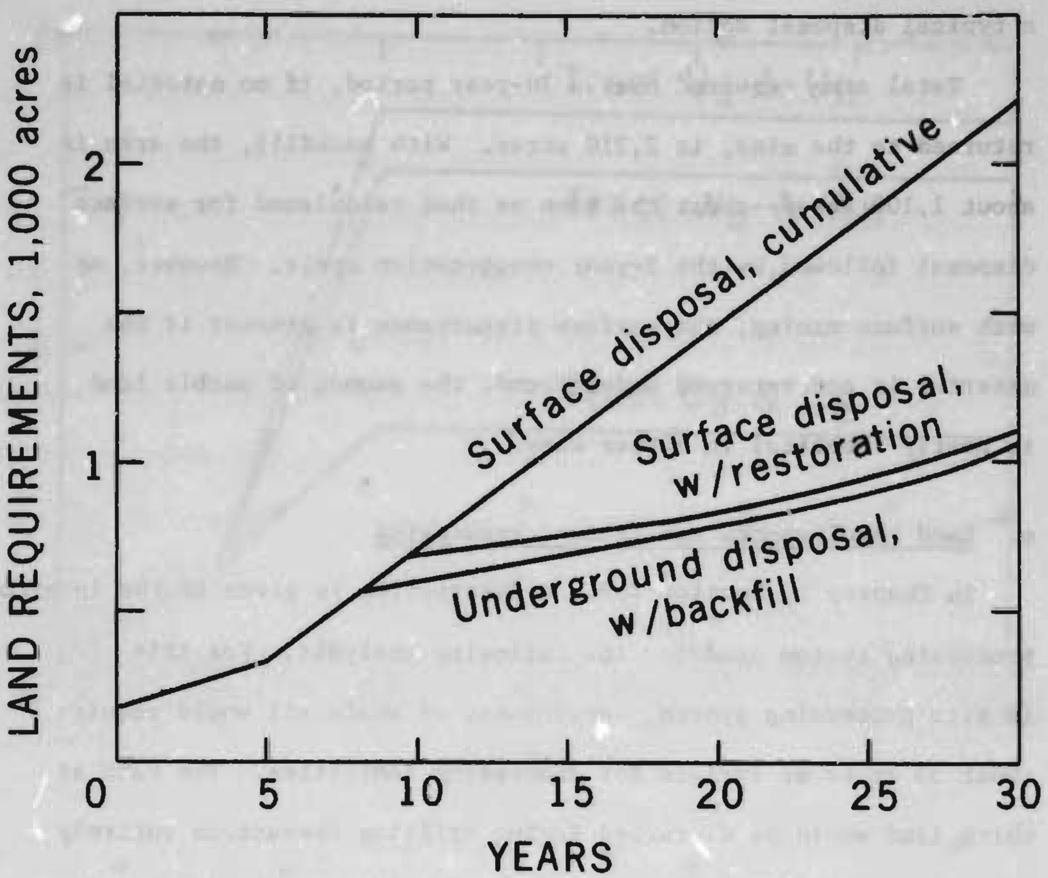

Figure III-2.--Land Requirements for a 50,000 Barrel Per Day Underground Mine for a 30-Year Development Period.

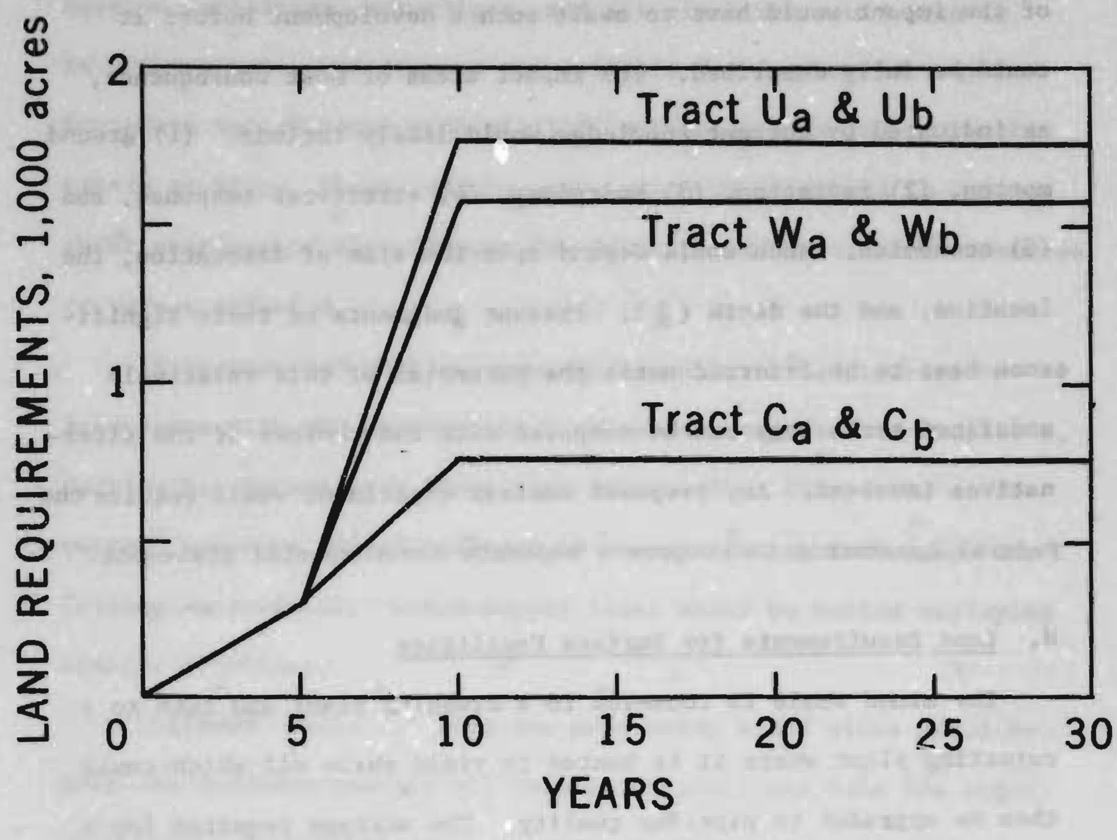

Figure III-3.--Land Requirements for a 50,000 Barrel Per Day In Situ Recovery System for a 30-Year Development Period.

Although now only a remote possibility, nuclear methods might some day become a part of the technology. Significant examination of the impact would have to await such a development before it could be fully described. The impact areas of most consequence, as indicated by current knowledge, would likely include: (1) ground motion, (2) radiation, (3) hydrology, (4) structural response, and (5) economics. Much would depend upon the size of detonation, the location, and the depth (3). Present judgments of their significance have to be deferred until the potential of this relatively undefined technology can be compared with the choices of the alternatives involved. Any proposed nuclear experiment would require the Federal Government to prepare a separate environmental statement.

d. Land Requirements for Surface Facilities

The mined shale is conveyed to a crushing plant and then to a retorting plant where it is heated to yield shale oil which could then be upgraded to pipeline quality. The acreage required for a modern, well-engineered processing plant is considerably less than is needed for the mining and spent shale disposal operations. A 50,000-barrel-per-day plant would be expected to occupy somewhat less than 140 acres for the crushing, crushed-shale storage, retorting, oil upgrading, oil storage, and related parking, office, and shop facilities. The oil storage area itself would require about 40 acres of this total. For in situ operations, a total of 50 acres would be required for facilities.

Off-site requirements would have an effect on the surrounding surface area to some degree. Access roads, power and gas transmission facilities, waterlines, and oil pipelines would need to be constructed. Underpasses and suitable fencing may be required to reduce interference with wildlife migration patterns and with cattle grazing. These impacts are considered in detail in subsequent sections of this Chapter dealing with the particular resources or values affected.

It is expected that new powerlines would be constructed in accordance with the environmental criteria referenced in Chapter I, Section D. Natural-gas lines also described in Chapter I, as required, would be buried underground using existing techniques for filling excavations. Water-supply lines would be buried employing similar practices.

Upgraded shale oil from the processing plant sites would be moved to refinery centers via connecting pipelines from the sites to existing transcontinental pipelines. These connecting lines, 12 to 16 inches in diameter, would need to be constructed as described in Chapter I, Section D.2.e. Eventually, expansion of main pipelines would probably become necessary, disturbing the area along the existing rights-of-way.

It is not possible to accurately estimate the total off-site surface area that will be disturbed since this will depend on the individual site locations (See Volume III). However, it is expected that an additional 1,700 to 2,000 acres would be needed for each site, including that of access to the facility by roads.

e. Urban Land Requirements

Increased urbanization would be associated with oil shale development. Because the shale region is now predominantly rural, urbanization would inevitably have an environmental impact on the area, largely losing land from agricultural use to homesite and community development.

It is difficult to quantitatively estimate the cumulative land required by urbanization. In general, most new permanent urban construction probably would be in existing population centers at or near the shale lease sites in each State. Temporary employment for plant and urban construction would be substantial (approximately equal to permanent operating employment), creating need for temporary housing (mobile home parks, for example) in addition to permanent housing. Expansion of support facilities (business districts, hospitals, and schools) would also result. A few new small communities may appear, but they are likely to be scattered. It is possible that as much as 10,000 acres of land would be urbanized by 1980 and 15,000 to 20,000 acres by 1985 as a result of oil shale processing activities and the resultant increase in regional population. The increase would be distributed in the states of Colorado, Utah, and Wyoming generally in proportion to the level and type of production achieved in each State.

3. Cumulative Land Requirements

The foregoing analyses of land impacts have been combined with the projected development schedule of Table III-2 to develop an order-of-magnitude estimate of the cumulative land impact over a period of time. This analysis must necessarily be approximate due to the many assumptions that must be made and the very long time projection of 30 years. For a 1-million-barrel-per-day level of production, the total surface area that would be affected would approximate 50,000 acres without backfilling or about 35,000 acres if backfilling techniques were employed. However, as shown in Figure III-4, the cumulative surface area not usable for other purposes begins to level off at about 20,000 acres. This is due to the assumptions of restoration, volumes of canyons, and the mining plan utilizing backfilling methods discussed earlier in this section. Once the 1-million-barrel-per-day level of production is reached, the annual addition to the disturbed area needed to maintain this rate is approximately 1,200 acres.

In addition to the land required for the processing complexes described above, 15,000 to 20,000 acres will be required for urban development, and the utility rights-of-way would need probably less than 10,000 acres total.

As the technology advances, an oil shale complex at full-scale production may extract recoverable reserves in greater quantity than anticipated in developing these data for the lease tracts. In this case, development at a single surface mine, for example, may be possible for periods of up to 50 to 70 years and the impact, therefore, potentially greater than the impact considered in this analysis.

In summary, the 30-year total aggregated impact for a 1-million barrel-per-day production will approach 80,000 acres, of which about

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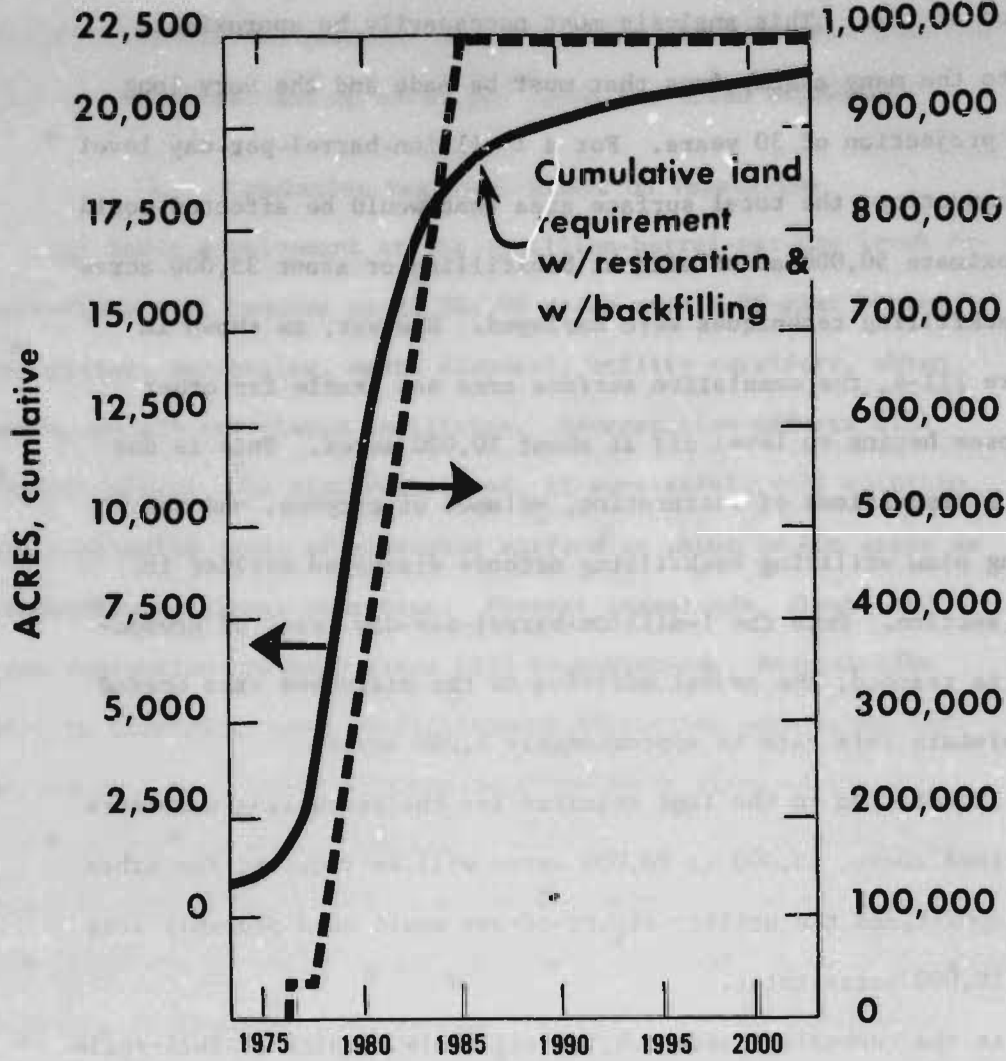

Figure III-4.--Cumulative Land Requirements for Oil Shale Development for a 30-Year Period Related to an Ultimate Production of 1-Million Barrels Per Day by 1985.

50,000 acres will be required for production, 10,000 acres for utility corridors, and up to 20,000 acres for urban expansion.

4. Cumulative Regional Impact on Vegetation

Oil shale development at the 1-million-barrel-per-day level of operations will require up to 80,000 acres over a 30-year period for mining, processing, waste disposal, utility corridors, urban needs, and all associated facilities. Revegetation efforts will follow initial land disturbance and, if successful, will maintain the continuing level of disturbed surface at about 20,000 acres as production continues over time. Present grasslands, shrub, and tree vegetation on these areas will be destroyed. Revegetation will be started as soon as development operations permit, but considerable time will be required to reestablish shrub and tree cover in the pattern of existing vegetation. Various shrub-grass types now cover about 67 percent of the region, and forest types, including the extensive pinyon-juniper type, cover about 33 percent. Grasses can usually be well established in 3 to 5 years on soils of the region. Successful establishment and enduring cover over large areas has yet to be demonstrated. Shrub and tree species can ordinarily be established on small areas in 5 to 10 years, but trees often require 50 to 100 years to grow to sizes similar to those of mature stands now occurring in the area. Successful establishment of shrub and tree cover over large areas and under varying conditions is uncertain.

Once a revegetated plant community is established, management of biotic influences will determine its successional course. If excessive grazing is allowed, the plant community will regress toward lower successional stages of plant life, and erosion on waste shale areas will increase significantly. If grazing is controlled on revegetated areas, plant succession should ultimately move toward the potential plant community that each site will support for its micro climate and soil conditions.

Plant communities and soils generally evolve together. On disturbed areas, revegetation will be accomplished on soils that have evolved with the indigenous plant community. Spent shale material, however, has significantly different properties than the soils that have evolved on the shale sites (4). Based on present knowledge, the spent shale material will more closely resemble the undeveloped saline soils of the salt desert shrub type. Unless the spent shale material is managed in a manner similar to that described in Chapter I, Section D.1., successful revegetation may be limited to salt-tolerant species. Since all disturbed areas will not be on public lands, this same degree of management and control cannot be assumed for all lands.

If salt-tolerant plants are established, some plant successional activity would probably occur as natural climatic factors modify the soil conditions over time. However, vegetation establishment on spent shale materials has not been observed long enough under varied conditions to provide a basis for predicting the extent and rate of the successional changes that would occur or the maintenance requirements for an enduring soil-holding cover.

If irrigation is withdrawn from spent shale sites densely vegetated with non-adapted plants, the natural climate could not support the stands. However, if stands of native plants are adapted to the site and are more sparsely established by the same methods, these would probably persist and progress towards a potential plant community resembling the surrounding natural communities. This process could require lengthy periods of time. Any inability to establish or hold an effective soil stablizing vegetative cover on the cumulative area of the waste piles would lead to their accelerated erosion.

Although oil shale development is cumulative in nature, the direct impact on timber growing stock over time would probably the relatively small and on commercial forest stands relatively minor. There are about 17 million acres of forest in the upper Colorado River Basin, most of which lie outside the oil shale region at higher altitudes. Within the shale region itself, most of the forest area is non-commercial in character, pinyon-juniper being the dominate forest type involved. However, there would be a stimulus to timber harvesting in the Upper Basin for increased production of wood products from commercial forest areas to satisfy increased demand for construction material. Grazing by wildlife and livestock and watershed protection will be adversely affected due to oil shale development as discussed in subsequent sections of this chapter.

In summary, the aggregate impact on vegetation will be: (1) complete removal or burial of existing vegetative cover on disturbed areas, (2) reduced capacity to control erosion in all affected localities increasing the need for extensive solid waste management and attempts at large scale revegetation, (3) change in the mix of tree, shrub and grass species now occurring on the areas, (4) reversal of the natural plant succession toward an enduring climax vegetative cover types, and (5) an adverse effect of uncertain degree and duration on the soil-holding capability of the introduced cover and its direct utility as substitute wildlife food and cover.

5. Cumulative Impact on Regional Land Use

Cumulative land-use changes are anticipated in the oil shale areas as industrialization progresses. The present pattern of land ownership is expected to remain essentially unchanged, but patterns and intensity of land use could shift significantly.

Nearly all the oil shale region's Federally owned lands, which comprise 72 percent of the total, have been classified for retention in public ownership and continued multiple-use management. The present primary uses are livestock grazing, as wildlife habitat, for outdoor recreation, and petroleum exploration and production. The same lands have significant watershed protection values as part of the upper Colorado River Basin watershed.

Use patterns on the bulk of the State and private lands which comprise the remaining 28 percent of the region are similar to the Federal land-use patterns. Cultivated and/or irrigated lands account for only about 4 percent of the total land surface; because of the sparse population and very limited industrial development, acreages devoted to residential and industrial uses are very minor.

This ownership and use pattern is typical of much of the Upper Colorado River Basin within which the oil shale region is located. However, agricultural, industrial, commercial, municipal, and residential uses account for a higher percentage of the Upper Colorado River Basin as a whole than of the oil shale region itself.

Title to Federal lands in the oil shale area has been clouded for years because of the existence of unpatented mining claims. Unpatented mining claims have been filed on essentially all Federally owned lands for locatable, as well as now leasable minerals, including oil shale. The claims are of two classes--those filed before passage of the Mineral Leasing Act of 1920 (generally for oil shale) and those filed subsequent to 1920 after oil shale had been classified as a leasable mineral not subject to location. Public Land Order 4522 dated September 23, 1968, withdrew some 12 million acres of Federal oil shale lands from all forms of location. All mining claims on lands withdrawn by PLO 4522 are being systematically inventoried, the present ownership of the claims is being determined, and owners are being contacted relative to relinquishments or initiation of validity determination-contest proceedings.

A large portion of the Piceance Creek Basin and key oil shale areas in the Unita and Washakie Basins have been cleared of title conflicts through voluntary relinquishments or validity determination-contest proceedings. About 7,000 claims are presently in various stages of contest proceedings in Colorado, Utah, and Wyoming. Determination of the ownership of such contested lands will impact individual claimants, but will eventually allow development to expand.

Industrialization will hasten conflicts for use of the surface resources on public lands. An expanding population and road system will intensify recreational land uses of the national forests, national parks, monuments, and recreational areas which are located in and around the oil shale region. These impacts are considered below in Section G of this Chapter. Increased pressure on an Indian reservation and a wildlife refuge located within the region may be experienced. Careful planning at the local level will be required for orderly growth and development as discussed in Section H of this chapter. Only where vigorously pursued and enforced can zoning mechanisms be effective.

Oil shale development will impact most directly on the existing use of the land by fauna (Section E) and on grazing (Section F). Eventually, competition for available surface water will be intensified, gradually shifting emphasis from agriculture to industrial and municipal use, which could modify and/or arrest the established trend toward irrigated farmlands (Section C). Utilization of the land surface for mineral exploration and development will increase. Over time, the pattern of recreation use will change from primarily extensive use (such as hunting) to more intensive urban-related activities (such as golf). Areas that are now primitive in character will sustain intensified use, thus reducing their long-term productivity as a primitive, outdoor-recreation region.

These impacts will be cumulative in nature and, over time, will tend to significantly alter existing patterns of land use. The most significant impacts are expected to occur in and around the Piceance, Uinta, Washakie, and Green River Basins.

C. Regional Impact on Water Resources

Water resources of the oil shale regions of Colorado, Utah, and Wyoming are complex and varied. As described in Chapter II of this Volume, surface water supplies are available from the area's large rivers -- the Green, the White, and the Colorado -- most of which originate from the higher elevations due to rainfall and/or snowmelt. Ground water is also a potential source of water for oil shale development, particularly within the Piceance Creek Basin of Colorado.

Demand for water will change with time as an evolving industry grows to maturity. Demand will be created for use in processing as well as for use in communities that will be required to support industrial development.

The relationship between demand for and supply of water associated with oil shale development will therefore depend on many factors whose relationship will change over time.

This section assesses the probable magnitude of the water requirements, the ground water plus surface water supplies, and the probable impact on the region's water resources due to oil shale development. Boundaries on the demand-supply estimates are provided through contingency forecasts of possible future events.

1. Demand for Water

The water required for processing and for associated urban populations has been the subject of several investigations. In 1954, Prien (5) estimated that a 1-million-barrel-per-day shale oil industry would require that 227,500 acre-feet of water per year be diverted, of which 82,500 acre-feet would be returned to local waters. The net consumption for such a scale of operations would total 145,000 acre-feet per year.

Cameron and Jones, Inc. (6), in 1959, established a water-diversion requirement of 200,000 acre-feet per year for a 1-million-barrel-per-day operation, of which 130,000 acre-feet per year would be consumed.

In 1968, the Department of the Interior (7) estimated 145,000 acre-feet of water per year would be required to support the 1-million barrel-per-day level of production, of which 61,000 to 96,000 acre-feet per year would be consumed.

A summary of the above discussed studies is given in Table III-4. As indicated, the consumed-water requirement ranges from 61,000 to 145,000 acre-feet per year for a 1-million-barrel-per-day industry. These studies have provided important background information concerning the general range of water requirements. However, the present study has extended the scope of the earlier studies through examination of the water requirements for shale disposal and revegetation and for cooling water for process and domestic power.

Water consumed in processing and that consumed for an associated urban population are separately listed in Table III-5 for various "unit" sized commercial developments. These individual demand requirements have been combined according to the projected schedule of development given previously in Table III-2 to enable estimates of the total water consumed by underground, surface,

Table III-4.--Water Demand Estimates.

Source	Demand, acre-feet per year	
	Estimated Requirement	Adjusted for 1-million barrel-per-day oil shale industry
Frien, (5)	227,500 diverted, 145,000 consumed for 1 million bbl/day	227,500 diverted, 145,000 consumed
Cameron and Jones (6)	252,000 diverted, 159,000 consumed for 1,250,000 bbl/day	200,000 diverted, 130,000 consumed
Department of the Interior (7)	145,000 diverted, 90,000 consumed for 1-million bbl/day	145,000 diverted, 61,000 to 96,000 consumed

Table III-5.-- Water Consumed for Various Rates of Shale Oil Production 1/ (Acre-feet/year).

Shale Oil Production (Barrels per day)

	50,000 Underground	100,000 Surface Mine	50,000 In Situ	400,000 Technology Mix 2/	1,000,000 Technology Mix 2/
PROCESS REQUIREMENTS					
Mining and Crushing	370- 510	730-1,020	---	2,600- 3,600	6,000- 8,000
Retorting	580- 730	1,170-1,460	---	4,100- 5,100	9,000-12,000
Shale Oil Upgrading	1,460-2,190	2,920-4,380	1,460-2,220	11,700-17,500	29,000-44,000
Processed Shale Disposal	2,900-4,400 3/	5,840-8,750 3/	---	20,400,30,900	47,000-70,000
Power Requirements	730-1,020	1,460-2,040	730-1,820	5,800- 9,200	15,000-23,000
Revegetation	0- 700	0- 700	0- 700	0- 4,900	0-12,000
Sanitary Use	20- 50	30- 70	20- 40	200- 300	1,000- 1,000
Subtotal	6,060-9,600	12,150-18,420	2,210-4,780	44,800-71,500	107,000-170,000
ASSOCIATED URBAN					
Domestic Use	670- 910	1,140-1,530	720-840	5,400-6,900	13,000-17,000
Domestic Power	70- 90	110- 150	70- 80	500- 600	1,000- 2,000
Subtotal	740-1,000	1,250-1,680	790-920	5,900-7,500	14,000-19,000
GRAND TOTAL	6,800-10,600	13,400-20,100	3,000-5,700	50,700-79,000	121,000-189,000
AVERAGE VALUE	8,700	16,800	4,400	65,000	155,000

1/ Assumes the same technologies as those used to develop Table III-2.
2/ Assumes development schedule as those shown in Table III-2.
3/ Water used is 20% by weight of the disposed spent shale.

Sources: Water requirements for mining, crushing, retorting, and shale-oil upgrading are based on process engineering studies by the U.S. Bureau of Mines (8). Water power requirements are based on Jimeson and Adkins (9). The water needs for shale disposal are based on stability research by Denver Research Institute (10) on experimental work by Colorado State University (4) and by the Colony Development Operation (11). Water requirements for revegetation of processed or spent shale will range from zero as a given area is built up, to about 1 foot per year for each acre to be revegetated (12). Urban population associated with a given plant size was made by the U.S. Bureau of Mines (8), and the water demands per capita have been obtained from the work of Ryan and Wells (13).

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and in situ mining technologies that, in combination, may expand to the 400,000- or 1,000,000-barrel-per-day level of production.

As shown in Table III-5, the water consumed estimates for processing in the 1-million-barrel-per-day development scale ranges from 107,000 to 170,000 acre-feet per year, and that consumed by the urban population associated with this scale of operation ranges from 14,000 to 19,000 acre-feet per year. The grand total, 121,000 to 189,000 acre-feet per year, is higher than the studies presented in Table III-4 due largely to the added water demands for processed shale disposal, revegetation, and power. In the present study, this range is considered to be the most likely requirement for consumed water. However, water consumed may be higher or it may be lower, depending on various contingencies considered below.

a. Demand Contingencies

In the estimates of water needs given above, certain of the components considered in an integrated processing system can be estimated with a high degree of certainty, e.g., mining and crushing, retorting, and upgrading. In other operations, viable technical alternatives exist which significantly change the water required to accomplish the same end, e.g., aerial condensers versus water cooling for use in power generation.

The true water needs for shale disposal and revegetation are yet to be established in large-scale operations; hence, water estimates for these operations could be subject to considerable error. A final factor that needs to be considered is the extent to which oil shale development may stimulate the growth of ancillary industrial development, thereby increasing the demand for water.

This section considers major demand contingencies to establish the boundaries on the most likely water demand estimate given in the section above.

(1) Mining and Crushing - The water consumed in mining and crushing for either an underground or surface mining operation is well established and relatively insignificant in the overall water balance (about 5 percent), being limited generally to dust control. The importance of water is not the quantity required but the water that may be provided by the mine and benefically used in other phases of the operation. Produced mine water is considered below in detail under "Supply of Water" (2.).

(2) Retorting - The retorting systems discussed in Chapter I, Section C.1 of this Volume have well-established water demand requirements. Each, in fact, produces substantial quantities of water that range from 2 to 10 gallons per ton of shale processed. From an overall sense, the 7 percent required for this operation is relatively insignificant.

(3) Upgrading - Shale oil upgrading has normally been considered a necessity in oil shale development due to the poor flow characteristics of the raw product. However, a recent patent (14) has suggested that partial refining is not a necessity since

the pour point of crude shale oil can be reduced to $0^{\circ}F$ to $20^{\circ}F$. Also, oils produced by in situ means may have superior flow characteristics over those produced by conventional above-ground retorting systems (Table I-8, Chapter I). Thus, it may be possible through technology to significantly reduce the water consumed for shale oil upgrading which, in Table III-5, is estimated to range from 29,000 to 44,000 acre-feet per year (about 20 percent of the total water consumed for the 1-million-barrel-per-day scale of operations).

(4) Processed Shale Disposal - This accounts for nearly 40 percent of the water needs for an oil shale industry and is still in the experimental stage. In full-scale operations, water requirements may be either higher or lower than estimated in Table III-5. It could be higher, for example, if slurry disposal is used which would increase the water consumed by about 880 acre-feet per year for a typical 50,000-barrel-per-day operation. Applied to the mix of technology used to develop the water-demand table, this would increase demand by 14,000 acre-feet over that presented in Table III-5 for the 1-million-barrel-per-day industry.

Conversely, the demand estimates for this function may prove to be as high as actual experience is gained in solid-waste management. Assuming 50-percent less water is required than is given in the lower value for this function Table III-5, about 23,000 acre-feet less water would be required than the 121,000 to 189,000 acre-feet best estimate for the 1-million-barrel-per-day industry.

(5) Power Generation - Selection of the type of cooling systems for plants that generate electricity for use in the plant and for use by the associated urban population will have a significant impact on the water resources of the region. About 1,000 MW of power (1,600 MW installed) will be required to support the processing requirements of a 1-million-barrel-per-day shale oil industry, and about 80 MW will be required for the urban support population estimated to total 115,000 persons. The current installed capacity of the tri-State area is 3,528 MW. An increase of approximately 1,600 MW (installed) for a 1-million-barrel-per-day shale oil industry represents an increase of almost 50 percent. This analysis assumes that the power will be generated in the oil shale region, although some of the power could be supplied from sources outside the region, thus reducing regional water requirements. Water consumed for power cooling is estimated to range from 16,000 to 25,000 acre-feet per year, about 13 percent of the total for the 1-million-barrel-per-day industry.

Selection of the choice of a suitable means of dissipating waste heat will depend on a number of factors as outlined in a recent review (9):

> ...The principal types now in use or planned are:
> (1) Once-through (cooling) using fresh or saline water;
> (2) Cooling ponds;
> (3) Wet cooling towers; and
> (4) Dry cooling towers.

Once-through cooling systems are generally used where adequate supplies of water are available and no significant adverse effects on water quality are expected. Sources of water include rivers, lakes, estuaries, and the ocean. Once-through systems are normally more economical than other systems. The only consumptive water uses are those resulting from increased evaporation in the source water bodies because of the addition of heat.

Where water supplies are limited and suitable sites are available, cooling ponds may be constructed so that water may be recirculated between the condenser and the pond. Sufficient infl w would be needed, either from upstream runoff or by diversion from another stream, to replace the natural evaporation and the evaporation induced by the addition of heat to the pond. A pond surface area of one to two acres per megawatt of plant capacity is normally required to dissipate the heat. Cooling ponds are frequently used for other beneficial purposes, including recreation.

Where conditions are not favorable for once-through cooling or for the construction of cooling ponds, cooling towers are generally employed for the dissipation of waste heat. Cooling towers may be used to provide full cooling requirements, to provide full cooling during parts of the year, or to provide partial cooling during certain periods or throughout the year. In wet cooling towers, the warm water is brought in direct contact with a flow of air, and the heat is dissipated principally by evaporation. Cooling towers may be either of natural- or mechanical-draft design. Because of the large structures involved and the added pumping and other costs, wet cooling towers are usually more expensive than once-through systems or cooling ponds.

As a rule of thumb, a 100-MW plant operating with a 15°F temperature rise across its condenser requires a cooling water flow of about 1,400 cfs if fossil-fired and 2,000 cfs if nuclear. With once-through cooling, the consumptive use of water for each type plant of this size is about 12 and 17 cfs, respectively. The consumptive use increases to 16 and 27 cfs for cooling ponds and 28 to 40 cfs when wet cooling towers are employed. Consumptive use represents about one percent of condenser flow in once-through cooling and two percent in wet cooling towers.

Currently, the maximum size of a wet cooling tower employing natural draft is about 400 feet in diameter and 450 feet high. A tower of this size can provide the cooling requirements for a 500-MW nuclear plant or an 800-MW fossil-fired plant.

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Wet cooling towers using mechanical draft are constructed in multiple cells and a plant may contain one or more banks of cells. Forced draft type fan diameters are limited to 12 feet or less, compared to nearly 60 feet for the induced draft type, which necessitates more cells for a given capacity.

In a dry cooling tower, the water would circulate in a closed system with the cooling provided by a flow of air created either by mechanical or natural draft. No water would be lost by evaporation. Because of the large surface area required for heat transfer and the large volumes of air needed to be circulated, however, dry cooling towers are substantially more expensive than wet towers. There are no large dry cooling towers at power plants in this country. Recently, a dry cooling tower for a 20 MW plant was constructed in Wyoming.

From the above, consumptive use of water for fossil fuel plants will vary from 0 to 28 acre-feet annually per megawatt of generating capacity. For the individual cooling system, these requirements are as follows:

	Annual Water Consumption Acre-feet per Megawatt of Generating Capacity
Dry cooling tower	0
Once-through	12
Cooling ponds	16
Wet cooling towers	28

A value of 15 acre-feet annually per megawatt of generating capacity was assumed to be the most likely estimate of water requirements and was used in the cooling water estimates given in Table III-5. If 10 acre-feet of water per megawatt of power is assumed, water consumed by the 1-million-barrel-per-day industrial development would be reduced to about 10,000 acre-feet per year. Conversely, an assumption of all wet cooling towers at 28 acre-feet annually per megawatt of generating capacity would increase water consumption to about 37,000 to 45,000 acre-feet per year.

(6) Revegetation - While disposal is actually taking place, very little water would be required for revegetation. In the case detailed in Volume III, Chapter II, this time interval would approximate 5 years. Once the pile had reached its ultimate height, experimental work has indicated that about 1 foot of water per year per acre is required to reestablish vegetation (12). However, revegetation of natural vegetation has not yet been attempted on the scale that would be required for commercial development. Consequently, the actual amount and the length of time required for a particular site has not been firmly established. Assuming that 50-percent more water is required than was estimated in Table III-5 for the 1-million-barrel-per-day scale of operations, the water required for revegetation would be increased by 6,000 acre-feet per year.

(7) Sanitary and Domestic Use - The requirements for sanitary needs during processing and for domestic uses for the associated urban population are relatively small, about 10 percent of the consumed water for the 1-million-barrel-per-day industry. Certain types of processes may require fewer working personnel than those described for the typical case. For example, 900 persons instead of 1,200 persons may be able to operate a 50,000-barrel-per-day oil shale operation (11). This would reduce the total population needed to support a 1-million barrel-per-day industry from 115,000 persons to 96,000 persons. The water required

for associated sanitary needs during processing and related urban growth would therefore be reduced by 3,000 to 5,000 acre-feet per year below those needs given in Table III-5.

(8) Ancillary Industrial Development - It is not possible to detail the types of growth of ancillary industrial development that may be stimulated by oil shale development. Increased manufacturing of mobile homes may be expected, as would expansion of existing local industries that produce electronic components. However, these types of industrial developments are not intensive users of water.

The sodium minerals in or associated with oil shale deposits have potential for future development. However, as described in Chapter I, Section C.1.f, three constraints will act to retard the growth of a sodium minerals industry: (1) the unproven nature of the technology, (2) suitable lands, and (3) limited markets. Thus, it is considered unlikely that such processing facilities would be developed as an adjunct to the 1-million-barrel-per-day shale oil development considered in this Volume, but a limit of two or three plants utilizing nahcolitic/dawsonitic shale may eventually be supported. Such a minerals processing industry would significantly increase water requirements.

A recent study by the Bureau of Mines (15) has indicated that a plant that produces 50,000 barrels per day of shale oil plus nahcolite and dawsonite minerals would require 27,000 to 38,000 acre-feet of water per year. This represents a process-water increase of 16,000 to 32,000 acre-feet per year over the values given previously in Table III-5 for the 50,000-barrel-per-day plant that produces shale oil only. For two plants, the incremental increase in process water ranges from 32,000 to 64,000 acre-feet per year, or up to one-third more water than is required by a 1-million-barrel-per-day shale oil industry.

(9) Summary - As discussed in the subsections above, possibilities exist that either more or less water will be consumed than was forecast in Table III-5. Uncertainties exist concerning the mix and/or type of oil shale development, including the development of ancillary industries or other industrial development, growth and level of population, the efficiency of water use, and the effects of ground water disposal and water-rights transfers on supply (discussed in Part 2 below). Some of these uncertainties can be examined by analysis of the sensitivity of projected water demands to changed assumptions. This analysis was developed in the preceding sections, the results of which are summarized in Table III-6. As indicated therein, technologic developments may require less water for upgrading. Water for processed shale disposal may be higher due to the use of slurry disposal. Water for power generation may be either higher or lower than forecast. Revegetation may be higher, but sanitary and domestic use of water may be lower if fewer workers are required.

Taking the lower range from Table III-5 for the 1-million-barrel-per-day development (121,000 acre-feet) and subtracting the range of those demand contingencies which would reduce this requirement (39,000 to 45,000 acre-feet per year) indicates the minimum water consumed could be as low as 76,000 to 82,000 acre-feet per

Table III-6.--Contingent Water Consumption Forecasts For A 1-Million Barrel-Per-Day Shale Oil Industry.

	Range of Water Consumption (Acre-feet/year)		
	Lower Range	Most Likely	Upper Range
PROCESS REQUIREMENTS			
Mining and Crushing	6,000	6,000 - 8,000	8,000
Retorting	9,000	9,000 - 12,000	12,000
Shale Oil Upgrading	17,000 - 21,000	29,000 - 44,000	44,000
Processed Shale Disposal	24,000	47,000 - 70,000	84,000
Power Requirments	10,000	15,000 - 23,000	37,000 - 45,000
Revegetation	0	0 - 12,000	18,000
Sanitary Use	1,000	1,000 - 1,000	1,000
Subtotal	67,000 - 71,000	107,000 - 170,000	204,000 - 212,000
ASSOCIATED URBAN			
Domestic Use	9,000 - 11,000	13,000 - 17,000	17,000
Domestic Power	0	1,000 - 2,000	2,000
Subtotal	9,000 - 11,000	14,000 - 19,000	19,000
TOTAL	76,000 - 82,000	121,000 - 189,000	223,000 - 231,000
ANCILLARY DEVELOPMENT			
Nahcolite/dawsonite	-	-	32,000 - 64,000 1/
GRAND TOTAL	76,000 - 82,000	121,000 - 189,000	255,000 - 295,000

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

year. In a like manner, the maximum estimate from Table III-5 (189,000 acre-feet) may be increased by 34,000 to 42,000 acre-feet by processing contingencies for a maximum water consumption of 223,000 to 231,000 acre-feet per year. Nahcolite/dawsonite development would extend this maximum range from 255,000 to 295,000 acre-feet per year.

In summary, it appears that the range of values given in Table III-5 for a 1-million-barrel-per-day industry is a reasonable estimate of water requirements; e.g., 121,000 to 189,000 acre-feet per year. Process contingencies may either increase or decrease the consumption requirements, but these are reasonably well balanced and as a practical matter are likely to have offsetting influences. For example, upper-range water requirements for processed shale disposal may be offset by lower requirements for revegetation. The major increase in water consumption is not likely to be due to process or related urban development but to the growth of an ancillary industry to process nahcolite or dawsonite.

