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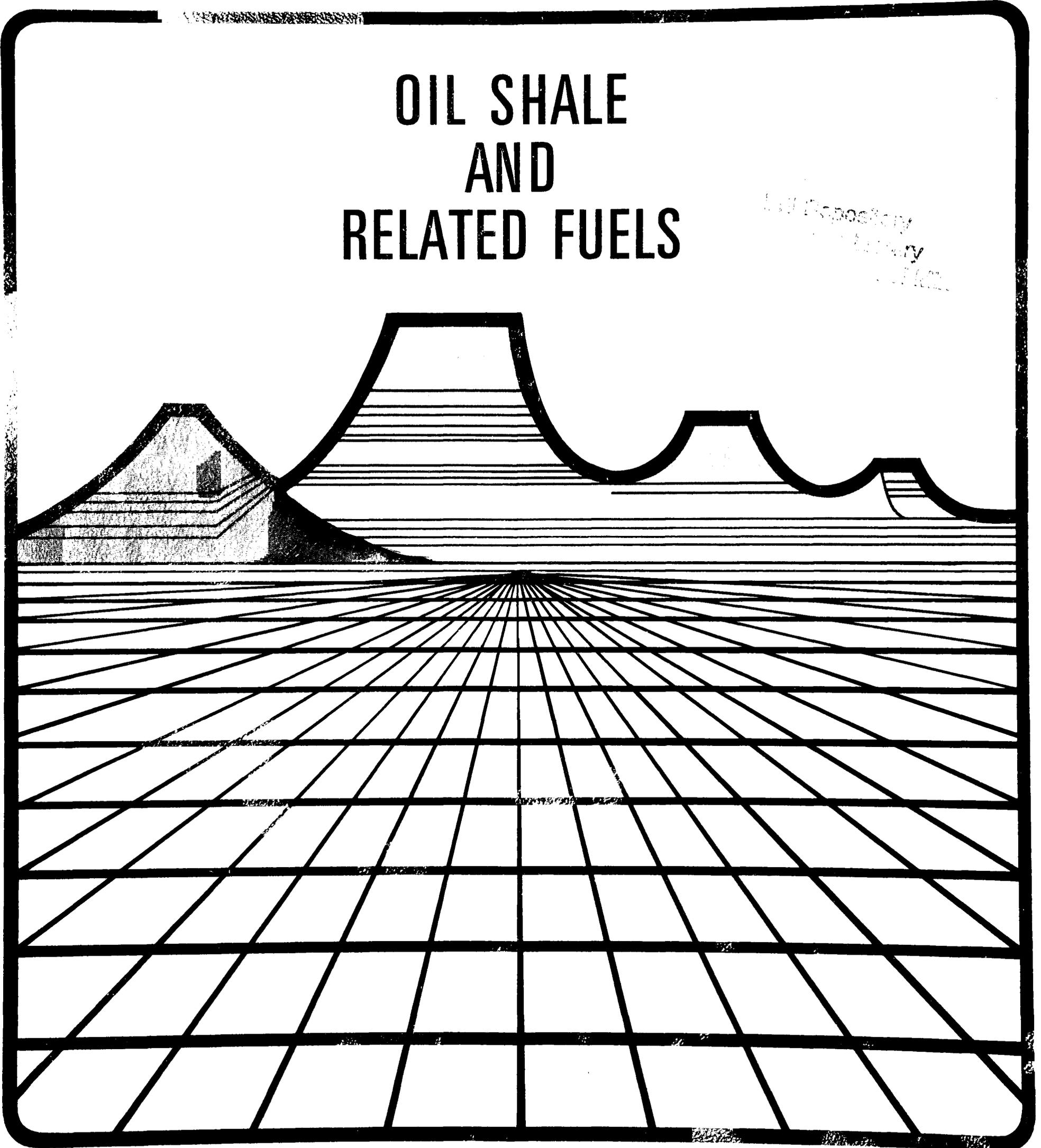
DECEMBER 1, 1966

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# OIL SHALE AND RELATED FUELS

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CAMERON AND JONES INCORPORATED  
DENVER • COLORADO



**OIL SHALE**  
**and**  
**RELATED FUELS**

**Quarterly Report**

**December 1, 1966**

**Cameron And Jones  
Incorporated  
Denver, Colorado**



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## HIGHLIGHTS

### Courts Adjudicate Water Right Priorities in Colorado's Oil Shale Area (Page 80)

In Colorado's oil shale area two District Courts completed adjudication procedures and issued decrees concerning the priorities for water rights during this reporting period. It normally requires many years for any given Colorado State Water District to be opened for Court adjudication proceedings and for a decree to be issued following such proceedings.

Decrees were issued late in November for State Water Districts 39 and 43. These are districts that are located in the heart of the oil shale area. Many of the water right applications and adjudications concern water supplies intended for use in oil shale developments.