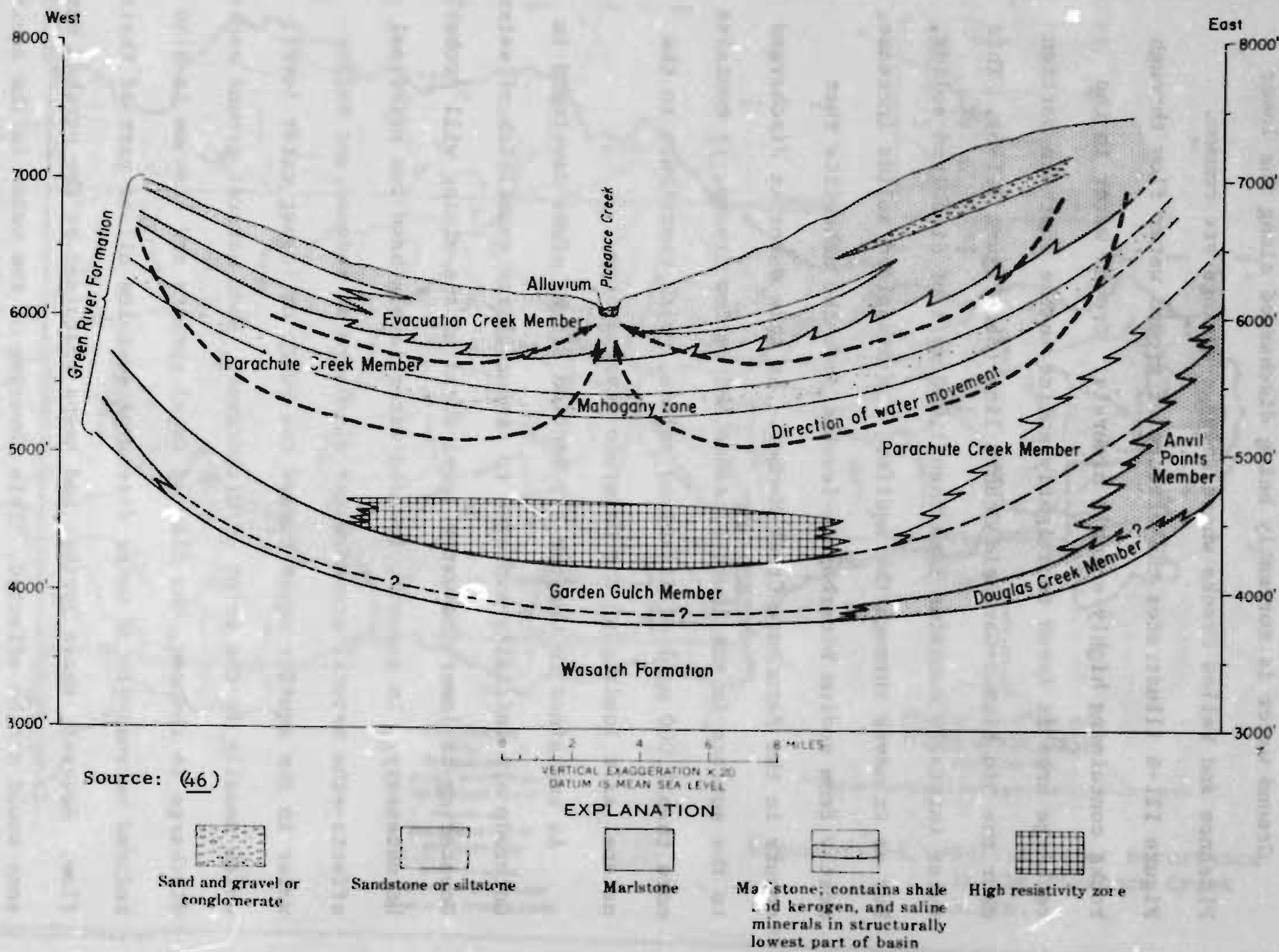
2. Supply of Water

a. Ground Water

The amount and quality of the ground water produced as a consequence of oil shale development plays an important role in the overall water demand-supply balance for a maturing oil shale industry. The ground water in the Piceance Creek of Colorado is of principal interest in assessing supply potentials since the oil shale deposits of Utah and Wyoming are not expected to contain substantial amounts of ground water (Chapter II).

As explained in Chapter II, Section B.5.b of this Volume, recent hydrological data indicates that estimates of 2.5 million acre-feet of water in storage in the Piceance Creek Basin may be a very conservative estimate based on a storage coefficient of 0.01 (10^{-2}). Weir (16) reported that a porosity of 30 percent was determined from a sidewall neutron porosity log of hole RB-D-01 at the Project Rio Blanco site, and he concluded that the effective storage coefficient was at least 0.15. Coffin and Bredehoeft (17) used a storage coefficient of 0.1 (10^{-1}) for estimating the rate of ground water flow into an oil shale mine. If this storage coefficient were applicable for all the Green River Formation of the northern half of the Piceance Creek Basin (approximately 630 square miles), calculations show about 25 million acre-feet of water in storage which is used in this analysis as the best estimate of the ground water in storage.

In Colorado, ground water in the Green River Formation is recharged around the margins of the basin by direct infiltration of precipitation on outcrops of the aquifers and by downward percolation of water from narrow alluvial deposits in the higher stream valleys. The water moves down dip toward the central part of the basin and is discharged through springs and seeps in the lower parts of the principal stream valleys, as shown in the diagrammatic section across the Piceance Creek Basin (Figure III-5). Some of the water that enters the ground on the ridges reappears as fresh-water springs in adjacent canyons. The remainder moves down dip to discharge areas.



Source: (46)

Figure III-5. DIAGRAMMATIC SECTION ACROSS THE BASIN

Ground water is currently being discharged along the lower Piceance and Yellow Creeks where seepage springs are common. Figure III-6 illustrates the effects of ground water flow through rocks containing highly soluble minerals. Ground water in the recharge area is fresh to slightly saline in the southern portion near the Rio Blanco-Garfield County line (See Figure III-6). This water initially contains less than 1,000 mg/l of dissolved solids, but as it moves through the aquifer, the dissolved solids increase, mostly from sodium bicarbonate leached from the nahcolite that occurs in the Parachute Creek Member. As this water is discharged to the surface in the lower Piceance and Yellow Creeks, it contains more than 7,000 mg/l of dissolved solids, which contribute to the natural salt loading of the Colorado River system.

As explained in Chapter II, Section B.5.b, mines developed in Colorado are initially expected to produce large quantities of water. Dewatering to lower the water level ahead of the mining will probably be necessary. In general, lowered water levels have two principal effects--the natural ground water discharge is reduced, and saline water in the aquifer moves toward the point of lowest water level, which usually is the point of withdrawal. When natural ground water discharge is reduced, the flow of local springs and streams is also reduced because ground water discharge sustains all or part of their flow. However, those springs and seeps sustained by the perched water zone would not be affected. This lowering of the water in the aquifer is a function of time and rate of withdrawal. LeGrand (24) has described the impact of mine dewatering as follows:

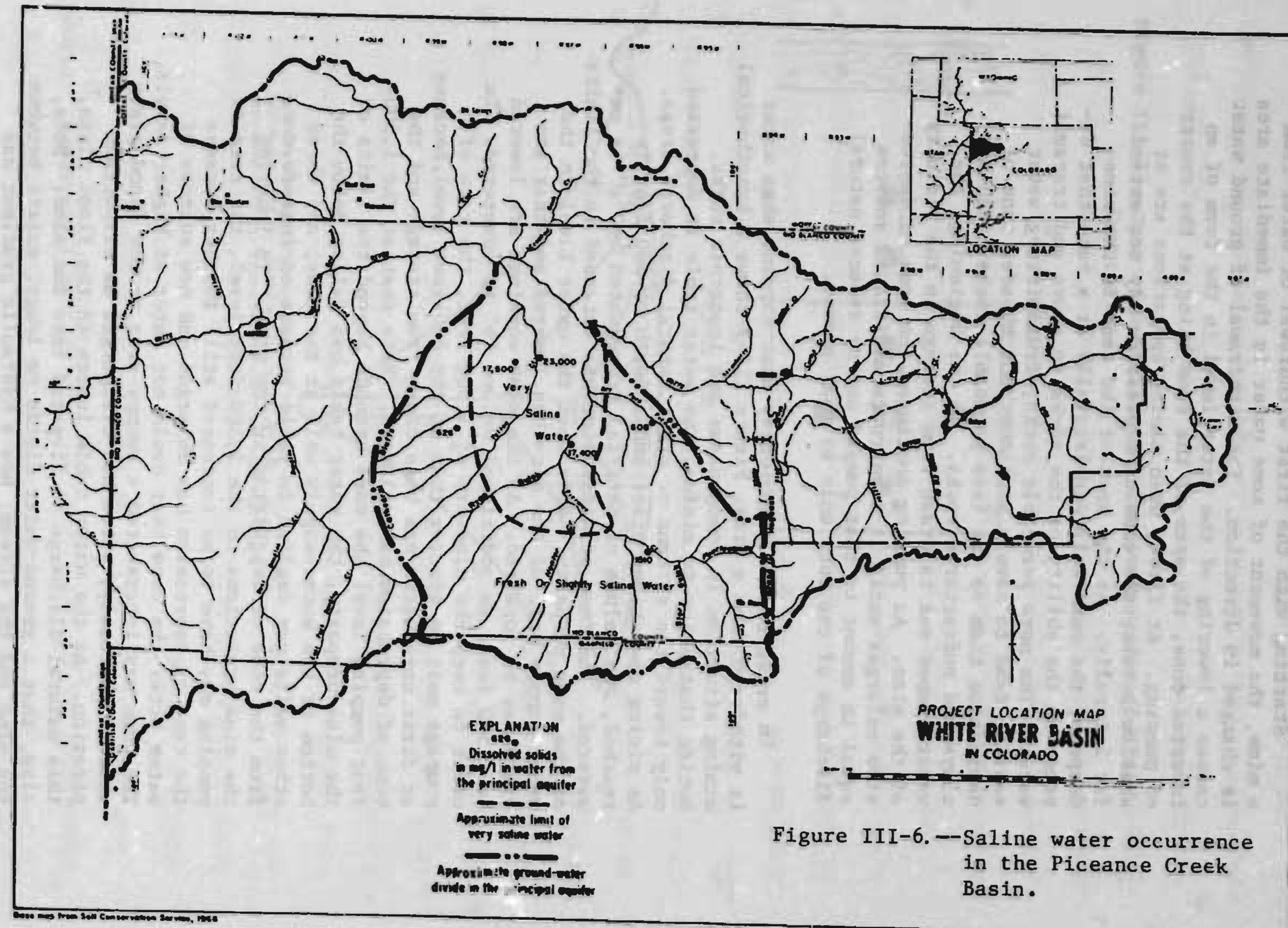
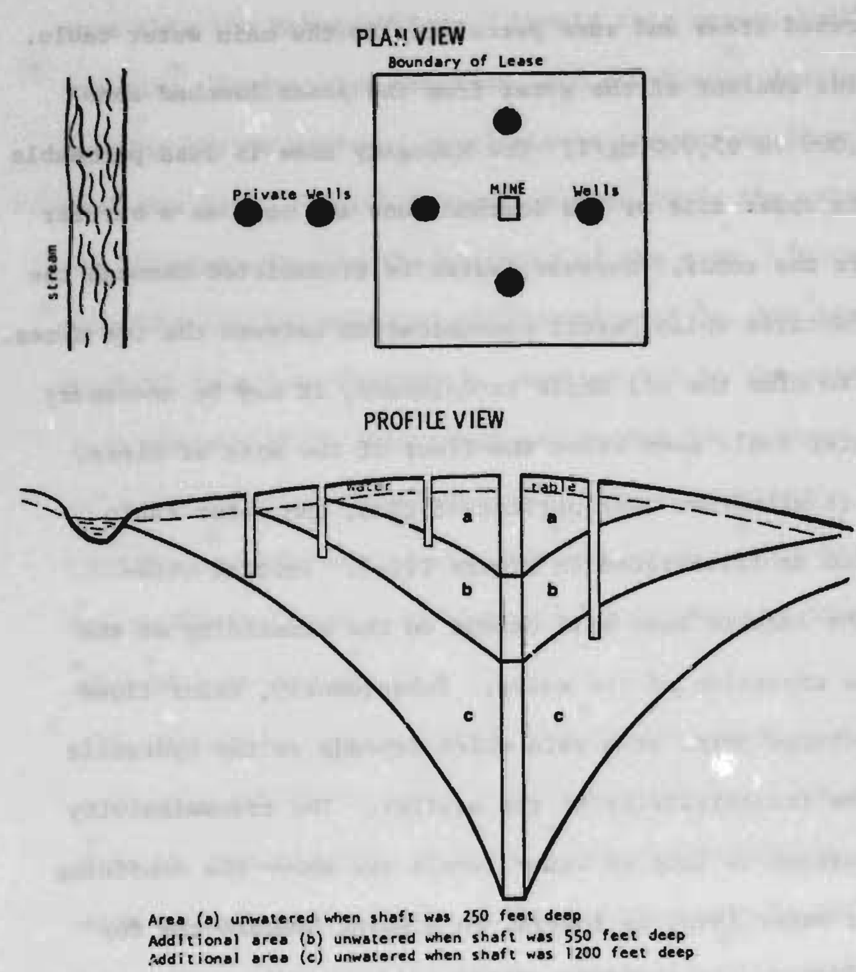


Figure III-6.—Saline water occurrence in the Piceance Creek Basin.

Starting with the first withdrawal of water from a mine, the movement of some water in the immediate area is changed in direction. The withdrawal of ground water causes a lowering of the water level in the form of an inverted cone, the apex of the cone being at the center of pumping. At first, when mining operations are at shallow levels, the cone of depression may not extend far laterally. As the apex of the cone in the mine deepens, the cone enlarges laterally at a rate that depends on the ability of the rocks to store and transmit water. The more permeable rocks, transmitting water easily, tend to have a shallower but broader cone of depression than do the less permeable rocks, such as clays and unfractured rocks. In the beginning, the water pumped out is drawn from storage in the vicinity of the mine. As pumping continues, the cone of depression enlarges until it interrupts additional sources equal in amount to that pumped out or reduces natural discharge of the rock unit by that amount.

In order to see graphically what happens when water is withdrawn from a mine, Figure III-7 shows a hypothetical mining situation in homogeneous and isotropic rocks. Notice that prior to mining, the water table is depressed only toward the streams or other natural discharge areas. As mining operations start and a depth of 600 feet is reached, the volume of material represented by "a" is unwatered. The cone of depression has extended to the limits of the mine property. Note that the water level in the water-supply well of the mine has lowered and that its yield may be impaired. As the mine workings are lowered to 1,500 feet, an additional volume "b" is unwatered. In order to keep the mine dry at 1,500 feet, the rate of pumpage must be greater than at the 600-feet level, because at first more water has been drawn from storage and the cone of depression has enlarged. Note that at the 1,500-feet pumping level the cone extends beyond the limits of the mine property, the water table has fallen below the bottom of the water-supply well at the mine, and three other wells may decline in yield because of interference from the cone of depression in the mine. In lowering the mine operations to the 2,500-feet level, the rate of pumping may have to be increased still further, because the cone of depression has enlarged and new sources of water enter the cone that could not enter at higher levels. The cone has intersected a swampy area on the flood plain where, previously, water had discharged as evapotranspiration. As the water table lowers in the flood plain, this natural discharge is diverted into the mine. Note, also, that a ground-water divide no longer exists between the mine and the stream; now a hydraulic gradient has been established from the stream to the mine, and a major--perhaps serious--source of recharge has been intercepted.

Figure III-7.--Cone of Depression as the Consequence of Mine Dewatering.



Source: Reference (18)

The two principal aquifers in the Piceance Creek Basin are separated by the Mahogany bed and are called the upper-zone and the leached-zone aquifer. The upper-zone water is relatively good quality in the recharge area with a salt content generally less than 1,000 mg/l. Some of this water discharges to the surface in springs in perched areas and some percolates to the main water table. Dissolved solids content of the water from the lower leached zone ranges from 2,000 to 63,000 mg/l. The Mahogany zone is less permeable than either the upper zone or the leached zone and acts as a barrier to flow between the zones. However, water is transmitted through the Mahogany by fractures which permit communication between the two zones.

In order to mine the oil shale in Colorado, it may be necessary to draw the water table down below the floor of the mine or mines. As this water is withdrawn over periods of time, the water table would be lowered as illustrated in Figure III-7. Initial withdrawals from the leached zone will depend on the elasticity of the aquifer and the expansion of the water. Subsequently, water flows toward the discharge point at a rate which depends on the hydraulic gradient and the transmissivity of the aquifer. The transmissivity will remain constant as long as water levels are above the confining bed. After the water level is lowered to a point beneath the top of the aquifer, the transmissivity will decrease as the saturated thickness decreases.

The amount of water to be pumped from a given mine will depend directly on the aquifer characteristics, the competency of the strata overlying and underlying the zone to be mined, and the type of mine (surface or underground). At the present time, it is expected that mining will be initiated in the Mahogany Zone. It is not yet known if water levels above this zone will need to be lowered for underground mining, but fractures and faults may permit excessive drainage of water from both the upper zone and the leached zone into the Mahogany Zone. Should this occur, bulkheading, pre-grouting, progressive grouting, and overburden dewatering and pumping may be employed to eliminate the inflow of water. If these measures fail, it will be necessary to lower the water table below the Mahogany Zone in the vicinity of the mine. It is not known what the initial rates of withdrawal will be, but based upon hydrological data (See Chapter II, Section B.5.b) the present best estimate is a maximum of 30 cubic feet per second for surface development and 40 cubic feet per second for underground development (22,000 to 29,000 acre-feet per year). Initial rates cannot be sustained and may gradually decline to about 18 cubic feet per second at the end of a 30-year period.

The conditions set forth above represent a situation of maximum environmental impact which will occur when both aquifers are pumped. That is, the quantity of water to be pumped will be a maximum and more of the water will be saline, which leads to considerations of how excess saline waters may be managed, as discussed in Part 3.a of this Section. As the quantity and/or quality of the mine water decreases, it is also assumed that surface-water sources will need to be diverted in greater quantities. The water balance for both a surface and an underground mine is explored in Section 3, below.

b. <u>Surface Water</u>

The availability of water from the Colorado River system has been detailed in Chapter II, Section B.5.a. Flow in the Colorado River system is highly regulated by major storage reservoirs that include Lake Mead, Lake Powell, Navajo Lake, Blue Mesa Reservoir, and Flaming Gorge Reservoir. Years of negotiation have led to existing treaties, compacts, agreements, and court decrees which have resulted in dividing the water of the river between the basin states and between the United States and Mexico. Although differences in interpretation of the agreements persist and are unresolved, the total amount available for current and committed future uses has been estimated.

The virgin flow of the Colorado River at Lee Ferry has been computed for various periods of record beginning with 1896. For the period 1906 to 1970, the average annual virgin flow is estimated to be about 14,952,000 acre-feet. Annual flows have ranged from less than 6 million acre-feet in 1934 to over 24 million acre-feet in 1917. Since the establishment of the gage at Lee Ferry in 1923, the average annual virgin flow at that point on the river has been about 13.8 million acre-feet.

Under existing agreements, the water potentially available for oil shale development has been calculated (Chapter II, Table II-4). As detailed in that section, some 341,000 acre-feet of water per year is potentially available and is distributed as follows, in acre-feet:

Colorado		167,000
Utah		107,000
Wyoming		67,000
	Total	341,000

Industrial water can be obtained in western Colorado from Bureau of Reclamation reservoirs (Ruedi and Green Mountain Reservoirs). Potential future sources could be obtained from projects now authorized by Congress (Table II-3, Chapter II) and potential private projects. In addition, many firms known to be interested in oil shale development have obtained conditional decrees to direct flow during the winter and during the high-runoff season (Table II-4, Chapter II). Conversion of existing irrigation rights to industrial use by purchase is also possible.

In addition, water could be made available from Flaming Gorge Reservoir for use in Wyoming, Utah, or Colorado, and from the Fontenelle Reservoir for use in Wyoming. The amount of water that may actually be used in a given state, however, is constrained and may not exceed existing compact agreements. Thus, the actual amount potentially available for oil shale development is 341,000 acre-feet, even though water in excess of this amount is currently available from existing reservoirs for use in the three-State area. 1/

1/ Water is currently available from:

1. Ruedi and Green Mountain Reservoirs, 78,000 acre-feet for use in Colorado.
2. Flaming Gorge Reservoir, 250,000 acre-feet for use in Wyoming, Colorado, and Utah.
3. Fontenelle Reservoir, 100,000 acre-feet for use in Wyoming.

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In 1963, the U.S. Supreme Court held that the withdrawal of land from entry for Federal use may also result in the reservation of a Federal water right for the use of water on the reserved land (19). This has been assumed to include the Naval Oil Shale Reserve in western Colorado. More recent Supreme Court decisions hold that the United States has waived sovereign immunity on a limited basis in suits to adjudicate Federal water rights (20). As a result of these decisions, the Federal Government is currently engaged in adjudication proceedings in water courts in Colorado to determine the extent of water rights for reserved lands in Colorado, including the Naval Oil Shale Reserve. Until these proceedings are completed, the status of water rights for the Naval Oil Shale Reserve is unknown.

3. Demand-Supply Water Balances

The total water demand-supply situation is extremely complex and will change with time. The relationship between demand for and supply of water is illustrated in Figure III-8. As shown, water of low quality can be used for processed shale disposal and for the mining and crushing operation. However, high quality water is needed for retorting, shale oil upgrading, power development, revegetation, sanitary use, and associated urban expansion. Both the shale oil upgrading and retorting operations produce low-quality water which will be available during the processing life and therefore will significantly reduce the water requirements. For example, a 1-million-barrel-per-day shale oil industry is expected to consume between 121,000 to 189,000 acre-feet of water per year. This range can be reduced between 10,000 and 40,000 acre-feet per year by crediting water obtainable from retorting and shale oil upgrading, depending on the processing scheme.

As explained in the previous Section, it is likely that during the early stages of oil shale development large quantities of water may be available from the initial mines in Colorado. The wells would be equipped with high-lift pumping equipment to lift the water to the surface. Based on hydrologic data (Chapter II, Section B.5.b) and the hypothetical mine development given in Volume III, Chapter III, it is assumed that, of the cumulative water produced, 30 percent will be of high quality and 70 percent of low quality. The distribution of the water quality will, however, change with time. Initially, the water will be of high quality since it will be coming mostly

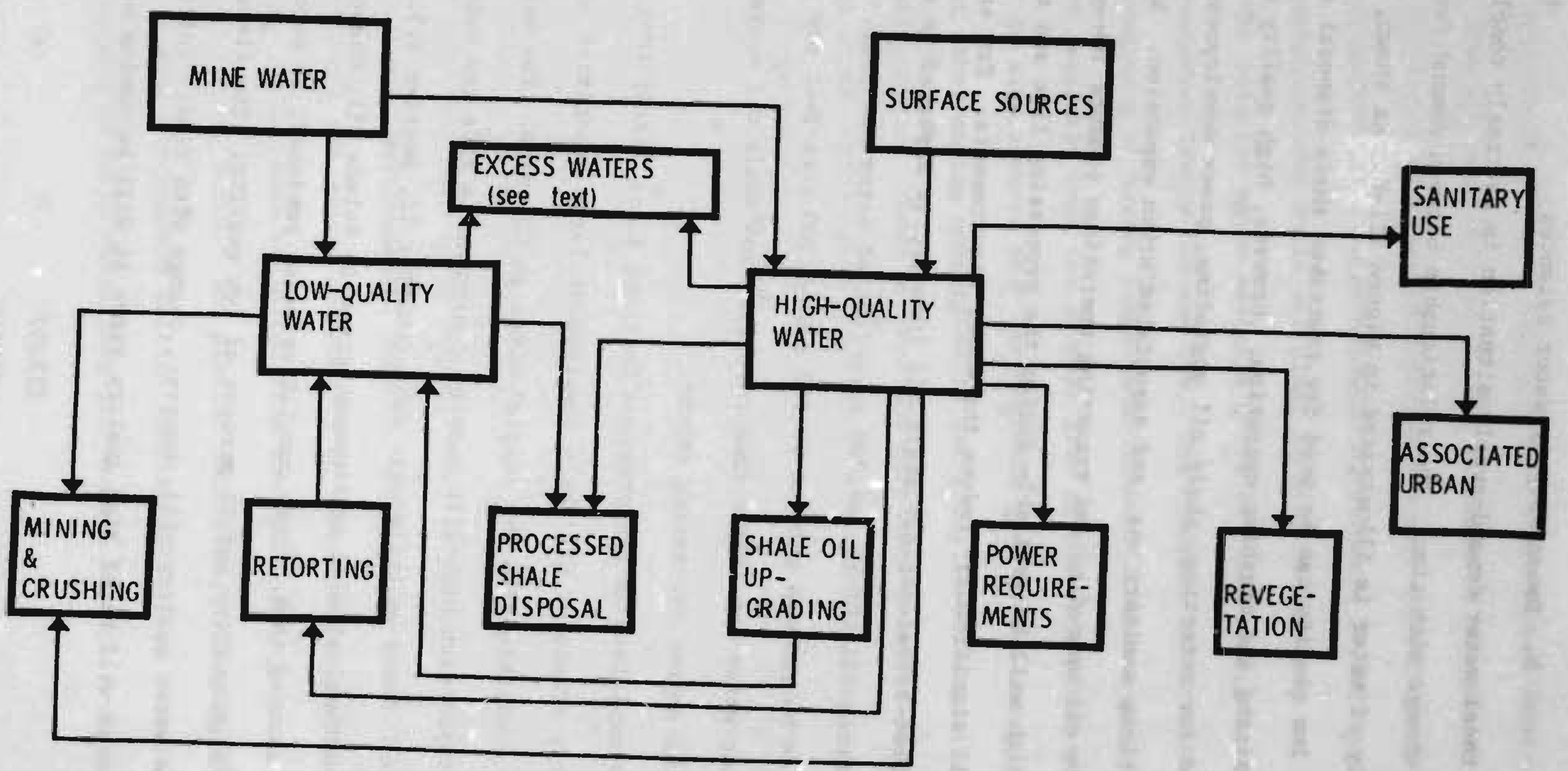

Figure III- 8 .--Flow Diagram Showing the Processing and Urban Water Needs and the Sources of Supply.

from the upper-zone aquifer. The volume of water pumped from or moving up from the leached zone aquifer as pressure is reduced will probably increase with time and will contain more dissolved solids. Table III-7 typifies the water balance for either a 50,000- or 100,000-barrel-per-day shale oil plant located in Colorado and is based on the detailed water analysis given in Volume III, Chapter IV, for prototype Tracts C-a and C-b. The analysis assumes the extreme condition of having large quantities of various-quality mine water available over the 30-year life of the mine/plant complex. It is also assumed that interference from ground-water pumpage at other mining operations is not going to occur during the operating phase. These assumptions make this analysis extremely optimistic since little water would need to be diverted from surface sources. By comparison, if the mines are dry, as is likely in Utah, then all water would have to be diverted from surface sources as shown in Table III-7. Therefore, at one extreme, large amounts of excess mine water of low quality are available while at the other extreme, no mine water is produced.

It has been assumed in this analysis that a maximum initial volume of water may need to be pumped. Such an assumption will magnify potential environmental impacts, since it may be possible to withdraw only the amount and quality of water needed for actual operations. It has been estimated from the hydrologic data of Chapter II, Section B.5.b. and similar data given in Volume III, Chapter II, that the maximum initial pumping rates from both aquifers may approximate 30 to 40 cubic feet per second, depending on mining

Table III-7.--Thirty Year Cummulative Demand-Supply Water Balance 1/

		Thousands of Acre-feet							
		Underground Mine; 50,000 Bbls/day				Surface Mine; 100,000 Bbls/day			
		Water Requirements 2/	Water Produced 3/	Excess Water	Diverted Water	Water Requirements 2/	Water Produced 4/	Excess Water	Diverted Water
Process Requirements	High Quality Water	75-127	175	60-100	0-12	151-234	175	25-46	22-58
	Low Quality Water	88-133	373	240-285	--	178-266	373	107-195	--
	Subtotal	163-260							
Associated Urban	High Quality Water	20-27	--	--	20-27	34-45	--	--	34-45
	Total	184-287	548	300-385	20-29	363-545	548	132-241	56-103

1/ Water requirements and produced water based on a 30-year period.

2/ This would represent the maximum diverted surface water requirements should no water be available from processing or from the mines.

3/ Assumes a maximum pumpting rate of 40 cfs declining to 18 cfs in the 30th year.

4/ Assumes maximum initial pumping rate of 30 cfs declining to 18 cfs in the 30th year.

method employed, in the initial phases of development and decline to a rate of approximately 18 cubic feet per second in the latter stages of development. Over a 30-year period of time, excess water could cumulatively total 300,000 to 385,000 acre-feet for the 50,000-barrel-per-day plant. Surface mine development to 100,000 barrels per day would require more water than underground development (See Table III-5). Assuming the same pumping rates as above, the amount of excess water would be reduced to 132,000 to 241,000 acre-feet. Several technical options are available to handle excess mine water as discussed below.

a. Excess Mine Water

In the early stages of oil shale development, excess water is expected to be of high quality and may be released directly to local streams. Over time, the excess mine water will increase in salinity, and discharge to local streams will no longer be possible without treatment.

Desalting technology is well established for waste waters of the type that may need to be treated. Gas may be available from the surface retorts which suggests the possibility of a thermal process such as distillation being used. Using the distillation processes, water recovery up to 98 percent can be obtained. The distilled water would be approximately 10 ppm dissolved solids or less and could be blended with additional saline water to obtain a product suitable for release to surface streams. Waste brine from the distillation processes can be disposed in conjunction with the spent oil shale. Because of the low hardness, fouling by calcium scale formation should not be a problem. Recovered sodium bicarbonate and carbonate minerals may possibly find a market in existing trona chemical companies located west of Green River, Wyoming. Conceivably, because these companies are presently refining these same chemicals from deep mining operations, a crude product obtained from the oil shale waste waters may be of value in these operations as well as in other similar markets (21, 22).

Another option includes solar evaporation of the excess waters. As indicated in the water quality impact section below, such evaporative ponds would require large surface areas; from about 4,000 acres at an altitude of 4,000 feet at 10 inches of rainfall per year to nearly 11,000 acres at an altitude of 7,000 feet assuming a rainfall of 20 inches per year.

After sufficient amounts of water have been withdrawn, it might be possible to reinject excess mine waters into the aquifer, or it may be used to stimulate recovery of petroleum in nearby oil fields. Recycling of the excess mine waters may delay for many years the need for diverting and consuming large amounts of surface waters for oil shale development.

It is not likely that any one alternative would be employed to manage excess mine waters since the quantity and quality of these waters will change with time. A more likely pattern in the early stages of industrial development is the release of good quality excess water directly to local streams. As needed, treatment of the water to remove salts and release of treated water may be employed. Storage in reservoirs for use in subsequent operations and/or reinjection may also be used as the industry matures. The complexity of the likely patterns indicates the need for a water management plan.

b. Water Management

Although large volumes of water may be available during the initial mine development in Colorado from mine dewatering, less pumpage may be required to keep new mines dewatered as the oil shale industry grows to maturity. This could be brought about by a gradual decline in rates of flow of ground water from those mines which are in operation which in turn would draw down the water table in the aquifer as a whole. Each mine will exhibit its own particular characteristics which will require different engineering solutions, since in one instance, large amounts of water may be available and, in the other, large amounts of water must be diverted.

The actual situation will depend on time of development, where the development takes place, and the size of the process. A mix of development is the most likely situation; some mine water will probably be produced initially to lessen the requirements for surface water. In the latter years, however, surface water would be used and consumed in ever increasing quantities. While it cannot be precisely quantified at this time, the most probable upper limit on water consumption will approximate 189,000 acre-feet per year for a 1-million barrel per day industry. (See Part I above). The quantity of surface water required in the latter stage of development will depend largely on what is done with the excess mine water produced in the early stages of development and on evolving technology.

A water management plan could involve a number of technical alternatives. Initially, water in excess of needs may be (1) released to streams, (2) treated and released, or (3) stored for future use in impoundments. Following the initial high production rate, injection wells could then be employed to restore excess water and part of the pressure to the aquifers. The water would then be available for use at some later stage of development.

The injection of saline water into the leached zone would cause a pressure build-up in the zone which would be dependent on (1) the injection rate, (2) transmissivity and storage coefficient of the receiving zone, (3) the length of time after injection begins, and (4) the distance from an injection well. The injection rate can be controlled by the number of injection wells relative to the quantity of excess water. To demonstrate possible mine water problems, Coffin and others (17) used an average transmissivity for the leached zone in the central part of the Basin of about 20,000 gallons per day per foot and a storage coefficient of 10^{-4} to compute the estimated change in hydraulic pressure caused by pumping with time and distance. Pressure increases from injection can be estimated in the same manner.

For the purpose of evaluating the potential pressure increases that might be caused by injection of excess water into the leached zone, calculations were made assuming an average injection rate of about 450 gpm per well during the first 10 years, 225 gpm during the second 10 years, and 158 gpm during the third 10 years (based on a declining quantity of excess water); the transmissivity of 20,000 gallons per day per foot; and the storage coefficient of 10^{-4}. The calculations (Volume III, Chapter IV. Section B.4) show that at a distance of 10 feet from the injection well, the pressure increase will be equivalent to 58 feet of water at the end of the first 10 years (it would be more in the well bore due to turbulent flow adjacent to the well), an additional increase of 24 feet during the second 10 years, and another 19 feet during the third 10 years, making a total of 101 feet for a 30-year period. At a distance of 5,000 feet, the pressure increase from one injection well would be equivalent to 42 feet at the end of 30 years. If the storage coefficient is greater, for example 10^{-1}, the change in water level would be less. A large number of injection wells would compound the pressure buildup, as the injection into the well would increase the pressure buildup in all other wells in the well field. Depending on the quantity of water injected, the pressure increases may become too great to allow continued injection.

An increase in the hydraulic pressure in the leached zone in the central part of the basin would increase the rate of flow upward through the overlying Mahogany zone into the upper water-bearing zone and eventually into the Piceance and Yellow Creek in the lower parts of their valleys. The effect of injection can be minimized by proper well spacing and injection rates, but long-term injection at high rates may not be feasible. In the areas most likely to be affected by injection, the quality of water in the upper zone is naturally degraded by upward leakage from the leached zone to the upper zone. The quality of the water in local streams would not be degraded initially. However, over time, the salinity of the water reaching the streams may increase should injection cause an upward movement and surface discharge of poor quality ground water.

Although requirements for disposal of excess water may be large due to high pumping rates at a given initial mine development, injection could reduce the need to treat excess water.

Hydrological models could be developed to guide water management plans during oil shale expansion. Mine development and subsequent hydrological test data will make it possible to explore the possibility of reinjecting excess water for future use. It may be feasible to develop a water management system that will minimize the need for diverted water and water treatment while maximizing the full utilization of the ground water by keeping it in the area for future use.

While this extension of the useful life of the aquifers cannot now be quantified, such a system would have an effect similar to that shown in Figure III-9. It could defer for several years the need to divert large quantities of surface water. Such a system would not eliminate the need for surface water in the long run, but proper management might minimize the quantity of surface water which would be diverted to support a mature oil shale industrial development.

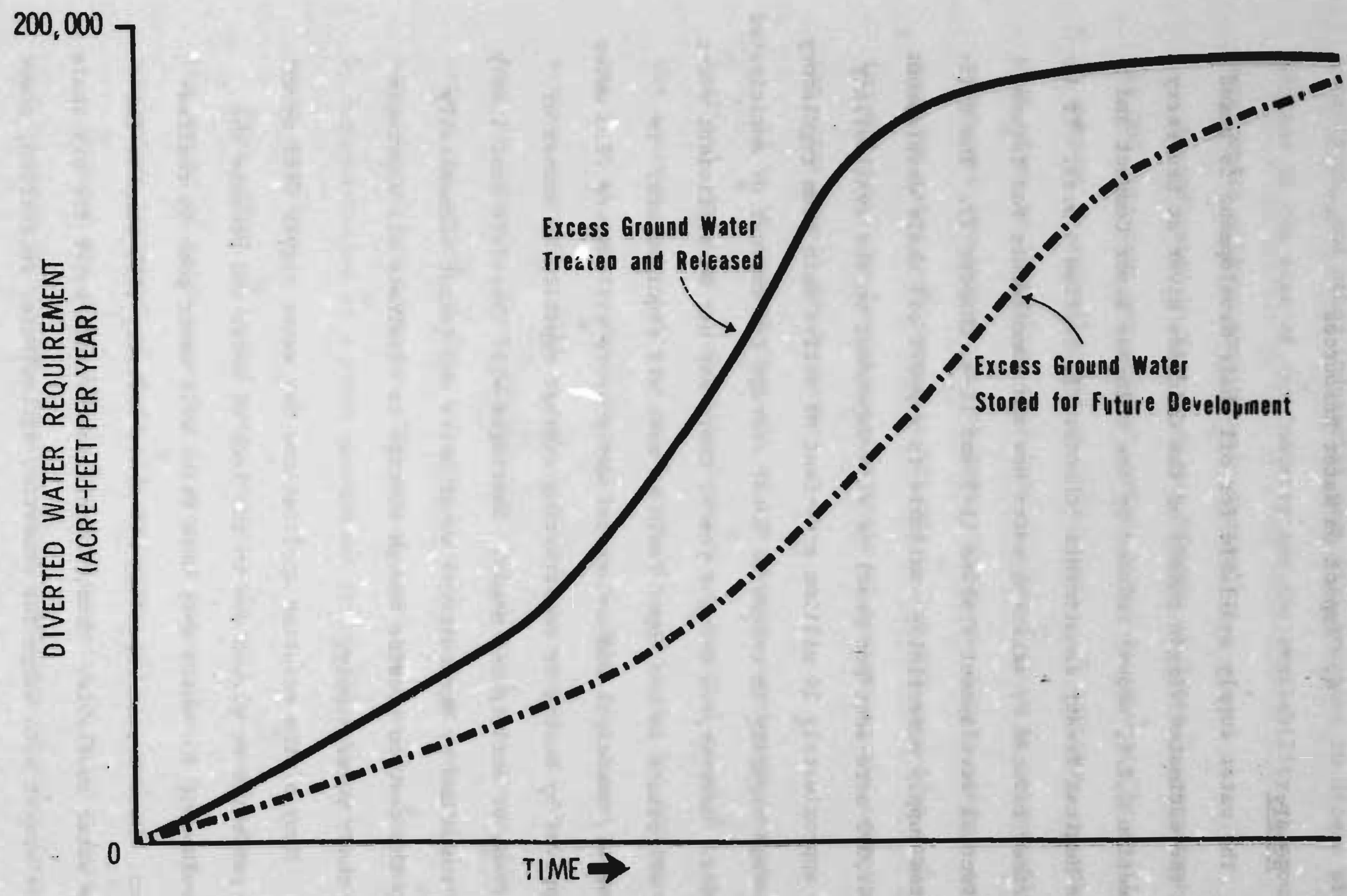

Figure III- 9.—Diverted Water Necessary to Support a 1-Million-Barrel-per-Day Shale Oil Industry.

4. Impact on Water Resources

a. Supply

The water supply available for oil shale development is based on the estimated virgin runoff of the Colorado River at Lee Ferry (Section C.2.6, above) reduced by the Colorado River Compact and the Mexican Treaty commitments (Chapter II, Section B.5.a). It is further reduced by existing water use and commitments for future potential development (Tables II-3 and II-4, Chapter 2). The estimated supply potentially available to support oil shale development (341,000 acre-feet per year) is also dependent on the availability of approximately 26 million acre-feet of active main stem regulatory storage capacity in excess of local storage for current or anticipated needs. However, in drought years, there may not be sufficient water at all points in the Upper Basin to meet all requirements. In general, municipal and industrial water users will assure firm water supplies by buying or constructing storage capacity in excess of current or anticipated needs. Shortages will therefore most likely be sustained by agricultural water users who cannot economically pay the cost to provide enough storage to eliminate all shortages in their water supply.

Many of the existing applications for water rights will never be perfected or proven due to the lack of water and because the development for which they were filed will never come to realization. However, an expanding oil shale industry will compete for the water available. Thus, competition between water for oil shale development with water for domestic, agriculture, recreation, power generation, and other industrial uses will increase in direct proportion to the size of the industry and the availability of ground water which will be continuously decreasing.

As indicated in Part 2 above, "Supply of Water," approximately 341,000 acre-feet per year of surface water is potentially available to support an expanding oil shale industry. In addition, an unknown part of up to 25 million acre-feet of ground water is potentially available to support development in Colorado. Since the likely maximum consumptive water requirement is 121,000 to 189,000 acre-feet annually for the 1-million-barrel-per-day scale of operation, the competition for water should not be severe.

If it is assumed that all of the maximum contingent demands are realized, and that a nahcolite/dawsonite industrial complex is developed, the maximum upper range is still probably within the 341,000 acre-feet per year of surface water potentially available, the actual amount of surface water that will be made available to support oil shale development is unknown. Thus, the availability of water may eventually act to retard the growth of this industry as well as other industrial and agricultural developments. The actual level may well be determined by implementation of a water management system for conserving ground water supplies.

The effect of ground water withdrawals will be cumulative, and the amount of water remaining in storage and available for each succeeding increment of shale oil production will be smaller.

Although the Green River Formation contains 25 million acre-feet of water in storage, pumping large quantities of water from it would change the points of discharge. Continuous pumping of large amounts of ground water for a number of years could dry up springs over a large part of the basin and stop much of the seepage to the creeks. Many of the water holes used by wildlife would disappear and the base flow of Piceance and Yellow Creeks would be appreciably diminished to the detriment of present appropriators (46).

Ground water discharged to lower Piceance and Yellow Creeks contains several thousand mg/l of dissolved solids. Reducing this discharge will tend to decrease the salt load in the river that presently flows into the White River. However, even if the full amount of salt added to the White River is eliminated (about 100 tons per day), it would make a minor impact on the overall salt balance of the Colorado River system.

In summary, oil shale development will set in motion a cumulative long term change in water use patterns across the oil shale region. This change will be small in the initial years of development as ground water supplies are depleted. Over time, increasing amounts of surface water supplies will be consumptively used, which will intensify competition for available supplies. However, it should be noted that both ground-water and surface water are subject to an appropriative system which, under law, might have a limiting effect on any potential dimuntion of prior appropriative rights. Water for municipal and industrial use will eventually assume an enlarged role in the demand-supply patterns.

Since uncertainties remain concerning supplies, 1/ it cannot be assumed that the ultimate size of an oil shale industry will be limited to a 1-million-barrel-per-day level by the water

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1/ Authorization and construction of new storage projects, success of weather modification and desalting programs, inter-basin transfers, present and future claims to water rights, frequency of periods of drought, the rate of full utilization of water by the upper Basin States, the cost of water management, water rights transfers, and ground water disposal.

supplies now believed to be available or potentially available in the future. Ultimately, the water need of an expanding oil shale industry, coupled with other water demands, may intensify the attempts to justify the need for water supply augmentation into the region. New impoundments, were they to occur, would affect the recreation uses of the rivers, creating increased opportunities for such activities as boating, but decreasing the eligibility of the rivers for classification as wild and scenic.

b. Water Quality

Salinity concentrations progressively increase from the headwaters to the lower reaches of the Colorado River and are caused by two different processes (1) salt loading, and (2) salt concentrating. The first is caused by both natural and manmade sources, increasing the salinity by increasing the total salt load of the river. By contrast, salt concentrating effects are largely produced by removing and consuming relatively high quality water or by evaporation in reservoirs and thereby concentrating salts into a lesser volume of water.

The present and expected future increases in the salinity of the Colorado River system have been presented in Chapter II, Section A.5, of this volume. As discussed therein, water use is progressively impaired as salinity concentrations rise, and at threshold levels outlined below, the water is no longer acceptable for certain uses. In the Colorado River Basin, the expected future salinity concentrations will only marginally impair in-stream uses such as recreation, hydroelectric power generation, and propagation of aquatic life (23).

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In the lower Colorado River, salinity concentrations have not reached the threshold levels for municipal, industrial, and agricultural uses. However, some impairment of these uses is now occurring and future increases in salinity will increase this adverse impact.

Investigations of the potential impact of future salinity levels reveal that only small effects on water uses could be anticipated in the Upper Basin. Water in the Upper Basin will be suitable for most purposes even after the projected increases in salinity take place. Increases in salinity from activities in the Upper Basin will take place if the water is diverted for industrial or other uses, including agricultural. Diversion of the relatively low-salinity water in the Upper Basin for an oil shale industry will decrease the dilution of the higher salinity water that enters the system below the oil shale area. Diversion of the same amount of water for agricultural purposes could increase the salinity, both because the return flow will be concentrated by evapotranspiration and because it will contain minerals and fertilizers leached from the soil.

Domestic use comprises the major utilization of municpial water supplies. Both municipal and industrial water users incur increasing costs as salinity levels increase above 500 mg/1, the maximum level recommended by the U.S. Public Health Service for drinking water standards. Total hardness, a parameter closely related to salinity, is of primary interest in assessing water quality effects on these uses. Increases in hardness lead to added soap and detergent consumption, corrosion and scaling of metal water pipes and water heaters, accelerated fabric wear, added water softening costs, and in extreme cases, abandonment of a water supply. By most hardness measures, raw water supplies derived from the Colorado River at or below Lake Mead would be classified as very hard.

Boiler feed and cooling water comprise a major portion of water used by industry in the Basin. Mineral quality of boiler feed water is an important factor in the rate of scale formation on surfaces, of corrosion in the system, and quality of produced steam. In cooling water systems, resistance to slime formation and corrosion are affected by mineral quality. The required mineral quality levels are maintained in boiler and cooling systems by periodically adding an amount of relatively good quality water (make-up water) and discharging from the system an equal volume of the poorer quality water (blowdown).

Salinity effects on agricultural uses are manifested primarily by limitations on the types of crops that may be irrigated with a given water supply and by reductions of crop yields as salinity levels increase above 500 to 700 mg/l. Other conditions being equal, as salinity levels increase in applied irrigation water, salinity levels in the root zone of the soil also increase. At levels above 1,000 mg/l, the types of irrigated crops grown may be limited, and at levels exceeding 2,000 mg/l, only certain crops can be produced by application of highly specialized and costly techniques.

Because different crops have different tolerances to salts in the root zone, limits are placed on the types of crops that may be grown. When salinity levels in the soil increase above the threshold levels of a crop, progressive impairment of the crop yield results. The primary means of combating detrimental salinity concentrations in the soil is to switch to salt tolerant crops or to apply more irrigation water and leach out excess salts from the soil if adequate drainage is available.

The previously described physical impacts of salinity upon consumptive uses of water can be translated into economic values by evaluating how each user might alleviate the effects of salinity increases. Municipalities could: (1) do nothing and the residents would consume more soap and detergents, or purchase home softening units; (2) build central water softening plants; or (3) develop new, less-mineralized water supplies. Industrial users could combine more extensive treatment of their water supply with the purchase of additional make-up water, based upon the economics of prevailing conditions. The options available to irrigation water users are governed by the availability of additional water. If the irrigator does nothing, he will suffer economic loss from decreased crop yields. If additional water is available, and subsurface drainage is adequate, root-zone salinity may be reduced by increasing leaching-water applications. The irrigator would incur increased costs for purchase of water, for additional labor for water application, and for increased application of fertilizer to replace the fertilizer leached out. If no additional water is available, the irrigator can increase the leaching of salts from the soil by applying the same amount of water to lesser acreage. This, of course, results in an economic loss, since fewer crops can be grown. Detrimental effects can be reduced, in some cases, by the addition of $CaSO_4$ to the water. The last option is to plant salt tolerant crops. An economic loss would usually occur, since salt tolerant crops usually produce a lower economic return.

The economic cost of salinity increases has been estimated by the Environmental Protection Agency (13). The yield-decrement method, which measures reductions in crop yield resulting from salinity increases, was selected to evaluate the economic impact on irrigated agriculture. For industrial use, an estimate of required make-up water associated with salinity increases was selected to calculate the penalty cost. Municipal damages were estimated by calculating the required additional soap and detergents needed.

The economic detriments due to the 1970 salinity levels of the Colorado River at Hoover Dam (760 mg/l) was estimated by the Environmental Protection Agency to be about $16 million annually (24).[1/] Oil shale development will not significantly add to the salinity detriment of the Colorado River due to salt concentrating for many years after development is initiated, assuming no return flows and that substantial amounts of ground water and water from the retorts and from upgrading are available for use as discussed in Part 3, above. Over time, ground water supplies will become

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1/ Based on salinity levels projected for the analysis. Actual present modified levels for 1970 is 745 mg/l and, therefore, the economic detriment is somewhat less than previously estimated.

depleted, and increasing amounts of surface water will need to be used. Eventually, the full 121,000 to 189,000 acre-feet per year may be obtained from surface supplies. Under these conditions, the salinity at Hoover Dam would increase by about 10 to 15 mg/l [1/] to 770 to 775 mg/l.

Based on the Environmental Protection Agency's analysis of the physical and economic impacts of salinity (23), salinity increases due to concentrating effects from oil shale development are expected to have only minor impacts on existing water users (municipal, industrial, agricultural, hydroelectric, recreation, and propagation of aquatic life). These impacts can be expressed in economic terms using EPA's economic disbenefit of about $67,000 annually for each milligram per liter increase in salinity. The total maximum economic cost associated with a 1-million-barrel-per-day industry (assuming consumption of 121,000 to 189,000 acre-feet per year) would range from about $670,000 to $1,000,000, an increase from 4 to 6 percent over the 1970 level of $16 million attributed to salinity detriments. Should oil shale development require the total 341,000 acre-feet potentially available (Part 2 above) the salinity increase at Hoover Dam would increase about 27 mg/l and the economic disbenefit would approximate $1,800,000, an increase of about 10 percent over present levels to 770 to 786 mg/l.

Salt concentrating impacts represent a minimum expected impact, since salt loading due to return flows of water will be additional. These returns could come from disturbance of the ground water due to reinjection of excess water, leaching of shale disposal piles,

1/ Includes an estimated 0.4 mg/l due to the salt loading from sewage facilities (See Section H.1d below).

accidental release of saline mine waters, with return flows of water having salt levels higher than receiving waters. Other impacts could occur from accidental release of industrial wastes such as oil, byproduct storage pile leaching, off-site construction, and the release of organic materials to aquifers as the consequence of in situ processing. The cumulative long-term effect on water quality that might occur cannot be totally quantified; however, it is possible to postulate hypothetical examples that present an order-of-magnitude estimate of a number of potential impacts. These are presented below.

5. Potential Impacts on Water Quality - Two Hypothetical Examples

The quality of water in the oil shale regions could be affected by several factors as a result of oil shale operations. Even though there has been no actual experience with large-scale oil shale operations, one can anticipate several probable practices and associated impacts that might result from these operations.

One of these practices (as discussed in Volume III, Chapter III) is the disposal of large quantities of processed oil shale in existing canyons. There is the possibility of disposal-pile failure, that is, "falling in" of the face of the pile that will facilitate erosion and consequently increase salt loadings and silt loading of runoff water. Entrance of these waters into existing creeks and rivers will have adverse effects. These adverse effects will be compounded by the type of flash flooding that occasionally occurs in the region.

Another practice that could have potential water quality impact in the region is the possible impoundment of waste water in evaporation ponds. Failure of pond dikes could lead to dispersal of the impounded water. The salt-loaded waters and silt due to erosion could run off into creeks and rivers reducing the quality of the existing water.

While there are no data for assessing the absolute impacts from any of the above practices, estimates can be made to illustrate the potential maximum water quality impacts that can arise. The following sections provide estimates for the two possible conditions of (1) disposal-pile failure and flash flooding, and (2) failure of evaporation ponds.

a. Failure of Disposal Pile

After the spent shale has been transported to a disposal site, provision must be made to create a mechanically stable disposal pile to prevent erosion and/or leaching. Chapter I, Section D.1 detailed the current state-of-the-art that pertains to the management of solid wastes. The present section examines the possible adverse effects that could increase salt and sediment loading to the Colorado River system as a consequence of this disposal operation.

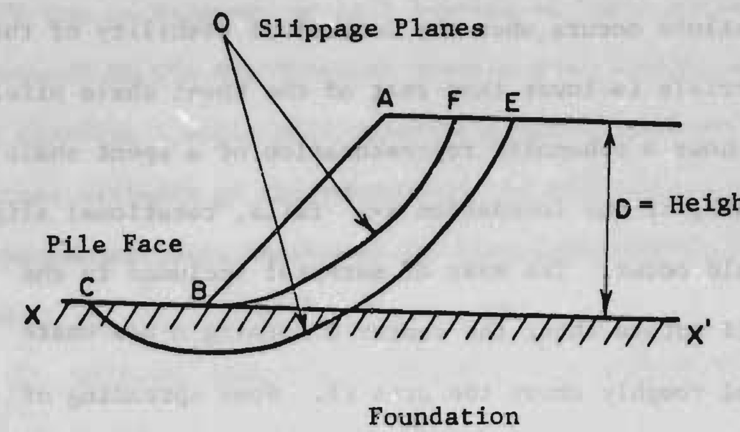
The disposal piles at the open end of a disposal canyon (Volume 1, Chapter I, and Volume III, Chapter III) must be engineered in a manner that will produce a mechanically stable surface because failure of the foundation will increase the probability that sediments and salts leached from such materials will reach local streams. The discussion in Volume I, Chapter I, Section D.1, while generally discussing the problems, did not quantitatively discuss potential water-quality impacts. The discussion that follows considers those factors that can lead to slope failure of a disposal pile.

The most common type of slope failure is rotational shear. This type of failure occurs when the mechanical stability of the foundation materials is lower than that of the spent shale pile. Figure III-10 shows a schematic representation of a spent shale disposal pile and, if the foundation x-x^1 fails, rotational slip of the face would occur. The mass of material included in the area ABCEA would rotate about the center 0 forming a new waste pile distributed roughly above the area CB. Some spreading of the materials to the left and some to the right of CB would be expected as the top of the pile crests and the moving material comes to equilibrium.

A second type of mechanical failure is also possible. Assume the height D is increased to a point where the angle ABX does not provide slope stability. If the spent oil shale is sufficiently rigid, the material under the area ABFA would fail and be deposited at the base of the new slope BF, fanning out to the left of point B.

During the buildup of the waste material to its design height, some erosion will occur. As indicated in Chapter I, Section D.1, this material can be trapped by a small retaining pond and then returned and used in subsequent disposal operations. Of particular

Figure III-10.--Schematic Representation of a Spent Oil Shale Pile.



Source: (10)

concern during the active buildup of a disposal pile is the occasional flash flood common to the oil shale area. The probable magnitude of the potential sediment and salinity problems associated with such an event on both local waters and on larger receiving rivers is considered below.

The principal adverse effects of stability failure would be the relocation of the open end of the disposal pile. Subsequent effects due to sediment or salt loading of local streams will be illustrated by the hypothetical example that follows which considers flash flooding. While this assessment establishes an order-of-magnitude estimate of the potentials, it must necessarily be based on experimental data which has not been confirmed by actual observation.

(1) Rainfall Intensity - The greatest concern for erosion potential in the oil shale regions is not with the typical snow or rain that occur throughout the year but with the occasional rainfall intensities which may cause flash flooding. Jennings (25) indicated the maximum point rainfall for Grand Junction, Colorado, for the period 1900 to 1961, was as shown in Table III-8. Severe flood damage in the vicinity of Rifle, Colorado, in August 1930 was caused by a storm reported to total 2.18 inches over a 2-hour period. However, these towns are in low lying valleys, and storm intensity is frequently greater at higher elevations.

The data presented in Table III-8 is not representative of the whole oil shale region but does represent an extended period of rainfall intensity measurement in the Colorado basin. Intense

Table III-8.--Peak Rainfall Intensities For Grand Junction, Colorado. (1900 - 1961)

Period (Minutes)	Amount (Inches)	Date
5	0.39	August 22, 1914
10	0.54	August 22, 1914
30	0.66	August 5, 1918
60	0.92	September 2, 1938
360	1.41	September 2, 1938
24 hr 1,440	2.50	November 17, 1908

Source: (25)

rainfall as high as 4.7 inches per hour (12 times the maximum rainfall for a 5-minute measuring period) has been recorded, but intensities of this size are usually not sustained for long periods. The data also show that the high-intensity storms occur largely in August and September.

A maximum 6-hour storm is often considered for planning purpose. U.S. Weather Bureau Technical Paper No. 40 (26) gives a probable maximum 6-hour rainfall for a 10-square-mile-area of 10 to 12 inches for the region and is based on a set of hypothetical physical conditions. The 100-year maximum 6-hour rainfall is given as 2.5 to 3.0 inches or approximately 4 times less than the probable maximum. Probability charts (27) for May to October indicate that a 6-hour rainfall would total 1.9 inches only 1 percent of the time. For the analysis given below, a rainfall intensity from 0.3 to 0.5 inches per hour was assumed for a 6-hour period (1.8 to 3.0 inches of water total). This intensity was selected to assess the possible impact due to heavy but infrequent amounts of rainfall.

(2) Sediment and Leachable Material - In this analysis, a canyon typical of those described in Volume III, Chapter IV, Section A.2, was assumed to be used as a disposal site. Small retention ponds will normally be employed to trap materials eroded by normal rainfalls. However, in the example given below, it is assumed that all impoundments fail due to the severity of the rains. The amount of leachable material from spent shale depends upon the raw material and the process used in retorting. The

maximum amount of leachable material was experimentally determined as 1,120 mg/100 gm from spent shale retorted by the TOSCO process and 970 mg/100 gm from spent shale retorted by the gas combustion process (4 , p. 46). Converting this to mg/ft^3 using a density of 100 lb/ft^3 (Volume I, Chapter I, Table I-5) indicates about 500,000 mg/ft^3 of leachable material for TOSCO processed shale and about 440,000 mg/ft^3 for gas combustion processed shale.

Runoff of rainwater or melted snow from the disposal site would leach the spent shale to indeterminate depths. Table III-9 gives amounts of material that could be removed by leaching if the spent shale pile were leached to specific average depths.1/ Runoff from the spent shale will also contain suspended solids. Experimental values of sediment yield for varying rainfall amounts are presented in Table III-10. The range of values given in the table is used to obtain a reasonable estimate of the sediment yield for rainfall intensities considered in the two hypothetical examples. The volume of water for a specific storm intensity over an area of 700 acres (the expected area of one spent shale disposal site) is given in Table III-11, assuming diversion channels are present so that no water except that falling on the pile leads to leaching or erosion.

(3) Expected Impact from Salts -In order to estimate the impact on water quality, a number of other assumptions must also be made. A storm of 0.3 to 0.5 inches per hour for 6 hours (an infrequent but possible occurrence) was chosen based on historical

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1/ Realistically, there will be channeling of the spent shale pile. This assumption above was used to simplify the calculations.

Table III-9.--Amount of material that could be leached from 700 acres of spent shale if it were completely leached to the depth shown.

Average Depth Leached (inches)	Material that could be leached from 700 acres (mg) TOSCO	Gas Combustion
2	2.5×10^{12}	2.2×10^{12}
4	5.1×10^{12}	4.5×10^{12}
6	7.6×10^{12}	6.7×10^{12}
8	10.2×10^{12}	8.9×10^{12}
10	12.7×10^{12}	11.2×10^{12}
12	15.2×10^{12}	13.4×10^{12}

Table III-10.--Sediment Yield as a Function of Rainfall.

Rainfall Intensity (in/hr)	Density (top 3 inches) (lb/ft^3)	Sediment Yield ($lb/ft^2/hr$)
0.54	86	.0150
0.46	86	.0067
1.00	86	.0143
1.70	86	.033
2.25	86	.083
0.94	86	.0484
0.40	101	.0062
1.20	101	.028
2.12	101	.0454
1.72	101	.0643

Source: 4, p. 61, and pp. 100-109.

Table III-11.--Volume of Water for Specific Storm Intensity.
(700 acres)

Total Rainfall (inch)	Volume of Water (gallon)	(acre/foot)
0.5	9.5×10^6	29
1.0	19.0×10^6	58
1.5	28.0×10^6	87
2.0	38.0×10^6	116
2.5	47.0×10^6	145
3.0	57.0×10^6	174
6.0	114.0×10^6	348

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data. To facilitate the calculations, all runoff from this storm was assumed to flow into nearby streams. Prototype Site C-b (Volume III, Chapter II) was selected as a typical location where runoff may flow into Piceance Creek.

The necessary factors needed to make the estimate of impact on water quality are (1) amount of runoff from an area of 700 acres, (2) total weight of leachable material if this 700 acre site is totally leached to some average depth, (3) combination of these two ranges of values to indicate the average salinity of this runoff, (4) salt load and stream volume of Piceance Creek, and (5) estimate of runoff from the drainage area due to this storm and the salinity of this runoff water.

For a rainstorm of 0.3 to 0.5 inches per hour lasting 6 hours, the amount of runoff from the spent shale area of 700 surface acres would be from 34 to 57 million gallons of water (104 to 174 acre-feet). If the top 2 to 4 inches of spent shale is totally leached, the amount of dissolved solids contained in this volume of water would be from 2.2×10^{12} to 2.5 to 10^{12} mg from the top 2 inches or from 4.5×10^{12} to 5.1×10^{12} mg from the top 4 inches, depending upon the method used to process the shale.

Assuming uniformity of runoff and uniformity of dissolution of leachable material, the salinity of the runoff water was calculated; e.g., (1) for a storm of 0.3 in/hr for 6 hours totally leaching the top 2 inches of spent shale, the salinity of the runoff water would range from 17,000 to 19,500 mg/1; and (2) for a storm of 0.5 in/hr for 6 hours totally leaching the top 4 inches of spent shale, the salinity of the runoff water would range from 21,000 to 24,000 mg/1.

From estimates of the volumes of water for (1) the average flow of Piceance Creek, (2) runoff from the spent oil shale disposal site, (3) runoff from the drainage area, and (4) the estimated total salt load of each, the possible salinity range of the discharge at the mouth of Piceance Creek was estimated. Therefore, (1) for a storm of 0.3 in/hr lasting for 6 hours over the whole drainage area, and with total leaching of the top 2 inches of the 700 acre spent shale disposal site, the salinity was calculated to be 220 mg/l, and (2) for a storm of 0.5 in/hr lasting for 6 hours over the whole drainage area, and with total leaching of the top 4 inches of the 700 acre spent shale disposal site, the salinity was calculated to be 193 mg/l. Under these storm conditions, the water quality of Piceance Creek would not be greatly affected by leaching the minerals contained in the spent shale area. In general, a heavy storm would increase the flow of water and tend to reduce the dissolved-solids concentration. However, for this example, the total salt load would be increased by 2,400 to 5,500 tons. (Calculations supporting the above conclusion are presented in Appendix A to this chapter.)

Weathering and leaching of the shale piles will occur over long periods of time. The net impact on the region's water resources due to such long-term erosion is uncertain since sediment and minerals are currently being released to local waters due to natural forces. Over the relatively short term (decades), the spent shale piles, if maintained in a mechanically stable condition, may contribute somewhat lower salt/sediment loads than are now contributed to the region's river system by the unconsolidated materials typically found on canyon floors. Over a longer period (several decades), the same area would revert to the geologic weathering patterns more typically found in the region. The net change from a possible short-term benefit to a longer interval that is similar, or perhaps worse than that now existing, cannot now be quantified.

(4) Expected Impact from Sediments - Another impact on the quality of regional creeks and streams could come from sediment Transported from the spent oil shale disposal site to them.

Using the rainfall intensity data of subsection (1) above, it was assumed that for a rainfall intensity of 0.3 to 0.5 in/hr from .004 to .02 pounds of sediment per square foot per hour would be eroded from the spent oil shale piles (see Table III-10). The amounts of sediment washed to Piceance Creek would be 0.2 acre-foot for a storm of 6 hours and 0.3 in/hr rainfall, and 0.8 acre-foot for a storm of 0.5 in/hr for 6 hours.

The sediment yield for the drainage area is 0.2 to 1.0 acre-foot/mi^2/yr (28, map opposite p. 52). The total annual sediment due to erosion from the total drainage area (629 sq. mi.) would be (0.2 to 1.0) x (629) or from 126 to 629 acre-feet/year.

The sediment yield from the drainage area would probably be much higher than 1.0 acre-foot/mi^2/yr for a 6-hour storm having an intensity of 0.5 in/hr. But even if it is not, the 0.2 to 0.8 acre-foot of sediment from spent oil shale amounts to only 0.03 to 0.1 percent of the total sediment discharge into Piceance Creek based on 1.0 acre-foot/mi^2/yr sediment yield from the drainage area. Thus, the sediment washed from spent oil shale to nearby streams would have adverse impacts near the disposal site, in this example Piceance Creek, but would not be expected to have significant impact downstream when related to impacts from existing sediment discharge under the assumed storm conditions.

The sediment yield range of .004 to .02 $lb/ft^2/hr$ used in this analysis may not be totally applicable because these values were measured on a 0.75-percent slope. Although most of the surface of a 700-acre spent shale pile could be graded to this slope, or even to a negative slope, the slope of the pile face would be much greater. Thus, channeling and head cutting could occur at the face which, over time, would lead to larger amounts of sediment reaching local streams than were calculated. The impacts on local streams would therefore be correspondingly increased.

Possible impacts from minor constituents that are dissolved in the runoff from spent oil shale should not be significant. Concentrations of the following minor constituents in leachate from spent oil shale are less than levels considered safe for drinking water: Al^{+++}, Ba^{+++}, Cu^{++}, Cr^{+6}, Fe^{+++}, Mn^{++}, Pb^{++}, Zn^{++}, Br^{-}, Cl^{-}, CO_3^{-2}, F^{-}, I^{-}, NO_3^{-}, and PO_4^{-3} (16, p. 69). The major constituents of dissolved solids are Na^{+}, Ca^{++}, Mg^{++}, K^{+}, SO_4^{-2}, HCO_3^{-}, and Cl^{-}. Concentrations of Cl^{-} and K^{+} are much lower than the other major constituents.

The average estimated time required to fill a 700-acre disposal area to a depth of 250 feet is 5 years (Volume III, Chapter III). At the end of this time, the spent oil shale would be covered with natural soil, and revegetation would be initiated to provide surface cover. The disposal site would be reduced as a significant source of dissolved solids and sediments, but probably not completely eliminated due to natural erosion and leaching over extended periods as described above.

b. Failure of Evaporation Pond

The acreage necessary for an evaporation pond can be calculated assuming (1) the maximum amount of excess low quality water, (2) no runoff from surrounding areas to the pond, (3) no appreciable seepage through the bottom or sides of the pond, and (4) the water level in the pond remains constant. From these assumptions, it follows that the sum of water volume that is excess to the mining operation and precipitation that falls on the pond must equal the amount of water lost due to evaporation. Average evaporation rates for the oil shale region are given below:

Altitude (ft)	Evaporation Rate (ft/yr)
4,000	4.6
5,000	4.0
6,000	3.5
7,000	3.25

Source: Bureau of Reclamation

The maximum amount of excess water of poor quality is expected from an underground operation near the center of the Piceance Creek Basin using a mine development plan that requires dewatering of both the upper zone aquifer and the saline zone aquifer. A 50,000-barrel-per-day underground mine may produce about 250,000 acre-feet over a 30-year period with the annual amount of excess poor-quality water decreasing from 16,000 acre-feet per year for the first few years to 5,000 acre-feet for the last few years. The amount of excess water lost by evaporation would depend on the altitude and precipitation, which fluctuate widely across the region, and also on the size of the pond. The maximum acreage necessary for the evaporation pond for a 50,000-barrel-per-day complex as a function of these parameters is given below:

Maximum Acreage Necessary For An Evaporation Pond

Altitude (feet)	Rainfall (inches/year)		
	10	15	20
4,000	4,200	4,800	5,500
5,000	5,000	5,800	7,000
6,000	5,900	7,100	8,900
7,000	6,500	8,000	10,600

The size of the evaporation pond needed to dispose of the maximum expected quantity of poor-quality water indicates that other methods of disposal will probably be employed, e.g., treatment and surface release of high-quality waters or reinjection. Each of these would have its own range of potential impacts as discussed in Part 3.b. above. Large evaporation pond sites are not believed to be available in the area where the water is expected to be produced, i.e., the Piceance Creek Basin. However, if evaporation ponds are used, they must be located in an area where failure would not introduce saline water to local streams. Any release to the normally low-flowing streams and creeks in the oil shale region would have major adverse impacts. These impacts would be similar to a heavy rainfall with localized scouring, downstream flood damage, and destruction of biota and flora in the channel. The impact on any fish population will be high if the concentration of certain minor constituents, e.g., fluoride, nitrate, phosphate, and heavy metals, is above a few parts per million, and every such accident would constitute an increase in the total salt load at Hoover Dam.

6. Miscellaneous Impacts on Water Quality

Although salinity is considered to be the most serious water quality problem in the Colorado River Basin, there are a number of other water quality problems of varying degrees of significance which warrant discussion. The following sections discuss the most significant sources of water quality degradation and the effects of such degradation on water uses as measured by various parameters.

a. Municipal Wastes

Municipal wastes are described as those liquid-carried wastes of domestic and service industry origin. Within the Colorado River Basin, the majority of the discharges from waste water treatment plants enter the river system and are the primary sources of bacteriological and organic pollution. Most of the municipal waste sources in the basin receive secondary treatment plus disinfection, which is the minimum degree of treatment required by the basin states in populated areas. However, scattered, low-density settlements may result in widely scattered local point sources which are difficult to control.

Compliance schedules have been established for municipalities whose waste discharges are not meeting the water-quality standards set by the states. At the present time, pollution from municipal waste sources (except for salt as discussed in Section H.1.d. below) is confined to those reaches of stream immediately downstream of the waste effluent, and measures are being taken or have been planned for the control or abatement of pollution from these sources.

With the population increases expected from oil shale development, increased amounts of salts, nutrients, and organic material entering surface water may be expected which could lead to localized eutrophication and changes in the aquatic ecosystem. Although increased capacity of municipal treatment facilities should reduce much of this to a minimum adverse impact in localized areas, some will still escape control and be cumulatively added to the basin system. The rate and amount will depend upon the population increase.

b. Industrial Wastes

Industrial wastes are defined as those spent process waters, cooling waters, wash waters, and other waste waters associated with industrial operations. The pollutants derived from industrial wastes other than salinity are toxic materials; oils and grease; floating materials; oxygen-demanding substances; heat; color-, taste-, and odor-producing substances; and bacteria.

The pollution problems associated with the discharge of industrial wastes in the Colorado River system have been generally confined to local reaches of stream. Industrial wastes may reach the Colorado River system as a result of oil shale activity. Although the amount and distribution of such wastes cannot be estimated, if wastes are introduced in sufficient quantities, the dissolved-oxygen content of streams will be decreased, leading to a lower life-sustaining capacity of the stream, lower aquatic populations due to disease, decrease in esthetics due to floating materials such as oil and grease, tainted water or aquatic species due to the presence of odorous substances, death of aquatic species due to toxic materials, and overall lowering of water quality. As industrialization spreads, the effect will be cumulative.

c. Dissolved Oxygen

As indicated above, the dissolved-oxygen concentration is a measure of the water capacity to support life and assimilate organic wastes. The records show that the dissolved-oxygen concentrations in the Colorado River Basin are generally above established standards. However, a marked reduction in the concentration can be found during the summer months downstream from some municipal and industrial discharges and in some streams with very low flows. A 1966 investigation indicated that there might be a wide diurnal variation in the oxygen concentration in some reaches because of the large amount of algae in the streams with oxygen saturation being reached during a sunlit day and a minimal concentration occurring at night when oxygen is used by the plants. Decreases in dissolved oxygen reduce the capacity of streams to support life. The amount of this reduction is dependent upon the extent of the decrease in dissolved oxygen, a factor which cannot now be estimated. However, there will be some effects on the dissolved-oxygen concentrations of creeks and rivers in the oil shale region as a result of the oil shale operations.

d. Temperature

The Colorado River Basin water temperatures vary widely, reaching the highest levels during the summer months when they vary from near freezing in the high mountains to above 90°F in the lower reaches. Warmer temperatures may increase the rate of growth and the decomposition of organic matter and of chemical reaction, resulting in bad odors and tastes, and also decrease the dissolved-oxygen concentration available to sustain a fishery.

Changes in water temperature in the basin result primarily from natural climatic conditions. The large reservoirs, however, may affect the stream temperatures for a considerable distance below the reservoir. Temperature records indicate that Flaming Gorge Reservoir has little or no effect on winter temperatures but cools the summer temperatures of the Green River up to 5°F at the Green River, Utah, station. Navajo Reservoir appears to have no effect on the temperatures of the San Juan River at the station near Bluff. Lake Powell appears to warm the winter temperatures of the Colorado River at the Grand Canyon station by up to 10°F and cool the summer temperatures by about the same amount.

Thermal springs, waste-water discharges, and irrigation return flows may increase the temperatures in the receiving water, but added heat is usually dissipated in a relatively short distance from the source. Flow depletions and changes in stream channel characteristics may also increase the effects of natural climatic conditions causing cooler or warmer water temperatures.

Temperature increases due to municipal and industrial waste discharges have been minimal; however, the construction of thermal power plants in the basin with a return of the cooling water to the streams or reservoirs presents a potential for temperature increases. These effects from the oil shale operations would be localized but could be significant for trout waters as discussed under "Fauna," Section E, below. Considering the vastness of the Colorado River system and inherent wide normal temperature variations, thermal effects are generally expected to be of little consequence outside localized areas with the significant variable being plant location. As industrialization spreads, the results will be cumulative for the river system.

e. Heavy Metals

Various heavy metals such as copper, lead, zinc, iron, manganese, and arsenic are found in the water of the basin. These vary from trace amounts to potentially hazardous levels. The presence of these heavy metals, generally contributed by drainage from active and inactive mining operations can cause decreases in aquatic population if they reach sufficient concentrations. At very low levels, they may not be fatal but can be concentrated by some species, thus leading to upsets in the food chain. Ingestion could lead to contamination of some fish species making them unsafe for human or animal consumption. As indicated above (Section C.5.a(4)), little heavy-metal contamination from leaching of spent oil shale residue is expected, although other potential sources are catalysts and chemicals used in oil upgrading and gas processing sections of the shale oil plants. These chemicals and catalysts consist of iron catalysts, iron oxide, char, and monoethanolamine (MEA). All are solids expect for MEA which is a liquid. MEA is water soluble whereas the others are only very slightly soluble (part per million levels). The total amount of these wastes which may be buried in the spent shale piles is 248 tons per year for a 50,000-barrel-per day-operation of which 50 tons would be MEA (Chapter I, Section D.5.d.). Although the amount of waste materials is small compared to the amount of waste materials from a 50,000-barrel-per-day plant (248 tons as compared to 27,000,000 to 30,000,000 tons), such wastes may cumulatively build over time. Short-term impacts should be minor, but over time (decades and centuries) weathering and erosion of the piles would probably expose such wastes to runoff waters. The long-term impact of such weathering is unknown and will depend on the physical state of the wastes after being buried for long periods, the resulting concentration of the metals in runoff waters, and the dilution of these concentrations as they reach local streams. Leaching action, however, could result in reduced aquatic populations. The management of these wastes is described in Chapter I, Section D.4.d.

f. Toxic Materials

Toxic materials are contributed to a stream through industrial and agricultural operations. Limited long-term monitoring at four surveillance stations on the Colorado River has detected low levels of pesticide residues--DDD, DDE, DDT, dieldrin, and endrin. In recent years, several fish and bird mortalities attributed to these residual pesticides have occurred downstream of and in irrigation drains along the lower Colorado Basin. It is expected that there will be some small increase in the amount of toxic materials that will find their way into the water resources of the oil shale region. These increases could result from increased, uncontrolled use of pesticides by an expanding population in the region and possibly from oil shale operations. The effect on water quality will be higher levels of persistent hydrocarbon in the river system. These hydrocarbons will accumulate in the food chain resulting in lower reproductive rates for some wildlife as discussed in "Fauna" (Section E).

g. Bacteria

A possibility exists for bacterial pollution of water resources from the increased population associated with the oil shale development due to increased demand on the treatment facilities. The degree of the effects on public health will depend upon the rate at which treatment facilities are enlarged or improved to handle this increased load. Although this cannot be projected at this time, bacteriological pollution can limit the use of water due to the increased economic costs of disinfection and waterborne diseases such as typhoid, infectious hepatitis, salmonellosis, and others. In those cases where it exceeds the criteria set for body-contact recreation, it results in the closure of swimming areas. With high coliform counts (an indicator of the degree of pollution), the use of water as a public water supply is impaired.

h. Sediments From Erosion of Off-Site Construction Activities

It is estimated that approximately 30,000 acres of land will be required for utility rights-of-way, town site expansion, and transportation networks (Chapter III, Section B.3) for a 1-million-barrel-per-day shale oil industry. During construction, and for some short period thereafter, these areas would be subject to higher than normal erosion which could contribute some sediments to local streams. The normal sediment yield for the oil shale region is 0.2 to 1.0 acre-feet per square mile per year (Chapter III, Section C.5.a(4)). For this 30,000 acres, the normal range of sediment yield would be 9 to 48 acre-feet per year as compared to 126 to 629 acre-feet per year from a typical stream like Piceance Creek. During construction, the erosion rate would be higher, yielding greater amounts of sediment than this range. Utility corridors would be over rough terrain and not all of the sediments would reach any one stream. Similarly, the erosion from town site expansion and development of transportation networks would increase sediment loading of streams in very localized areas. The effects of this sediment loading on aquatic life are discussed in Fauna (Section E).

7. Summary Analysis: Cumulative Impact on Water Resources

A comprehensive effort to assess past trends in water use and to project future trends was completed by the Water Resources Council in 1968 (29). Regional as well as national assessments were made, including both the Upper and Lower Colorado Regions. More recently, in 1971, the Environmental Protection Agency has focused attention on water quality in the Colorado River Basin (30), drawing upon extensive baseline data that have been developed over many decades by the Geological Survey and the Bureau of Reclamation. Additionally, the National Water Commission has now completed their charge established by law (31) to study virtually all water problems, programs, and policies in the context of their relationship to the total environment. These studies provide the general framework against which the impact of oil shale development may be assessed.

Oil shale development will significantly change the water demand-supply balances that currently exist in the oil shale regions of Colorado, Utah, and Wyoming. In the preceding analysis, conditions have been chosen to emphasize the range of conditions that may be encountered. Oil shale mining may be hampered by ground water in Colorado where large volumes of water, excess to immediate needs, may result from mine dewatering. Conversely, mines may be essentially dry, as is likely in Utah and in some locations in Colorado.

Oil shale development will impact on water supplies and on water quality. The nature and severity of these impacts will change over time. During the initial years of development, large amounts of good quality ground water from mine dewatering may be available to support operations. The salinity of such waters may increase as withdrawal proceeds causing changes in the way it must be used in the operations.

The removal and use of ground water as a result of mine dewatering could lead to salt loading and other impacts. Such withdrawal would decrease the flow of water wells and some springs within the area around the mine and would change the points of discharge. Since ground water withdrawal is expected to exceed the recharge, over time ground water supplies in the Piceance Basin of Colorado will become significantly reduced. If not augmented by the release of good quality water from the mine, fish habitat in, and vegetation adjacent to, local surface streams may be lost or reduced with a corresponding reduction in plant and animal populations. Such pumping would have adverse effects on present surface supplies and, over time, ground water withdrawal could interfere with existing water rights in the Piceance Basin. Eventually, increasing amounts of surface water will be consumptively used which will intensify competition for available regional supplies. Thus, surface waters would need to be diverted for use in all three States. Municipal and industrial use in the Upper Basin would eventually assume a larger role.

Increased municipal and industrial use could at some time cause a shift away from irrigated lands. Adequate amounts of surface water are potentially available (341,000 acre-feet) to fully support the 1-million-barrel-per-day scale of operations which is expected to require from 121,000 to 189,000 acre-feet of water per year. These demands may be higher or lower depending on process contingencies and other variables. Development beyond the 1-million-barrel-per-day level is possible but, at some point, water availability could place a limitation on the ultimate size. If availability of, or competition for, water supplies limits oil shale development, attempts to justify augmentation may intensify.

The impacts of such a complex industrial development cannot be precisely quantified although reasonable judgments can be made concerning possible adverse effects. If the water required to support

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a 1-million-barrel-per-day industry were withdrawn totally from surface supplies, salinity would increase due to the concentration of salts in the remaining small quantity of water. The most likely range of salinity increase at Hoover Dam due to consumptive use at the 1-million-barrel-per-day level is estimated at 10 to 15 mg/l over the current (1970) level of 760 mg/l. This increase in salinity would cause an economic detriment in the Lower Colorado Basin estimated to range from $670,000 to $1,000,000 per year. Under more extreme water demand conditions, e.g. assuming consumption of all the surface water potentially available (341,000 acre-feet per year), the salinity would increase by 27 mg/l and the economic disbenefit would approximate $1,800,000.

In addition to these salt concentrating impacts from the consumptive use of surface water, salt loading would also increase the salinity in the Colorado River System and at Hoover Dam. The potential sources of this additional salinity increase include leaching of spent shale both during waste pile buildup and after revegetation; reinjection of mine water and upward movement and surface discharge of saline waters; accidental release of low-quality mine water, including failure of evaporation ponds; and any return flows of saline water. Additional impacts on water quality could be caused by accidental spillage of processing effluents, chemicals, and waste products.

A hypothetical example has been given to estimate the amount of dissolved salts from leaching of a spent shale pile. Total leaching of the top 4 inches of a typical 700-acre spent shale

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site due to a heavy storm would not significantly change the salinity of local streams such as Piceance Creek, although the total salt load of the Colorado River system would be increased by 2,400 to 5,500 tons. After completion of the disposal pile and revegetation, leaching will still occur but the rate is uncertain. Eventually, the spent shale piles would revert to geologic weathering patterns typically found in the region. In addition, chemical and other waste materials that may be buried in the disposal piles contain a potential for long-term environmental problems due to the introduction of very low concentrations of such materials into local waters by leaching, but their impact is uncertain.

Injection of excess mine waters has been considered in this analysis as a possible means of water management in Colorado. Such injection will raise water tables in the area of injection which may increase local surface flows and could increase the upward movement of waters from the leached zone aquifer to the upper zone causing increased discharge of salts to local streams. Additionally, fluorides and other ions contained in the waters of the leached zone aquifer (Chapter II, Section B.5.b) will continue to discharge to local streams, but the concentrations, rates, and points of discharge of such waters may change due to changes in the real pressure distribution. The impact of this will depend upon the rate of discharge and the dilution of such ions by local streams and cannot now be estimated.

Any release of large quantities of low quality mine water to local streams, including evaporation pond failure, could temporarily, but severely, impact these waters with a consequent loss of aquatic life.

Accidental spillage of oil, processing effluents, or chemicals are likely over time, but should be infrequent and scattered. In situ processing could release organic materials into ground water. If such materials reach local surface waters in sizeable amounts, depletion of fish populations and other aquatic life would be possible for some distance downstream.

Erosion of disposal piles (both during buildup and after revegetation) and of off-site construction areas such as utility corridors, transportation networks, and town site expansion will lead to increased sediment loads in local streams. During the buildup of a waste disposal pile, sediments washed from each such pile (under the storm conditions assumed in the analysis) would increase the annual sediment normally discharged to a stream like the Piceance Creek,but by less than 1 percent. Even if revegetation is successful, these spent shale piles would contribute sediments to local streams. Channeling and head-cutting due to natural erosion would occur over extended periods of time (decades and centuries) with increasing amounts of sediment and additional salts reaching local streams. Sediments from the construction of utility corridors and other off-site construction should be short-term and cause localized stream sedimentation.

Population increases will lead to larger amounts of sewage effluent. Most of this increase is expected to flow to sewage treatment facilities. Unless sewage treatment facilities are enlarged to handle the increase, localized adverse impacts on water quality are expected due to the increased amounts of organic materials and nutrients entering local streams. This could lead to localized eutrophication with subsequent changes in the ecosystem in these affected areas. All of the population increase will probably not occur in present municipalities. In this event, there will be scattered, uncontrolled point sources of sewage to local streams which could lead to areas of eutrophication in addition to those from municipalities.

The increased sewage load to streams could lead to increased bacterial pollution which may limit use of water in some areas for recreation, increase costs of disinfection, and increase the incidence of waterborne diseases.

Industrial wastes may reach the Colorado River system. These wastes could contain toxic materials, chemicals, oil and grease, heavy metals, and odorous substances. Introduction of these wastes into local waters could lead to lower aquatic populations, decreased esthetics, tainted water and fish, and lower water quality.

Heavy metals could also come from leaching of spent shale piles. These may come from waste chemicals and spent catalysts buried in the shale piles. The quantities of such materials would be relatively small. Short-term impacts should be minor, but over time the waste buildup and leaching will be cumulative. The long-term impacts are unknown, but in sufficient concentrations, such wastes could lead to reduced aquatic populations, both animal and plant.