In this report we review the status of all water right applications in the State Water Districts within the oil shale area and we present the listings of the priorities recently decreed by the Courts for Districts 39 and 43. In our next report we will present descriptive data concerning each of the priorities recently adjudicated that relate to proposed oil shale developments.

### Sodium Mineral Occurrences in the Oil Shale Formations (Page 61)

Published data concerning the saline mineral occurrences within the Green River formation have been sparse and non-specific. During this reporting period, two publications have appeared which present recent and authoritative data on the saline mineral deposits of Colorado's Piceance Basin.

One of these papers, Dawsonite in the Green River Formation of Colorado, by USGS and Bu Mines authors,

Sodium Mineral Occurrences in the Oil Shale Formations  
(Page 61) (Continued)

represents a compilation of data made available to the authors by various companies that have core drilled in the central portion of the Piceance Basin.

A second publication, Economics of Oil Shale, by Irvin Nielsen, presents specific data from core drilling on one of the sodium prospecting permit areas of the Piceance Basin and relates the data to the economics of producing oil from oil shale.

Both papers are reviewed, and Nielsen's paper is reproduced for reference purposes.

Federal Energy Study Calls For Increased Government-Sponsored Research on Oil Shale and Coal (Page 69)

An interdepartmental energy study by Federal agencies suggests a long period of government-sponsored research before making Federal oil shale lands available for development. The study, published late in November as, Energy R&D and National Progress, gives high priority to R&D for pollution control and abatement. The report suggests that a worthwhile research objective would be the ultimate replacement of fossil fuels by nuclear energy. The report is reviewed and excerpts from the report dealing with oil shale, tar sands and coal as sources of oil are reproduced in the Appendix.

Bu Mines Experiments With Non-Nuclear In Situ Processes in Oil Shale at Wyoming Field Test Site (Page 25)

In a continuing series of field tests, the Bureau of Mines is investigating "Electro-Fracing", "Nitro-Fracing" and steam-thermal in situ processes in shallow oil shale formations located west of Rock Springs. The field test area for these investigations was visited and the status of the test investigations is reported.



Bu Mines Experiments With Non-Nuclear In Situ Processes  
in Oil Shale at Wyoming Field Test Site (Page 25) (Cont'd)

The "Nitro-Fracing" tests are of particular interest. The Bu Mines investigators have been successful in their efforts to detonate nitroglycerin after the liquid nitro has been pressure-injected into thin fractures and fissures within the oil shale formations. The process shows promise as a means for increasing the permeability of oil shale formations.

Colony Development Company Partners Realign Operating  
Responsibilities (Page 12)

Indefinite results from the 1-1/2 year program for testing the TOSCO retorting process have been manifested in a recent decision to re-align operating responsibilities of the Colony Development Company partners at the "semi-works" oil shale project in Colorado.

Standard Oil Company of Ohio, a 40% Colony partner, has withdrawn from active participation in the project and has announced that it will re-evaluate the capital cost and needs of full-scale projects such as shale oil.

Cleveland Cliffs Iron Company, a 30% Colony partner, will continue to mine oil shale to supply needs of the 100 ton/day retort and to test mining procedures. The costs will be borne by the Colony partners in accordance with their interests in the venture.

The Oil Shale Corporation (TOSCO), a 30% Colony partner, will continue to operate the prototype TOSCO process retort, but will do so at its own expense rather than at the expense of the partnership.

With its partners traveling separate paths, Colony Development Company's unified operations are essentially non-existent at the Parachute Creek project.

September Conference Highlights Planning Progress for  
Proposed Nuclear Test in Oil Shale (Page 47)

Representatives of twenty-four organizing companies met at Las Vegas, Nevada on September 29 and 30 to review the terms of an operating agreement for a 5-year, \$5.4 million test program for conducting a nuclear detonation experiment in oil shale formations.

The operating agreement, as drafted for review, would become operative when CER Geonuclear Corporation has negotiated an acceptable R&D contract with the Government and when at least ten participating parties agree to participate in the program.

It was proposed, and the group representatives agreed, that there is a need to establish various Subcommittees to the Operating Committee in such categories as Product Recovery, Underground Phenomena, etc., and that an Executive Committee is needed to evaluate technical progress and to provide guidance to the Operating Committee.

Guidelines for negotiations with the Government were discussed. These discussions led to the decisions by the participants that the Government be invited to participate, but only as a technical contributor and that a representative of the Bureau of Mines would be welcome to serve on the Operating Committee.

Merging of Coal Companies into Other Organizations  
Remains in Vogue (Page 113)

Consolidation Coal Company merger into Continental Oil Company was completed in September. Peabody Coal Company and Kennecott Copper Company may be combined next year. And, General Dynamics Corporation is trying to buy more control of United Electric Coal Companies.