The use of cooling towers could lead to localized thermal pollution. The major impact would occur where warmer waters were introduced to trout habitat leading to lower trout populations as discussed in "Fauna," Section E, of this chapter.

The major effect of introduction of industrial wastes, municipal wastes (primarily sewage effluent), heat, and bacteria to streams will be a decrease in the dissolved-oxygen content of the streams. Lower dissolved-oxygen concentrations result in lower life-support capacity of the streams.

Increased amounts of pesticides will probably reach the Colorado River system due to their use at plant sites and by the increased populace. Due to the persistence of such compounds, they would accumulate in the food chain causing lower reproductive rates for some wildlife species.

The growth of an oil shale industry, supporting facilities, and possible ancillary industrial development such as recovery of nahcolite or dawsonite would increase the possibility of adverse impacts on the water resources of the oil shale region. Uncertainties exist in assessing the full magnitude of these cumulative impacts, and such uncertainties can be eliminated only when sites are known, designs fixed, operational controls tested, and actual industrial growth experienced and monitored.

This analysis has reduced some of the uncertainties inherent in oil shale development to reasonable estimates of future adverse effects, but such things as the frequency of accidental spillage of materials such as oil and processing effluents, release of low quality mine water, and long term containment of the waste piles cannot now be quantified.

In all likelihood, such water management options as release of good quality water directly to streams, desalting and release, impoundment, and/or reinjection may all be employed to support a

1-million-barrel-per-day oil shale industry. While reinjection of excess mine waters appears to be a technically feasible means of water management, the ultimate impact on ground and/or surface water will require further analysis before such a system can be accepted as environmentally feasible.

The location of future operations within the three-State area of Colorado, Utah, and Wyoming will be an overriding factor in the cumulative impact from large-scale industrial development. It is believed that these cumulative impacts are controllable but the long-term effect of industrialization will cause a general decline in water quality, with the impacts focused most directly on the White and Green Rivers and, ultimately, the Colorado River system. The potential for serious degradation exists but, due to the uncertainties inherent in many of the individual impacts, the degree of severity cannot be quantified.

APPENDIX A

Supporting Calculations for Estimated Salt loadings and Silt loadings of Water.

(a) Maximum Expected Impact From Leachable Materials.- For a storm of 0.3 to 0.5 in/hr lasting 6 hours, the amount of runoff from the spent shale area of 700 surface acres would be from 34×10^6 to 57×10^6 gal (Table III-11). If the top 2 to 4 inches of spent shale are totally leached, the amount of dissolved solids contained in this volume of water would be from 2.2×10^{12} to 2.5×10^{12} mg from the top 2 inches and from 4.5×10^{12} to 5.1×10^{12} mg from the top 4 inches, depending on the methods used to process the shale (Table III-9).

Assuming uniformity of runoff and uniformity of dissolution of leachable material, the average salinity of the runoff water would be:

(1) For a storm of 0.3 in/hr for 6 hours totally leaching the top 2 inches of spent shale:

$$\frac{2.2 \times 10^{12} \text{ to } 2.5 \times 10^{12} \text{ mg}}{(34 \times 10^6 \text{ gal})\ (3.78 \text{ l/gal})} \quad \text{or about 17,000 to 19,500 mg/l}$$

(2) For a storm of 0.5 in/hr for six hours totally leaching the top 4 inches of spent shale:

$$\frac{4.5 \times 10^{12} \text{ to } 5.1 \times 10^{12} \text{ mg}}{(57 \times 10^6 \text{ gal})\ (3.78 \text{ l/gal})} = 21{,}000 \text{ to } 24{,}000 \text{ mg/l}$$

At the confluence of Piceance Creek with the White River, it is estimated that Piceance Creek delivers approximately 100 tons/

day (9.0×10^{10} mg/day) of dissolved salts to the White River (32, p. 82).

Streamflow records at the mouth of Piceance Creek yield an average flow of 17 cubic feet per second (35, pp. 352-354) or 4.2×10^7 liter/day. These two values of streamflow and total salt load give an average salinity of 2,200 mg/l.

Runoff from the drainage area must also be taken into account. For the drainage area of 629 square miles (Table II-21, Volume I, Chapter II) assuming 25- to 50-percent runoff to Piceance Creek, the total volume of water from the storm would be:

(1) 25-percent runoff:

$$(629\ mi^2)(640\ \frac{acre}{mi^2})(\frac{43,560\ ft^2}{acre})\ \frac{(.25)(1.8\ \text{to}\ 3.0\ in)}{(12\ in/ft)}\ (3.78 l/gal)(\frac{7.48\ gal)}{ft^3}$$

or from 1.9×10^{10} to 3.1×10^{10} liters.

(2) 50-percent runoff = $3.8 \times 10^{10} - 6.2 \times 10^{10}$ liters

The salinity of this runoff water from the drainage area can be estimated from experiments run on surface soil samples from the area. The salinity of filtrates from three soil samples was 0-100 mg/l (4, p. 72). Using the 100 mg/l value, the following amounts of dissolved solids would be transported to Piceance Creek by runoff: from 1.9×10^{12} to 3.1×10^{12} mg assuming 25-percent runoff and from 3.8 to 10^{12} to 6.2×10^{12} mg assuming 50-percent runoff.

Knowing the volumes of water for (1) average flow of Piceance Creek; (2) runoff from the spent oil shale disposal site; and (3) runoff from the drainage area, and with the estimated total salt load of each, the possible salinity range of the discharge at the mouth of Piceance Creek can be estimated using the following equation:

$$\frac{\text{Salt Load of Piceance Creek} + \text{Salt Load of Runoff from Spent Shale} + \text{Salt Load of Runoff from Drainage Area}}{\text{Volume of Water in Piceance} + \text{Volume of Runoff from Spent Shale} + \text{Volume of Runoff From Drainage Area}}$$

= Salinity of Discharge

Average Salt Load of Piceance Creek = 100 tons/day

$= 9 \times 10^{10}$ mg/day

Average Flow of Piceance Creek = 17 cubic feet/sec

$= 4.2 \times 10^{7}$ 1/day

Salt Load of Runoff from Spent Shale = 2.2 to 5.1×10^{12} mg

Volume of Runoff from Spent Shale = 34 to 57×10^{6} gal

= 1.3 to 2.1×10^{8} 1

Salt Load of Runoff from Drainage Area = 1.9 to 6.2×10^{12} mg

Volume of Runoff from Drainage Area = 1.9 to 6.2×10^{10} 1

Using these values the range would be:

$$\frac{9.0 \times 10^{10}\ \text{mg} + 2.2 \times 10^{12}\ \text{mg} + 1.9 \times 10^{12}\ \text{mg}}{4.2 \times 10^{7}\ 1 \quad + 1.3 \times 10^{8}\ 1 \quad + 1.9 \times 10^{10}\ 1} = 220\ \text{mg/1}$$

for a storm of 0.3 inches per hour rainfall lasting 6 hours over the whole drainage area and with total leaching of the top 2 inches of the 700-acre spent shale disposal site, and

$$\frac{9.0 \times 10^{10}\ \text{mg} + 5.1 \times 10^{12}\ \text{mg} + 6.2 \times 10^{12}\ \text{mg}}{4.2 \times 10^{7} 1 \quad + 2.1 \times 10^{8} 1 \quad + 6.2 \times 10^{10} 1} = 183\ \text{mg/1}$$

for a storm of 0.5 inches per hour rainfall for 6 hours over the whole drainage area with total leaching of the top 4 inches of the 700-acre spent shale disposal site.

If the storm occurred over only 10 percent of the drainage area, the volume of runoff water from the drainage area would be from 1.9×10^9 to 3.1×10^9 liters assuming 25-percent runoff and from 3.8×10^9 to 6.2×10^9 liters assuming 50-percent runoff. The amount of dissolved solids, assuming a 100 mg/l concentration, would be from 1.9 to 10^{11} to 3.1×10^{11} mg assuming 25-percent runoff and from 3.8×10^{11} to 6.2×10^{11} mg assuming 50-percent runoff. The range of salinity would then be:

$$\frac{9.06 \times 10^{10}\ \text{mg} + 22 \times 10^{11}\ \text{mg} + 1.9 \times 10^{11}\ \text{mg}}{4.16 \times 10^{7}\,\text{l} + 1.3 \times 10^{8}\,\text{l} + 1.9 \times 10^{9}\,\text{l}} = 1200\ \text{mg/l}$$

to

$$\frac{9.06 \times 10^{10}\ \text{mg} + 51 \times 10^{11}\ \text{mg} + 6.2 \times 10^{11}\ \text{mg}}{4.16 \times 10^{7}\,\text{l} + 2.1 \times 10^{8}\,\text{l} + 6.2 \times 10^{9}\,\text{l}} = 900\ \text{mg/l}$$

The calculations above, as compared to existing conditions of 2200 mg/l discharged from the Piceance Creek to the White River, indicate that the water quality of Piceance Creek would not be greatly changed by leaching of the minerals contained in the spent shale areas although the total salt load would be increased. A heavy storm would increase the flow of water and reduce the dissolved-solids concentration as it does now.

b. Maximum Expected Impact from Sediment

Another impact could come from sediment transported from the spent oil shale disposal site to nearby streams. Taking a range of values of sediment yield for spent oil shale from Table III-10 for rainfall intensity of 0.3 to 0.5 in/hr as 0.004 to 0.02 $lb/ft^2/hr$, the following amounts of sediment would be washed to Piceance Creek:

(1) $$\frac{\left(0.004\ \frac{lb}{ft^2\ hr}\right)(700\ \text{acres})(6\ \text{hrs})}{(100\ lb/ft^3)} = 0.2\ \text{acre-feet}$$

for a storm of 6 hours and 0.3 in/hr rainfall;

(2) $$\frac{\left(0.02\ \frac{lb}{ft^2\ hr}\right)(700\ \text{acres})(6\ \text{hrs})}{(100\ lb/ft^3)} = 0.8\ \text{acre-feet}$$

for a storm of 6 hours and 0.5 in/hr rainfall.

D. Impact on Air Quality

1. Introduction

With passage of the Clean Air Amendments of 1970, States were required to meet the National Ambient Air Quality Standards for 1975 by promulgation and enforcement of emission regulations. Emission regulations vary from State to State as well as from municipality to municipality. The degree of control required in an area may not be the same as that required in another area because of the existing air quality and the number and type of pollution sources. In some States, stringent emission regulations have been promulgated and enforced, which could restrict certain types of commercial or industrial expansion.

To comply with the Environmental Protection Agency's requirements, the States had to determine the degree of control required, by measuring the existing ambient air quality and determining the amount of reduction necessary to achieve the ambient air quality standards.

By January 30, 1972, each State had submitted to EPA an implementation plan for achieving the National Ambient Air Quality Standards by 1975. The implementation plans included the emission standards which were deemed necessary to achieve the selected ambient air quality goals.

A summary of the Federal ambient air quality standards for particulates, sulfur dioxide, nitrogen oxides, carbon monoxide, photochemical oxidants, and hydrocarbons appears in Table III-12.

Table III-12.--National Ambient Air Quality Standards.

	Primary Standard[1/] µg/m³	Primary Standard[1/] ppm	Secondary Standard[2/] µg/m³	Secondary Standard[2/] ppm
Sulfur oxides -				
annual arithmetic mean	80	0.030	60	0.021
24-hour concentration	365[3/]	0.137	260[3/]	0.091[3/]
Particulate matter -				
annual geometric mean	75		60	
24-hour concentration	260[3/]		150[3/]	
Carbon monoxide -				
8-hour concentration (mg)	10[3/]		Same as Primary	
1-hour concentration	40[3/]			
Photochemical oxidants -				
1-hour concentration	160[3/]	0.08[3/]	Same as Primary	
Hydrocarbons -				
(corrected for methane)				
3-hour concentration (6-9am)	160[3/]	0.24[3/]	Same as Primary	
Nitrogen oxides -				
annual arithmetic mean	100	0.053	Same as Primary	

1/ Primary Standards: Maximum permissible concentration to protect human health.

2/ Secondary Standards: Maximum permissible concentration to protect plants and wildlife.

3/ Not to be exceeded more than once a year.

A summary of ambient air quality standards adopted by Colorado, Utah, and Wyoming is given in Table III-13. It will be noted from a comparison of the State and Federal Standards that concentrations, averaging times, and methods of calculations vary somewhat. In addition, because of the variation in existing ambient air quality, between the three States and the desire to maintain high air quality, different emission standards have been adopted by each of these States that will apply to future oil shale processing facilities. In instances where State standards have not been set, or where State standards are less stringent than national standards (for example, Utah's standard for particulates), the national standards will take precedence.

Determining what constitutes "significant deterioration" of air quality and exactly how it can be prevented has recently become a public policy issue. It has not yet been resolved.

On June 11, 1973 the U. S. Supreme Court affirmed, by an equally divided court, the judgment of the U. S. Court of Appeals for the District of Columbia on November 1, 1973 affirming the decision on May 30, 1972 of the U. S. District Court for the District of Columbia to issue a preliminary injunction requiring the Administrator of the Environmental Protection Agency (EPA) to promulgate regulations "as to any State plan which he finds, on the basis of his review, either permits the significant deterioration of existing air quality in any portion of any State or fails to take the measures necessary to prevent such significant deterioration." On July 16, 1973 the Administrator of EPA proposed four alternative plans setting forth various approaches to defining and preventing "significant deterioration" in areas where air pollution levels currently are below the national ambient air quality standards. These proposals and additional background information are published at 38 F.R. 18986, July 16, 1973. Any final plan(s) promulgated by EPA with respect to the definition and prevention of "significant deterioration" would be incorporated into the proposed prototype oil shale lease program since the proposed Oil Shale Lease Environmental Stipulations already provide that:

> At all times during construction and operation, lessee shall conduct its activities in accordance with all applicable air quality standards and related plans of implementation adopted pursuant to the Clean Air Act, as amended...and applicable State standards. (Volume III, Chapter V, Section 8(A).

Thus, all applicable environmental standards will need to be met.

TABLE III-13.--State Ambient Air Quality Standards ($\mu g/m^3$) 1/.

	Colorado	Utah	Wyoming
Particulates	45 2/	90	75
Sulfur Dioxide	10 2/	60 4/	71 5/
Nitrogen Oxides	none	none	none
Oxidants	3/	none	none
Hydrocarbons	3/	none	none
Carbon Monoxide	3/	none	none

1/ All States must enforce the U.S. Ambient Air Quality Standards in addition to state air quality standards.

2/ By January 1, 1980.

3/ Colorado has developed standards for these pollutants applicable to the Denver Met. Air-Quality Region only.

4/ Proposed.

5/ H_2S Standard - ½-hour maximum.

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In the discussion which follows, the impact of oil shale processing on air quality is given for a likely range of technologies that may be employed as an industry grows to maturity. Before any plant may be constructed, however, appropriate permits would be required. Thus the efficiency of specific environmental control technologies for a specific processing complex would be compared to the then existing standards. No plant could be constructed if this detailed analysis indicated that the standards would not be attained. For the analyses below, concentrations based on the emission from hypothetical plants, are related to the National and State ambient standards in Tables III-12 and III-13 where appropriate.

2. Air Pollution Potential of Oil Shale Development

The principal sources of potential air pollution from oil shale development would be dust and vehicular emissions during construction, solid particulates resulting from blasting and mining as well as from the overburden and spent shale disposal operations, dust produced during crushing and retorting operations, and gases from retorting and oil upgrading operations. Included in these retorting and refining gases would be the gases from the burning of various process fuels. Such fuel utilization is expected to be largely on site to serve process needs and to generate power. It is possible, however, that power may also be generated eventually in centrally located installations serving several shale plants, if a multiplant industry develops as projected. In this case, if excess process gas is available from individual shale plants, it could be utilized by the central power plants.[1/] Since the available gas would be burned in the general shale area in either situation, the effects on air quality would be similar. For this reason, the following, more detailed discussions do not differentiate between on-site or off-site burning of process gases.

a. Air Pollution Potential from Construction Activities

During construction, operation of mechanical equipment would result in exhaust emissions from diesel and gasoline engines and in production of noise and dust. Noise would be more noticeable than similar highway construction activities because of the lower ambient sound level. Emissions and dust from construction activities would be controlled by available technologies. For example, dust would be controlled by spraying. The effects would normally

1/ Alternatively, the green coke obtained as a byproduct from shale oil upgrading could be used as a fuel in power plants specifically designed for this purpose.

be only of a short-term nature, that is, during the life of the construction activity which would be usually less than two years.

b. Air Pollution Potential from Mining Operations

Oil shale operations will involve mining oil shale by either surface mining or underground mining for later processing. Either of these two types of mining operations have air pollution potential, particularly from the production of airborne dust and particulate matter. A discussion of these pollutants from mining operations was discussed in Volume I, Chapter 1, Section D.2. A summary of these effects is reported here.

In an underground mine, dust and particulates are produced by the mining operation. The mine ventilation air for a 50,000 barrel-per-day plant will be about 2 to 3 million cubic feet per minute. The ventilation exhaust air scrubbers could contain about 20 pounds of dust per hour (See Chapter I, Section D.5.b). This quantity of dust would increase to about 60 pounds per hour when blasting is conducted. These blasting operations would probably take place about three times per day. A production of about 25 pounds of dust per hour would probably be typical. This dust, which would be collected by the scrubbers, would be sent to the processed shale disposal area.

By enclosing the crushing, grinding, and screening operations, the conventional control technology (wet scrubbing, bag filters, and/or dust suppression with water) would be adequate to reduce emissions from these sources to about 35 pounds per hour in 400,000 cubic feet per minute of air (0.01 grains/cu. ft.). The collected dust could be added to the processed shale disposal pile.

Conveying operations offer potential for dust emissions due to wind, spillage, or process upsets. Enclosed conveyors and dust collectors at transfer points will largely minimize this potential problem. Raw shale storage piles would be suitably enclosed against wind erosion when the shale is finely divided. Some spillage may still be expected, and it would be necessary to provide for reclaiming such spillage. It is estimated that up to 20 pounds per hour of added airborne particulates could result from these miscellaneous sources.1/

With particulate emissions controlled within the attainable levels set forth above, all processes can meet process weight rate vs allowable emission regulations. Under Colorado emission standards, which are the most stringent of the three oil shale States, this allowable rate of emission for a 50,000-barrel-per-day plant would be about 60 pounds per hour maximum from each airborne particulate source opening.

1/ Not included in this figure are airborne particulates after scrubbing, from the TOSCO II fluid bed shale preheat system. This is a source of airborne particulates unique to the TOSCO II indirect-heat process.

c. Air Pollution Potential from Stack Gases

As explained in Chapter I, the separation systems for oil recovery would also remove water and particulate matter. If the off-gases from the retorts were to be used as a fuel, sulfur oxides would be emitted in proportion to the sulfur content of the gases used. For example, either of the gases available from internal combustion retorting processes shown in Chapter I, Table I-3, may be burned as a low-Btu fuel gas, either for process heat or for generation. Depending on the operating mode for the internal combustion retorting process, i.e., high-temperature retorting results in greater yield of total gases including greater carbon-oxides concentrations, the equivalent sulfur dioxide emitted in the stack gas would vary from 4,114 to 7,760 lb /hour (equivalent to 24.7 to 46.6 tons of sulfur per day from a 50,000-barrel-per-day plant). Gases not burned for power generation and not otherwise combusted will contain hydrogen sulfide, a substance having an unpleasant odor similar to that of rotten eggs.

(1) Sulfur Oxides - Solid and liquid fossil fuels generally contain appreciable quantities of sulfur, usually in the form of inorganic sulfides and/or sulfur-containing organic compounds. Combustion of the fuel in power plants forms sulfur oxides in the ratio of 40 to 80 parts of sulfur dioxide to 1 part of sulfur trioxide.

Sulfur dioxide is a nonflammable, colorless gas. In concentrations above 0.3 to 1 ppm in air, most people can detect it by taste; in concentrations greater than 3 ppm it has a pungent, irritating odor to most people.

Sulfur trioxide in ambient air is either derived from combustion sources directly or from the oxidation of atmospheric sulfur dioxide. Sulfur trioxide may exist in the air as a vapor if the water vapor concentration in the air is low enough; but if sufficient water vapor is present, the sulfur trioxide combines with water to yield corrosive sulfuric acid.

The estimated concentration of SO_2 in the resultant stack gases will be difficult to control to the 500 ppm emission standards[1/] required under Colorado air control regulations (which are the most stringent of those in the three States). If either of the fuels were burned in multiple furnaces, the resulting stack gas could also meet the 417 lb/hr maximum allowable emission permitted by Colorado from a single contamination source. It may be necessary in the long run, however, either to treat the original fuel gases to reduce hydrogen sulfide, or to utilize one of the sulfur dioxide removal processes anticipated to be available for reduction in the flue gases. One potential scrubbing compound which has been proposed for the latter option is the nahcolite associated with some of the deeper oil shales.

If the indirect-heat-process retort gases (equivalent to the TOSCO II process) shown in Table I-3 were burned directly as fuel, some 16,300 lb/hr of SO_2 would result, which is an unaccept-

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1/ This 500 ppm emission standard is not an ambient air quality standard but a standard for SO_2 concentration in the discharge gases from any opening to the air.

able rate of emission. 1/ These gases would, therefore, be pretreated to reduce their H_2S concentration prior to combustion for process heat or power generation. Commercial technology (such as monoethanolamine, diethanolamine, or hot potassium carbonate processes) is available for this treatment, since these gases do not contain air as in the case of internal combustion retort gases. The Colony design uses a low-pressure MEA (monoethanolamine) process which would reduce the H_2S concentration to no more than 25 grains per 100 standard cubic feet, or 0.05 volume percent (equivalent to 99-percent removal of H_2S). The stack gases from burning this fuel would contain about 0.07 pounds of SO_2 per million Btu of heat input, which would meet both national and State emission standards in the shale region. Waste products may be disposed of in the shale disposal piles.

In the indirect-heat process, the stack gases from burning gaseous fuels would contain a total of about 100 ppm, which would meet both national and State emission standards (500 ppm SO_2) in the shale region. 1/

If fuels other than retort gases are required in the plant, fuels essentially free of sulfur, such as natural gas or low-sulfur oil, could be used.

If it is assumed that the conventional Claus process would be used to recover sulfur from the refinery gases, sulfur in the untreated process tail gas would correspond to a daily emission of as much as 4.5 tons of equivalent sulfur. Standards of the

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1/ Sulfur dioxide from liquid fuels could add another 100 ppm.

State of Colorado limit such emissions to 5 tons per day. Although the calculated value is less than the Colorado standard, it would be normal plant practice to add a tail gas unit to recover by-product sulfur. These units are now being put into use in the industry to reduce the sulfur effluent. The additional unit could reasonably be expected to reduce the final sulfur released to about 0.5 tons per day. Alternatively, the Stretford process, which is receiving considerable attention in this country as a substitute to the Claus process for refinery operations, would also be expected to effect a comparable overall reduction of sulfur (34).

(2) Nitrogen Oxides - Of the various oxides of nitrogen, the most important as air pollutants are nitric oxide (NO) and nitrogen dioxide (NO_2). By convention, the term NO_x represents mainly the sum of NO and NO_2, the only significant nitrogen oxide air pollutants. They are chiefly emitted from combustion processes in which the nitrogen and oxygen are subjected to temperatures in excess of 1093°C (2000°F). The major oxide in combustion emissions is NO_2.

Nitric oxide (NO) is a colorless, oderless gas. Normally, at low NO concentrations of 1.2 mg/m^3 (1 ppm) or less, the direct reaction with oxygen of the air proceeds slowly. The oxidation of NO to NO_2 is speeded up enormously, however, by photochemical processes involving reactive hydrocarbons such as those produced by the combustion of gasoline in automobiles. However, these reactive hydrocarbon species are not expected to be associated with oil shale development in quantities large enough to initiate photochemical activity.

Nitrogen dioxide (NO_2) causes reduction of visibility and coloration of the horizon sky in degrees dependent on its concentration, the viewing distance, and the aerosol concentration. Nitrogen dioxide is corrosive and highly oxidizing and is physiologically irritating and toxic.

Although a great deal of laboratory development is underway, presently there are no adequately demonstrated nitrogen-oxide absorption processes for flue gas treatment. One process of limited success is the 20-percent NO_x absorption capability of lime-slurry scrubbing.

Combustion modifications are the only practical mechanisms presently available for reducing NO_x emissions. Such modifications have been developed to a reasonably high degree for gas-fired boilers. NO_x from oil-fired boilers is more difficult to control, and with coal firing, an acceptable combusion modification technique does not yet exist to reduce NO_x emissions on existing boilers.

The basic concept utilized to reduce formation of NO_x is reduce either the temperature of combustion or the oxygen concentrations. Oxygen concentrations can be minimized by low excess air firing and dilution by flue gas recirculation. However, this control method would normally increase CO concentrations. Gas temperature can be reduced locally by either air- or fuel-rich (off-stoichiometric) combustion. One can only speculate as to other control concepts which may eventually be applicable to oil shale retort gases, but future developments in technology should be able to further minimize NO_x emissions.

For each 50,000-barrel-per-day plant, NO_x emissions are presently estimated to be in the order of 330 to 500 lbs/hr (4 to 6 tons per day). Standards for NO_x have not been established in any of the three oil shale states. The national primary standard for ambient air is 100 $\mu g/m^3$, and the EPA emission standard is 0.2 lb NO_2 per million Btu.[1/] With attention to proper burner design flue gas recirculation, and excess air control, it is felt that these standards can be met.

(3) Carbon Monoxide.- Carbon monoxide is present in the oil shale retort gases. The quantity of this gas in retorting gases is approximately 5 volume percent of the gas (Chapter I, Table I-3). These retort gases, however, will be combusted in power plants as described earlier. The carbon monoxide in the retort gases will be combusted to carbon dioxide.

There will be some undetermined levels of carbon monoxide released to the air in the vicinity of the oil shale operations. This carbon monoxide will arise from indirect sources such as incomplete combustion of fossil fuels in internal combustion engines, heating fuels, disposal of waters, and so on. It is not

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1/ Emissions consist mainly of NO, which oxidizes to NO_2 in the atmosphere. Consequently, the NO is calculated to NO_2 and added to the small amount of NO_2 formed simultaneously with NO during the combustion process. The figure shown is for oil-fired steam generators.

expected that significant quantities of carbon monoxide will be put into the atmosphere as a direct result of the oil shale operations. The effects of carbon monoxide on living things is considered in a later section of this Impact on Air Quality section. The physiological and epidemiological effects are summarized for information purposes.

Insignificant levels of hydrocarbons are also expected from the oil shale operations since these hydrocarbons, together with carbon monoxide, would be burned in power plants.

3. Cumulative Impact on Air Quality

a. Quantity of Potential Air Pollutants

This section is devoted primarily to the cumulative impact on air quality as directly related to oil shale operations. It is not possible to assess the cumulative non-oil-shale-development impacts with any degree of exactness since the nature, size, and rate of growth of satellite developments are not predictable nor are their power and similar requirements known. To illustrate, direct power requirements for a 1-million-barrel-per-day shale industry and associated domestic growth would approximate 1,600 megawatts of installed capacity (1,000 megawatts average output). Much, if not all, of this generating capacity could be fueled with a combination of excess process gases from the shale operations and utilization of byproduct coke or fuel. However, any fuel shortage plus the fuel to supply generating capacity required for satellite growth would have to be made up from other sources -- for example, low-sulfur shale oil, natural gas, or low-sulfur western coals. Alternatively, additional power might be generated outside of the shale region and imported.

The potential air pollution problems directly accompanying oil shale development are similar to those already encountered elsewhere in industry. As a result, the techniques now in general industrial use or under development to control the particulates, sulfur oxides, and nitrogen oxides present in various flue gases, or the dusts produced in mining, crushing, and mineral waste disposal, would be applicable to oil shale processing.

The amount of particulates from mining, crushing, and conveying large tonnages of both raw shale and spent shale which is not collected by the standard recovery techniques previously described for these operations was estimated to total 80 lb/hr for each 50,000 barrels per day of production.

In addition to these sources of airborne particulates, dust could occur from processed shale disposal and from retorting and refining operations. It is expected that residual dust from the processed shale disposal operations would be adequately controlled by wetting and compaction. The subsequent cementation reactions or interlocking of grains through compaction which result throughout the shale disposal piles, including the surface, would virtually eliminate fugitive dust release from the disposal operations.

Product gases from retorting and refining operations would be nearly free of particulates by virtue of the recovery procedures used in separating them from the oil and other liquids with which they are coproduced. While catalytic conversion processes will probably be involved in upgrading shale oil on site, they are expected to be fixed-bed hydrogenation systems with little, if any, of the emission-release problems characteristic of the moving or fluid-bed systems that historically have released catalysts and other particulates to the air. Gases from upgrading operations also are expected to be very low in sulfur by virtue of the thorough treatment to recover sulfur as one of the plant byproducts.

If a level of production of 1 million barrels per day is reached in 1985, the cumulative total of particulates from this industry is estimated to range from 20 to 100 tons 1/ per day from the projected 17 sites in the three-State region. At each site, this would comply with State and Federal emission visibility regulations and with State regulations for process weight rate versus allowable emission per opening. For the region, the cumulative total of particulates increases as industry increases.

As previously described, a major source of gaseous products from shale processing is the off-gases from retorting. However, these gases would not be released directly to the air. Instead, they may be treated for sulfur reduction prior to use as fuel to satisfy process and utility system heat requirements. As a result, such combustible components as carbon monoxide, hydrogen, and hydrocarbons present in the gases originally produced (which could pose air pollution problems if released to the atmosphere) would be efficiently burned.

It is the sulfur dioxide in the stack gases from the burning of retort gases and/or fuel oils which is the major potential cause

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1/ The airborne particulates from the TOSCO II retort system fluid-bed preheater are an exception and with current technology could be twice the maximum shown.

of air quality deterioration from a shale industry. On the basis of the data previously developed for the indirect-heat and the internal-combustion retorting processes, the cumulative total sulfur dioxide released to the atmosphere in the three-State region by a million-barrel-per-day industry could vary from as little as 50 to 70 tons per day if desulfurized indirectly-heated retort gas were used exclusively as fuel, to as much as 2,000 tons per day for burning some types of internal-combustion retort gases. The lower limit is within acceptable Federal and State air quality standards. It is expected that the higher emission rate could be reduced to perhaps 10 percent of this value (i.e., 200 tons per day), by the application of SO_2 stack gas removal technology now in process of development. At this reduced level, applicable air quality standards would be met. As with particulates, the total cumulative impact for the region increases with increasing industrialization.

It is estimated that the cumulative loading of NO_x to the atmosphere in the three-State region could reach 80 to 150 tons per day for a 1-million-barrel-per-day industry in 1985. 1/

1/ Not included is the minor amount of pollutants that would be released from approximately 900 vehicles per day that would transport about 1,300 workers to each site. Based on Environmental Protection Agency standards for 1973, carbon monoxide (CO) = 39 gm/mile, hydrocarbons (HC) = 3.4 gm/mile, and oxides of nitrogen (NO_x) = 3.1 gm/mile, and a round trip distance of 120 miles, the residual concentrations of these pollutants would be as follows: (in tons per day) CO = 4.7, HC = 0.4, and NO_x = 0.4.

The impact of the previously discussed cumulative loadings for a 1-million-barrel-per-day industry on ambient air quality is influenced by the temperature inversions which occur in various parts of the three-State region. The following description is given of temperature inversions in Colorado (35):

> A nighttime inversion, with light-drainage winds, is typical throughout the Piceance Basin. Under these conditions, the typical nighttime surface flow pattern is down the creek drainage to the north, then turning westward down the White River Valley. The vertical temperature structure is usually neutral to moderately unstable during afternoon, with a temperature inversion forming shortly after sundown. The trapping layer under this inversion is probably less than 1,500-feet thick. A short-term temperature record on Cathedral Bluffs indicated that the inversion height is usually below 8,500 feet (mean sea level).
>
> During mid-winter, the inversion normally breaks at least by early afternoon. Under certain synoptic conditions, however, temperature inversion conditions may persist for several days at a time. During the summer and fall months, the inversions will normally break by midmorning.

It is clear from the above that source emissions to the atmosphere must be so controlled that pollutants would not accumulate under inversion conditions. Wherever feasible, processing facilities should be located on upland surfaces rather than in valleys and canyons, and high stacks should be employed where necessary. However, plant siting on private lands does not come under the jurisdiction of the Interior Department.

b. Possible Dispersion of Air Pollutants

The dispersion of pollutants from a typical (50,000 barrel/day) plant site has been assessed (36).

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The dispersion of sulfur dioxide was given maximum attention in the study since its emission and dispersion **are the most critical** to meeting air quality standards. The stack gases from burning the retort off-gases from an indirect - heat process as fuel were selected for illustration since this process may well be the first to attain commercial-scale production. It was assumed that only 90 percent of the sulfur (as hydrogen sulfide) in the retort gases would be removed, although conventional MEA (monoethanolamine)-scrubbing technology for H_2S may attain over 99 percent reduction.

(1) Mathematical Model - Pertinent parameters were examined by using a mathematical model in order to determine ambient ground-level distributions of sulfur dioxide as a function of distance from source, stack height, and assumed level of control.

The model used is complex but contains many simplifying assumptions. The following empirical description is presented to provide a general overview of the factors and accuracy involved in estimating the ambient ground-level concentration of pollutants. A full mathematical description is available in D. B. Turner's "Workbook of Atmospheric Dispersion Estimates" (37).

Several investigators have successfully used meteorological data in mathematical dispersion models to predict downwind concentrations of pollutants. Such modeling has shown moderate success under simple-terrain conditions, that is, flat terrain with steady winds, but less accuracy in mountainous terrain. The mathematical models used in the calculations for ground line concentrations for this study were developed in 1961 by Pasquill and Gifford. Their model, which is consistent with other earlier investigators' results, assumes that the plume spread has a Gaussian distribution (Figure III-11). The Gaussian distribution has a vertical and horizontal standard deviation σ_y and σ_z. The coefficients σ_y and σ_z vary with the atmospheric stability, as well as the distance away from a source. Various efforts have been made to define the values of σ_y and σ_z. Probably the most-used coefficients for the standard deviations have been developed by Pasquill and Gifford and published in Turner's workbook. That workbook has served as a fundamental reference for making dispersion calculations for this project.

Turner has commented on the accuracy of the dispersion estimates as follows: "Because of a multitude of scientific and technical limitations, the diffusion computation method presented in this manual may provide best estimates, but not infallible predictions." Generally speaking, under good conditions, that is, flat terrain, uniform wind, and stable conditions, the concentration estimates will be good to within a factor of two. As would be expected, the magnitude of the potential error increases with complex terrain. For a lack of any other method for determining downwind concentrations, mathematical modeling was selected to predict the impact on air quality from the oil shale plants.

One of the most sensitive factors used in the calculation for ground line concentrations is the effective stack height, H. Many researchers believe that the estimate for the effective stack height is the key to success for accurate modeling of atmospheric

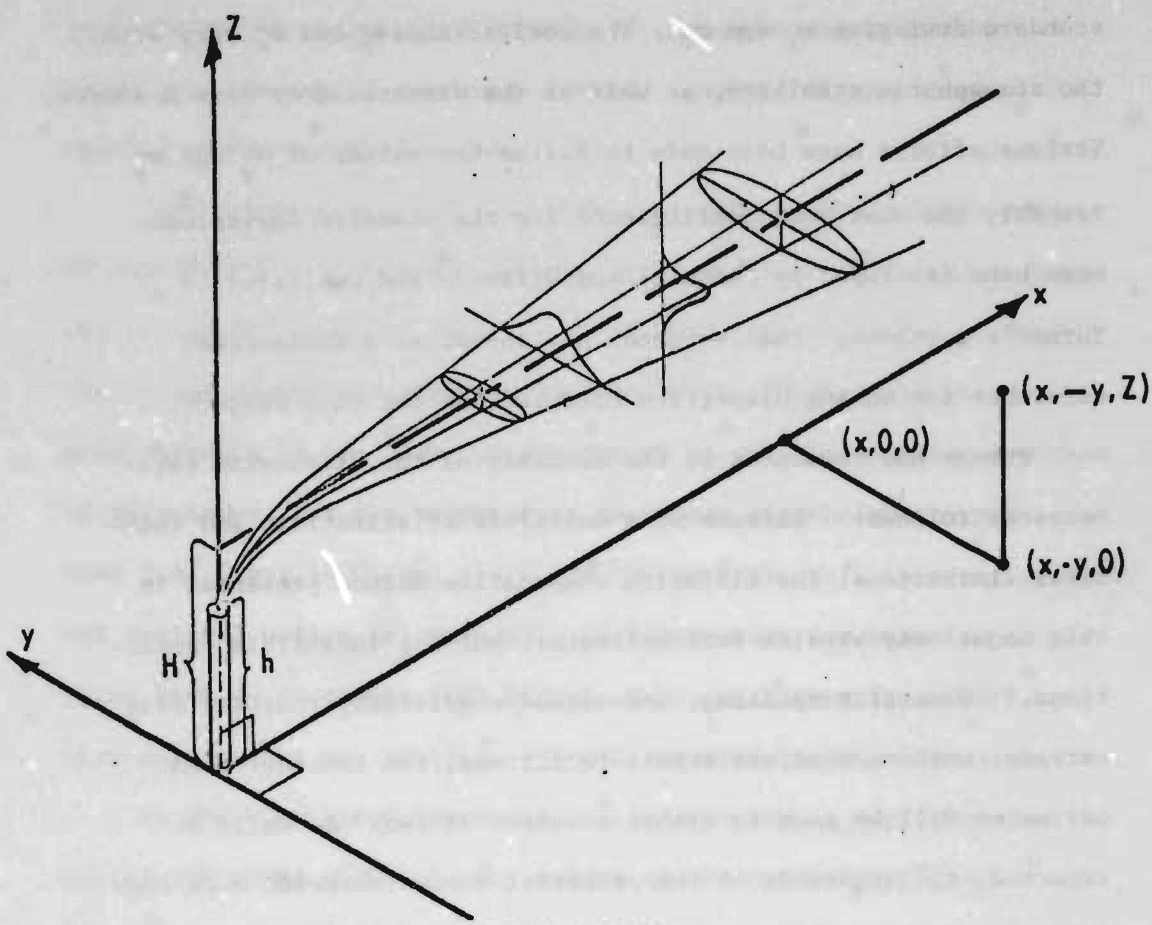

Figure III-11.
Diagram Showing the Model for the Air Pollutant Dispersion Calculations.

dispersion. Holland's equation for determining effective stack heights as is used in Turner's workbook was used for the oil shale dispersion calculation of this study. Generally speaking, Holland's equation will provide low estimates of the effective heights of emissions, therefore providing a slight safety factor in predicting ground concentrations.

In dispersion calculations, the most important air layer to be considered is that nearest the ground, varying in thickness from one to several thousand feet. Turbulence due to the wind and heating of the ground are greatest in this layer. Turbulence due to solar heating of the layer is determined by the temperature structure of this layer. If the temperature decreases with height by more than 5.4° C per 1000 feet (1° C per 100 meters), this layer is unstable and vertical motion is enhanced. If temperature decreases at a lower rate or increases with height, i.e., an inversion condition, vertical motions may still be present but will be less prominent.

As the wind speed increases, pollutants from a continuous source are mixed with a larger volume of air per unit of time. In addition to this dilution, spreading of the material perpendicular to the direction of transport by turbulence further disperses the pollutants. Therefore, in a real situation, pollutants are dispersed due to a combination of complex vertical and horizontal air motions which are dependent upon the temperature gradients and the variation of wind speed and their direction within the surface layer.

Any model that attempts to describe the complex phenomena described above must, by necessity, incorporate a number of simplifying assumptions. Stability is assumed to be the same throughout the dispersion layer with no transfer of pollutants through layers of dissimilar stability, i.e., no turbulent mixing of air layers. Since mean wind speed and direction are used, the variation of wind speed and direction with height are not taken into account. This does not cause large estimating errors during neutral or unstable conditions, e.g., daytime, but can lead to over-estimation of downwind concentration during stable conditions.

For this study, the mathematical equation used to determine ground-level concentrations at a given point is a function of mean wind speed, rate of emission of pollutants, effective stack height, and the standard deviations of plume concentration distribution vertical and perpendicular to the direction of plume travel. The rate of emission is assumed to be constant. Effective stack height is the height of the stack itself plus the distance the plume rises before it levels off, and this depends upon the exit velocity of the stack gases, the inside diameter of the stack, the wind speed, the atmospheric pressure, the stack gas temperature, and the air temperature. The standard deviations of plume concentration distribution are measures of the cross-sectional changes in concentration of the pollutants through the plume as it travels downwind. These deviations are assumed to be Gaussian, i.e., uniform.

Values for the standard deviation of plume concentration distribution vary with the turbulence of the atmosphere, the height above the surface, the surface roughness, wind speed, and the distance from the source. The condition for estimating the statistical distribution of the plume dispersion parameters σy and σz, is considered to be the lower several feet of the atmosphere with surface terrain to be relatively open country. Variations due to distance from the source can be estimated from graphs in Turner's Workbook (37, p. 7).

Turbulence of the atmosphere and wind speed as a measure of the stability of the atmosphere are divided into six classes, A through F, with A being the least stable and F the most stable. These categories for varying wind speed and cloud cover for the oil shale area are given in Table III-14 . When the stability class is determined, the estimated values for standard deviations can be determined from Turner's Workbook (37). The calculated stability category distribution (as percent) for the oil shale region is shown in Table III-15.

With the above assumptions and the estimated values, the maximum ground-level concentration as a function of actual stack height and stability category is shown in Table III-16 .

Due to the number and types of assumptions made, inaccuracies are possible when applying the model to the oil shale areas of Colorado, Utah, and Wyoming. Values estimated for the vertical standard deviation of plume concentration distribution may contain errors in the most stable and most unstable categories when used to

Table III-14.--Stability Categories.

SUMMER DAY

Cloud Cover (tenths)	Wind Speed (miles/hour) 0-3	4-7	8-12	≥13
0-3	A	A	B	C
4-7	A	B	C	D
8-10	C	D	D	D

SUMMER NIGHT

Cloud Cover (tenths)	Wind Speed (miles/hour) 0-3	4-7	8-12	≥13
0-3	F	F	E	D
4-7	E	E	D	D
8-10	D	D	D	D

WINTER DAY

Cloud Cover (tenths)	Wind Speed (miles/hour) 0-3	4-7	8-12	≥13
0-3	B	C	C	D
4-7	C	C	D	D
8-10	D	D	D	D

WINTER NIGHT

Cloud Cover (tenths)	Wind Speed (miles/hour) 0-3	4-7	8-12	≥13
0-3	F	F	E	D
4-7	F	E	E	D
8-10	E	D	D	D

Table III-15.--Calculated Stability Category Distribution.
(Percent)

Time	Stability Category A	B	C	D	E	F
Summer Day	21	19	28	32	0	0
Summer Night	0	0	0	47	26	27
Winter Day	0	1	9	90	0	0
Winter Night	0	0	0	76	13	11
Annual*	7.0	6.5	10.8	58.8	8.7	8.2

* Annual figures are weighted for seasonal variation in length of day.

Table III-16 .--Normalized Maximum Ground-Level Concentration Factors* ($1/m^2$) For Various Stability Categories And Actual Stack Heights.

Stability Category	100	200	300	400	500	600	700	800
	ACTUAL STACK HEIGHT, FEET							
A Very Unstable	65.5	18.8	9.8	6.1	4.5	3.4	2.8	2.3
B Unstable	24.2	6.4	3.0	1.8	1.3	0.8	0.7	0.5
C Slightly Unstable	17.3	4.5	2.0	1.1	0.7	0.5	0.4	0.3
D Neutral	18.7	4.6	1.6	0.8	0.5	0.3	0.2	0.1
E Stable	28.7	3.9	1.7	0.7	0.4	0.2	0.2	0.1
F Very Stable	39.9	5.2	1.3	0.4	0.2	0.1	0.1	0.1

$$\text{*Concentration} = \frac{\text{Conc. Factor } (1/m^2) \times \text{Emission Rate (gm/sec)}}{\text{Wind Speed (m/sec)}} = gm/m^3$$

predict concentrations far from the source. However, the error may be less than 100 percent for: (1) all stabilities within a distance of less than 1,000 feet from the source; (2) neutral to moderately unstable conditions within distances of a few miles; and (3) unstable conditions within the lower 3,000 feet of the atmosphere that contain a strong inversion above 3,000 feet for distances out to 6 miles or more. The uncertainties in the standard deviations perpendicular to the direction of travel are generally less than the standard deviations vertical to the direction of travel. From the foregoing, it should be recognized that the values obtained from this model are present best estimates of the ground-level concentration of pollutants expected from oil shale development and that these values may contain errors. However, the values do provide a reasonable estimate against which to judge the probable consequence of development as described in this section.

(2) Results and Conclusion - Typical results are shown in Figure III-12 , for an 800-foot effective stack height and 90-percent SO_2 control. Under these conditions, the maximum ambient concentration of SO_2 is 4 $\mu g/m^3$, and occurs at a point approximately 10 miles northwest of the stack. This maximum concentration is within national ambient air quality standards for SO_2 (Table III-12) and also within State standards (Table III-13).

At the 800-foot stack height, the study indicated that several 50,000-barrel-per-day plants could be located as close as 15 miles to one another along the prevailing southeast-northwest dispersion

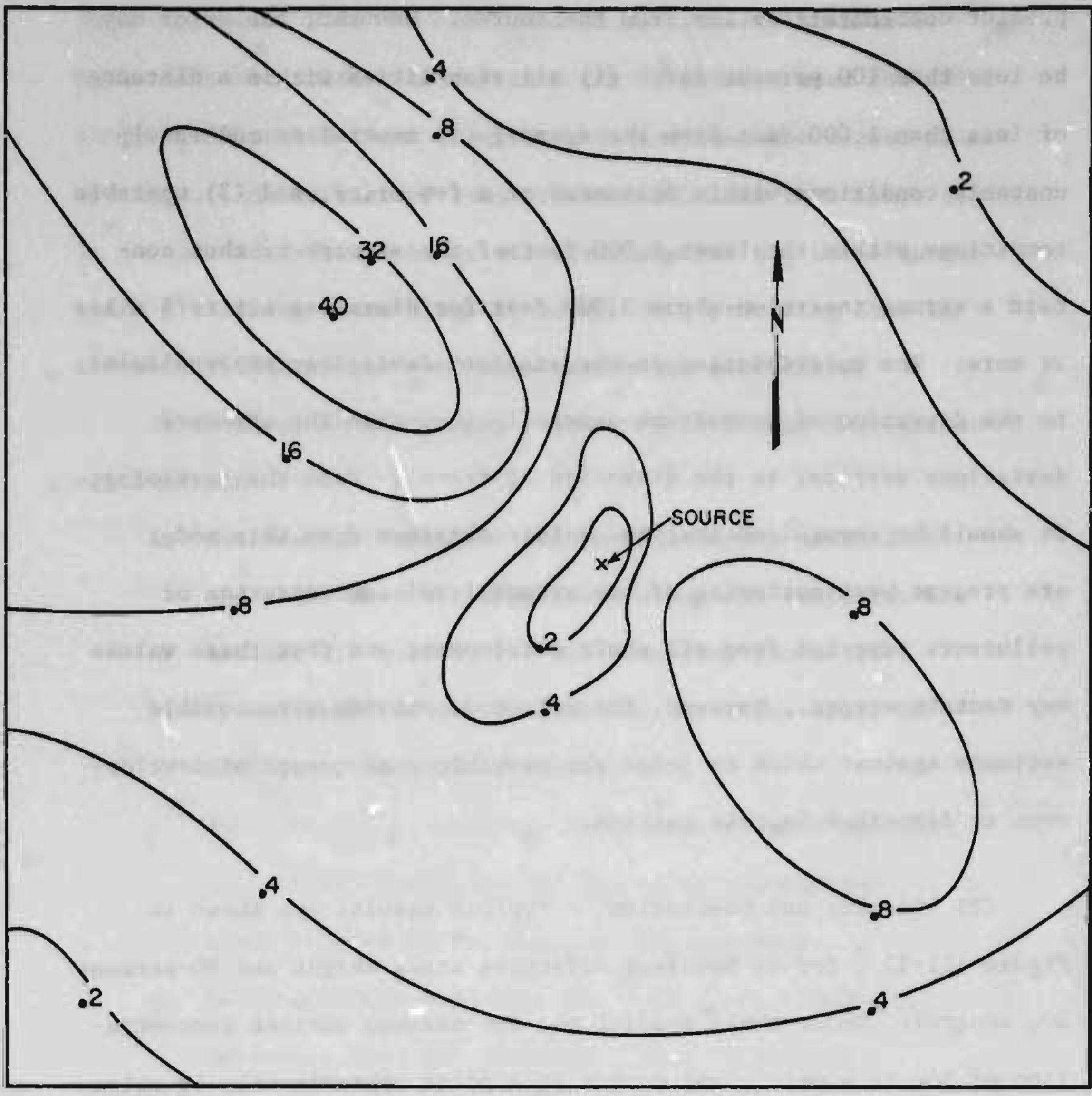

Figure III-12.--Annual Average Ground-Level Concentration of Sulfur Dioxide.
(micrograms per cubic meter)

SCALE - 1 inch = 20,000 feet

ASSUMPTIONS:

Indirect-heat retort (50,000 barrels per day)
90-percent control of sulfur
Effective stack height 800 feet

Source: Reference(36).

axis and still meet national ambient air quality standards. More efficient sulfur removal than the 90 percent used for this study would permit lower stack heights and somewhat closer plant spacings. In the case of less severe conditions than those studied, it is concluded that ambient air standards for SO_2 could be met under prevailing meteorological conditions, providing that the economic burden of the control measures was acceptable.

In summary, it would appear that the following conclusions may be drawn:

a. Particulate emissions can be effectively controlled and could meet all applicable standards (emission and ambient air quality for all retorting processes).

b. Hydrocarbon and carbon monoxide emissions would be well below acceptable limits.

c. Nitrogen oxide emissions could meet present ambient air quality standards for NO_x using conventional stack heights and no specific NO_x controls.

d. Sulfur-dioxide emissions are a critical component. Emissions from the indirect - heat retorting process can meet both State and Federal standards with 90-percent or greater presulfur removal from the fuel gases and suitable stack heights. At lesser sulfur removal efficiencies and/or effective stack heights lower than those studied, the Colorado State standards would quickly become unattainable. In the case of the internal - heat retorting processes, U.S. secondary ambient air quality standards for SO_2 can be met with a combination of tall stacks and proper control strategy. However, Colorado's stringent 1980 standards, especially those with respect to maximum allowable rates of emission from a single contamination source, could not be met without considerable improvements in current sulfur-dioxide removal, stack-gas technology. Such technology is currently under intensive investigation for all industrial combustion processes.

e. If Wyoming State standards are to be met, none of the retort gases could be vented unburned to the atmosphere because of their hydrogen-sulfide content.

4. Air-Quality Impacts on Humans, Animals and Plants

The effects of cumulative long-term exposure to air with emissions of the type and concentration described will be felt primarily by vegetation and long-term residents.

The data available consists of both laboratory studies and epidemiologic studies. The latter are studies dealing with the effects of pollution from the ambient air on groups of people living or working in a community or area. There are many experimental studies but they are limited because of use of high concentrations for short periods of time. This data does not lend itself to long-term projection for low pollutant levels. The epidemiologic studies give some indication of long-term effects but the methods of analysis are hindered by the data itself; e.g., using mortality data is an insensitive method of measuring health effects due to inappropriate designation of cause of death, variation in certification of cause of death, and usually a lack of autopsy data.

In the sections that follow, the present state of knowledge of the effects of various air pollutants on humans, plants, and animals is reviewed and related to the potential unfavorable impacts on these groups by any air pollutants derived from an oil shale industry.

a. <u>Effect of Air Pollutants on Humans</u>

(1) Sulfur Oxides - Laboratory studies of SO_2 effects on humans show the major effect to be constriction of air passages in the lungs. For healthy individuals, the manner of ingestion, i.e., through the mouth or through the nose, is significant. Ingestion through the nose can result in 95-to 98-percent absorption of SO_2 at high concentrations thus acting as a protective agent for the rest of the respiratory system (<u>38</u>, p. 85). Most individuals respond to 5 ppm and above of SO_2. Sensitive individuals can detect 1 to 2 ppm SO_2 and may show severe constriction at 5 to 10 ppm (<u>38</u>, p. 85).

Epidemiologic studies considered both SO_2 concentration and particulates. In London, an increase in the daily death rate was detected when the concentration of SO_2 reached 715 $\mu g/m^3$

(.25 ppm) and 750 $\mu g/m^3$ particulates. The elderly and people with heart conditions were most affected. At daily SO_2 concentrations of 1,500 $\mu g/m^3$ and 2,000 $\mu g/m^3$ particulates, the death rate increased 20 percent over base-line levels (38, p. 144-145).

In Rotterdam, a 24-hour mean SO_2 concentration of 500 $\mu g/m^3$ (.19 ppm) for 3 to 4 days increased the mortality rate. Rotterdam has low particulate levels, lending special significance to this observation (38, p. 145).

A study in Genoa, Italy, of housewives all over 65 years of age, nonsmokers with no industrial exposure, and who had lived in the same area for long periods showed increased frequency of coughing, labored breathing, and bronchitis in areas having "clean" air vs "dirty" air. The range of annual mean SO_2 concentrations was 80 $\mu g/m^3$ (0.028 ppm) in the clean areas to 265 $\mu g/m^3$ (0.093 ppm) in the dirty areas (38, p. 145).

All of these studies showed an increase in morbidity rate (rate of disease occurrence).

(2) Nitrogen Oxides - Laboratory studies of the effects of NO_x on humans are confined to NO_2 effects. It has been found that at concentrations above 835 $\mu g/m^3$ (.29 ppm), all subjects tested detected the odor of NO_2 (39, p. 9-15).

Exposure of patients both with moderate to marked pulmonary disease and with no respiratory disease to 940 to 5,640 $\mu g/m^3$

(0.32 to 1.95 ppm) for 2 to 3 hours on several occasions showed no effects (39, p. 9-15).

Exposure of healthy males to a combination of 10,500 to 13,000 $\mu g/m^3$ (3.6 to 4.5 ppm) SO_2 and 7500-9400 $\mu g/m^3$ (2.6 to 3.2 ppm) NO_2 for 10 minutes with 2-week intervals between exposures with ingestion through the mouth showed the two gases to be additive in effect . SO_2 caused bronchoconstriction immediately after inhalation but returned to normal after 30 minutes, and NO_2 caused maximum constriction 30 minutes after exposure. Recovery time for NO_2 was not measured. The variation in time for effects to occur indicates that SO_2 and NO_2 act by different mechanisms (39, p. 9-15).

Many occupational exposures to high NO_x concentrations have been reported. These exposures have been classified in six degrees: (1) 940,000 $\mu g/m^3$ or higher (336 ppm), acute pulmonary edema and death within 48 hours; (2) 564,000 to 752,000 $\mu g/m^3$ (194 to 259 ppm), pulmonary edema and broncho-pneumonia with death in 2 to 10 days; (3) 282,000 to 376,000 $\mu g/m^3$ (97 to 129 ppm), bronchiolitis fibrosa obliterans with death in 3 to 5 weeks; (4) 94,000 to 188,000 $\mu g/m^3$ (32.4 to 65 ppm), bronchiolitis with focal pneumonitis lasting 6 to 8 weeks followed by spontaneous recovery; (5) 47,000 to 141,000 $\mu g/m^3$ (16.2 to 48.6 ppm), varying degrees of bronchitis and bronchopneumonia, but complete recovery; and (6) chronic intermittent exposure to 18,800 to 75,200 $\mu g/m^3$ (6.5 to 25.9 ppm) may produce chronic pulmonary fibrosis and emphysema (39, P. 9-16).

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Workers in a sulfuric acid plant were exposed to 4,900 $\mu g/m^3$ (1.7 ppm) NO_2 for 3 to 5 years. Multiple clinical symptons, biochemical changes, and blood alterations were reported. In contrast, Italian workers in a nitric-acid plant exposed for an unreported number of years to average NO_2 concentrations of 56,400 to 65,800 $\mu g/m^3$ (19.5 to 22.7 ppm) showed no signs or symptoms of injury (39, p. 9-17).

Epidemiological studies are few, but two cover the survivors of the Cleveland Clinic fire of 1929 and residents of four areas of Chattanooga.

In the Cleveland Clinic fire, the gases involved were NO, CO, and hydrogen cyanide (HCN) with estimated concentrations of 63.3 gm/m^3 (21,800 ppm), 46 gm/m^3 (15,800 ppm), and 6 gm/m^3 (2,060 ppm), respectively. The survivors consisted of people who were present in the building at the time of the explosion, entered the building that afternoon, were exposed to smoke in an adjacent building, and assisted rescue and first-aid workers. Ninety-eight to 99 percent of the people present at the fire were identified through record searches and 87 percent were studied. People present at the fire who did not fall in any of the four categories were used as controls. The ratio of cumulative observed survival rates and cumulative expected survival rates, compared for the period 1929-1965, showed no statistically significant differences between mortality rates of exposed and nonexposed groups (39, p. 10-1).

The Chattanooga study consisted of four areas. One area, close to a TNT plant, had high NO_2/low particulates; one had high particulates/low NO_2; and the other two areas were "clean" areas used as controls. SO_2 values were less than 2.8 $\mu g/m^3$ (.001 ppm) in all four areas. Two possible health effects were studied: impaired ventilatory function in elementary school children and increased frequency of acute respiratory illness in family groups. The data was collected over the 1968-69 school year. The ventilatory performance of the children in the high-NO_2 area was significantly reduced compared to the control areas, and an 18.8-percent relative excess of respiratory illness was found. This increased incidence was found when the mean 24-hour NO_2 concentration was 117 to 205 $\mu g/m^3$ (0.04 to 0.07 ppm). In the high-particulate area, a 10.4-percent relative excess was found. These differences in illness rate could not be explained by differences in family composition, economic level, demographic characteristics, prevalence of chronic conditions, or smoking habits (39, pp. 10-1 thru 10-5).

(3) Carbon Monoxide - Laboratory studies of the effects of CO on man indicate that measurement of the amount of CO-hemoglobin formed in the blood is the most universal factor for relating the effects of CO on humans. The normal level of CO-hemoglobin in the body is 0.5 percent. No human health effects have been seen for CO-hemoglobin levels below 1 percent.

For the range of 2 to 5 percent, the following have been observed: At about 2.5 percent in nonsmokers (exposure to 58,000 μg/m^3 (20 ppm) for 90 minutes), impaired time discrimination has been seen; at about 3 percent (exposure to 58,000 μg/m^3 (20 ppm) for 50 minutes), visual acuity and relative brightness threshold have been impaired; at about 5 percent, reduced performance of simple tests and impaired visual discrimination have been observed. Cardiovascular changes were also seen at levels above 5 percent (40, pp. 8-14 through 8-24, and 8-27 through 8-34). The concentration of CO needed to give these results is dependent on breathing rate and length of exposure.

Exposure of man over a long period to low-level CO may lead to adaptation through increased hemoglobin and red blood cell counts but there is not enough data to substantiate this. It has been seen in animals (40, p. 8-52).

Epidemiologic studies show three possible effects of prolonged exposure to CO, but none has been definitely substantiated. There may be a chronic CO-poisoning syndrome consisting of headache, dizziness, labored breathing, diarrhea, urinary frequency, sweating, thirst, weight loss, loss of sexual drive, and insomnia (40, p. 9-4). Exposure to weekly average CO values of 9000 to 16,000 μg/m^3 (3.1 to 5.5 ppm) may increase mortality in hospitalized patients with myocardial infarction (40, p. 9-18). Two studies show drivers involved in traffic accidents had higher CO-hemoglobin levels than control populations indicating CO lowers the ability to concentrate and react (40, p. 9-18).

Moderate cigarette smoking (approx. ½ to 1 pack per day) leads to a CO-hemoglobin level of about 6 percent. The CO concentration of inhaled cigarette smoke is 46,000 to 57,00 $\mu g/m^3$ (15.9 to 19.8 ppm). Thus, cigarette smokers already have a high level of CO present without including other sources (40, p. 9-7).

(4) Impacts of Oil Shale Industry - Figure III - 12 shows the results of applying a mathematical model for determination of the annual ground-level SO_2 concentrations for a 50,000-barrel-per-day oil shale plant with SO_2 abatement (90-percent removal) using an actual stack height of 800 feet. The highest value predicted is 4 $\mu g/m^3$ (0.0014 ppm). A similar prediction for CO shows a maximum of 15 $\mu g/m^3$ (0.005 ppm) (36, p. 37). NO_x concentration, assuming control to reduce stack gases to at least 100 ppm NO_x, would be .2 $\mu g/m^3$ (.00007 ppm) (36, p. 48). If uncontrolled, which would not be acceptable standard engineering practice, the maximum predicted values are 40 $\mu g/m^3$ (0.014 ppm) SO_2 and 0.7 $\mu g/m^3$ (0.00025 ppm) NO_x. These values are predicted for the indirect - heat retort. For a 200-foot stack, the values would rise to 470 $\mu g/m^3$ (0.16 ppm) SO_2 (uncontrolled) and 47 $\mu g/m^3$ (0.016 ppm) SO_2 (controlled), and 7.2 $\mu g/m^3$ (0.0025 ppm) NO_x (uncontrolled) and 2.0 $\mu g/m^3$ (0.0007 ppm) NOx (controlled).

Short-term concentrations (24-hour maximum) predicted from the model for the controlled plant (indirectly-heated) were 19 ug/m^3 (.0066 ppm) SO_2 with an 800 foot stack and 444 ug/m^3 (.15 ppm) with a 200 foot stack (36, p. 38)

In the event that the oil shale recovery gases are simply vented to the atmosphere (uncontrolled), a staunch odor would be detected in a 20-mile radius around the plant. The H_2S gas has an odor threshold which varies from 10 ppb to 100 ppb (14 to 140 ug/m^3). Although neither Colorado, Utah or Wyoming have emission regulations for H2S, the gas does have an extremely objectionable odor and could conceivably result in complaints to the local control agencies.

No values for 24-hour maxima for NO_x or CO were predicted, but assuming a straight-line relationship using the same proportionalities for NO_x and CO as those seen for SO_2 (4 $\mu g/m^3$ annual average to 19, and 444 $\mu g/m^3$ 24-hour maximum for 800- and 200-foot stacks), the 24-hour maxima for NO_x would be 0.95 $\mu g/m^3$ (0.0003 ppm) for an 800-foot stack and 22.2 $\mu g/m^3$ (0.0077 ppm) for a 200-foot stack, and 71 to 1665 $\mu g/m^3$ (0.024 to 0.57 ppm) for CO.

At the predicted levels of maximum average annual ground-level concentrations of 4 $\mu g/m^3$ (0.0014 ppm) SO_2, 0.2 $\mu g/m^3$ (0.00007 ppm) NO_x, and 15 $\mu g/m^3$ (0.005 ppm) CO, the long-term effects on people in the region should be small, even for those groups known to be sensitive to low levels of pollutants, e.g., those with respiratory diseases and heart disease. Even if these predicted levels were too low by a factor of 100, the concentrations would still be exceptionally low when compared with levels examined in the previously listed epidemiologic studies.

With the 24-hour maximum ground-level concentrations of 19 to 444 $\mu g/m^3$ (0.007 to 0.15 ppm) SO_2, 0.95 to 22.2 $\mu g/m^3$ (0.0003 to .008 ppm) NO_x, and 71 to 1665 $\mu g/m^3$ (0.025 to 0.57 ppm) CO (depending on an actual stack height of 800 or 200 feet), the short-term effects should be negligible at the low values of the range. At the upper values, irritation of sensitive groups could result but this is highly unlikely at these levels.

Under inversion conditions where the concentrations could be high in very localized areas, there is a possibility of adverse effects. The plant sites are isolated from the major population centers, and the effect on these population centers should be slight. The only significant group of people that might be affected would be the plant workers. Since members of sensitive groups would not be expected due to the manual nature of the work, short-term effects under inversion conditions would be minimal. Mechanical failure in the plant, releasing large amounts of stack gases to the working area, is an extremely remote possibility. Should it occur, the workmen in the immediate area would be subject to substantial injury to their respiratory systems which could lead to hospitalization, but previously listed studies show the effects of short-term exposures to be at least partially reversible.

Another potential impact on humans relates to the carcinogenic activity associated with the byproducts of oil shale processing. The presence of carcinogens in processed shale was studied by Kettering Laboratory (41) in 1965 using TOSCO spent shale. Extracts from the spent shale were analyzed chemically to evaluate the probable carcinogenic potency of processed shale. An extract from coal dust was used for comparison. Chemical analysis indicated the presence of two known classes of carcinogens, benzo (α) pyrene and benz (α) - anthracenes, in the extracts from spent shale. A third class, dibenzacridines, was also indicated but identification was not positive. Chrysenes and pyrenes were also found, some of which may be carcinogenic. Coal dust yielded approximately 300 parts per million benzo (α) pyrene and approximately 40 parts per million benz (α)-anthracene; rubber tire dust and atmospheric dusts of American cities contain comparable quantities of these two carcinogens. By comparison, the total concentration of compounds known to be or suspected of being carcinogenic in the spent shale was 0.1 part per million. Thus spent shale shows a much lower concentration of carcinogens than common environmental dusts but does show weak carcinogenic potency.

Studies are underway by Denver Research Institute to further evaluate the carcinogen content of processed shales and to determine carcinogens in plants growing on oil shale and the possibility of residual carcinogens in processed shale being volatized to the air are also being studied.

Present data indicate that carcinogens from oil shale should not cause significant impacts on humans, animals, and plants. The results of the above studies should facilitate additional conclusions on these questions to the extent the studies apply.

b. Effect of Air Pollutants on Animals

Four general responses to air pollutants have been documented for animals: (1) development of pulmonary edema in some animals; (2) lessened immunochemical response; (3) reduced Vitamin C in blood; and (4) synergism of the toxic effects from combinations of certain pollutants (42, p. 9).

(1) Sulfur oxides - Previous studies of the effects of SO_2 on animals are not applicable to long-term evaluation of low-SO_2 concentrations since high ($>$ 10 ppm) SO_2 concentrations were used to accelerate and magnify the effects. These studies can only give an indication of possible effects.

The majority of the studies dealt with small, short-lifetime animals to give large amounts of data quickly. Extrapolation of these results to large animals and different species is hazardous.

In studies where mice, guinea pigs, grasshoppers, and cockroaches were exposed to sulfur dioxide, mice were found to be more resistent than guinea pigs at concentrations below 150 ppm. Between 300 and 1,000 ppm, this was reversed. The insect studies were similar. Thus, extrapolations from high to low concentrations between species is not necessarily reliable (38, p. 73).

In a study of guinea pigs using 33 to 1,000 ppm SO_2, exposure to the higher concentrations produced coughing, labored breathing, nasal membrane irritation, tear formation, eye irritation, abdominal distension, lethargy, weakness, paralysis of the hind quarters, visceral congestion, pulmonary edema, distension of the gall bladder and stomach, hemorrhages of lungs and stomach, and dilation of the right heart. Exposure to concentrations below 33 ppm yielded no significant mortality or signs of distress in healthy animals (38, p. 73-74).

Exposure of swine to 5 ppm SO_2 for 8 hours resulted in slight eye irritation and excess salivation (38, p. 74).

(2) Nitrogen oxides - Studies of NO effects on animals are limited. Exposure of mice to 3,075,000 $\mu g/m^3$ (1,060 ppm) NO for 12 minutes was lethal. Exposure for 6-7 minutes narcotized the mice but, if returned to fresh air after 4 to 6 minutes of exposure, the mice recovered rapidly (39, p. 9-1).

Guinea pigs exposed to 19,700 to 94,00 $\mu g/m^3$ (6.8 to 32.4 ppm) NO for 4 hours showed no change in pulmonary function (39-p.9-1)

Inhibition of bacterial enzyme activity occurred during exposure to 26,400 to 123,000 $\mu g/m^3$ (9.1 to 424 ppm) NO, but it was reversed upon removal of the NO (39, p. 9-2).

Studies of exposure to NO_2 is much better documented (39, p. 9-2 to p. 9-14). Exposure of guinea pigs to 9,800 $\mu g/m^3$ (3.4 ppm) for 2 hours or 24,400 $\mu g/m^3$ (8.4 ppm) for 1 hour caused increased respiratory rate and decreased tidal volume, but the animals returned to normal in clean air. Squirrel monkeys showed similar effects when exposed to 18,000 to 94,000 $\mu g/m^3$ (6.5 to 32.4 ppm) for 2 hours or 9,400 $\mu g/m^3$ (3.2 ppm) for 2 months. When exposed to 3,800 to 16,900 $\mu g/m^3$ (1.3 to 5.8 ppm) continually, tachypnea developed and persisted for 2 years after removal of the animals from exposure. Rats exposed to 1,500 $\mu g/m^3$ (0.52 ppm) for their lifetime showed a 20-percent increase in respiration rate. Dogs exposed to 900 to 3,800 $\mu g/m^3$

(0.3 to 1.3 ppm) NO_2 and 245 $\mu g/m^3$ (0.085 ppm) NO for 18 months showed no change in pulmonary function.

Rabbits exposed to 1,900 $\mu g/m^3$ (0.65 ppm) for 1 to 4 hours showed alteration of lung collagen and elastin, which was reversed within 24 hours after termination of exposure. But when exposed to 470 $\mu g/m^3$ (0.16 ppm) for 4 hours per day for 6 days, the alterations were not totally reversed within 7 days of termination of exposure.

Rats exposed to 3,800 $\mu g/m^3$ (1.3 ppm) for their lifetime showed formation of emphysema-like lesions in the lungs. When NO_2 concentration was reduced to 1,500 $\mu g/m^3$ (0.52 ppm), the lesions did not occur in all test animals, but did occur in some. Mice exposed to 940 ug/m^3 (0.32 ppm) for 3 to 12 months for 6, 18, and 24 hours per day also exhibited emphysema-like lesions. Dogs exposed to 47,000 ug/m^3 (16.2 ppm) for 6 months showed early evidence of pulmonary emphysema.

Mice, hamsters, and squirrel monkeys showed reduced resistance to bacterial pneumonia and influenza infections after exposure to varying NO_2 concentrations.

(3) Carbon Monoxide - Carbon-monoxide (CO) uptake by animals reduces the amount of oxygen available to the tissues. The effects of this interference with the oxygen-transport system depend on CO concentration, length of exposure, and species of animal. The general effects are changes in brain and heart functions as evidenced by alterations in electroencephalogram and electrocardiogram readings after exposure to 50 ppm CO concentrations for varying lengths of time. There were indications of adaptation

after long (3 months) exposure to 50 ppm CO with increases in hemoglobin and red blood cell count (40, pp. 8-47 and 48).

The lack of adverse effects in certain animals was also found; e.g., mice exposed to 50 ppm CO for 3 months to 2 years showed no changes in fertility, fetal survival, body growth, food intake, weight and water content of various organs, electrocardiogram, or blood chemistry (40 p. 8-48).

The major impact of CO would be on those animals already exhibiting deficient oxygen supply such as diseased animals and possibly on the developing fetus.

(4) Impacts of Oil Shale Industry - Using the values of 4 $\mu g/m^3$ (0.0014 ppm) SO_2, 0.2 $\mu g/m^3$ (0.00007 ppm) NO_x, and 15 $\mu g/m^3$ (.005 ppm) CO for maximum annual average ground level concentrations, long-term effects of the oil shale industry should be small. Domestic animals and wildlife can develop chronic respiratory disease and have increased susceptibility to natural diseases with long exposure to low levels of air pollutants. Severity of lung damage depends on total dosage rather than concentration indicating that the cumulative effect of pollutant inhalation may cause a decrease in animal populations over a long period of time, even if pollutant concentrations are kept within ambient air quality standards.

Cumulative long-term impacts are expected from animal ingestion of contaminated vegetation. Reduction of plant growth due to pollutants could also reduce the total available food supply. The combination of these two possibilities could lead to limited long-term reduction of animal populations.

The 24-hour maxima listed previously for SO_2, NO_x and CO were 19 to 444 $\mu g/m^3$ (0.007 to 0.15 ppm), 0.95 to 222 $\mu g/m^3$ (0.0003 to 0.075 ppm), and 71 to 1665 $\mu g/m^3$ (0.024 to 0.57 ppm), respectively, depending on whether the actual stack height was 800 feet or 200 feet.

At the lower end of these ranges, the short term impacts would be negligible and very localized if present. At the upper end, impacts would be greater and could lead to short-term damage to animals, but this damage may be reversible if the animals are only exposed for short time periods. But these effects would be localized and should not affect a substantial portion of the total animal population in this area.

Under inversion conditions, exposure of animals to high pollutant concentrations may increase the mortality rate in localized areas. Natural movement of the animals for foraging should reduce this impact to low levels.

c. Effects of Air Pollutants on Plants

Sulfur dioxide and nitrogen oxides have significant effects on plant life (38, Chap. 5; 39, Chap. 8). There are two classifications of possible injury--acute and chronic. Acute injury is characterized by rapid absorption of toxic concentrations of SO_2 or NO_x leading to dramatic changes in the plant, e.g., dramatic color changes from

SO_2 or cell collapse followed by necrosis from NO_x. Chronic injury is caused by long exposure times at low concentrations of SO_2 and NO_x. Symptoms may be blanching, leaf-drop, or lesions seen primarily on foliage. Chronic injury can lead to growth alteration, reduced yield, and changes in plant product quality. Chronic injury symptoms from exposure to SO_2 or NO_x are very similar and difficult to distinguish.

A broad range of factors is involved in the degree of susceptibility of plants to damage by SO_2 and NO_x. These include temperature, relative humidity, light intensity, soil moisture, nutrient supply, and age of plant or tissue exposed.

Generally, plant resistance to SO_2 and NO_x is much greater below 5° C (40° F). Plants show high resistance in winter probably due to lower plant activity with correspondingly high sensitivity in late spring and early summer.

Sensitivity to SO_2 and NO_x generally increases as relative humidity increases.

Minor variations in soil moisture during exposure to SO_2 and NO_x do not affect susceptibility providing there is sufficient moisture for normal plant growth. Plants growing with an insufficient water supply show higher degrees of resistance.

Plants growing in shade tend to have higher sensitivity than those growing in direct sunlight, while young plants and newer foliage are more resistant than older plants or foliage. Middle-age leaves have the highest susceptibility to damage.

(1) Sulfur oxides - Many studies of the effects of SO_2 on vegetation have been performed. Although the effects are fairly well understood, there are still many unresolved controversies.

Reduction in growth of pine trees near SO_2 sources has been reported. A lower yield of rye grass was observed when the plants were exposed to unfiltered air containing .01 ppm to .06 ppm SO_2 over a period of 46 to 81 days. No visible symptoms were seen and the presence of other pollutants was not documented (38, p. 62).

Conversely, at very low SO_2 concentrations, the SO_2 may be utilized by plants deficient in sulfur giving increased growth and production (38, p. 62).

Studies of short-term effects of SO_2 are available. Injury to Ponderosa pine, western larch, Pacific ninebark, and creambush rockspirea was reported after exposure to 0.5 ppm SO_2 levels for 7 hours (38, p. 64). This study concluded that the lowest concentrations of SO_2 detrimental to conifers was .25 ppm. Another study reported that larch, one of the most sensitive conifers, showed slight symptoms from 0.3 ppm SO_2 during an 8-hour exposure (38, p. 64). It was concluded that no damage should occur if concentrations in the range 0.3 to 0.5 ppm are not present and if the length of exposure at 0.3 ppm is short for any single exposure (38, p. 64).

Long term-studies in the vicinity of smelters show dramatic effects of SO_2 on plants over a wide range of SO_2 concentrations. The area affected was large, with tree damage noticed up to 52 miles from the smelters. Damage to Ponderosa pine, Douglas fir, and forest shrubs ranged from 60 to 100 percent (acute) in a river valley extending 30 miles from the smelter to 1 to 30 percent (chronic) at higher elevations extending 52 miles from the smelter. Installation of SO_2 control devices lowered the percentages to 20 percent and 4 percent, respectively. Eighty-one percent of the pines showed no cone production in Zone 1 after installation, but only 16 percent had no cones outside Zone 1. SO_2 concentrations 15 miles from the smelter in Zone 1 averaged .03 ppm during the summer with occasional peak concentrations greater than 0.5 ppm of 5- to 10-hours duration (38, p. 64).

Damage to at least 15 tree species, including hardwoods and conifers, in the vicinity of petroleum refineries processing crude oil, that used 3-percent sulfur pitch residue in the refining furnaces has been observed (38, p. 65). SO_2 concentrations exceeded 0.5 ppm for 10 hours per month with momentary peaks greater than 2 ppm. Slight to severe acute injury was reported for all species within 1 to 2 miles of the refineries.

These long-term studies indicate that even with relatively low SO_2 concentrations, damage can be extreme.

(2) Nitrogen oxide - NO_x leads to a reduction in "apparent photosynthesis" which is measured by the reduction in the amount of carbon dioxide (CO_2) absorbed by the plant (38, p. 8-1). While studies of NO_x effects are not as well documented, leaf-drop and chlorosis have been observed (39, p. 98-2).

Using nitric oxide (NO) at 8,700 to 29,000 $\mu g/m^3$ (3 to 10 ppm) on bean and tomato plants leads to a 60-to 70-percent reduction in apparent photosynthesis. Apparent photosynthesis returned to normal as soon as the exposure was ended and no visible injury was observed (39).

Comparison of NO and nitrogen dioxide (NO_2) on the rate of apparent photosynthesis in alfalfa and oats yielded threshold levels of 7,000 $\mu g/m^3$ (2.4 ppm) NO and 1,100 $\mu g/m^3$ (0.38 ppm) NO_2 necessary to reduce CO_2 absorption. Combining the gases gave an additive effect, i.e., combinations at these concentrations affected the plants more than each individual gas. NO caused a more rapid reduction than NO_2 in CO_2 absorption rate but recovery was more rapid after exposure to NO_2 ceased (39, p. 8-3).

The possibility of synergism, i.e., a situation in which the combined action of two or more agents acting together is greater than the sum of their separate actions, is also possible. For example, tobacco showed leaf injury after exposure for 4 hours to a mixture of 188 $\mu g/m^3$ (0.065 ppm) NO_2 and 260 $\mu g/m^3$ (0.09 ppm) SO_2, whereas exposure for 5 hours to 4,500 $\mu g/m^3$ (1.6 ppm) NO_2 yielded no injury (39, p. 8-4 and 39, p. 8-6).

(3) Carbon monoxide - Plants show no detrimental effects from CO below concentration of 290,000 $\mu g/m^3$ (100 ppm). Associated micro-organisms, e.g., nitrogen-fixing bacteria, also have shown no adverse effects below carbon monoxide concentrations of 290,000 $\mu g/m^3$ (100 ppm).

(4) Impacts of an Oil Shale Industry - Comparison of the annual average ground concentrations of 4 $\mu g/m^3$ SO_2 and 0.2 $\mu g/m^3$ NO_x with the concentrations used in laboratory studies indicates that expected long-term damage to vegetation in the region should be small

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except possibly for some localized areas, e.g., immediately adjacent to the source and about 10 miles northwest of the source. In these areas, some chronic injury could occur with subsequent reduction in plant varieties and populations. Some damage can be expected to alfalfa grown locally for cattle feed.

The possibility of synergism between SO_2 and NO_x could lead to long-term effects on these localized areas. But much more research into this possible synergistic relationship is required before it can be fully understood, and is presently being conducted.

Outside these localized areas the long-term impact should be minimal. Small amounts of sulfur from SO_2 may be beneficial to balance the nutrient supply. The resistance of vegetation in the area would probably be high due to the combination of low soil moisture content, low annual average humidity, and short growing season.

But plants may be more susceptible to secondary invaders such as bacterial or viral disease, fungi, or insects due to reduced vigor caused by pollutants. Reduced vigor may lead to an imbalance in the ecosystem and inability to compete properly, leading to reduced amounts of some species over the long-term.

Synergistic effects due to the presence of several pollutants may lead to greater damage than expected from each individual pollutant.

The short-term impacts of 19 to 444 $\mu g/m^3$ SO_2 and 0.95 to 222 $\mu g/m^3$ NO_x should also be localized. The lower levels of these ranges should not lead to any significant damage to plants in the area over a short period, even in very localized areas. The upper range could deplete plant populations significantly if synergistic effects do indeed occur for the species in this region leading to high incidence of leaf-drop and necrosis in the region.

The area has an average of 20 days per year of inversion conditions. During these periods pollutants are trapped and may build to high concentrations, even approaching the stack gas composition. When the inversion breaks, due to changes in weather conditions or due to the natural heating-cooling cycle of the region, these pollutants can reach ground level due to air currents and stay at high concentrations for short periods (hours) before dispersal. Repeated many times during each of the years the plant is in operation, such short-term impacts could cause significant and cumulative adverse effects on flora in highly localized areas. The areas affected are dependent on actual plant location, wind speed and direction, and factors involved in the inversion collapse

5. Cumulative Effect on Regional Air Quality

As presented in this analysis, development to a 1-million-barrel-per-day industry will require 17 processing complexes, the locations of which are uncertain. In addition, populations will expand, as will power generating capacity. Some secondary industry may be stimulated by the general activity related to oil shale development. For the whole region, the cumulative long-term effect will be influenced by the location of plants and people and the potential for synergism between individual pollutants and emission sources.

It is anticipated that all applicable ambient air quality standards can be met, both Federal and more strigent State standards. However, except for the indirect - process, Colorado's 1980 standard that limits the amount of sulfur that can be released from a single source could probably not be met without improvements in stack gas control technology or changes in the standard.

Assuming no concentrating effects from scattered point sources, the cumulative long-term effects upon the oil shale region will likely be:

1. A decline in ambient air quality;
2. Increased occurrence of smoke plumes, an increase in haze and some lowered visibility;
3. Localized and limited damage to vegetation and animals over long periods of time;
4. Possible injurious, but generally reversible, effects on humans working or living in the vicinity of the plants if an accident occurs;
5. Possible short-term effects on persons living in the vicinity of the plants during inversion conditions.

If synergism between individual pollutants occurs and/or plant siting leads to higher concentrations of pollutants than expected, more severe impacts than those listed above may result.

E. Impacts on Fauna

1. General

The present population density and human activities of the oil shale region have been described earlier. However, it is well to emphasize that lack of industrial development and limited human activity in the area are the reasons why the region has retained much of its natural character.

Human activity and development within this region has been confined to cattle ranching, minor gas exploration and production, and recreational uses. The fauna of the area has retained much of its natural character, unlike other parts of the states where development has been more intense. There are many species of animals which do not tolerate human activity occupying this area. They include mountain lion, black bear, elk, and various raptors, particularly the eagles and falcons. In addition, the area contains highly productive populations of more tolerant species such as deer, coyote, bobcat, rabbits, and many species of birds, small mammals, reptiles, and amphibians.

Oil shale development will modify the essentially natural character of the environment and increase competition between man and the natural fauna for space and physical resources. This will inevitably result in a reduction in the population density of the majority of the species of animals now occupying the oil shale region. Those species that are presently endangered or have demonstrated in other areas an inability to compete with man for space and resource will be greatly reduced, and in some cases, possibly extirpated.