The Office of Coal Research Announces a Coal De-Ashing Pilot Plant (Page 115)

Pittsburg & Midway Coal was awarded OCR contract for \$4,000,000 pilot plant to solvent-extract and de-ash two tons of coal an hour. It will be built at Tacoma, Washington.

Products of the plant will be available in sufficient quantity to permit commercial testing. The de-ashed coal is a high-heating-value, low-sulfur solid with almost no ash, with properties which may make it a superior boiler fuel. An interesting by-product is the mineral matter from the coal. This should not be confused with coal ash which has been exposed to oxidizing conditions.

Midwestern Coal and Lignite Potential Evaluated (Page 120)

A report to the Office of Coal Research by Robert R. Nathan, Inc. has been announced. It follows a similar report on Far Western coal and covers the States of Minnesota, Iowa, Missouri, North Dakota, South Dakota, Nebraska, Kansas, Oklahoma, Texas and Louisiana. The report comprehensively covers coal and lignite occurrences, potential markets and includes recommendations for both industry and government.

Status of Proposed Power Plants in the Southwest (Page 121)

Coal-fired power plants have sprung into being in the southwest in the last five years. New plants and additions to existing ones are planned. Over 14,000 Mw of new generating capacity may be added.

Coal Land Holdings on Public Lands of New Mexico Presented (Page 127)

The San Juan Basin of New Mexico has been the scene of recent coal land activity. The subject is discussed and a map showing coal exploration permits and coal lease areas on public lands is presented.

COMING EVENTS CONCERNING  
OIL SHALE AND RELATED FUELS

Date	Coming Event
December 4-8, 1966	59th Annual Meeting American Institute of Chemical Engineers, Detroit, Michigan.  Program contains no papers concern- ing oil shale.
December 14, 1966	Colorado State Water Conservation Board. Regular Quarterly Meeting, Room 132, State Services Building, 10:00 AM, Denver, Colorado.
January 17, 1966	Quarterly Meeting of the Board, Colorado River Water Conservation District, 1st National Bank Building, Glenwood Springs, Colorado.  (Generally concerns water develop- ments in the oil shale area of Colorado).
February 9-11, 1967	70th National Western Mining Con- ference, Hilton Hotel, Denver, Colorado. Program not available.
February 19-23, 1967	96th Annual Meeting, American Institute of Mining, Metallurgical and Petroleum Engineers, Biltmore Hotel, Los Angeles, California.  Tentative program includes two sessions on "Liquids from Coal, Tar Sands and Oil Shale".  <u>February 21, A.M. Session:</u>  Winger, J. C., (Chase National Bank), "Outlook for the Domestic Energy Market for the Next Decade".



Date

Coming Event

---

Major petroleum company executives will discuss, "The Applied Demand Gap" and, "Rationale for an Emerging Synthetic Hydrocarbons Industry".

An executive of the Interior Department will discuss Interior's point-of-view concerning future energy sources.

February 21, P.M. Session:

Presentation will be made concerning the following subjects:

Tar Sands  
Office of Coal Research  
Hydrogasification of Coal or  
Oil Shale  
H-Coal or H-Oil Process  
Gilsonite  
Oil Shale

April 2-8, 1967

7th World Petroleum Congress  
Mexico City, Mexico

World Petroleum Congresses are held every four years. At this 7th Congress, according to a tentative program prepared by the Mexican Organizing Committee, there will be presented two panel discussions of special interest. These are:

Panel Discussion No. 13:

"Occurrence and Prospects of Tar Sands". General topics tentatively scheduled for discussion include the tar sand deposits, the chemical and physical nature of tar sands, technical problems of mining and processing tar sands, and in situ methods for recovery of bitumen from tar sands.

Date

Coming Event

---

Panel Discussion No. 14:  
"Occurrence and Prospects of Oil Shales". General topics tentatively scheduled for discussion include the oil shale occurrences and prospects, geologic settings, constitutional aspects of kerogen, synthesis of oil shale, precursors of oil shale, associated saline minerals, yield predictions from log analysis and brief summaries concerning oil shales in Brazil and Thailand.

April 6-7, 1967      4th Annual Oil Shale Symposium. Sponsored jointly by the Colorado School of Mines, the C.S.M. Research Foundation and the American Institute of Mining, Metallurgical and Petroleum Engineers, Brown Palace Hotel, Denver, Colorado.

Program not available.

May 21-24, 1967      62nd National Meeting, American Institute of Chemical Engineers, Hotel Utah, Salt Lake City, Utah

Program to include one session on "Fossil Hydrocarbons".

September 10-15, 1967      154th National Meeting, American Chemical Society, Division of Fuel Chemistry. Chicago, Illinois

Program to include a "Symposium on Oil Shale and Shale Oil."

# **OIL SHALE**





## DENVER RESEARCH INSTITUTE (DRI)

### DRI Awarded Oil Shale Waste Study Grant

The Denver Research Institute was awarded a \$56,910 grant by the U. S. Department of the Interior for a study of the disposal and uses of oil shale wastes. The grant is for one year and is expected to be renewed annually to complete a three-year program proposed by DRI. The grant was awarded in accordance with provisions of Public Law 89-272, more commonly known as the "Solid Waste Disposal Act", which was discussed in the March 1, 1966 issue of this report, pages 15-16. The research will be conducted in the chemical division of Denver Research Institute of the University of Denver. Dr. Thomas Nevens will direct the project.

Nevens stated that the one-year study will be fundamental and will be concerned with the investigation of the pozzuolanic characteristics that are exhibited by spent shale or can be induced in spent shale. This cementing or setting up characteristic may be relied upon to cause solidification or compaction of piles of waste shale discharged from retorts. The study will not be slanted toward a spent shale product produced by any specific retorting process. It will have as its objective a study of the reactions that occur in spent shale that cause spent shale to set up. There has been some indications that the shale wastes do set up, and data concerning the necessary conditions for encouraging these reactions will be sought.

No particular attempt will be made during this study to develop uses for spent shale.

DRI is conducting other oil shale studies at its Center for Fundamental Oil Shale Research. At present, Humble Oil and Refining, Shell Development, The Oil Shale Corporation and Aquitaine Oil are participating sponsors. The research program underway was discussed in the June 1, 1966 issue of this report, beginning on page 67.

## COLONY DEVELOPMENT COMPANY

### December Status of the Colony Development Company Project

A rearrangement of the management and the operating responsibilities of the Colony Development Company was announced during the September-December reporting period. Indicative of the December status of the Colony project was the November announcement that The Oil Shale Corporation (TOSCO), one of the Colony partners, would resume and continue the test operations of the prototype oil shale retort. The Standard Oil Company of Ohio, a 40 percent partner in the Colony venture, has withdrawn from active participation in the project. Cleveland Cliffs Iron Company, a 30 percent partner, continues to mine oil shale to supply feed for the 100 ton-per-day retort and to test mining procedures. With each partner traveling separate paths, unified operations of the Colony Development Company are essentially non-existent at the Parachute Creek site.

The 1-1/2 year program for testing the TOSCO retorting process, using the prototype retort, has shown the process to be infeasible. TOSCO, understandably, doesn't think so and continues the testing of the process, but strictly at its own expense. The primary shortcoming of the process is its high cost of operation; the high cost being due to low throughput and to heat-carrier ball breakage.

During September the prototype retort was operated utilizing screens at several points to remove fine shale and broken balls. A heater, presumably for use in pre-heating shale, was installed in the system.

The ball breakage problem remains unsolved. An additional problem which does not yet have a solution is the collection of dust solids in the product.



December Status of the Colony Development Company Project  
(continued)

Louie Erck, director of research for Cleveland Cliffs Iron Company, heads up a committee which is investigating new retorting processes.

C. E. Spahr Discusses Colony Project Slowdown

C. E. Spahr, president of the Standard Oil Company of Ohio, addressed the New York Society of Security Analysts on November 8, 1966, and stated that his company has reached the stage where it must re-evaluate the capital cost and needs of full-scale projects, and will go slow on future developments, such as shale oil. He stated that SOHIO scientists had not solved all of the problems inherent in the project's retorting process. In addition, the oil shale project has experienced delays in delivery of new type equipment needed to carry out further development. A factor mentioned by Spahr as affecting his company's decision to slow up the shale work was the lack of government policies on leasing of new acreage and on depletion allowance for oil shale. Spahr stated also that the Colony group thinks that shale oil may be a little further in the future than at first thought, but that shale's prospects are greater, sooner and more significant than those of conversion of coal to gasoline.

Edward Morrill, Colony President, Promoted to Senior Vice Presidency of Standard of Ohio

During October, Edward F. Morrill, president of Colony Development Company, was elected by the Sohio board to become a senior vice president of the Standard Oil Company of Ohio and to become a member of the board's executive committee.

Morrill remains as president of Colony Development Company.

ADDITIONAL  
COLORADO OIL SHALE DEVELOPMENTS

Oil shale developments in Colorado which concern the Colony Development Company, The Oil Shale Corporation and Denver Research Institute are discussed under separate chapter headings of this report. Additional developments in Colorado are discussed below.

Crestone Exploration Leases Fee Lands, Contemplates an In-Situ Shale Oil Recovery Test

Crestone Exploration Company entered into a lease agreement in August of 1966 with John Savage, et.al., for the use of 2510 acres of fee oil shale land for purposes of "mining and operating for and producing oil and gas from oil shale". The land occupies portions of T5S, R99W and T6S, R100W and is shown on the fold-out map presented with this chapter of the report.