Regional effects of oil shale development on fauna would reflect the sum of diverse local impacts and their ecological interactions. Such interactions are frequently complex, subtle, and invisible. For example, where springs or streams are dried up as a result of mining or lowering of the water table in the semi-arid Piceance Basin of Colorado, an irreversible shift of both behavior and distribution of associated animals will be set into motion. Vegetation and immobile animals dependent on the water source will be lost. More mobile animals, such as resident livestock, mule deer, wild horses, song birds, rodents, and raccoon, which water and live in the vicinity, will seek new water sources. However, since population levels are determined by the availability of suitable habitat, displaced animals will eventually succumb to natural mortality or displace other resident animals at adjacent watering areas. Reduction in numbers of prey animals will reduce the abundance of predators such as hawks, eagles, coyote, and bobcat. The effects of this particular impact include the loss of an ecological feature, as well as its associated faunal populations, and the imposition of competitive pressures on populations at adjacent watering areas.

Recognizing the complexity of effects resulting from individual impacts, such as the one discussed in the preceding paragraph, there is no reasonable way to quantitatively assess, before the event, regional environmental effects resulting from a broad spectrum of land uses and human activities. Within this framework, the following two sections are directed at the various impacts, both actual and potential, and their likely ecological cause-effect relationships on fauna of the oil shale region.

2. Localized Industrial Impacts

a. Access

The opening of roads and trails into the relatively undisturbed areas of the Piceance, Uinta, and Washakie Basins will result in a combination of new pressures on local fauna. Opening and development of tracts will be accompanied by new road networks and improved highways. In many cases, hunting pressures and other human uses would be increased over existing levels in the locale of developed tracts. Increased vehicular activity and man use of trails and the general countryside will bring about additional mortality to wildlife. For example, a significant increase in road kills of deer and various small game will occur. Rabbit hunters would kill many rabbits, hawks, small carnivores, and rodents. There would be increased pressure upon coyote and bobcat through predator calling by hunters. Increased trapping would take many coyote, bobcat, foxes, badger, raccoon, skunks, ringtail cat, and some raptors.

Animals seen along roads and large birds perched on fence posts and power line poles will be indiscriminately shot in greater numbers as use of such roads increases. Mortality studies of eagles and hawks in the West have shown that bullet wounds are still the most frequent cause of death, in spite of legal protection by both Federal and State laws. Such predatory and scavenging species are attracted to roadsides to feed on road-kill carcasses. They are also attracted to powerlines and poles as perches due to the good visibility from these elevated points and the apparent safety.

A significant visual effect of a regional oil shale industry which is closely associated with wildlife values would be the loss of natural scenic quality caused by the visual and audio impact of roads, pipelines, spent shale disposal sites, transmission lines, signs, and air traffic.

b. Faunal Stress

Activities and noise accompanying construction and operation (road, oil pipeline, powerline construction, vehicle traffic, and airstrips for low-frequency use by light planes) of an oil shale installation will cause stress and disturbance to established wildlife behavior and activity patterns in the locality of the development. Mule deer are particularly vulnerable to stress in the late winter and early spring months. Does are carrying their fawns at this time, and many are in a weakened condition due to the hardships of winter. Little harassment is needed under these conditions to cause abortion of the fawn or mortality to the doe. Harassment can come from many sources, such as being frightened by snowmobiles or trail bikes. The impact of each particular disturbance in itself might be relatively small, but the effect over the life of each lease will be a chronic disturbance leading to displacement of wildlife in the tract vicinity. Displacement of animals creates territorial competition with animals on adjacent habitat. When disturbance is sufficiently extended and severe, the displaced animals eventually succumb to natural mortality or displace animals in an adjacent habitat.

Nearly all mobile species avoid busy areas during periods of noise and disturbance. Where their habitats are affected by development, species most disturbed would include mountain lion, bear, elk, mule deer, antelope, foxes, bobcat, sage grouse, eagles, hawks, and various species of migratory birds. The mountain lion, elk, and peregrine and praire falcons are particularly intolerant. The vicinity of mines and other developed sites will largely be lost to them as suitable habitat. The golden eagle is particularly intolerant of human activity. A Bureau of Sport Fisheries and Wildlife golden eagle survey has shown that they nest in moderate numbers along the Front Range in eastern Colorado and in similar cliff habitat near open country in western Colorado. Several nesting sites have been identified in the Piceance Basin. Greater numbers move into north-eastern and northwestern Colorado from the north in winter. The survey shows that the nesting population between Pueblo and Fort Collins has declined about 25 percent in the past 5 years, primarily because of disturbance from the expanding metropolitan growth in that area. Although urban and industrial development will not be so great in the oil shale region, proportional losses of golden eagle, as well as other intolerant birds and mammals, can be expected.

Some species, such as elk and mule deer, are particularly vulnerable to stress induced from routine low-level aircraft flights and aerial harassment. The extent of such aerial disturbance would be dependent upon the number and location of air strips and the volume of air traffic which would be involved. There may be several air strips for low-frequency use by light planes at the mining locations. Assuming that aircraft are operated in a safe manner, without deliberate harassment, few problems are foreseen away from the approach and departure areas. As the area becomes more densely settled, this type of disturbance will be less of a problem.

Increased ground vehicle traffic in the vicinity of the oil shale deposits will result in an increased level of road kills of deer and other animals. For example, development in the Piceance Creek Basin will greatly affect the traffic on the access highways. Highway 13, between Rifle, Colorado, and Meeker, had a use in 1972 of 873 vehicles per day. In 1972, 107 deer were killed in deer-auto collisions. This highway bisects one of the largest deer migration routes in the West. With increased traffic going to and from oil shale sites, this number can be expected to increase proportionally. This should also hold true for traffic on all new access roads within this same migration route. Highway 139, between Loma and Rangely, had a vehicle use in 1972 of approximately 160 vehicles per day. The deer kill by automobiles was negligible. With an increase in traffic, this area is susceptible to high deer mortality. Highway 64, between Rangely and Meeker, which bounds the Colorado oil shale deposits on the north, is another highway of high deer-auto accident incidents. This highway is used at the rate of 390 vehicles per day. Traffic may double or triple over the life of basin development with deer-auto accidents increasing accordingly. In 1972, 52 deer were killed by vehicles on this highway. Vehicle use rates are not available for the Piceance Creek road. However, in 1972, 52 deer were killed in auto-deer collisions on this road.

In summary, in 1972, the number of deer killed on highways within and around the oil shale area of Colorado totaled approximately 200. This does not include deer that were crippled and died away from the highways. It is estimated that these same high losses will occur on roads that will be built within the project areas and that losses will increase at a rate commensurate with increased road construction and traffic loads in the region. Additional wildlife losses, in the form of small mammals such as rabbits, hare, chipmunks, squirrels, woodchuck, and others, can also be expected.

c. Loss of Habitat

Oil shale operations would require physical use of undeveloped lands for mining, pipeline and road construction, spent shale disposal, and buildings. Areas stripped of natural cover and the spent shale disposal areas would be vulnerable to wind and water erosion, until stabilized through revegetation or other means. The actual land area which would be required for a full-scale regional oil shale industry cannot be precisely predicted. However, up to 80,000 acres may be involved as the industry expands to the million-barrel-per-day-production level. The effect of development on the land surface is cumulative as discussed in Section b above. The length of time over which the use of this habitat would be completely lost to faunal use is dependent upon the time the area remains unvegetated and the success of re-establishing wildlife food and cover. Re-establishment of wildlife food and cover on disposal piles may take from 20 to 70 years as discussed in Chapter I, Section D. It has not yet been demonstrated that spent shale piles can be revegetated with plant communities that will adequately supply the needs of the fauna presently found in the region.

Serviceberry, bitterbrush, mountain mahogany, and black chokeberry are preferred browse species for mule deer along with moderate use of sagebrush, rabbitbrush, and pinon pine. Antelope and sage grouse prefer open sage country with good mixtures of forbs. Antelope also range more saline lands with growths of four-wing saltbush and winterfat. Elk are mainly grazers which require wooded land nearby for cover. In areas where they have been introduced in Utah and Colorado, chukar partridge prefer open saline areas with shadscale and four-wing saltbush. Doves are found in most open areas with plentiful grasses and forbs. Jackrabbits are plentiful in most fairly open country, and provide the main food supply for wintering golden eagle throughout the region and smaller numbers of wintering bald eagle, mostly in Utah. Should mined areas and disposal piles not be revegetated with preferred browse, grass, and forb species, drastic and permanent local reductions in wildlife populations will result.

Canyons proposed for spent shale disposal provide nesting places for cliff swallow, canyon wren, other small birds, and possibly eagles; denning sites for coyote, bobcat, mountain lion, foxes, ringtail skunks, weasels, and other smaller mammals; and/or critical winter habitat for deer and elk. All these animals will be lost from the immediate areas of the disposal sites in canyons filled with waste material. Topographic changes will not permit restoration of typical canyon vegetation. Thus, even with successful revegetation of spent shale, the ecosystem dependent upon the canyon topography will be irretrievably lost. The loss will be cumulative as more canyons are filled over time.

The effects of such physical land alteration upon the fauna in the vicinity is both direct, by movement and mortality, and indirect, by competition and loss of biotic productivity. Such losses would probably be, in general, proportionate to the area disturbed. For example, when the deer population is at or near the carrying capacity of the land, as it usually is on winter ranges in western Colorado, any displaced deer would be forced into competition with other deer on adjacent land. Natural mortality then reduces the herd to the range carrying capacity. Such reduction occurs from increased fawn mortality, especially during harsh winters, and increased exposure of weakened animals to predation. Removal of existing browse plants on winter range on the lease tracts and disposal areas can be expected to result in marked local reduction in mule-deer numbers. Combined effects of habitat alteration and human disturbance with full development of an oil shale industry in the Piceance Basin may be expected to cause an estimated minimum 10-percent reduction in the winter deer population. The estimated population range in recent years is 30,000 to 60,000 head. If disturbed areas and disposal piles are not revegetated with suitable winter browse species, the population reduction is expected to exceed 10 percent. Where antelope frequent development areas, a similar reduction is anticipated. As discussed in Chapter V, Volume III, stipulations on the prototype leases require the lessee to restore fish and wildlife habitat which is damaged or destroyed.

Where natural surface water features such as springs, seeps, and small streams dry up or are changed due to lowering of natural ground water tables, the animal and plant community associated with such features will be eliminated. Animals with ranges extending beyond spring and riparian habitat, but dependent on such features, would be forced to move to other areas. This would result in increased competition for resources other than water, and where these resources were being fully utilized, the overall population of the species would be reduced as noted above.

The sage grouse is an important example of a species dependent on springs and wet meadows in late summer. Chicks require succulent green food such as clover and dandelions. In late summer when the range dries up, the sage grouse hens bring their broods down off the sage-covered uplands to feed along the edges of meadows and springs. Loss of surface water usually results in loss of sage grouse from the area, and this would probably occur throughout the areas of Piceance and Yellow Creeks or other drainages that suffer a lowering of the water table.

Vegetation adjacent to dirt roads and trails, stockpiles, and construction sites will be regularly covered with dust. This constitutes a minor type of habitat loss, since such vegetation would lose its wildlife food and cover value only until washed off by subsequent rains. Vegetation can also be damaged by air contaminants as discussed in Section D.4.c Dependent small animals and birds will depart the habitat when the condition becomes chronic.

d. Water Quality

Fish and other aquatic organisms have, like all organisms, ranges of tolerance to the physical and chemical parameters of their environment. The most commonly recognized factors that limit the distribution of these aquatic organisms are temperature, turbidity, pH, water velocity, oxygen supply, and conductivity.

As an example, trout can survive at temperatures ranging from below freezing to 72°F. Growth, however, occurs between 38° F and 58° F, and successful reproduction is even more critical, requiring temperatures between 45° F and 55° F. Stream temperatures above 55° F during the spawning and incubation period will curtail the reproductive capacity of the trout population, even though adults may continue to flourish.

Ellis (43) proposed the following criteria for the quality of water required to support a good mixed warm water fish population and its food organisms. This quality would be favorable to the population, not merely sublethal.

1. Dissolved oxygen - not less than 5 mg/l.
2. pH - approximately 6.7 to 8.6, with an extreme range of 6.3 to 9.0.
3. Specific conductance - maximum of 1,000 to 2,000 mho X 10^{-6}. (western alkaline streams).
4. Free carbon dioxide - not over $3cm^3$/l.
5. Ammonia - not over 1.5 mg/l.
6. Suspended solids - millionth intensity level for light penetration not less than 5 meters.

Any one of the parameters listed above could be changed in local streams and downstream rivers by effluents, accidental spills, impoundments, and/or erosion. For instance, sufficient amounts of leached substances and saline ground water released to surface waters from excavations, overburden piles, or spent shale piles, could cause a shift in pH and conductivity into a range that would interfere with the vital functions of aquatic organisms.

The extent and severity of the effects of the above-described changes depends upon the particular habitat and species affected and the composition and volumes of polluting substances. Unless carefully controlled, such discharges could significantly reduce the aquatic populations of streams and their riparian fauna. These communities are diverse and include trout, suckers, catfish, minnows, herons, geese, ducks, rails, cormorant, bitterns, killdeer, song birds, beaver, muskrat, mink, and stream-bottom invertebrates.

Both wind and water erosion will introduce sediment into surface waters. In aquatic habitat where resulting turbidity and siltation might exceed natural levels, adverse effects would occur in the form of lowered biological productivity. This results from reduced aquatic flora due to reduced light penetration, mechanical damage to gills of aquatic animals, and physical covering of fish spawning and nursery areas. The extent of such erosion and its effects cannot be predicted since detailed information on potential erosion-causing features such as electric transmission lines, roads, and pipelines does not exist at this time.

Adverse impacts upon aquatic and riparian fauna can also be expected in the event that one or more supply impoundments were constructed on the White or Green Rivers or their tributaries. The extent and types of faunal effects cannot be determined at this time, since their prediction would depend upon presently unavailable information, including location and size of the projects. Potential effects upon fauna of impoundments on these streams would include change from riverine to lacustrine ecosystems; interference with fish reproduction through blockage of spawning migrations; and a reduction of spawning habitat of the endangered Colorado River squawfish. This species has very specialized requirements for spawning and successful reproduction. It will not reproduce in cold tailwaters or in reservoirs because the species is adapted to turbid, swift, warm rivers.

e. <u>Oil Losses</u>

It is estimated that about 150 miles of new pipeline will be required to transport 1 million barrels of shale oil daily to major existing petroleum pipelines (See Chapter I). This increase in pipeline mileage will bring with it the risks of oil spills due to pipeline losses caused by corrosion of pipe and equipment damage or other accident. Although the average quantity of oil spilled due to transportation by these pipelines would be relatively small (estimated to average from about 1 to 100 barrels per year), the danger of a large-volume spill does exist.

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In the event of an accidental loss, the oil would follow natural drainage features. Mortality from contact with oil would occur to trees, shrubs, and other vegetation; waterfowl, shore and wading birds; fish, and other aquatic organisms. Some species of both land and water mammals would also be affected. Revegetation of oil-soaked soils could be extremely slow. Magnitude of mortality and other adverse impacts would depend upon the location and volume of the spill and the particular habitat types affected. In the event of an oil spill of a few to 100 barrels at the time of spring runoff, fast running water could carry spilled oil long distances down the drainage before it could be contained. A large spill could destroy the entire population of nesting ducks and shore birds for many miles downstream. The oil would kill the larvae of many insects found in the water by smothering them. This would affect the whole food chain including fish, birds, and mammals. Recovery requires a long mitigating effort and several years would pass before the ecosystem would return to normal.

f. <u>Herbicides, Pesticides</u>

Chemical control of insects, birds, mammals, or plants will result in the introduction of the control agents into the ecosystem. As the greatest quantities of pesticides are expected to be applied by local governments and private homeowners, the potential impacts are discussed in Section E.3.a.

g. Air Quality

The impacts of air contaminents on flora and fauna are discussed in Section D.4.

h. Impacts Upon Threatened Species

Twenty threatened (including endangered) species or species of undetermined status are believed to exist in the oil shale region (Table II-14, Chapter II). Four of these are fish which exist in adjacent sections of the White and Green Rivers and tributaries (See Chapter II, Threatened Species). Up to 80,000 land acres could be directly affected by construction and operation activities of a regional oil shale industry. Impacts from this land use and associated industrial activities are difficult to quantify, as no threatened species are known to physically inhabit or breed on any of the six prototype oil shale tracts (Volume III). Further, industrial sites and additional lease sites on private and public lands needed to reach the 1-million-barrel-per-day production level are probably years away from decision and their locations uncertain. By virtue of its relatively undisturbed nature, much of the region is now available for permanent, seasonal, or transient use by these species. Threatened species are subject to the same effects and will generally exhibit the same reactions as the other species discussed above. Thus, development would prohibit or hamper the use of disturbed lands as habitat for threatened species. The associated industrial activities and noise would have disturbance and probable displacement effects on any threatened species which may presently reside on or close to lease tracts. Habitat destruction and, in the case of predatory birds, pesticide residues are probably the chief reasons for decline of these species. Filling of canyons with spent shale would destroy habitat for the spotted bat.

The extent to which oil shale operations would affect the Colorado squawfish, bony-tail chub, hump-backed sucker, and Colorado River cutthroat trout is dependent upon the quality of the surface waters (see the preceding discussion on Water Quality). The water quality decline in some streams exposed to waste discharge and industrial accidents could have serious effects. In the case of the squawfish, impoundments could destroy breeding habitat. If degradation or physical alteration was to occur in waters inhabitated by these species, a further population decline would be expected.

The reader is referred to the discussion of additional Impacts on Threatened Species due to indirect effect of development in the following section.

3. Regional Impacts From Urbanization and Human Pressures

a. Urbanization

Increasing population growth in the region as a result of oil shale development, along with the associated human activities, will have an adverse effect on existing fauna and flora of the region. The types of impacts and their effects, such as access to unaltered habitat, disturbance of animals, loss of habitat, and alteration of water quality, as already discussed in Section E.2., and air pollution, as discussed in Section D.4., would be expected to occur across the oil shale region as a whole. Land use in the form of homes, roads, parking lots, and service facilities will reduce food and cover vegetation and thereby reduce or eliminate associated populations of both terrestrial and aquatic animals. Increased access will bring more people in closer contact with wildlife resources.

Increased urbanization of this area will likely occur along natural water courses, thus degrading their natural values through the introduction of sewage containing high biological oxygen demand, nutrients, and toxic substances. Human activities, such as boating, fishing, and other recreation activities, also degrade the water quality by the introduction of gas, oil, and litter into the water. These practices, among other things, ultimately reduce available oxygen, increase phytoplankton production, and raise water temperature. The environment can become altered to the extent that endemic species can no longer sustain themselves. Increased ground vehicle traffic across the oil shale region will result in more frequent road kills of deer and other animals as previously described.

Dogs in rural areas are not normally contained and roam the countryside chasing deer, elk, antelope, and rabbits at will. Dog packs have created serious problems for wildlife in many other semi-inhabited areas through direct mortality and through creation of severe stresses by harassment. Stress on animals in poor condition in winter can cause death.

Additional pesticides will be used by municipalities and private citizens. Use, particularly by householders, can only be controlled through marketing restrictions. Quantities used and methods of application are uncontrolled. The region currently shows low levels of pesticide residues. Urban and industrial pesticide use can be expected to increase these levels significantly, at least in localized areas.

The effects of this introduction cannot be assumed, due to lack of data on quantities and specific types of agents which will be used. However, chlorinated hydrocarbons and phenoxy herbicides, even if properly registered and applied in accordance with Federal regulations and manufacturer's recommendations, could cause an extremely detrimental impact on downstream flora and fauna through a dangerous cumulative effect, i.e., addition to the existing level of pesticides from other sources. Existing pesticide residues which have been identified in the region include such chlorinated hydrocarbons as DDT, DDE, dieldrin, and endrin.

Potential effects include disruptions of metabolism and reproductive capacity in fishes, birds, and mammals. The following information was extracted from research results summarized by Menzie (44).

In laboratory studies, adverse effects have been observed in the reproduction of raccoons fed a diet containing 2 ppm dry weight of dieldrin. This level is frequently exceeded as residues in food organisms in areas which have been treated with aldrin or dieldrin. Adult female raccoons fed dieldrin produced fewer, smaller litters than did untreated controls. Embryonic survival was poorer. With males, sexual development was delayed, the animals were less aggressive, and they grew more slowly and gained less weight between fall and spring than did untreated controls.

In Alaska, peregrine falcons have experienced large reductions in eggshell thickness since 1946. These birds now lay eggs with shells as thin as those associated with the declining falcon populations of The United Kingdom, California, and the Eastern United States. In 1970, about 60 percent of the known peregrine falcon aeries in Alaska failed. The eggshell-thinning phenomenon is caused by residues such as DDE and dieldrin. This phenomenon is also exhibited by the bald eagle, sparrow hawk, mallard, cormorant, herring gull, and ibis, all of which are listed in Table II-26, Chapter II, as occuring in the oil shale region.

Exposure of salmonids such as rainbow trout and coho salmon to endrin and dieldrin has been shown to result in liver glycogenolysis, almost complete inhibition of an ammonia detoxifying system in the brain, and adverse effects on amino acid metabolism and thyroid activity.

Wild fires result in a temporary loss of wildlife food and cover, although the burnings are in some cases beneficial through a resulting regrowth of plants of a secondary successional stage which are the most beneficial to wildlife populations. For example, when climax stands of pinon and juniper are burned off, the first plants to appear are herbs, forbs, annual plants such as grasses and weeds, and seedlings. This stage provides more food for wildlife than the climax pinon-juniper. Another condition is the creation of an edge effect between the burned and the unburned area which is beneficial to wildlife by providing cover adjacent to food. The slow process of nutrient recycling through decomposition of detritus takes years, while nutrient recycling through burning is an almost immediate process.

With the projected increases in human population, the frequency of man-caused fires would increase, but the average size of a burn may be smaller due to earlier detection. The effect of repeated fires is cumulative for the vegetation and related wildlife.

b. Fish and Wildlife Management

Projections of hunting and fishing supply and demand without regional oil shale development by the year 2,000 in the Colorado, Utah, and Wyoming portions of the upper Colorado River region were obtained from the Upper Colorado Region Comprehensive Framework Study (45).

By state, the hunting projections are: Colorado - 1.340 million hunter days (mhd) supply vs. 1.024 mhd demand, or a 0.316 mhd surplus; Utah - 1.107 mhd supply vs. 0.445 mhd demand, or a 0.662 mhd surplus; Wyoming - 0.172 mhd supply vs. 0.178 mhd demand, or a 0.006 mhd deficit. These projections are totals of all types of hunting, i.e., big game, small game, and waterfowl.

With oil shale development, additional hunting demand will be generated and hunting opportunities will be reduced through habitat loss. However, the 978,000 hunter day surplus projected without oil shale development in Colorado and Utah will probably absorb the impact of a regional oil shale industry in those two states. In contrast, a 6,000 hunter day deficit for all types of hunting has been projected for Wyoming by the year 2000 without oil shale development. It should be noted that projections show a deficit of 25,000 hunter days for big game hunting. While projected surpluses in small game and waterfowl hunting reduce the overall deficit to 6,000 days, big game hunting is in much more limited supply state-wide and nation-wide. Big game hunting also provides a greater economic return per hunter to the state. Increased hunting pressure and reduced hunting opportunities due to oil shale development cannot be absorbed in this area of Wyoming. Any significant additional hunting needs generated in Wyoming as a result of oil shale development, coupled with reduced hunting opportunities, would aggravate the deficit and would necessitate additional compensating wildlife management programs, such as intensive habitat management (e.g., area protection and planting of preferred food and cover vegetation) and/or hunting restrictions (e.g., smaller bag limits, shorter seasons, closed areas, or restrictions in license sales).

Increased use of the oil shale region would create localized adverse impacts upon both game populations and quality of the hunting experience. Resulting increases in hunting pressure would have the potential to significantly reduce game populations, thus requiring additional regulatory management steps. For rabbits, showshoe hare, and mourning dove, which are presently not harvested near their population capacities, such additional harvesting would probably not be harmful. However, increases in kill of mule deer, elk, moose, antelope, sage grouse, and sharptail grouse would require careful regulation in order to avoid undesirable downward population trends. Region-wide increased hunting pressure would have the most potential for impact upon very low abundance species, such as black bear and cougar.

By state, fishing projections by the year 2000 without oil shale development are: Colorado - 5.807 million angler days (mad) supply vs. 3.206 mad demand, or a 2.601 mad surplus; Utah - 3.502 mad supply vs. 1.827 mad demand, or a 1.675 mad surplus; Wyoming - 1.681 mad supply vs. 0.312 mad demand, or a 1.369 mad surplus. Thus, it appears that the angling opportunity available at that time would accommodate additional regional angling demand and reduced angling opportunity generated by oil shale development.

However, a predictable decrease in the quality of both angling and hunting experience will occur wherever intensified use occurs. The quality of hunting and fishing is enhanced when it is pursued in remote areas and under uncrowded conditions. As an area becomes more civilized or as the man-days use increases, the quality and availability of solitude and naturalness decline. This decline in the quality of the outdoor experience is usually accompanied by such things as a decline in the number of trophy animals, a reduction in the size of game fish, or the introduction of conditioned game farm birds. Under these circumstances, specific fish or wildlife management plans, such as more intensive habitat management and/or hunting restrictions, would be required to adjust or alleviate such problems, but they could not restore the elusive qualities associated with the present semi-remote conditions.

c. Urbanization Impacts Upon Threatened Species

The urbanization associated with a regional oil shale industry would probably have an adverse, but unquantifiable effect on populations of the 20 species listed in Table II-14, Chapter II.

Land use for urbanization would be expected to remove habitat of value to these species. The broad range of human activities, introduced into their habitats ranging from recreation to day-to-day work, would be a source of regional stress and disturbance. For species which lack mobility due to restrictive habitat requirements, such encroachment would probably result in local extinction. Mobile species would avoid disturbed areas and, in so doing, lose access to both the affected habitat and the prey that may have resided in it.

Since urban areas can be expected to be located on or near water courses, turbidity and siltation can be expected to increase, at least during construction. Pollutants from storm sewers and, depending on treatment system, domestic sewage will degrade the aquatic habitat. These factors will have a depressing effect on any populations of the fishes listed.

Increased pesticide and herbicide levels could affect populations of aquatic organisms and, through various food chains, reduce the reproductive capability and affect the metabolism of the few remaining peregrine and prairie falcons and fish species such as the Colorado River cutthroat trout.

4. Cumulative Impacts on Fish and Wildlife

The scope of the 1-million-barrel-per-day industry visualized by about 1985 includes: 115,000 new inhabitants and associated urban development; an expanded road, pipeline, and power transmission system; and water consumption of 121,000 to 189,000 acre-feet per year (depending on various contingencies, consumption could be as little as 76,000 or as high as 295,000 acre-feet per year).

The cumulative regional effects on fish and wildlife will stem from the following causes: reduction in water quality, including siltation, various effluents, increased salinity and possible accidental spills of oil and other toxic substances; reduction in water supply (drying of springs, seeps, and headwater streams through alluvial water-table drawdown); increased urbanization and associated increases in road mileage, traffic, powerlines, solid and liquid wastes, hunting, fishing, camping, and off-road recreational vehicle use; increased noise from construction, equipment operation, and blasting; vegetation removal on up to 80,000 acres; and the filling of 15 to 50 canyons with spent shale (depending on disposal methods). These aspects are examined for cumulative impacts on the following broad classes: threatened species; big game; raptors, small game and other small animals; and fish.

a. Threatened Species

Those species dependent on limited habitat or remoteness from harassment will suffer most. Filling of canyons with spent shale will destroy habitat for falcons and the spotted bat. If colonies of burrowing rodents are destroyed, any black-footed ferrets in the area will be displaced and probably destroyed. Reduced water quality or impoundments in waters inhabited by the Colorado squawfish, Colorado River cutthroat trout, bony-tail chub, and humpbacked sucker will result in further population declines for these species. Habitat subject to noise and disturbance will be lost to peregrine and prairie falcons.

b. Big Game

Mule deer (estimated over recent years to be approximately 30 to 60,000 head in the Piceance Basin) will be reduced a minimum of 10 percent by disturbance and by displacement and competition as their habitat is destroyed. The extent of reduction will depend on whether disturbed areas are revegetated with winter browse species. Where antelope frequent areas affected by development, a similar reduction is expected. Animals such as the elk, moose, bear, and mountain lion, which are less tolerant of human activity, will be denied a greater amount of habitat because of avoidance of noise and human activity. This will lead to the virtual disappearance of such wilderness species from the region directly or indirectly affected by oil shale development. Hunting pressure will increase and harvest of game species will probably have to be reduced by more restrictive hunting regulations.

c. Raptors, Small Game, and Other Small Animals

Loss of habitat, reduced water supply, increased hunting pressure, and casual shooting will reduce populations of such animals as hawks, eagles, bobcat, raccoon, and ringtail cat and force displacement and increased competition for remaining food and water. The sage grouse, a scarce but highly prized game bird, will probably almost disappear from the oil shale regions of Colorado. Reductions in small prey species such as rodents and rabbits will also cause reductions in populations of predators.

d. Fish

Drying of streams, degrading of water quality, and impoundments and/or water diversion will cause reductions in, or change in desirability of, fish populations. Species especially vulnerable to changes in physical conditions or water quality (temperature, pH, toxic substances) include trout and whitefish as well as the threatened species mentioned above. Although fishing may be retained by stocking and other management steps, there will be a long-term decline in high-quality fishing, which depends on natural-spawned fish growing to good size in a relatively undisturbed environment.

F. Impact on Agriculture and Grazing

The oil shale lands themselves are not agricultural in the sense that they are not generally suited to cultivation. They are, however, subject to livestock use under grazing lease or permit from the Department's Bureau of Land Management. As with other mineral leasing, the use of the surface for grazing would not be precluded by oil shale lease issuance. Normally, the surface use would continue, except for areas undergoing active development, mining, or production as well as areas used for plant sites, access roads, and other similar uses. (See Section A, this Chapter.) Also, forage would be lost due to changes in the water table as a consequence of mine dewatering. Possibly, where canyons and gullies would be used as disposal sites, there could be some enhancement in their appearance and agricultural usefulness as a result of the contouring, fertilization, revegetation, and stabilization which would all be part of surface restoration operations.

Leasing of public oil shale lands could have an indirect impact on private land farming activities in the sense that cultivated lands adjacent to existing communities may be converted to business or residential use as those communities expand. It is very difficult at present to accurately estimate the total acreage which might be affected in that way, but it may approximate 15,000 to 20,000 acres for a 1-million-barrel-per-day industry.

An initial loss of grazing capacity on the leased lands cannot be avoided. This will result in varying degrees of economic loss to the livestockman, depending upon the extent to which private base ranches or other lands can provide additional grazing, the type of mining done, and the success of revegetation efforts. The long-term effect of industrialization would be some reduction of forest and brush cover.

The mining method or combination of methods used on the tracts determines the total number of acres affected, on- and off-tract, as explained in Section A of this Chapter. Of the total acres affected, those acres occupied by the plant, storage, and related facilities and improvements, including roads, would be unavailable for grazing during the life of the lease. Acreage that would be temporarily unavailable for grazing, which could average 20,000 acres for the 1-million-barrels-per-day industry, would include those lands where filling of overburden and spent shale was in process as well as areas of active mining. This acreage would be rehabilitated and revegetated as operations would permit, thus rendering it available for grazing during the life of the lease.

For instance, at the end of 30 years of lease operation and depending on the mining methods used, the average annual loss of animal unit months (AUMs) in Colorado would range from an estimated 60 to 260, while that acreage put back into grazing production because of restoration and revegetation could range from an estimated 60 to 270 AUMs per year. For Utah and Wyoming, at the end of 30 years of lease operation and depending on the mining methods used, the annual loss of AUMs could range from 275 to 317, while that acreage put back into grazing production because of restoration and revegetation could range from 275 to 1,080 AUMs per year.

Some disturbance to the grazing animals will take place because of increased activity, which could result in lowered total meat production. A larger populations density as a result of the project would increase the probability of animal disturbance from recreationists and possibly from theft.

There would be some additional effect on grazing in the areas (on and off lease tract) adjacent to the actual mining and retorting operations. Such activity may disturb livestock, which could result in lowered meat production.

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G. Impact on Esthetic, Recreational, and Cultural Values

Oil shale development will degrade the recreation and associated esthetic resources and activities of the region.

Areas that would be most affected scenically include: Cathedral Bluffs, Piceance Creek, sections of the Green River, Sand Wash Historical Landmark, Book Cliffs, and Kinney Rim. With the proposed projects, the general landscape would be changed from a quite natural asymmetric type to a symmetric landscape with buildings, roads, trails, pipelines, power lines, and cleared rights-of-way.

Archaeological and historical values along the White River in Utah are known to exist adjacent to the proposed project oil shale lands.

Examples include the Freemont Indian Culture, ghost towns of Rainbow and Watson, abandoned sections of the Uintah Railroad, and the old crossings of Ignacio Stage Stop and Old Uridge. Kinney Rim in Wyoming is the heart of the historic Wind River Shoshone and Commanche country. Indications are that campsite and animal-kill sites will be found in this particular basin dating from present to historic times dating back 10,000 years. All of these areas could be affected directly (on site) or directly (off site) as the proposed projects are developed.

Any development would result in the following impacts:

(1) Clear air would be degraded by dust from mining operations, on site as well as off site, on roads and other urban facilities.

(2) Visual impact from disposal of spent shale would be notable until restoration activities are completed; approximately 50,000 acres would be affected by industrial development.

(3) Visual impact on the asymmetric landscape would be impaired by utility rights-of-way such as pipelines, powerlines, roads, trails, and stack heights.

(4) An oil shale industry would probably have little impact on the recreational use of the tracts during the first few years. As the development progresses, it is estimated that approximately 5 percent (for underground operations) to 25 to 50 percent (for surface operations) of the hunting potential in and around the sites to be developed would be lost due to loss of wildlife habitat as well as the movement of wildlife species to other areas. Associated recreation activities that would be affected include camping, sightseeing, and rock hounding.

(5) Deer hunters and other types of outdoor enthusiasts would be forced to use other areas adjacent to the development sites thereby creating increases in hunter and other recreation use densities on the other areas. By such action, the existing quality of the other areas would be reduced.

(6) Improved accessibility created by the proposed projects would create moderate increases in outdoor recreation activities throughout the basins, putting increased pressure on existing facilities.

(7) The development of the open pit operation could provide an unusual vista which could increase tourist traffic beyond that associated with normal outdoor recreation activities.

The impact on outdoor recreation and its associated esthetic and cultural values is directly related to the refuse generated from mining and processing as well as the amount of land disturbed by the mining process used. Refuse will accumulate despite every attempt at control and where it does it will have damaging effect upon the environment, for example, junk equipment, combustible materials, excess chemicals, and spent oil and lubricants.

Oil shale development will create better access to the resources of the region and open up new areas for outdoor recreation. However, better access will create an increase in traffic, litter, and vandalism which could reduce the quality of the recreation experience.

H. Impact on Existing Economic and Social Environment

1. Overall Regional Impact

A number of assumptions must be made to study this potential economic impact. Although the assumptions could be varied, the cumulative effect of development on both private and public lands presented in this review is based upon what are considered to be reasonable projections and assumptions. This analysis also provides an indication of the urban planning needed to facilitate adjustment to a new industry.

Oil shale development will generate both permanent and temporary employment within the region. Extensive flows of capital into and out of the region also will occur as the equipment and services needed to sustain the operations are utilized.

a. Sequence of Development

The projected sequence of development has previously been presented (Section 1 of this Chapter and Table III-2). The analysis which follows can be directly related to site locations only for the development prior to 1982. The location of the plants that may be built beyond 1981 cannot now be estimated.

b. Employment and Population

Development of oil shale will create both temporary and permanent employment, a factor which must be considered in regional development plans.

(1) Temporary - All temporary employment will be associated with the construction of the plants and urban communities. Temporary support employment would be required to provide services to these construction employees. These jobs would be temporary only in the sense that the job terminates with the completion of the construction. As long as the industry continues to develop, shifting of construction personnel should take place between the different plant sites. Thus, as shown in Table III-17, total temporary employment would increase from about 3,500 in 1973 to 16,400 in 1977. Table III-17 only considers the employment associated with this first 400,000-barrel-per-day capacity. If additional development beyond the prototype program takes

TABLE III-17.--Colorado, Utah, and Wyoming--Oil Shale Temporary and Permanent Employment, Temporary and Permanent Population.

Year	Temporary employment				Permanent employment			Population 5/		
	Plant construction	Urban 1/ construction	Support 2/ 3/	Total	Plant	Support 2/ 4/	Total	Temporary	Permanent	Total
1973	1,470	696	1,365	3,531				8,615		8,615
1974	1,470	696	1,365	3,531				8,615		8,615
1975	4,410	2,088	4,095	10,593				25,845		25,845
1976	5,360	2,571	4,997	12,928	1,293	996	2,289	31,542	6,183	37,725
1977	6,830	3,267	6,362	16,459	1,293	996	2,289	40,157	6,183	46,340
1978	6,600	3,334	6,265	16,209	3,879	2,988	6,867	39,548	18,549	58,097
1979	4,180	2,165	3,998	10,343	6,069	4,674	10,743	25,236	29,016	54,252
1980	2,710	1,469	2,633	6,812	7,362	5,670	13,032	16,621	35,199	51,820
1981					10,090	7,771	17,861		48,242	48,242

1/ Derived from value of labor for urban construction.

2/ Assumes 1.37 employed people per new household.

3/ Based on employment multiplier of 0.63 times temporary plant plus urban employment. Source: Same as footnote 5, but modified to reflect the experience that ½ of all construction support workers will not bring their families into the region.

4. Based on employment multiplier of 0.77 times permanent plant employment. Source: Consulting Services Corp., for the Public Land Law Review Commission, Study of Impact of Public Funds on Selected Regional Economies, April 1969, p. 104.

5/ Based on a family size of 3.7 persons. Source: Bureau of Census data for Colorado, Utah and Wyoming.

Source: Bureau of Mines. The number of operating employees per unit of shale oil produced will decrease as the size of the plants increases.

place, temporary employment to bring productive capacity up to one million barrels per day by 1985 would expand to 29,000 in 1981 and 1982.

(2) Permanent - All permanent long-term employment would be associated with the daily operation of the plants and in providing supporting services. As shown in Table III-17, permanent employment would increase as additional plants come on stream, reaching approximately 17,800 in 1981. These plants will of course operate beyond 1981 and employment at each plant would remain stable once operation began. Development of the industry to one million barrels per day by 1985 would increase permanent employment by an additional 24,600 positions to 42,400.

The employment per unit of capacity would not be as great for this second stage of development since production would presumably be from larger, more efficient plants.

(3) Population - As shown in Table III-17, the total employment associated with oil shale development and the families of these new employees should result in the population of the region growing by about 48,200 people in the 1973-81 period. The 400,000-barrel-per-day capacity operating in 1981 will continue to support this 48,200 additional population, but this level would begin to decrease if the production rate were to decline.

If development to one million barrels per day takes place by 1985, the shale-oil-related population would grow by an additional 66,600 to 114,800. The growth in population per barrel of shale oil capacity is smaller for this second stage of development because of the presumption that larger, more efficient plants would be used.

(4) Current Employment and Population - In the seven counties which comprise the oil shale region, the 1970 population was approximately 119,000, of which 44,000 were employed (Table III-18). The creation of over 17,800 new permanent jobs by 1981 or 42,400 by 1985 cannot be satisfied from the existing population, and therefore a migration into the region would result. Over a 9-year period to 1981, the total population of the area would thus increase by 40 percent on the basis of a 400,000-barrel-per-day industry. On the basis of a one-million-barrel-per-day industry, population would increase 96 percent by 1985.

c. Expenditure Flows

The oil shale industry should stimulate expenditures for both plant equipment and urban facilities. In addition, significant payment of money to the employees (as salaries) and to Federal, State, and local governments (as taxes and other revenues) would also be produced. These economic changes are discussed immediately below and the impacts of these changes are discussed in Parts d, e, and f of this section.

(1) Plant and Urban Construction - The cost of the oil shale plant depends upon both the technology used and the size of the expected output (Tables III-19 through 25). These data and the previously described development schedule (Table III-2) were used to estimate annual plant equipment purchases from 1973 to 1981 (Table III-26). Nearly $1.2 billion would probably be spent over this time period

TABLE III-18.--Population and Labor Force of Counties Within the Oil Shale Region, 1970.

(Thousands of people)

State County	Population	Total employment-16 years of age and over	Percent Unemployed
<u>Colorado</u>			
Garfield....	14.8	5.9	4.9
Mesa........	54.3	20.1	5.4
Rio Blanco..	4.8	1.9	2.1
<u>Utah</u>			
Duchesne....	7.3	2.4	4.6
Uintah......	12.7	4.0	7.0
<u>Wyoming</u>			
Sweetwater..	18.4	7.0	4.4
Uinta.......	7.1	2.6	4.6
Total	119.4	43.9	4.9

Source: 1970 Census of Population, General Social and Economic Characteristics. U.S. Department of Commerce, Washington, D. C., 1972.

TABLE III-19. Shale Oil Capital, Operating and Resource Costs

	50,000 B/D and underground mining	100,000 B/D and underground mining	100,000 B/D and Open Pit Mining	50,000 B/D, in situ
Resource cost $/Bbl	3.49	2.84	2.86	4.71
Single plant costs:				
Capital cost MM$	254	426	436	228
Operating cost MM $/yr	30.6	52.0	47.8	54.9
Operating labor (no. of workers)	1,293	2,190	2,190	1,435
Plant costs For 250,000 B/D Capacity				
Capital MM$	1,270	1,065	1,090	1,140
Operating cost MM$/yr	153	130	120	275
Operating labor (no. of workers)	6,465	5,475	5,475	7,175

Source: Calculations made by the Process Evaluation Group, U.S. Bureau of Mines, Morgantown, W. Va., 1972.