John Savage, one of the lessors of the land, stated that Crestone Exploration claims to hold the patent rights to the Carl Belser invention (U.S. #2,725,939) of an "apparatus for producing oil from shale in situ". The Belser patent is reproduced and presented as pages A-18 and A-19 of the Appendix section of this report.

We have some question about the importance of this proposed test and there is no assurance that it will take place. Savage has stated that he is not involved in the technicalities of the project, but, "if someone desired to develop an oil shale project, I wouldn't want them not to have a place to stand". Crestone Exploration Company was incorporated in Colorado in 1965 by W. B. Wallace, T. W. Henritze and D. T. Hunt, all of Denver.



### Three-County Oil Shale Planning Unit Proposed

The Colorado counties of Mesa, Rio Blanco and Garfield are planning the formation of an "Oil Shale Institute" which would plan in advance for the many needs of an oil shale industry. The proposed Oil Shale Institute would be set up as a non-profit corporation with board members chosen from the three counties. Mesa County has no oil shale deposits, but Grand Junction, the county seat, is by far the largest city in Colorado's oil shale area. The formation of and activities of the Oil Shale Institute will be observed and reported upon, if significant.

### Status of Oil Shale Civil Action Cases in Colorado Reviewed

The status of all of the oil shale civil action cases now before the United States District Court in Denver and before the United States Court of Appeals in Denver is shown on the tabulations presented in the two pages that follow.

One of these civil actions (#8682) was ruled upon by the U. S. District Court during this reporting period. Humble Oil and Refining Company was awarded judgment over Mobil Oil Company in an action which involved a land-transfer option agreement. The issues will be discussed under separate heading, in the section which follows the tabulations.

OIL SHALE CIVIL ACTION CASES

BEFORE THE UNITED STATES DISTRICT COURT IN DENVER:

CIVIL ACTION NUMBER	NAME OF PLAINTIFF	NAME OF DEFENDANT	COMPLAINT FILED DATE*	SCHEDULED TRIAL DATE AND/OR DISPOSITION
8156	JOSEPH B. UMPLEBY	SEC'Y OF INTERIOR UDALL	8/14/63	READY FOR TRIAL. DATE NOT SCHEDULED.
8680**	TOSCO	SEC'Y OF INTERIOR UDALL	7/10/64	CONSOLIDATED WITH 8685, 8691, 9202. CONSOLIDATED CASES WENT TO TRIAL JULY 18, 1966. AWAITING JUDGMENT.
8682	MOBIL OIL COMPANY	WASATCH DEVELOPMENT CO. (LANDS PURCHASED BY HUMBLE OIL, FEBRUARY 1966)	7/10/64	TRIED MAY 31, 1966. NOVEMBER 17 JUDGE WESLEY BROWN RULED IN FAVOR OF DEFENDANT, HUMBLE OIL.
8685**	JOSEPH B. UMPLEBY AND WASATCH DEVELOPMENT	SEC'Y OF INTERIOR UDALL	7/13/65	TO TRIAL JULY 18. AWAITING JUDGMENT.
8691**	BARNETTE T. NAPIER	SEC'Y OF INTERIOR UDALL	7/15/64	TO TRIAL JULY 18. AWAITING JUDGMENT.
9202**	P. C. BROWN AND TOSCO	SEC'Y OF INTERIOR UDALL	6/14/65	TO TRIAL JULY 18. AWAITING JUDGMENT.
9252	H. H. AND D. D. HUGG	SEC'Y OF INTERIOR UDALL	7/ 7/65	READY FOR TRIAL. NO DATE SET.
9406	PACIFIC OIL COMPANY	SEC'Y OF INTERIOR UDALL	9/24/65	READY FOR TRIAL. SET FOR JANUARY CALENDAR.
9458	JOHN W. SAVAGE	SEC'Y OF INTERIOR UDALL	10/26/65	NO ACTION SINCE JUNE 14 MOTION TO STAY DISCOVERY.

OIL SHALE CIVIL ACTION CASES (CONTINUED)

<u>CIVIL ACTION NUMBER</u>	<u>NAME OF PLAINTIFF</u>	<u>NAME OF DEFENDANT</u>	<u>COMPLAINT FILED DATE*</u>	<u>SCHEDULED TRIAL DATE AND/OR DISPOSITION</u>
9641	UNION OIL COMPANY	SEC'Y OF INTERIOR UDALL	10/27/65	READY FOR TRIAL. NO DATE SET.
9642	EQUITY OIL COMPANY	SEC'Y OF INTERIOR UDALL	10/27/65	READY FOR TRIAL. NO DATE SET.
9464	GABBS EXPLORATION COMPANY	SEC'Y OF INTERIOR UDALL	10/27/65	READY FOR TRIAL. NO DATE SET.
9465	TOSCO, ERTL, PRICE, ET AL	SEC'Y OF INTERIOR UDALL	10/27/65	READY FOR TRIAL. NO DATE SET.

BEFORE THE UNITED STATES COURT OF APPEALS, TENTH CIRCUIT, DENVER:

<u>DOCKET NUMBER</u>	<u>NAME OF PLAINTIFF</u>	<u>NAME OF DEFENDANT</u>	<u>DATE DOCKETED</u>	<u>REMARKS</u>
8722	C. W. BRENNAN	SEC'Y OF INTERIOR UDALL	4/27/66	FORMERLY CIVIL ACTION #8542, SEE VOL. 3, NOS. 1 AND 2 FOR DISCUSSION OF ISSUES AND LOWER COURT'S ADVERSE RULING. NO DATE SET FOR HEARING OF APPEAL.

\* FOR COPY OF COMPLAINTS, SEE THE OIL SHALE REPORT OF THE APPROPRIATE PERIOD, APPENDIX SECTION.

\*\* CASES 8680, 8685, 8691 AND 9202 CONSOLIDATED FOR TRIAL.



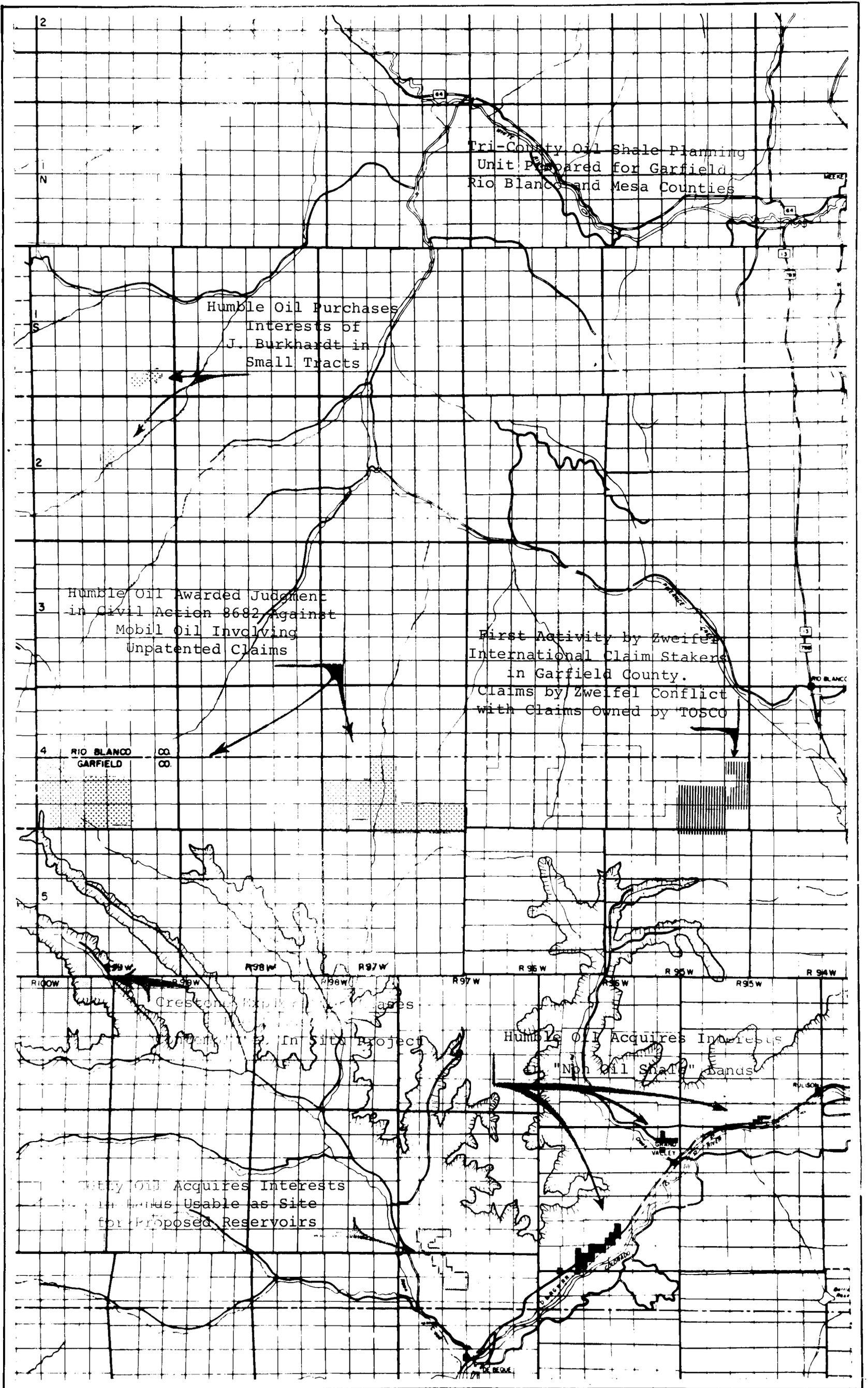
## Court Rules in Favor of Humble Oil in Civil Action 8682

In this civil action (No. 8682), Mobil Oil Company, the Plaintiff, asked the Court to interpret and enforce the terms of a 1958 Option Agreement with Humble Oil and Refining Company. The Court ruled in favor of Humble Oil and Refining Company, which now retains the lands involved, location of which is shown on the fold-out map.