TABLE III-20.--Oil Shale Plant-- 50,000- and 100,000-barrel-per-day capacities with underground mining-- Capital Cost Summary.

EXPENSE	50,000 B/CD 1/	100,000 B/CD 1/
Mine:		
Initial investment...............	$13,535,200	$24,609,400
Present worth of deferred expense (discounted at 12 pct).......	7,985,400	14,518,900
Retorting plant:		
Retorting......................	76,105,400	115,381,100
Crushing and screening..........	8,123,600	12,316,000
Briquetting.....................	1,043,500	1,582,000
Refinery........................	66,122,400	113,339,700
Utilities.......................	24,193,200	41,469,400
Facilities......................	18,026,000	30,898,200
Subtotal........................	215,134,700	354,114,700
Initial Catalyst................	4,759,000	9,517,700
Total plant cost (insurance and tax base)................	219,893,700	363,632,400
Interest during construction, plant.	9,853,700	16,225,200
Interest during development, mine...	308,900	561,700
Startup expense.................	6,619,900	11,033,100
Subtotal for depreciation..........	236,676,200	391,452,400
Working capital.................	17,382,000	34,764,400
Total...........................	254,058,200	426,216,800

1/ Barrels per calendar day.

Source: Calculations made by the Process Evaluation Group. U. S. Bureau of Mines, Morgantown, W. Va. 1972.

TABLE III-21--Oil Shale Plant-- 50,000- and 100,000-barrel-per-day capacities with underground mining-- Operating Cost Summary 1/ (Annual cost, dollars).

EXPENSE	50,000 B/CD 2/	100,000 B/CD 2/
Natural gas........................	$164,700	$329,400
Charge for use of water............	54,700	109,300
Annual catalyst and chemicals......	2,667,500	5,335,000
Direct labor, plant................	1,762,100	2,980,900
Direct labor supervision, plant....	319,200	540,000
Direct labor, mine.................	3,122,600	5,282,500
Direct labor supervision, mine.....	223,400	378,000
Maintenance labor, plant...........	2,556,600	4,365,000
Maintenance labor supervision, plant...........................	248,300	420,000
Maintenance labor, mine............	902,200	1,526,300
Maintenance labor supervision, mine............................	186,200	315,000
Operating supplies, mine...........	6,061,400	10,104,400
Operating supplies, plant (20 pct of plant maintenance)...........	1,072,300	1,814,000
Maintenance materials, plant (100 pct of maintenance labor).	2,556,600	4,325,000
Payroll overhead, mine (35 pct of payroll).......................	1,552,100	2,625,600
Payroll overhead, plant (25 pct of payroll).......................	1,221,500	2,066,500
Administration and general overhead, plant................	730,600	1,235,900
Administration and general overhead, mine.................	764,800	1,293,800
Insurance, mine....................	270,700	492,200
Insurance, plant...................	4,127,200	6,490,100
Total..........................	30,564,700	51,986,900
Byproduct credit...................	3,554,200	7,108,400
Operating labor (Workers).........	1,293	2190

1/ Excludes property taxes and depreciation.

2/ Barrels per calendar day.

Source: Calculations made by the Process Evaluation Group, U.S. Bureau of Mines, Morgantown, W. Va., 1972.

TABLE III-22.--Oil Shale Plant-- 100,000-barrel-per-day capacity with open pit mining-- Capital Cost Summary

(Dollars)

Mine:	
Initial investment	$30,761,800
Present value of deferred expense (discounted at 12 percent)	18,148,600
Retort plant:	
Retorting	115,381,100
Crushing and screening	12,316,000
Briquetting	1,582,000
Refining	113,339,700
Utilities	41,469,400
Facilities	30,898,200
Subtotal	363,896,800
Initial catalyst	9,517,700
Total plant cost, insurance and tax base	373,414,500
Interest during construction:	
Plant	16,225,200
Interest during development:	
Mine	702,100
Startup expense	11,033,100
Subtotal for depreciation	401,374,900
Working capital	34,764,000
Total	436,138,900

Source: Calculations made by the Process Evaluation Group, U.S. Bureau of Mines, Morgantown, W. Va., 1972.

TABLE III-23.--Oil Shale Plant-- 100,000-barrel-per-day capacity with open pit mining-- Operating Cost Summary. 1/

(Dollars)

Operating Cost Items	Annual cost
Natural gas	329,400
Charge for use of water	109,300
Annual catalyst and chemicals	5,335,000
Direct labor, plant	2,980,900
Direct labor supervision, plant	540,000
Direct labor, mine	4,226,000
Direct labor supervision, mine	302,400
Maintenance labor, plant	4,325,000
Maintenance labor supervision, plant	420,000
Maintenance labor, mine	1,221,000
Maintenance labor supervision, mine	252,000
Operating supplies, mine	8,081,900
Operating supplies, plant (20 pct of plant maintenance)	1,814,000
Maintenance materials, plant	4,325,000
Payroll overhead, mine	2,100,500
Payroll overhead, plant	2,066,500
Administration and general overhead, plant	1,235,900
Administration and general overhead, mine	1,035,000
Insurance, mine	615,200
Insurance, plant	6,490,100
Total	47,805,100
By-product credit	7,108,400
Operating labor (Workers)	2190

1/ Excludes property taxes and depreciation.

Source: Calculations made by the Process Evaluation Group, U.S. Bureau of Mines, Morgantown, W. Va., 1972.

TABLE III-24.--Oil Shale Plant-- 50,000-barrel-per-day capacity with in situ retorting --Capital Cost Summary.

(Dollars)

Recovery plant and compression	$91,543,800
Initial wells	3,145,800
Refinery	46,727,400
Pipelines	12,352,800
Plant facilities	5,618,800
Plant utilities	21,295,900
Total construction	180,684,500
Initial catalyst and chemicals	4,902,300
Total plant cost (insurance and tax base)	185,586,800
Interest during construction	9,279,300
Startup expense	6,328,500
Subtotal for depreciation	201,194,600
Working capital	26,506,100
Total	$227,700,700

Source: Calculations made by the Process Evaluation Group, U.S. Bureau of Mines, Morgantown, W. Va., 1972.

TABLE III-25.--50,000-Barrel-Per-Day Capacity with In Situ Retorting--Operating Cost Summary. 1/

(Dollars)

EXPENSE	Annual cost
Water use charge	$ 34,200
Annual catalyst and chemicals	1,874,800
Direct labor	2,290,100
Direct labor supervision	271,700
Maintenance labor	1,034,000
Maintenance labor supervision	106,300
Maintenance material	1,034,000
Operating supplies	434,900
Payroll overhead	925,600
Administration and general overhead	1,265,600
Insurance - retorting, recovery, and refining	3,711,700
Methane	5,027,400
Annual wells	36,878,700
Total	54,889,000
Byproduct credit	1,783,800
Operating labor (workers)	1,435

1/ Excludes property taxes and depreciation.

Source: Calculations made by the Process Evaluation Group, U.S. Bureau of Mines, Morgantown, W. Va., 1972.

TABLE III-26.--Plant Equipment and Urban Materials[1] Purchased.
(Millions of Dollars)

Year	Plant equipment	Urban materials	Total
1973	51.2	16.7	67.9
1974	51.2	16.7	67.9
1975	153.6	50.1	203.7
1976	190.7	61.7	252.4
1977	241.9	78.4	320.3
1978	234.0	80.2	314.2
1979	145.7	51.9	197.6
1980	94.5	35.2	129.7
Total	1,162.8	390.9	1,553.7

1/ Urban construction is estimated at $45,000 capital cost per household for new residential, commercial, and community facilities. Of this total, $30,000 is allocated to materials and $15,000 to labor.

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for the equipment needed to produce a 400,000-barrel-per-day shale oil output from both private and public lands. An additional $1.7 billion would be spent by 1985 if development to 1 million barrels per day takes place.

Urban construction would be required to provide housing and service facilities to the new employment stimulated by this industry. Development will occur primarily in the existing urban centers which are most convenient to the plant locations. Rock Springs, Wyoming, Vernal, Utah, and Rangely and Grand Junction, Colorado, will probably be the major centers of initial growth and development. Urban construction would probably take place concurrently with plant construction, in order for the urban facilities to be available for the operating employees when the plant construction would be completed. In calculating the amount of urban materials that would be purchased (Table III-26), it has been assumed that no appreciable capital investment would be made for the benefit of temporary construction employees that cannot be used by the permanent operating employees. As shown, over $390 million may be spent for urban construction materials over the 1973-80 period. Another $540 million would be spent by 1985 to accommodate a 1-million-barrel-per-day industry.

Because a limited manufacturing base currently exists within the seven counties that comprise the oil shale region, it has been assumed that nearly all plant and urban construction materials would be purchased outside the region during this period. Together, these expenditures (Table III-26) would total nearly $1.6 billion over the 8-year period beginning in 1973 and an additional $2.2 billion by 1985.

(2) Employee Incomes - The projected amount of salary spent was used to approximate the income that would be spent within the region, an assumption that would be true only if the total value of tax payments leaving the region equals the value of the profits that remain. As shown in Table III-27 about $920 million would be paid as salaries to construction and construction-support employees through 1981. Of the $1.4 billion total, $1.28 billion or 91 percent of the gross salaries should remain within the oil shale region.

By 1985, an additional $1.8 billion in salaries would be paid to new employees connected to the expansion to one million barrels per day plus the $660 million earned by the old employees from 1982-85.

(3) Tax Flows - Total taxes and public revenues should increase to about $307 million per year by 1981 (Table III-28). These amounts would accrue as follows: 71 percent to the Federal Government, 11 percent to State, and 18 percent to local governments. The annual Federal share by 1981 would be $219 million, derived mainly from the income tax payments of shale oil producers and from personal income taxes. State revenues would reach $33 million per year by 1981, derived mainly from State income tax on oil shale profits ($19 million) and that portion of the royalty payment rebated to the States ($6. million). Individual income tax, other-business income tax, and sales tax make up the remaining $8 million. Use tax on construction material is zero in 1981 since no construction associated with the 400,000-barrel-per-day capacity will be underway in 1981.

Local taxes, which are essentially property taxes, would total $54 million in 1981. The oil shale producers would pay $3 million

TABLE III-27.--Salaries and Distribution: Colorado, Utah, and Wyoming.
(Millions of dollars)

	Construction[1/] (plant and urban)	Construction Support[2/]	Operating[3/]	Urban[2/] support	Total	Salaries spent within region[4/]
1973	30.5	10.2			40.7	35.0
1974	30.5	10.2			40.7	35.0
1975	91.5	30.6			122.1	104.9
1976	111.3	37.4	13.6	7.5	169.8	149.0
1977	141.8	47.6	13.6	7.5	210.5	184.0
1978	139.2	46.9	40.8	22.5	249.4	223.4
1979	88.9	29.9	61.5	35.1	215.4	198.8
1980	58.4	19.7	75.1	42.6	195.8	184.9
1981			106.6	58.4	165.0	165.0
Total	692.1	232.5	311.2	173.6	1,409.4	1,280.0

1/ Plant construction salaries assumed to be $15,000 per man-year and urban construction salaries $12,000.

2/ All support salaries were estimated at $7,500 per man year.

3/ Operating salaries assumed to range from $9,400 to $12,500 per man-per year depending on the size of the plant.

4/ Assumes that one quarter of the construction workers will not bring their families into the region and that these workers will spend only one quarter of their salaries in the region.

TABLE III-28 .--Taxes and Public Revenues: Colorado, Utah and Wyoming.
(Millions of dollars) 1/

	Federal	State 2/	Local 2/	Total
1973	4.9	3.5	--	8.4
1974	4.9	3.5	--	8.4
1975	14.8	10.7	--	25.5
1976	45.8	16.8	7.1	69.7
1977	50.7	20.3	7.1	78.1
1978	107.8	28.5	21.3	157.6
1979	150.5	30.7	33.6	214.8
1980	175.2	32.0	40.7	247.9
1981	219.5	33.1	54.3	306.9
Total	774.1	179.1	164.1	1,117.3

1/ Figures were calculated by the U.S. Bureau of Mines using tax rates provided in the Annual Report of the Colorado Department of Revenue, Fiscal Year Ending June 30, 1969, and the Federal Internal Revenue Code of 1954 including the Tax Reform Act of 1969. The Mineral Leasing Act of 1920 was used to appropriate Federal/State shares of the royalties.

2/ State and local tax rates applicable in Colorado were used to estimate regional tax revenues. Federal revenues are independent of State location of plant sites.

tax on resource value and $40 million on plant value. Taxes on other private property would add another $11 million.

If the industry reaches a one-million-barrel-per-day production rate in 1985, tax revenues in that year should total $759 million. This total would be made up on $541-million Federal, $86-million State, and $132-million local taxes.

(4) Distribution of Bonuses, Rents, and Royalties Received by the Federal Government - The monies collected by the Federal Government as bonuses, rents, and royalties from oil shales leases are redistributed among the County, State, and Federal Governments for specific uses established by law.

The Mineral Leasing Act of 1920 provides in Section 35:

> That 10 per centum of all money received from sales, bonuses, royalties, and rentals under the provisions of this Act excepting those from Alaska, shall be paid into the Treasury of the United States and credited to miscellaneous receipts; for the past production 70 per centum, and for future production 52-1/2 per centum of the amounts derived from such bonuses, royalties, and rentals shall be paid into, reserved, and appropriated as a part of the reclamation fund created by the Act of Congress, known as the Reclamation Act, approved June 17, 1902, and for past production 20 per centum, and for future production 37-1/2 per centum of the amounts derived from such bonuses, royalties, and rentals shall be paid by the Secretary of the Treasury after the expiration of each fiscal year to the State within the boundaries of which the leased lands or deposits are or were located, such monies to be used by such State or subdivisions thereof for the construction and maintenance of public roads or for the support of public schools or other public educational institutions, as the legislature of the State may direct.

The 52-1/2 percent paid into the reclamation fund is used for "the examination and survey for and the construction and maintenance of irrigation works for the storage, diversion, and development of waters for the reclamation of arid and semiarid lands in the said States and Territories, and in the State of Texas, and for the payment of all other expenditures provided for in" the Reclamation Act of 1902 (USC Title 43 § 391).

The 37.5 percent that is paid to the States is allocated by Colorado, Utah, and Wyoming, as follows:

Colorado

33.3% to the State public school fund
66.7% to the county from which it was derived to be used for public schools or public roads but not more than 75% to either use in any one year. No single county shall be paid an amount in excess of $200,000

Utah

90% of the monies received shall go into the uniform school fund to support the public schools of the State
10% shall be allocated to the county in which the mineral was produced to be used for road purposes

Wyoming

3% to originating county for roads
3% to State Highway Commission for road work in originating county
35% to State for roads
50% credited to the foundation program fund for the public schools
9% credited to the University of Wyoming

d. Urban Development

The development of 400,000 barrels of shale oil by 1981 would result in a population increase of 48,200 people which represents a 40-percent increase over the present population. Some of the small cities would grow to several times their current size.

Larger cities, with over 10,000 population, could almost double in size.

Urban growth and development will also require electric power. The requirements for the new urban population is only 6 percent of the power requirements of the oil shale facilities. It is assumed that these needs have been provided for in the expansion required for these plants themselves.

Two of the greatest needs of the new population will be housing and schools. Housing requirements for 48,200 people would be approximately 13,000 dwelling units.[1] Although there may be an abnormally high percentage of mobile home occupants during the initial stages of industrial development, it is believed this tendency will be greatly decreased once the employment and population become more stable. Growth effects (disorderly sprawl, substandard housing, sanitation problems, etc.) on local communities will vary depending upon the zoning and construction standards set and the degree of enforcement. The possibility exists that low-quality substandard conditions will occur, and in some communities, residential growth will not be uniformly controlled

The number of students between the ages of five and eighteen will increase by approximately 15,500 in the area. Based on a classroom size of 30 students, an additional 500 classrooms will be needed throughout the entire region.

1/ Based on 3.7 persons per family.

Adequate housing and related sewer and sewage treatment facilities will be a significant problem associated with a large influx of oil-shale-related population. Local contamination of ground water in the area has recently resulted from makeshift cesspools associated with mobile homes at construction sites and elsewhere. Advance planning and controls can prevent similar problems from occurring as oil shale development progresses.

As indicated in Table III-29, the major communities in the shale region are presently served by waste water treatment facilities designed to remove at least 85 percent of the 5-day biological oxygen demand and suspended-solids loading. The actual removal efficiencies of these plants varies from 60 to over 90 percent, depending upon operating conditions.

With the exception of the treatment facilities at Grand Junction, the treatment capacities of the facilities in the other communities will have to be expanded by 1981 to handle the waste loadings generated by an oil-shale-related population increase of 48,200. The impact on water, assuming this expansion, has been considered in Section C. As shown in column 8 of Table III-29, plant capacity expansion varies from none at Grand Junction, Colorado, to a sevenfold increase at Grand Valley, Colorado. It is estimated that these treatment plant expansions (including plant, interceptors, pumping stations, and outfalls) will require a cost outlay of approximately $3.3 million (1972 dollars). These costs do not include the expenditures which will be necessary for

Table III-29 --Municipal Wastewater Treatment Facilities.

Community Name	Present Pop.	Sewers	Type of Waste Treatment	Discharge To	1981 Pop.	Plant Design Capacity Population Equivalent (PE)	Capacity Expansion Above Present 2/
Rangeley, Colo.	1,500	Separate Storm - Sanitary	Secondary Treatment Aerated Lagoons and Polishing Pond	White River	10,500	3,200	3
Meeker, Colo.	1,500	Combined and Separate Storm - Sanitary	Secondary Treatment, Extended Aeration	White River	7,700	2,000	4
Rifle, Colo.	2,500	Separate Storm - Sanitary	Secondary Treatment, Oxidation ponds	White River	8,000	3,500	2
Glenwood Springs, Colo.	4,100	Separate Storm - Sanitary	Secondary Treatment, High-Rate Trickling Filter With Recirculation	Colorado River	8,100	12,000 1/	none 3/
Grand Valley, Colo.	<100	Separate Storm - Sanitary	Secondary Treatment, Extended Aeration	Parachute Creek	2,000	300	7
Grand Junction, Colo.	20,200	Combined and Separate Storm - Sanitary	Secondary Treatment, High-Rate Trickling Filter	Colorado River	32,700	46,000	none
Vernal, Utah	4,000	Separate Storm - Sanitary	Secondary Treatment, High-Rate Trickling, Filter	Ashley Creek to Green River	8,000	5,000	1.6
Rock Springs, Wyo.	11,650	Separate Storm - Sanitary	Secondary Treatment, Standard-Rate Trickling Filter	Bitter Creek (dry)	17,000	12,000	1.5
Green River, Wyo.	4,200	Separate Storm - Sanitary	Secondary Treatment Oxidation Ponds	Green River	6,000	5,100	1.2

1/ Includes West Glenwood Treatment Plant with a present design P E of 2,000.

2/ Represents comparison of Column 6 with Column 7, i.e. for Rangely, Column 6 is three times as large as Column 7, therefore treatment plant capacity will have to be tripled.

3/ Some expansion of the West Glenwood Treatment Plant will probably be necessary if the population locates west of Glenwood Springs in the Roaring Fork Valley.

improvement of existing sewers and installation of new sewer systems.

It is estimated that the additional 48,200 people in the communities of the oil shale area will cause the discharge of an additional 4,800 tons of salt per year into the receiving waters of the oil shale area. This salt loading will result in an increase in salinity at Hoover Dam of 0.3 mg/l. In addition, some 96 tons per day (35,000 tons per year) of solid wastes will be generated by these 48,200 new residents. The cost of disposing of this garbage, trash, etc., in sanitary landfills will be approximately $33.1 million per year.

In the calculation of construction salaries and purchases of construction materials, $2,700 per person has been allowed for the capital cost of new public construction. This is a liberal allocation in view of the estimated costs of some of the more important individual public capital costs. Schools are estimated (13) to cost $350 per person, hospitals $120 per person, water treatment and distribution $150 per person, and sewage disposal $150 per person.

Local property taxes are estimated to total about $1,125 per person per year of which 80 percent would come from payments on the oil shale facilities. Thus, overall local tax revenues should be large enough to amortize the required urban capital expenditures.

There will be a lag between the time when expenditures must be made for public construction and the time when property tax revenues become available to amortize these expenditures (Table III-30). The financing of public expenditures by municipal bonds is the usual way of overcoming this lag.

Small communities may not be able to issue bonds sufficient to finance the necessary expenditures because of their small tax base. In such cases it may be possible for the State to lend its credit to underwrite such issues.

Another avenue to the financing of new urban development could be the "Urban Growth & New Communities Development Act of 1970" of the U.S. Department of Housing and Urban Development. Under this program, the Federal Government guarantees loans made to developers for the construction of private and public facilities in new communities.

An additional problem of municipal financing will arise when the urban development associated with an oil shale plant is not in the same county as the plant. Since the plant will contribute 80 percent of the new local tax revenues, urban development will be difficult to finance without access to the taxes generated by the plant.

This problem is not unique to the oil shale area. It occurs when a large employer is near a county line or when the suburbs of a large city are in a different county than the city proper. It can be alleviated in a number of ways, most of which require State legislation. Regional taxing authorities can be

TABLE III-30.--Public Construction Expenditures 1/ and Local Tax Receipts: Colorado, Utah, and Wyoming. (Millions of dollars)

Year	Tax receipts	New public construction expenditures
1973	--	5.6
1974	--	5.6
1975	--	16.7
1976	7.1	20.6
1977	7.1	26.1
1978	21.3	26.8
1979	33.6	17.3
1980	40.7	11.8
1981	54.3	--
Total	164.1	130.5

1/ On the basis of $10,000 per permanent family.

created; bi-county school and water districts can be established; and the State can redistribute its allocation of funds to the counties.

e. Social and Community Impacts

The predominantly rural oil shale region will be changed by the prototype leasing program. The changes will not only occur in the physical environment but will also occur in the community structures and organizations, in the economic and political systems of the area, and perhaps more importantly, in the social structures or lifestyles of all the people involved.

The influx of 48,200 new inhabitants to the area will have the most visible impact on the social and community structures. For the most part, these people will migrate from more urbanized and densely populated regions. They will expect certain amenities and conveniences, and patterns of living which will not be readily available in the oil shale region. This may be a relatively simple adjustment for some of the immigrants to make. Others will not want to or be as capable of making the adjustments even for a relatively short period of time and will influence the worker turnover rate.

The influx of those new residents, however, will have the greatest impact on the original inhabitants of the area. Over the leasing period, their life styles will change. The advent of a new industry and new employers represents technological progress, and any progress or change in one section of the society will initiate change in the social sector. However, a period of adjustment and cultural lag normally follows in which disorientation of people (and sometimes policies) occurs due to the naturally slower rate of social change.

The transformation from a semirural environment to an industrialized one will mean a faster, more-crowded pace of life at the very least. It will increase crime rates (Table III-31), change recreation patterns to more sophisticated urbanized (and more costly) styles, and will probably influence the unemployment rate as many unqualified people migrate to new areas of development looking for something better. The subjective nature of the cultural and social changes in living patterns and value judgments on life involved in evaluating these effects preclude accurate assessment.

In terms of social change, administrative items may or may not become major problem issues depending upon the local governments and/or planning commission's handling of them. These problems could include housing and street disruptions and possible initial overpopulating of school systems. Within each State, planning commissions have been established at the county level, and Colorado has also a State and regional planning commission. In at least two of the States, Wyoming and Colorado, zoning and subdivision regulations are already in effect which, if properly administered, can ensure orderly physical growth and development.

Two major problems which may arise during the construction period initially and may continue for some time during the production phase are inadequacies of housing facilities and the substantial

TABLE III-31.--U.S. Crime Rate in 1969.
(Number per 100,000 population)

City size	Violent crime	Property crime
Rural	100	1,150
Under 10,000	110	2,200
10-25,000	140	2,750
25-50,000	170	3,200

Source: Department of Justice, Federal Bureau of Investigation. Uniform Crime Reports for the U.S., 1969.

increase in road usage between urban centers and plant sites. Transportation routes and road improvement and maintenance usually represent a major difficulty to local governments in a rapidly industrializing area , as education and health facilities take priority and, in the beginning, public funds are limited.

The inadequacy of housing during the construction period especially may result in additional detrimental effects. The first effect could be overcrowding of existing facilities possibly creating health and safety hazards. Secondly, disproportionately high rents may also occur because of the high demand for housing. This could also affect the worker turnover rate. It is also expected that many of the workers, both construction and production, will bring mobile homes into the area.

One additional area of concern which cannot be quantified is the differences and possible antagonisms between the original townspeople and the immigrants. Though in many of the affected communities the immigrants will outnumber the original inhabitants, the immigrants would still be considered newcomers or outsiders and as such may not be readily assimilated into the communities.

Many of the inhabitants of these small communities chose and remained in this area to escape the pressures of urban living. They may resent immigrants because they represent increased urbanization. Stratification reflecting this attitude may be imposed by the inhabitants. A well-planned orientation program may be necessary to minimize these antagonisms.

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f. Health and Safety Impacts

The Bureau of Mines and industry have mined an estimated total of over 2 million tons of oil shale in experimental underground mines without a fatal accident. Despite this record, it should be recognized that any form of oil shale mining or in situ extraction process does have the potential of incurring hazards that may result in fatalities, injuries, or impaired health.

It is difficult to assess the potential for health and safety hazards, because no commercial oil shale industry exists and hence no actual comparable statistics are available. Underground, surface (open pit), in situ recovery, or combinations of these methods may be used in an oil shale industry. Comparable safety statistics from surface and underground mining operations for coal, metal, and nonmetal for the years 1959 through 1971 are summarized in Table III-32.[1/] As shown in that table, the average disabling work injuries per million man-hours (frequency rates) for underground operations range from a high of 1.19-fatal and 48.52-nonfatal injuries for coal to a low of 0.77 fatal injuries for metal and 40.67 nonfatal for nonmetal. In surface mining operations, the average frequency rates range from a high of 0.49-fatal and 24.51-nonfatal injuries for coal to a low of 0.27 fatal and 10.94 nonfatal injuries for metal. In preparation plants or mills, the average frequency rates range from a high of 0.43-fatal and 36.68-nonfatal injuries for coal to a low of 0.12 fatal and 10.42 nonfatal injuries for metal.

1/ Source: Mineral Industry Surveys, U.S. Department of the Interior, Bureau of Mines, Washington, D. C., 1960-1972.

In the absence of statistical information on oil shale mining and processing, the average of the frequency data (Table III-32) has been used to assess the probable frequency rates applicable to oil shale development. These data are given below:

Table III-32.-- Average Disabling Injuries, 1959-1971 Mining and Processing 1/. (Per million man-hours)

Function	Frequency Rates Fatal	Frequency Rates Nonfatal
Underground Mining	0.98	44.75
Surface Mining	0.35	18.00
Plant Operations	0.22	23.13

Safety statistics from the petroleum industry were used to assess the health and safety impacts of an in situ oil shale development since that technology is similar. Average injury frequency rates for the years 1968 through 1971 are summarized below: 2/

Table III-33.--Average Disabling Injuries, 1968-1971, (Per million man-hours)

Function	Frequency Rates Fatal	Frequency Rates Nonfatal
Drilling	0.27	46.93
Production	0.13	6.75
Refining	0.09	4.95

1/ Derived from data, Table III-34.
2/ Source: Annual Summary of Disabling Work Injuries in the Petroleum Industry. API Division of Statistics and Economics, Washington, D. C., April 1972.

TABLE III-34.--Disabling Injuries Per Million Man-Hours, 1959-1971.

	1959	1960	1961	1962	1963	1964	1965	1966	1967	1968	1969	1970	1971	AVERAGE
COAL														
Underground Mines														
Frequency rates:														
Fatal	1.11	1.20	1.34	1.34	1.28	1.12	1.21	1.12	1.05	1.63	0.95	1.20	0.84	1.19
Non-fatal	44.90	46.09	48.19	48.88	48.62	48.35	49.09	48.78	47.57	46.99	49.77	51.79	52.81	48.52
Surface Mines														
Frequency rates:														
Fatal	0.42	0.57	0.39	0.45	0.53	0.33	0.39	0.57	0.52	0.65	0.64	0.58	0.45	0.49
Non-fatal	22.52	24.81	24.66	23.68	24.87	24.81	26.39	25.25	23.07	24.97	22.22	25.60	25.06	24.51
Preparation Plants														
Frequency rates:														
Fatal	0.87	0.48	0.25	0.80	0.26	0.55	0	0.27	0.63	0.27	0.50	0.36	0.38	0.43
Non-fatal	39.75	39.19	40.53	36.42	44.51	49.49	51.62	28.59	33.68	27.62	27.24	29.34	28.93	3[illegible].68
METAL														
Underground Mines														
Frequency rates:														
Fatal	0.95	0.96	0.60	0.78	0.55	0.69	0.68	0.98	0.96	0.67	0.81	0.76	0.69	0.77
Non-fatal	42.41	45.40	46.78	44.26	45.62	44.34	42.87	43.64	42.62	41.56	44.74	50.20	51.27	45.05
Surface Mines														
Frequency rates:														
Fatal	0.27	0.31	0.21	0.26	0.22	0.26	0.27	0.22	0.30	0.46	0.34	0.26	0.20	0.27
Non-fatal	12.75	11.14	10.89	9.65	8.85	9.35	9.08	11.70	12.34	12.38	11.96	12.58	9.56	10.94
Mills														
Frequency rates:														
Fatal	0.33	0.09	0.06	0.28	0.11	0.11	0.06	0.14	0.15	0.04	0.11	0.14	0.18	0.12
Non-fatal	9.14	9.10	9.24	9.80	9.34	8.97	9.70	11.26	12.50	10.74	11.31	12.60	11.82	10.42
NON-METAL (except stone, sand and gravel)														
Underground Mines														
Frequency rates:														
Fatal	0.22	0.63	0.64	0.73	2.27	0.58	0.87	0.74	0.46	2.70	0.91	1.14	1.06	0.99
Non-fatal	42.96	46.60	36.88	42.64	39.64	37.96	39.20	37.49	43.00	47.67	36.91	38.61	39.26	40.67
Surface Mines														
Frequency rates:														
Fatal	0.35	0.46	0.30	0.25	0.10	0.45	0.38	0.22	0.43	0.17	0.29	0.24	0.17	0.29
Non-fatal	21.48	19.16	17.45	20.80	17.72	17.33	18.70	20.05	18.32	16.29	19.61	17.03	17.22	18.59
Mills														
Frequency rates:														
Fatal	0.12	0.15	0.07	0.12	0.03	0.08	0.14	0.15	0.19	0.05	0.16	0.16	0.16	0.12
Non-fatal	23.77	20.77	20.02	18.53	19.44	22.11	20.89	21.48	22.15	23.82	23.27	25.60	28.12	22.30

The frequency rates from Tables III-32 and III-33 were applied to a potential 1-million-barrel-per-day oil shale industry that could be developed over the 10-year period (1976 through 1985). A total of 97 fatal and 6,353 nonfatal injuries could be expected to occur as shown in Table III-35.

Table III-35.--Total Potential Disabling Injuries for One-Million Barrel per Day Oil Shale Industry (1976 through 1985).

Function	Injuries	
	Fatal	Nonfatal
Underground Mines	63.93	2,919.06
Surface Plants for Underground Mines	14.63	1,537.23
Surface Mines	6.22	320.40
Plants for Surface Mines	5.00	525.31
In Situ Drilling	5.72	996.79
Plants for In Situ Processing	1.00	54.06
Total	96.50	6,352.85

Derivation of the above data was based on data described below in Tables III-36 and III-37.

Table III-36 gives the estimated number of man-hours worked based on the development to a 1-million-barrel-per-day industry (Table III-37). Man hours worked were derived on the basis of 2,080 hours worked per year per employee. Administrative personnel are excluded because their injury frequency rates are low and this would tend to bias the estimated number of injuries downward.

The number of disabling injuries (Table III-37) was computed by applying injury frequency rates in Tables III-33 and III-35 to the man-hours worked; the last row in Table III-37 is identical to data previously summarized in Table III-35.

It can be expected that the effects of the newly updated and stronger laws relating to health and safety in the mineral industry as well as substantially increased staffing by the U.S. Bureau of Mines and States' industrial commission inspection teams should considerably decrease the number of disabling injuries in the future.

In addition, the Bureau of Mines is conducting extensive research in all areas of mine health and safety as part of a comprehensive health and safety program. These research results will be available to help guide the planning and evaluation of a developing oil shale industry.

2. Economic Impacts in Colorado

As detailed in Table II-2, development of the two prototype leases in Colorado is expected to result in a shale oil productive capacity of 50,000 barrels per day on one of the tracts with

TABLE III-36.--Man-Hours Worked.
(Millions)

Year	Underground		Surface		In Situ	
	Mine	Plant	Mine	Plant	Drilling	Plant
1976	1.19	1.21				
1977	1.19	1.21				
1978	3.56	3.63				
1979	3.56	3.63	1.78	2.27		
1980	4.74	4.83	1.78	2.27		
1981	5.93	6.04	1.78	2.27	1.93	.84
1982	8.30	8.46	1.78	2.27	3.86	1.68
1983	11.86	12.08	1.78	2.27	3.86	1.68
1984	11.86	12.08	4.45	5.68	3.86	1.68
1985	13.04	13.29	4.45	5.68	7.73	3.36
Total	65.23	66.46	17.80	22.71	21.24	9.24

TABLE III-37.--Potential Disabling Injuries.

Year	Number of Disabling Injuries														
	Underground				Surface				In Situ				Total	
	Mine		Plant		Mine		Plant		Drilling		Plant			
	Fatal	Non-Fatal	Fatal	Non-Fatal	Fatal	Non-Fatal	Fatal	Non-Fatal	Fatal	Non-Fatal	Fatal	Non-Fatal	Fatal	Non-Fatal
1976	1.17	53.25	.27	27.99									1.44	81.24
1977	1.17	53.25	.27	27.99									1.44	81.24
1978	3.49	159.31	.80	83.96									4.29	243.27
1979	3.49	159.31	.80	83.96	.62	32.04	.50	52.51					5.41	327.82
1980	4.65	212.12	1.06	111.72	.62	32.04	.50	52.51					6.83	408.39
1981	5.81	265.37	1.33	139.71	.62	32.04	.50	52.51	.52	90.57	.09	4.91	8.87	585.11
1982	8.13	371.43	1.86	195.68	.62	32.04	.50	52.51	1.04	181.15	.18	9.83	12.33	842.64
1983	11.62	530.74	2.66	279.41	.62	32.04	.50	52.51	1.04	181.15	.18	9.83	16.62	1,085.68
1984	11.62	530.74	2.66	279.41	1.56	80.10	1.25	131.38	1.04	181.15	.18	9.83	18.31	1,212.61
1985	12.78	583.54	2.92	307.40	1.56	80.10	1.25	131.38	2.08	362.77	.37	19.66	20.96	1,484.85
Total	63.93	2,919.06	14.63	1,537.23	6.22	320.40	5.00	525.31	5.72	996.79	1.00	54.06	96.50	6,352.85

underground mining by 1978 and 100,000 barrels per day on the other with open pit mining by 1979. In addition, oil shale plants on private lands in Colorado are projected at 50,000 barrels per day in 1976 with like amounts becoming operational in 1978 and 1981.

a. Employment and Population

The development of a 50,000 barrel per day plant in Colorado will result in significant population and revenue increases. Construction of this plant will necessitate a temporary population increase of 8,600. When the plant begins operation, the permanent population increase in Colorado will be 6,183 new residents associated with a 50,000 barrel per day plant.

The salaries of construction and permanent long-term employees which will be generated by operation of this plant will total $40.7 million for the first 3 years and then will level off to $21.1 million (because of the loss of the construction workers). The total figure for salaries spent within the region, however, will be $35.0 million the first 3 years and will then drop to the $21.1 million, because of the lesser number of families brought into the area by construction workers. Local revenues generated by this single operation will be $7.1 million but will not be realized until the plant is operating. State revenues, however, will begin to occur as soon as construction begins and will be $3.5 million for 3 years and then will increase to $4.8 million. (These figures differ from the ones presented in Tables III-35 and III-36 because those tables combine the salaries and public revenues from two plant operations.)

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Construction of the 100,000-barrel-per-day plant is projected to begin in 1976. This construction will provide employment for 2,420 for the 3-year construction period. An additional 1,179 construction jobs will be provided by urban construction during the same period. Construction personnel and their families will generate employment for 2,267 in supporting services. The overall population increase associated with the temporary employment for construction and construction support is estimated to be 14,312.

When the plant is in operation permanent employment there is expected to be 2,190. Permanent support employment after production begins is estimated at 1,686. This is below the level of temporary support employment, and a considerable proportion of these permanent support positions can be expected to be held by those holding temporary support positions.

Total new permanent population associated with the 100,000-barrel-per-day plant is estimated at 10,467.

During the 3-year construction period, expenditures for plant equipment and construction materials will average $117 million per year.

During the construction period, construction and support salaries will total $67.3 million per year. When operation of the plant begins, salary payments to operating personnel and the associated urban support personnel will be $33.3 million per year.

b. Expenditure Flows

The construction between 1973 and 1980 of the plants projected for both Federal and non-Federal lands in Colorado (Table III-2) will provide employment for up to 12,900 people. The peak in temporary employment for this group of plants will occur in 1976 and 1977. Additional construction in Colorado would keep the level of construction personnel from falling as shown in Tables III-38 and III-39. The population associated with the 12,900 temporary employment would be 31,500.

Permanent employment at shale oil plants will start at 1,293 in 1976 with the start-up of the first 50000 barrel per day plant.1/ It will reach 7,360 in 1981 when the fifth plant comes on stream. Support employment will bring total new employment in 1981 up to 13,000 and new population up to 35,200 (Table III-38). This compares with a 1970 population of 73,900 in the three affected counties of Colorado.

Expenitures for plant equipment and urban construction material will total $1.2 billion between 1973 and 1980, reaching a peak of $252 million per year in 1976 and 1977 (Table III-39). These materials and equipment are assumed to be brought in from outside the oil shale area.

Salaries paid to all types of employees, construction, construction support, operating, and urban support will reach a peak of $171 million per year in 1978 and then level off at $118 million per year when construction is completed (Table III-40).

1/ A richer shale would require less mining and processing therefore less manpower. One estimate (11) suggests 900 personnel would be required. This chapter uses the maximum employment projections throughout.

TABLE III-38.--Colorado--Oil Shale Temporary and Permanent Employment, Temporary, and Permanent Population.

Year	Temporary employment: Plant construction	Temporary employment: Urban 1/ construction	Temporary employment: Support 2/ 3/	Temporary employment: Total	Permanent employment: Plant	Permanent employment: Support 2/ 4/	Permanent employment: Total	Population 5/: Temporary	Population 5/: Permanent	Population 5/: Total
1973	1,470	696	1,365	3,531	-	-	-	8,615	-	8,615
1974	1,470	696	1,365	3,531	-	-	-	8,615	-	8,615
1975	4,410	2,088	4,095	10,593	-	-	-	25,845	-	25,845
1976	5,360	2,571	4,997	12,928	1,293	996	2,289	31,542	6,183	37,725
1977	5,360	2,571	4,997	12,928	1,293	996	2,289	31,542	6,183	37,725
1978	3,890	1,875	3,632	9,397	3,879	2,988	6,867	22,927	18,549	41,476
1979	1,470	696	1,365	3,531	6,069	4,674	10,743	8,615	29,016	37,631
1980	1,470	696	1,365	3,531	6,069	4,674	10,743	8,615	29,016	37,631
1981	-	-	-	-	7,362	5,670	13,032	-	35,199	35,199

1/ Derived from value of labor for urban construction.

2/ Assumes 1.37 employed people per new household.

3/ Based on employment multiplier of 0.63 times temporary plant plus urban employment. Source: Same as footnote 5, but modified to reflect the experience that ½ of all construction support workers will not bring their families into the region.

4/ Based on employment multiplier of 0.77 times permanent plant employment. Source: Consulting Services Corporation, for the Public Land Law Review Commission, Study of Impact of Public Funds on Selected Regional Economics, April, 1969, p. 104.

5/ Based on a family size of 3.7 persons. Source: Bureau of Census data for Colorado, Utah, and Wyoming.

Source: Bureau of Mines.

TABLE III-39.--Colorado--Plant Equipment and Urban Materials 1/ Purchased.

(Millions of dollars)

Year	Plant equipment	Urban materials	Total
1973	51.2	16.7	67.9
1974	51.2	16.7	67.9
1975	153.6	50.1	203.7
1976	190.7	61.7	252.4
1977	190.7	61.7	252.4
1978	139.5	45.0	184.5
1979	51.2	16.7	67.9
1980	51.2	16.7	67.9
1981	-	-	-
Total	879.3	285.3	1,164.6

1/ Urban construction is estimated at $45,000 capital cost per household for new residential, commercial, and community facilities. Of this total, $30,000 is allocated to materials and $15,000 to labor.

TABLE III-40.--Colorado--Salaries and Distribution.
(Millions of dollars)

Year	Construction 1/ (plant and urban)	Construction support 3/	Operating 2/	Urban 3/ support	Total	Salaries spent 4/ within region
1973	30.5	10.2	-	-	40.7	35.0
1974	30.5	10.2	-	-	40.7	35.0
1975	91.5	30.6	-	-	122.1	104.9
1976	111.3	37.4	13.6	7.5	169.8	149.0
1977	111.3	37.4	13.6	7.5	169.8	149.0
1978	80.8	27.2	40.8	22.5	171.3	156.2
1979	30.5	10.2	61.5	35.1	137.3	131.6
1980	30.5	10.2	61.5	35.1	137.3	131.6
1981	-	-	75.1	42.6	117.7	117.7

1/ Plant construction salaries assumed to be $15,000 per man year and urban construction salaries $12,000.