Briefly reviewing the issues in Civil Action #8682, General Petroleum Corporation (now Mobil Oil) and Wasatch Development Company (Humble later purchased all interests in the Wasatch lands) entered into an Option Agreement in 1958 concerning the unpatented lands shown on the map. General paid Wasatch \$278,000 for the exclusive option to acquire the claims upon later paying an agreed-upon purchase price of \$2,452,000 on or before October 1964. Wasatch would file patent applications for the lands and would pursue diligently the processing of the applications. As patents issued, Wasatch would convey warranty deeds to General on the lands.

Controversy developed when Wasatch was unable to obtain patents from the Bureau of Land Management and attempted to return Mobil's \$278,000. Mobil wished to exercise its option, but this was refused by Wasatch on the ground that since patents were not issued on the claims the option had expired. Mobil formally attempted to exercise its option in February of 1964. Wasatch again refused, and transferred its interests in the land to Humble. The controversy over existing rights under the Option Agreement was taken to the Courts in July of 1964 as Civil Action No. 8682. The ruling by U. S. District Court Judge Wesley E. Brown settled the controversy in favor of Humble by declaring void the Option Agreement.

A copy of the COMPLAINT of July 10, 1964 in Civil Action 8682 is presented in the Appendix section of this report beginning on page A-21.



CURRENT EVENTS IN THE OIL SHALE  
 AREA OF COLORADO'S PICEANCE BASIN





Humble Oil Forms "Coal and Oil Shale" Operating  
Department

Humble Oil and Refining has formed two new operating departments--minerals, and coal and oil shale. The coal and oil shale department will manage the company's interests in solid hydrocarbons usable as sources of energy. G. H. Shipley has been named General Manager of the Department. The coal and oil shale department has three major sections, namely:

Resources Acquisition, R. D. Sloan, Manager  
Planning and Business Analysis, G. D. Priestman,  
Manager  
Research and Technology, W. O. Taff, Coordinator  
and J. T. Patton, Advisor

Status of Equity's In-Situ Project -- New Project by Mobil?

Equity Oil Company's "BX" Experimental Project for in-situ recovery of oil from shale oil has reached the "data evaluation" stage, according to Paul Dougan, company geologist.

The basic concept of the process is the injection of heated methane into the oil shale formations to produce oil. The BX field experiment, located in Section 6 of T3S, R98W, Rio Blanco County, had as its objective the duplication of laboratory tests under field conditions. The project has been described in detail on pages 40-45 of the June 1, 1966 quarterly report.

Mobil Oil commenced drilling in September for an apparent in-situ project on lands held jointly by Equity and Mobil. The site of the new project is Section 34 of T3S, R99W, 6th P.M.

## UTAH OIL SHALE DEVELOPMENTS

### Western Oil Shale Corporation Starts Exploratory Drilling Program on State Leases

Western Oil Shale Corporation (WOSCO) holds 56,000 acres of oil shale land under state leases. The company has announced the start of an exploratory drilling program. Uintah Drilling Company has been contracted to drill the first hole at a site about 45 miles south of Vernal. Nash V. Dowdle, company president, has stated that a second core hole is planned after assay work has been completed on cores taken from the first hole.

### TOSCO Loses Land Option Suit

Civil Action No. 4738, filed in October of 1964 in the Fourth Judicial District Court for Uintah County concerning an option by TOSCO on oil shale lands controlled by F. V. Larson, has been decided in favor of the defendant, Larson.

In its 1964 complaint, TOSCO claimed that two distinct agreements had been reached with Larson. One for the acquisition of the Larson Oil Company land and the other relating to Larson's activities in obtaining control of other lands for TOSCO. The lands involved total about 20,000 acres, located in T. 9, 10, 11 and 12, S. R.25E. Salt Lake Meridian, Uintah County.

The following terms were agreed upon for the acquisition of the Larson Oil Company lands:

1. TOSCO would take a 6 month option on the land for \$20,000. During this period TOSCO would examine title, history and status of mining claims and patent proceedings, the extent of reserves and accessibility of mining.