2/ Operating salaries assumed to range from $9,400 to $12,500 per man per year depending on the size of the plant.

3/ All support salaries were estimated at $7,500 per man year.

4/ Assumes that one quarter of the construction workers will not bring their families into the region and that these workers will spend only one quarter of their salaries in the region.

Federal revenues generated by the oil shale industry will build up to $164 million per year by 1981, mainly from the corporate income taxes of the oil shale industry. Likewise, State revenues, which will reach $24 million in 1981, will be mainly from the State income tax of the shale oil industry. Local taxes of $41 million per year by 1981 will result mainly from property taxes on oil shale facilities (Table III-41).

3. Economic Impacts in Utah

Development of two prototype leases in Utah is projected to result in a shale oil productive capacity of 50,000 barrels per day by 1980 using underground mining. Construction of this capacity and of the required additional urban facilities would begin in 1977. Some of the additional urban facilities might be constructed in Colorado if Rangely, Colorado, becomes the residence for some portion of the plant's employees.

a. Employment and Population

Plant construction will provide employment for 1470 construction employees during the 3-year construction period. An additional 696 construction jobs will be provided by urban construction during the same period. These construction personnel and their families will generate employment for 1,365 in supporting services. The overall population increase associated with the temporary employment for construction and construction support is estimated to be 8,615.

When the plant is in operation permanent employment there is expected to be 1,293. This is about 870 less than the total construction employment. Personnel movement can be expected to be greater than this 870, however, since relatively few construction workers are expected to take positions as plant operators.

Permanent support employment after production begins is estimated at 996. This is a smaller support employment than during construction. A considerable proportion of these permanent support positions may be held by the same personnel that held the temporary support positions.

Total new permanent population is estimated at 6,183 (Table III-42). This population increase compares with the existing population in Uintah County of 12,700 and a population of 20,000 in the two Utah counties.

TABLE III-41.--Colorado--Taxes and Public Revenues Generated by Oil Shale Development.

(Millions of dollars)

Year	Federal	State 1/	Local 1/	Total
1973	4.9	3.5	-	8.4
1974	4.9	3.5	-	8.4
1975	14.8	10.7	-	25.5
1976	45.8	16.8	7.1	69.7
1977	45.8	16.8	7.1	69.7
1978	98.3	21.7	21.3	141.3
1979	141.0	23.9	33.6	198.5
1980	141.0	23.9	33.6	198.5
1981	163.7	23.9	40.7	228.3

1/ State and local tax rates applicable in Colorado were used to estimate regional tax revenues. Federal revenues are independent of State location of plant sites.

TABLE III-42.--Utah--Oil Shale Temporary and Permanent Employment, Temporary and Permanent Population.

Year	Temporary employment				Permanent employment			Population 5/	
	Plant construction	Urban 1/ construction	Support 2/ 3/	Total	Plant	Support 2/ 4/	Total	Temporary	Permanent
1973	-	-	-	-	-	-	-	-	-
1974	-	-	-	-	-	-	-	-	-
1975	-	-	-	-	-	-	-	-	-
1976	-	-	-	-	-	-	-	-	-
1977	1,470	696	1,365	3,531	-	-	-	8,615	-
1978	1,470	696	1,365	3,531	-	-	-	8,615	-
1979	1,470	696	1,365	3,531	-	-	-	8,615	-
1980	-	-	-	-	1,293	996	2,289	-	6,183
1981	-	-	-	-	1,293	996	2,289	-	6,183

1/ Derived from value of labor for urban construction.

2/ Assumes 1.37 employed people per new household.

3/ Based on employment multiplier of 0.63 times temporary plant plus urban employment. Source: Same as footnote 4, but modified to reflect the experience that 1/4 of all construction support workers will not bring their families into the region.

4/ Based on employment multiplier of 0.77 times permanent plant employment. Source: Consulting Services Corporation, for the Public Land Law Review Commission, Study of Impact of Public Funds on Selected Regional Economics, April, 1969, p. 104.

5/ Based on a family size of 3.7 persons. Source: Bureau of Census data for Colorado, Utah, and Wyoming.

Source: Bureau of Mines.

b. Expenditure Flows

During the 3-year construction period, expenditures for plant equipment and construction materials will average $68 million per year (Table III-43). Such equipment and materials are expected to be shipped in from outside the region.

During the construction period, construction and support salaries will total $41 million per year. When operation of the plant begins, salary payments to operating personnel and the associated urban support personnel will be $21.1 million per year (Table III-44).

During the construction period, Federal tax revenues generated mainly from personal income tax will be $4.9 million per year. State taxes will be $3.5 million per year mainly from the use tax on equipment and construction materials brought in from out of State.

When the plant is in operation Federal revenues will increase to $29.6 million per year, the increase being due to corporate income taxes and to royalty received on production. State revenues will be $4.8 million per year mainly from corporate income tax and the portion of royalty payments transferred to the State. Local taxes of $7.1 million per year will be collected as property taxes on the oil shale installation and on other residential and business properties (Table III-45).

TABLE III-43.--Utah--Plant Equipment and Urban Materials [1/]
Purchased.

(Millions of dollars)

Year	Plant equipment	Urban materials	Total
1973	-	-	-
1974	-	-	-
1975	-	-	-
1976	-	-	-
1977	51.2	16.7	67.9
1978	51.2	16.7	67.9
1979	51.2	16.7	67.9
1980	-	-	-
1981	-	-	-
Total	153.6	50.1	203.7

1/ Urban construction is estimated at $45,000 capital cost per household for new residential, commerical, and community facilities. Of this total, $30,000 is allocated to materials and $15,000 to labor.

TABLE III-44.--Utah--Salaries and Distribution.

(Millions of dollars)

Year	Construction 1/ (plant and urban)	Construction support 3/	Operating 2/	Urban 3/ support	Total	Salaries spent 4/ within region
1973	-	-	-	-	-	-
1974	-	-	-	-	-	-
1975	-	-	-	-	-	-
1976	-	-	-	-		-
1977	30.5	10.2	-	-	40.7	35.0
1978	30.5	10.2	-	-	40.7	35.0
1979	30.5	10.2	-	-	40.7	35.0
1980	-	-	13.6	7.5	21.1	21.1
1981	-	-	13.6	7.5	21.1	21.1

1/ Plant construction salaries assumed to be $15,000 per man-year and urban construction salaries $12,000.

2/ Operating salaries assumed to range from $9,400 to $12,500 per man per year depending on the size of the plant.

3/ All support salaries were estimated at $7,500 per man-year.

4/ Assumes that one quarter of the construction workers will not bring their families into the region and that these workers will spend only one quarter of their salaries in the region.

TABLE III-45.--Utah--Taxes and Public Revenues Generated by Oil Shale Development.

(Millions of dollars)

Year	Federal	State 1/	Local 1/	Total
1973	-	-	-	-
1974	-	-	-	-
1975	-	-	-	-
1976	-	-	-	-
1977	4.9	3.5	-	8.4
1978	4.9	3.5	-	8.4
1979	4.9	3.5	-	8.4
1980	29.6	4.8	7.1	41.5
1981	29.6	4.8	7.1	41.5

1/ State and local tax rates applicable in Colorado were used to estimate regional tax revenues. Federal revenues are independent of State location of plant sites.

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4. Economic Impacts in Wyoming

Development of two prototype leases in Wyoming is projected to result in a shale oil productive capacity of 50,000 barrels per day by 1981 using in situ retorting. Construction of this capacity and of the required additional urban facilities would begin in 1978.

a. Employment and Population

Plant construction will provide employment for 1,240 construction employees during the 3-year construction period. An additional 773 construction jobs will be provided by urban construction during the same period. These construction personnel and their families will generate employment for 1,268 people in supporting services. The overall population increase associated with the temporary employment during construction is estimated to be 8,006.

When the plant is in operation, permanent employment there is expected to be 1,435. Permanent support employment is estimated to be 1,105. This is a smaller support employment than during construction. A considerable proportion of the personnel in support jobs during construction can be expected to remain and fill the permanent support jobs.

Total new permanent population is estimated at 6,860 (Table III-46). This population increase compares with an existing population in Sweetwater County of 18,400 and in Uinta County of 7,100.

TABLE III-46.--Wyoming--Oil Shale Temporary and Permanent Employment, Temporary and Permanent Population.

Year	Temporary employment				Permanent employment			Population 5/	
	Plant construction	Urban 1/ construction	Support 2/ 3/	Total	Plant	Support 2/ 4/	Total	Temporary	Permanent
1973	-	-	-	-	-	-	-	-	-
1974	-	-	-	-	-	-	-	-	-
1975	-	-	-	-	-	-	-	-	-
1976	-	-	-	-	-	-	-	-	-
1977	-	-	-	-	-	-	-	-	-
1978	1,240	773	1,268	3,281	-	-	-	8,006	-
1979	1,240	773	1,268	3,281	-	-	-	8,006	-
1980	1,240	773	1,268	3,281	-	-	-	8,006	-
1981	-	-	-	-	1,435	1,105	2,540	-	6,860

1/ Derived from value of labor for urban construction.

2/ Assumes 1.37 employed people per new household.

3/ Based on employment multiplier of 0.63 times temporary plant plus urban employment. Source: Same as footnote 4, but modified to reflect the experience that $\frac{1}{4}$ of all construction support workers will not bring their families into the region.

4/ Based on employment multiplier of 0.77 times permanent plant employment. Source: Consulting Services Corporation, for the Public Land Law Review Commission, Study of Impact of Public Funds on Selected Regional Economics, April, 1969, p. 104.

5/ Based on a family size of 3.7 persons. Source: Bureau of Census data for Colorado, Utah, and Wyoming.

Source: Bureau of Mines.

b. Expenditure Flows

During the 3-year construction period, expenditures for plant equipment and construction materials will average $62 million per year (Table III-47). These materials and equipment are expected to be brought in from outside the county.

During the construction period, construction and support salaries will total $37 million per year. When operation of the plant begins, salary payments to operating personnel and the associated urban support personnel will be $26 million per year (Table III-48).

During the construction period Federal tax revenues generated mainly from personel income tax will be about $4.6 million. State taxes will be $3.3 million per year mainly from the use tax on equipment and construction materials brought in from out of State.

When the plant is in operation Federal revenues will increase to $26 million per year, the increase being due to corporate income taxes and to royalty received on production. State revenues will be $4.4 million per year mainly from corporate income tax and the portion of royalty payments transferred to the State. Local taxes of $6.5 million per year will be collected as property taxes on the oil shale installation and on other residential and business properties (Table III-49).

TABLE III-47.--Wyoming--Plant Equipment and Urban Materials 1/ Purchased.

(Millions of dollars)

Year	Plant equipment	Urban materials	Total
1973	-	-	-
1974	-	-	-
1975	-	-	-
1976	-	-	-
1977	-	-	-
1978	43.3	18.5	61.8
1979	43.3	18.5	61.8
1980	43.3	18.5	61.8
1981	-	-	-
Total	129.9	55.5	185.4

1/ Urban construction is estimated at $45,000 capital cost per household for new residential, commercial, and community facilities. Of this total, $30,000 is allocated to materials and $15,000 to labor.

TABLE III-48.--Wyoming Salaries and Distribution.

(Millions of dollars)

Year	Construction 1/ (plant and urban)	Construction support 3/	Operating 2/	Urban 3/ support	Total	Salaries spent 4/ within region
1973	-	-	-	-	-	-
1974	-	-	-	-	-	-
1975	-	-	-	-	-	-
1976	-	-	-	-	-	-
1977	-	-	-	-	-	-
1978	27.9	9.5	-	-	37.4	32.2
1979	27.9	9.5	-	-	37.4	32.2
1980	27.9	9.5	-	-	37.4	32.2
1981	-	-	17.9	8.3	26.2	26.2

1/ Plant construction salaries assumed to be $15,000 per man-year and urban construction salaries $12,000.

2/ Operating salaries assumed to range from $9,400 to $12,500 per man per year depending on the size of the plant.

3/ All support salaries were estimated at $7,500 per man-year.

4/ Assumes that one quarter of the construction workers will not bring their families into the region and that these workers will spend only one quarter of their salaries in the region.

TABLE III-49.--Wyoming--Taxes and Public Revenue Generated by Oil Shale Development.

(Millions of dollars)

Year	Federal	State 1/	Local 1/	Total
1973	-	-	-	-
1974	-	-	-	-
1975	-	-	-	-
1976	-	-	-	-
1977	-	-	-	-
1978	4.6	3.3	-	7.9
1979	4.6	3.3	-	7.9
1980	4.6	3.3	-	7.9
1981	26.2	4.4	6.5	37.1

1/ State and local tax rate. applicable in Colorado were used to estimate regional tax revenues. Federal revenues are independent of State location of plant sites.

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IV. APPLICABLE ENVIRONMENTAL STANDARDS

Oil shale development would be subject to the system of Federal and State environmental and pollution control laws and regulations in effect at that time. In addition, operators on Federal oil shale leases would have to comply with the provisions of their leases, and all special stipulations, and could proceed only under a Federally approved development plan. These special mitigation measures are presented in Volume III, Chapter V, of this Environmental Statement which describes the proposed action of offering for lease six oil shale tracts located on public lands.

Pursuant to Federal law, the States of Colorado, Utah, and Wyoming have enacted water and air pollution control legislation and have implemented these laws by regulations and the establishment of water and air quality standards. In addition, mined-land rehabilitation laws have been enacted by Colorado and Wyoming.

This section cites the current regulations and standards for each of the three States which would apply, as a minimum to oil shale development if it were to begin now. The laws, in their entirety, are readily available from the appropriate State agencies.

A. Colorado

1. Water quality regulations and guidelines issued by the Water Pollution Control Commission of the Colorado Department of Health, 4210 East 11th Avenue, Denver, Colorado, 80220:
   (a) Water Quality Standards and Stream Classification, adopted April 13, 1971;
   (b) Standards for the Discharge of Wastes, adopted November 21, 1972, effective January 15, 1973;
   (c) Rules and Regulations for Subsurface Disposal Systems, effective July 1, 1970;
   (d) Guidelines for the Design, Operation, and Maintenance of Mill Tailings Ponds to Prevent Water Pollution, adopted March 13, 1968; and
   (e) Guidelines for Control of Water Pollution from Mine Drainage, adopted November 10, 1970.

2. Air quality regulations and standards issued by the Air Pollution Control Commission of the Colorado Department of Health, 4210 East 11th Avenue, Denver, Colorado, 80220:
   (a) Colorado Air Quality Regulations and Ambient Air Quality Standards, adopted December 9, 1971, effective February 1, 1972.

3. Mined-land reclamation provisions issued by the Colorado State Bureau of Mines, 1845 Sherman Street, Denver, Colorado, 80203:
   (a) Guidelines for Implementation of the Surface Lands Stablization Provisions of the Colorado Mining Law,

issued to implement the 1969 amendment of the Colorado mining laws to require stabilization of surface areas disturbed by mining and related activities.

B. Utah

1. Water quality regulations and standards adopted by the Utah Water Pollution Control Board and the State Board of Health, issued by the Division of Health of the State of Utah Department of Social Services, 44 South Medical Drive, Salt Lake City, Utah, 84113:

   (a) Code of Waste Disposal Regulations:

   Part I - Definitions and General Requirements, adopted May 18, 1965;

   Part II - Standards of Quality for Waters of the State, adopted May 18, 1965, and revised June 2 and June 21, 1967;

   Part III - Sewers and Wastewater Treatment Works, adopted May 18, 1965;

   Part IV - Individual Wastewater Disposal Systems, adopted May 18, 1965, and revised June 2 and June 21, 1967; and

   Part V - Small Underground Wastewater Disposal Systems, adopted by Utah Water Pollution Control Board, May 18, 1965, and revised June 2 and June 21, 1967.

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2. Air quality regulations and standards adopted by the Utah Air Conservation Committee and the State Board of Health, issued by the Division of Health of the State of Utah Department of Social Services, 44 South Medical Drive, Salt Lake City, Utah, 84113:

   (a) Code of Air Conservation Regulations dated January 24, 1972:

   Part I - Definitions and General Requirements;

   Part II - Ambient Air Standards, effective November 11, 1969;

   Part III - Emission Standards, effective on different dates from March 1969 to January 1972; and

   Part IV - Emergency Controls, effective January 23, 1972.

3. Mined-land reclamation provisions adopted by the Utah Board of Oil and Gas Conservation, 1588 W. North Temple, Salt Lake City, Utah, 84116:

   (a) Rules and Regulations Governing the Development and Production of Crude Oil and Gas from Bituminous Sandstone and Crude Shale Oil from Oil Shale and Surface Land Reclamation Regulations Relating Thereto, adopted August 31, 1972.

C. Wyoming

1. Water quality standards issued by the Wyoming Department of Public Health and Social Services, State Office Building, Cheyenne, Wyoming, 82001:

   (a) Water Quality Standards for Interstate Waters in Wyoming, approved and adopted October 28, 1968 by the Wyoming State Board of Health.

2. Air quality standards and regulations issued by the Air Quality Section, Division of Health and Medical Services of the Wyoming Department of Health and Social Services, State Office Building, Cheyenne, Wyoming, 82001:

   (a) Wyoming Air Quality Standards and Regulations, revised by the Air Resources Council on January 22, 1972, and effective on April 9, 1972.

3. Federal air quality regulations applicable to the State of Wyoming, issued by the U.S. Environmental Protection Agency

   (a) U.S. Code of Federal Regulations, Title 40, Chapter 1, Subchapter C, Part 52, Subpart ZZ, Sections 52.2624(b), 52.2625(b), and 52.2626(b), published in the Federal Register of September 22, 1972.

4. Mined-land reclamation provisions issued by the Wyoming Commissioner of Public Lands, 113 State Capitol Bldg. Cheyenne, Wyoming, 82001

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V. ADVERSE ENVIRONMENTAL EFFECTS WHICH CANNOT BE AVOIDED

Throughout the progress of the oil shale development as described in this Environmental Statement, many mitigating measures will be applied to lessen the possible environmental impacts of the action. Nevertheless, there will be some effects which will be both adverse and unavoidable as a result of oil shale development as examined in the following sections.

A. Landscape and Esthetics

The development of an oil shale industry will require roads, mining, plant sites, waste disposal areas, utility and pipeline corridors, and associated services during the productive life of a lease which will unavoidably alter the appearance of the present landscape. Canyons may be filled to a depth of 250 feet and each may encompass an area of about 700 acres. Each canyon would, therefore, be unavoidably altered in appearance.

B. Land Disturbance and Vegetation

Development will unavoidably destroy existing vegetation which consists mainly of grassland and the noncommercial pinyon-juniper forest-type. Reestablished vegetation will be set back in the successional stages to the climax cover type endemic to the region. Species mix will be unavoidably altered and tree growing stock reduced. For the 1-million-barrel-per-day development level, about50,000 acres total will be directly involved with the actual operations; an additional 10,000 acres will be required for utility corridors; and 20,000 acres will be required for urban expansion.

Topsoil will be unavoidably lost. The impact of development will be significant in local areas, but small for the region which encompasses an area of about 17 million acres. These effects on land and vegetation will be cumulative.

C. Water Quality and Supply

Oil shale development will stimulate the demand for water for process requirements and for communities which will develop to support the oil shale industry. Estimates of expected water needs range from 121,000 to 189,000 acre-feet per year to support both processing and urban requirements. This amount may be higher or lower as explained in Chapter III, Section C-1. Initially, large amounts of ground water are expected to be available to support development. Over time, increasing amounts of surface water would be consumptively used, unavoidably increasing the competition for such waters, particularly for its use as irrigation. Salinity changes caused by concentration of the salts for a 1-million barrel per day shale oil industry would cause the salinity of the Colorado River at Hoover Dam to increase by about 15 mg/l (1.5 percent). In addition, some salt loading is likely from sedimentation, leaching, municipal, accidents and the discharge of ground water. These could result in a long-term unavoidable adverse effect on some surface waters. In addition, lower aquifer pressure and water levels will decrease the flow of springs presently used for vegetation, wildlife, irrigation and stock watering, and saline water or organic materials may move into aquifers that now are fresh, reducing the future quality of ground water available for human and agricultural use. Accidental release of industrial or municipal wastes containing toxic materials, high temperatures, or low oxygen content may occur.

Uncertainties remain in assessing the full magnitude of the potential impacts in the Upper Colorado River Basin with subsequent economic detriments to the Lower Colorado Basin. Even with tight controls, industrialization will result in a cumulative decline in regional water quality.

D. Air Quality

Since the air in the oil shale regions is essentially free of pollutants today, industrialization will have an unavoidable adverse effect on local and regional air quality. Emissions added to existing conditions would include particulates, sulfur dioxide/hydrogen sulfide, nitrogen oxides, and carbon monoxide. In the short term, there is not expected to be significant harmful effects to either humans, animals, or plants. However, their long-term productivity in localized areas could be reduced because of the additive effect of air pollutants. Although ambient air quality standards are believed attainable, the long-term effect of industrialization will result in a cumulative decline in the air quality of the region.

E. Fish and Wildlife

Canyon disposal will unavoidably destroy habitat for species such as the spotted bat, mountain lion, and several raptors that require unmolested habitat in cliffs and rough terrain. If colonies of prairie dogs are destroyed, any black-footed ferrets in the area will be displaced and probably destroyed. Reduced quality or impoundments in waters inhabited by the Colorado squawfish, Colorado River cutthroat trout, honey-tail chub, and humpbacked sucker will result in further population declines for these threatened species. Habitat subject to noise and disturbance will be lost to peregrine and prairie falcons, eagles, deer, and elk. The magnitude of these effects is uncertain.

Mule deer will be reduced by a minimum of 10 percent by displacement and competition as habitat is destroyed. The extent of the reduction will depend on whether disturbed areas are revegetated with sufficient winter browse species to maintain population levels. Animals such as the elk, moose, bear, and mountain lion, which are less tolerant of human activity, will be denied the remote habitat because of noise and human activity. This will lead to the virtual disappearance of such wilderness species from those parts of the region directly and indirectly affected by oil shale development and associated growth. Hunting pressure will increase, and harvest of some game species may need to be reduced by more restrictive hunting regulations.

Loss of habitat and browse, reduced water supply, increased hunting pressure, and casual shooting will reduce populations of hawks, eagles, bobcat, raccoon, and ringtail cat by forcing displacement and increased competition for remaining food and water. The scarce sage grouse will probably almost disappear from the oil shale region of Colorado. Reductions in small prey species such as rodents and rabbits will also cause reductions in populations of predators.

Drying of streams, degrading of water quality, and any impoundments created will cause reductions or changes in fish populations. Species especially vulnerable to changes in physical conditions or water quality (temperature, pH, toxic substances) include trout and whitefish as well as the threatened species mentioned above. The effects for most wildlife are essentially cumulative with advancing industrialization.

F. Grazing

At any one time, some 20,000 acres would not be available for any use as grazing. Thus, oil shale development will unavoidably reduce the present grazing capacity of the region by about 2350 animal unit months for each year of operation. Utility corridors are unavailable for grazing temporarily after revegetation. Changes in lifestyles or other factors could lead some present livestock operators to reduce ranching activities or cease entirely which would reduce utilization and production of beef.

G. Archeological

The general area was formerly inhabited by nomadic, hunting, Indian tribes. Archeological resources are believed to exist in unknown locations. Any disturbance of the surface would possibly disturb unknown historic or archeological sites or artifacts. The effect is uncertain, but believed to be minor.

H. Socioeconomic

Increased urbanization of a region which is primarily rural and remote would be an unavoidable consequence of oil shale development. Any change in the nature of the region would be either adverse or beneficial depending on individual preferences of the people inhabiting the area. It is difficult to make a value judgment on these social changes and hence to determine whether such changes constitute a net adverse effect for the inhabitants. In any event, conflicts in lifestyles will occur and population density will increase.

Changes in the economic environment would probably be regarded by most people as being beneficial due to the availability of new jobs, increased income and capital flow, increased tax base and services, and an immigration of people. These would probably also increase cultural and recreation facilities. However, there will be increased pressures on the activities of the population during the construction period caused by the physical activities of construction and by the short-term pressure on utilities, housing, and services. Large-scale growth can result in a region having an entirely different ethnic, cultural, and religious composition than it had before with far-reaching social effects.

I. Character of the Region

The oil shale basins are characterized by their wildlife resources, essentially undeveloped natural resource condition, and limited human activity. Oil shale development and expanding urbanization and population will intensify existing levels of use and competition for space and physical resources. Thus, the remote and primitive character of parts of the Piceance, Uinta, Washakie, and Green River Basins will be lost. Such development pressures will impact on the existing recreation environment beyond the boundaries of the development itself, including the use of nearby recreational areas in the Upper Basin.

VI. RELATIONSHIP BETWEEN LOCAL SHORT-TERM USES OF MAN'S ENVIRONMENT AND THE MAINTENANCE AND ENHANCEMENT OF LONG-TERM PRODUCTIVITY

A. Introduction

By undertaking oil shale development, the present generation of Americans will leave for future generations a region different than that which presently exists. As described in Volumes I and III of this Environmental Statement, the oil shale lands of primary commercial interest are in the Piceance Creek Basin in Colorado, the Uinta Basin in Utah, and the Washakie and Green River Basins in Wyoming, These areas of these States are presently relatively isolated and contain little or no industrial activity. Oil shale development will impose new influences and new impacts on the regions.

The amount of oil shale in place and the historical pattern of technology to improve upon technical efficiency and to organize for economics of scale indicates that industrialization for oil shale development will not be short-term once initiated. Individual 5,000 acre tracts, for example, may support a commercial surface mine development for 50 to 70 years. The influence of mature development is not now known, but if oil shale is developed to the 1-million barrel per day level as postulated in this volume, it will probably exert a cumulative influence upon the oil shale regions' environment for more than a hundred years.

The short-term uses of the oil shale regional environment will influence the long-term environmental productivity of the region by changing both its physical and socioeconomic character. The relationship between these short-term uses and long-term productivity of the environment will vary according to the environmental resource or value concerned: water, air, fish, wildlife, vegetation, primitive character, outdoor recreation, esthetics, grazing, soils, archeological, historical, and socioeconomic. The productivity of these various resources and values will react differently, both in timing and degree, to short-term uses. Long-term productive capacity in most cases will be maintained but in a declining trend. None of the resources or values, with the exception of mineral production itself, associated with socioeconomic development, and possible grazing, will experience an enhancement.

Only minor changes in productive capacity will occur at first. More significant reductions in productivity will occur after longer periods of time. This will be due to the cumulative effects of industrialization. Thus, it appears likely that over the long term, the quality and productivity of most resources will continue, but at reduced levels. Certain elements of a very few resources will experience a decline in productivity to the point of virtual disappearance.

As was indicated above, the long-term productivity of some resources and values will be maintained in an increasing trend. Mineral resource development will commence a new productive capacity not previously experience in the region. Thus, it is likely that the regional socioeconomic condition will improve significantly. It is not certain, however, how long this will continue. The possibility exists that other industries will develop to continue the improvement. Productive capacity will probably be enhanced also in two other areas: grazing opportunity and diversification of labor and professional skills of the regional population.

B. Regional Changes

The oil shale regions consist of open country, relatively primitive and isolated in many places, and primarily devoted to use as habitat by wildlife and limited ranching and recreational pursuits by man. Development of oil shale will set in motion a trend towards development of industrialized regions. The character of the industrialization will be similar to that commonly associated with the mining industry. These industrialization changes will intensify the utilization of the region's air, water, land, mixed mineral resources, and wildlife. The original condition of the land and the mineral resources will not be renewable as all of the region's resources become increasingly used by an expanding population.

Increased efficiency in both mining and processing would result in increasingly effective utilization of the oil shale resource itself. Innovative mining systems will probably result in higher percentages of extraction than now seem feasible, thus conserving the resource and decreasing the area required for a given rate of production. Increased yields in retorting and refining would decrease the mining load commensurately, also tending to decrease the mine and spent shale disposal areas required for given oil output rates. These expected efficiencies would tend to avoid or minimize some of the adverse long-term effects of the development.

C. Water Resources

Water exists in the oil shale regions sufficient to support an oil shale industry of at least a million barrels per day over an extended period of time. The dynamic nature and growth of an expanding industry can introduce additional demands on water. Oil shale development will stimulate water needs not only in the form of process requirements, but also in a secondary sense as communities develop to support the oil shale industry. Even with tight controls to avoid or minimize water contamination, the long-term effects of industrialization would result in a decline in water quality.

The long-term quality of the water will decline due to water consumption, possible return-flow effects, sedimentation, and industrial wastes. An increase in salinity with time will result for the Colorado River.

In the Colorado River Basin, generally, the expected future salinity is projected to be below threshold levels for uses such as recreation, hydroelectric power generation, and aquatic life; only marginal impairment of these uses is anticipated (1). Oil shale development is not expected to impair these uses any further.

In the lower Colorado River, salinity has not reached the threshold levels for municipal, industrial, and agricultural uses. However, some impairment of these uses is now occurring, and future increases in salinity will increase this adverse impact.

The quality of water being consumed and discharged by the different aspects of oil shale development adds more complexity to assessing the relationship between short-term use and long-term water quality. Water of good quality from underground aquifers can be recycled back into the system without detrimental effects. Water of poor quality can be used for various purposes but can itself present a disposal problem. Extremely poor quality ground water or water from the various process streams may either have to be treated and/or disposed of beneath the ground. The discharge and recharge of ground waters could result in a net reduction in the long-term productivity of some subsurface aquifers. This could lower aquifer pressure and water levels, thereby decreasing the flow of springs presently used for irrigation and stock watering. In addition, saline water may move into aquifers that now are fresh, reducing the future quality of ground water available for human and agricultural use. This latter condition may not be realized for some time since underground percolation of streams and resulting water migration could take years for the subsurface pressures to be redistributed.

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D. Air Resources

Since the air in the oil shale regions is essentially free of pollutants today, industrialization will adversely affect localized areas. Emissions added to existing conditions would include particulates, sulfur dioxide/hydrogen sulfide, nitrogen oxides, and carbon monoxide. Quantities of these pollutants would be expected to increase with time as the industry develops. It is expected, however, that in the short term there will not be significant harmful effects to either humans, animals, or plants.

Detailed studies do not currently exist on long-term human exposure to air at low emission concentrations. The long-term producitivity of exposed areas could be reduced because of the additive effects upon plants, animals, and humans. Ultimately, the oil shale resource will be exhausted insofar as man's plan for its production. After that time, and with the cessation of the industry, no further direct long-term effects on the environment will be experienced. Retention of a residual population and other industry in the region will lead to continued long-term degradation of the air quality through human activities, but the extent of the effect should be much less than during the shorter-term oil shale industrializing period.

E. Faunal Resources

The long-term productivity of the regional fish and wildlife resource will probably decline for several species. For those species requiring a habitat of primitive character, it will be lost, particularily in locations where active oil shale development takes place. The oil shale regions are presently semiremote and relatively unrestricted in use. They experience only minimal interference by man. A regional oil shale industry would involve a broad group of environmental impacts upon fish and wildlife and their habitat. Although occurring principally during tract development and oil production, some of these impacts would extend beyond the expected longevity of production. The permanent regional population increase would result in a continuing use of regional fish and wildlife resources, even after oil production ceased. This would transfer a semiremote area into one which is permanently inhabited. The displacement of wildlife in those inhabited regional areas will have a long-term effect on the wildlife productivity. Increased hunting and fishing would result due to the population increases. This could also contribute to fewer fish and wildlife in populous growth areas and the region generally. Because of this pressure and the fact that the industry would have very few features that would enhance productivity of biotic resources, it is expected that the short-term development of oil shale would reduce the long-term productivity of the region's faunal resources. Animals which live in the vicinity of the oil shale development would seek new water sources and habitat. Once development ceases and restoration is completed, the area could support additional wildlife provided adequate water sources are available. The returned population would most likely be a different species mix. In general the ecological balance would be disturbed and permanently affected by the different aspects of oil shale development. Canyons may be filled to a depth 250 feet and each disposal canyon could encampass an area of approximately 700 acres. Each canyon will, therefore, be permenently altered as a faunal habitat. Restoration will be undertaken to restore the canyon to a natural habitat which could once again support wildlife. Reestablishment of natural habitat would require an extended time period (decades), but it will probably be a different habitat than before.

F. Vegetation Resources

Oil shale development, by virtue of the extensive land requirements, will have both short-term and long-term effects on the vegetative resources of the oil shale regions.

A complete description and inventory of the vegetative resources of the oil shale regions is given in Volume I, Chapter II, of this Environmental Statement. The descriptions show that regions largely consist of pinyon-juniper, sagebrush, salt-desert shrub, and grasslands typical of the semiarid intermountain region. Oil shale development will destroy a certain amount of the existing vegetation in the area of the development. However, rehabilitation and/or revegetation plans for the land surfaces would attempt to restore and provide for the long-term productivity of the land. These plans may include re-establishment of browse on the land instead of the original vegetative resources to encourage further wildlife development. On the other hand, land-use planning may indicate that the land may be adaptable for some form of agricultural development. In this case revegetation with totally different classes of vegetation than those originally present may be attempted. These considerations indicate that options exist for maintenance and enhancement of long-term productivity. The exact nature of what one generation plans for future uses will depend upon development and execution of efficient and effective land-use programs.

G. Changes In Recreation Patterns and Esthetics

The oil shale region is in open country utilized for outdoor recreation because of its remoteness, difficulty of access, and natural condition. These qualities will significantly decline over the long term except in the high-peak country. Oil shale development will result in localized as well as basin and regional changes in recreation and esthetic resources.

The expected development in the three-State region, together with the related new urban service and utility corridors, would utilize less than one percent of the recreation lands currently in existence. However, the development will exert a considerable impact on the existing recreation environment beyond the boundaries of the development itself.

Recreation activities would shift from the more extensive types, e.g., hunting, etc., toward more intensive, urban-oriented recreation facilities, e.g., golf courses, reservoirs, playgrounds, swimming pools, etc. Change in the semiprimitive nature of the region due to industrialization would adversely affect its present character and reduce its long-term productivity as a primitive outdoor recreation region. Opportunities for more flexible recreation patterns would be realized and would be suitable to a larger resident population, although maybe more restricted for the nonresident population. This rate of recreational development would be controlled by the individuals who currently live in the areas and those who will be brought in to support oil shale development.

H. Changes in Socioeconomic Environment

The major influence that would take place in the oil shale regions will be that directly related to man's activities. The interplay between industrial man and the relatively undisturbed environment of the oil shale regions will bring about changes in the character of the regions. A primary impact will result from the influx of new people to support and operate the oil shale industry. For example, the 1970 census showed a total population of about 119,000 people in the tri-State oil shale region of Colorado, Utah, and Wyoming. It is estimated that the total increase in population in the tri-State region will be about 115,000 people. [1/] This increase in population means that the regions will experience about a 6 percent compounded annual growth rate compared to about 1 percent compounded annual growth rate for the nation. This increase in population means that community life in the region would change. The rural character of the region would give way to increased urbanization, and employment in industrial occupations would take place. Any change in the rural nature of the region would be either adverse or beneficial depending on individual preferences of the people inhabiting the area. It is difficult to make a value judgment on these social changes and hence to determine whether a net enhancement in the lives of the area's residents would result from oil shale development.

These changes in the socioeconomic environment would probably be regarded by most people as having a beneficial effect on long-term productivity. This assessment would be made on the availability of new jobs, increased income and capital flow, increased tax base and services, and an immigration of people which would probably

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1/ This population increase assumes a 1-million barrel per day industry by the year 1985.

result also in increased cultural and recreational facilities. The continuance of these effects would depend on a continuous supply of crude oil and oil shale. Should production cease, there would be a need to redirect those persons associated with oil shale development to other forms of employment. A slow emigration would probably result.

Increased efficiency in both mining and processing would result in increasingly effective utilization of the oil shale resource itself. Innovative mining systems would probably result in higher percentages of extraction than now seem feasible, thus conserving the resource and decreasing the area required for a given rate of production. Increased yields in retorting and refining would decrease the mining load commensurately, also tending to decrease the mine and spent shale disposal areas required for given oil output rates. These expected efficiencies would tend to maintain long productivity of the resource and mitigate some of the adverse long-term effects of the development.

The short-term use of the socioeconomic environment by the development of oil shale may tend to reduce long-term productivity in other respects. As indicated earlier in this Environmental Statement, there will be increased pressure on the routine activities by the population during the construction period. These would be caused by the physical activities of construction and by the short-term pressure on utilities, housing, or services that may be caused by poor planning or labor strikes. Such large-scale growth can result in a region having an entirely different ethnic, cultural, and religious composition than it had before. Far reaching effects can also be experienced on the socioeconomic environment due to commuting patterns. Thus, the effects of the industrial area could be felt for distances up to 40 or 50 miles from the production sites.

1. References

1. Environmental Protection Agency. Mineral Quality Problems of the Colorado River Basin, A Summary Report. 1971, p. 24.

VII. IRREVERSIBLE AND IRRETRIEVABLE COMMITMENT OF RESOURCES

The purpose of this chapter is to examine those resources which would be consumed and those that would be altered irreversibly and irretrievably by the proposed prototype oil shale leasing program. Such commitments would include: the consumption of certain mineral resources; changes in the relief of the terrain and in land-use patterns; modification of wildlife habitat; new directions in the patterns of community activities; and changes in existing recreation, esthetic, and cultural values.

A. Consumption of Mineral Resources

The principal mineral resources consumed by the proposed prototype program would be the shale oil and associated products, and the water and other resources required in their production.

By the year 1985, total production may be expected to rise gradually to 1 million barrels per day; a cumulative total of approximately 365 million barrels of shale oil and shale oil products would be produced annually for consumption. To achieve such an output, 425 million tons of raw shale would have been processed, 80 million tons of useful products removed, and up to 340 million tons of processed spent shale produced.

During 20 years of continuous operation, therefore, some 8.5 billion tons of oil shale resource would be irreversibly and irretrievably "consumed."

Ultimate recovery of oil shale mined underground, by room-and-pillar methods, should approximate 50 to 65 percent of the leased deposit without causing undue surface subsidence or damage. That resource left in place as barriers, e.g., manways, main and secondary entries, haulageways, airways, bleeder entries, shafts, slopes, room necks, and rooms, is necessary to protect the workmen, deposit, and the overlying surface lands. Such material, for all practical purposes, is irreversibly and irretrievably committed.

Theoretically, mining by surface methods should recover nearly 100 percent of the available material. In practice, this is not the case, since ore must be left as a barrier to protect lease boundaries, and benching is necessary to gain entry and exit to and from the deposit. Therefore, it must be assumed that between 10 to 20 percent of the oil shales would be lost to recovery and utilization.

In situ processing will probably result in only 50 percent recovery of the in-place resource. The remainder will be irretrievably lost.

B. Changes in Land Use Patterns

Land required for oil shale development can be classified into three categories: that associated with urban development, that associated with utility corridors and the expansion of the roadway system between urban areas and the plant sites, and that land associated with the development of the plant and mining areas themselves.

The area of land transformed from rural to urban use will be directly proportional to the new population of the area which in turn will be almost proportional to shale oil productive capacity.

For a new 115,000 population associated with a 1-million-barrel-per-day capacity by 1985, some 10,000 to 20,000 acres of land would be urbanized. For all practical purposes, this area would essentially constitute an irreversible and irretrievable commitment of this land.

New roads and utility corridors would require about 10,000 acres of land. Since normal use of this land may be expected shortly after initial construction, the land use may be considered temporary.

Topographic changes at the plant site will be caused by underground mine openings, surface mine excavations, processed shale disposal areas, and plant facilities. For a 1 million-barrel-per-day shale oil production operation, the total estimated land disturbed is about 50,000 acres. Spent shale could, in some underground mining operations, be replaced in the mine to provide permanent support for these excavations. Underground mine openings could be permanently sealed at the end of operations. Mining and surface disposal of processed shale would cause permanent changes in topography. Wildlife habitat would be destroyed. These changes and the original vegetative cover constitute an irreversible and irretrievable commitment of existing resource values.

Mule deer and antelope herds will be reduced by displacement and competition as habitat is destroyed. Animals such as the elk and mountain lion, which are less tolerant of human activity, will be denied a greater amount of habitat because of avoidance of noise and human activity. This will lead to proportionately greater reductions in numbers of these species. Hunting pressure and harvest will increase.

Drying of streams, degrading of water quality, and any impoundments created will cause reductions or changes in desirability of fish populations. Species especially vulnerable to changes in physical conditions or water quality (temperature, pH, toxic substances) include trout and whitefish as well as the threatened species mentioned above.

From 121,000 to 189,000 acre-feet per year of ground water and/or surface water would be used to support the water requirements of 1,000,000 barrel/day industry and supporting population. This amount of water is potentially available for oil shale development and would be obtained from ground water sources and be diverted from the Colorado, White and Green Rivers. However, since water supplies are replenishable, this use does not constitute an irretrievable commitment of a resource. However, construction of any impoundments associated with this scale of operation would constitute an irreversible commitment of the acreage required.

C. Changes in Socioeconomic Patterns

Increased economic growth resulting from oil shale development would significantly alter existing social structures and institutions. The evolution of an agricultural society to an industrialized one would be largely irreversible and may produce intermediate community instability. Strains of rapid population influx could result in a dichotomy between the established and new inhabitants of the region. Existing pre-industrial life styles with their emphasis on recreational activities and subsistence economic patterns eventually would be exchanged for an urbanized way of life. This trend, once established, is for all practicable purposes irreversible.

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