TOSCO Loses Land Option Suit (continued)

2. TOSCO would carry the lands to patent at its own expense.
3. TOSCO held the right to drop any portions which it deemed unpatentable or uneconomic.
4. TOSCO would pay a delayed rental to Larson Oil on patented lands owned. Yearly payments would be \$2.50 per acre for the first year, \$3.50 per acre the second year, \$4.50 per acre the third year and \$5.00 per acre every year thereafter. Payments would be semi-annual and would be applied to subsequent royalty payments.
5. Upon putting the property into production, TOSCO would pay Larson Oil a royalty of 5¢ per barrel of oil produced and sold.
6. The lease agreement contained an option for outright purchase of the land. Purchase price would be computed on the following formula: Present worth of the recoverable oil at 5¢ per barrel discounted over 20 years at a 12% rate.

The second part of the agreement was that Larson would act as TOSCO's representative to bring together the group of owners of the other shale lands in the area in committing the land to TOSCO as follows:

1. Larson would make the first pass in contacting all the owners to determine the cost and terms on which the land might be available. At this point TOSCO would be able to determine the desirability of proceeding further.
2. Larson would not reveal TOSCO's name at this stage of the negotiations.

TOSCO Loses Land Option Suit (continued)

3. Larson would be employed as a consultant by TOSCO for up to one year at \$1,200 per month plus expenses. During this time he would work toward assembling the small parcels into a single package and assist in the work involved in patenting the Larson Oil Company lands. If Larson succeeded in obtaining control of the small parcels for TOSCO, he would receive 1¢ per barrel on the oil produced from such lands.

TOSCO asked the Court to enforce the terms of the agreement.

Larson held that the agreement ended on January 15, 1964, when TOSCO failed to execute. Judge Joseph E. Nelson ruled on November 1, 1966, in favor of Larson. TOSCO, of course, did not acquire the property.

It has been reported recently that Larson has optioned his oil shale property to an unnamed major oil company, the option to expire December 15, 1966.



## WYOMING OIL SHALE DEVELOPMENTS

### Electro-Fracing, Nitro-Fracing and Thermal In-Situ Projects Underway at Bu Mines Field Test Site near Rock Springs

As part of the Bureau of Mines' investigations of non-nuclear methods of creating permeability in oil shale formations, a continuing series of field tests of several processes is being conducted in oil shale formations near Rock Springs, Wyoming. The processes being field tested are the Electro-Fracing (or Electro-Carbonizing) process, the Nitro-Fracing process and a steam-thermal process. Research groups from the Laramie Petroleum Research Center are investigating the Electro-Fracing and steam-thermal processes. They are being assisted by a research group from the Bartlesville, Oklahoma station which has previously tested the Nitro-Fracing process in limestone formations, and is now investigating its applicability to oil shale formations.

The Electro-Fracing process for increasing permeability of oil shale formations involves the controlled use of high-voltage electricity which is impressed across the oil shale formations between electrodes which have been positioned in drill holes.

The Nitro-Fracing process for increasing permeability of rock formations involves the use of de-sensitized nitroglycerin which is first injected into rock fractures and fissures and is then detonated. The detonation of the thin films of nitroglycerin increases the width of the existing fractures and creates new fractures, thus increasing the permeability of the formations.

The steam-thermal process reported here will involve the injection of 1000°F steam into an oil shale formation that had been previously subjected to Electro-Fracing and to Nitro-Fracing techniques. The steam will be the heat carrier.

Electro-Fracing, Nitro-Fracing and Thermal In-Situ  
Projects Underway at Bu Mines Field Test Site near  
Rock Springs (continued)

Separate, yet related tests of these three in-situ processes are being conducted at several sites within the field test area. At one test site, all three processes are involved. In order that the tests being conducted at the several test sites can be more clearly visualized, the test projects will be discussed separately.

The oil shale formations at the field test area occur at or very near the surface, and the bedding planes of the formations are essentially horizontal. The Fischer assay of the formations is rather low, averaging about 22 gallons of oil per ton of shale within the zones being tested. The area is easily accessible from Interstate Highway 80, and is situated about midway between Rock Springs and Green River. Being an arid area, it was anticipated that the oil shale formations would be dry, hard and relatively unweathered.

Tests at Site No. 1:

Test wells drilled at Site No. 1 encountered water in various quantities and at various depths. At a depth of about 40 feet, a very-permeable, 2-inch layer of volcanic tuff was encountered. The unexpected permeability and the presence of water were discouragements to the Laramie research group's plans for Electro-Fracing experiments. Dry, impervious formations would be most desirable for evaluating results of Electro-Fracing. Preliminary tests of the Electro-Fracing process were attempted, but the inherent permeability of the formation (and the moisture) made it difficult to evaluate results. It was decided that the Electro-Fracing tests would be made at a new and more appropriate site.

The research group from Bartlesville utilized the permeable 2-inch thick seam of tuff as a receiver for de-sensitized nitroglycerin in a preliminary test of the Nitro-Fracing process. Fifty quarts of nitroglycerin



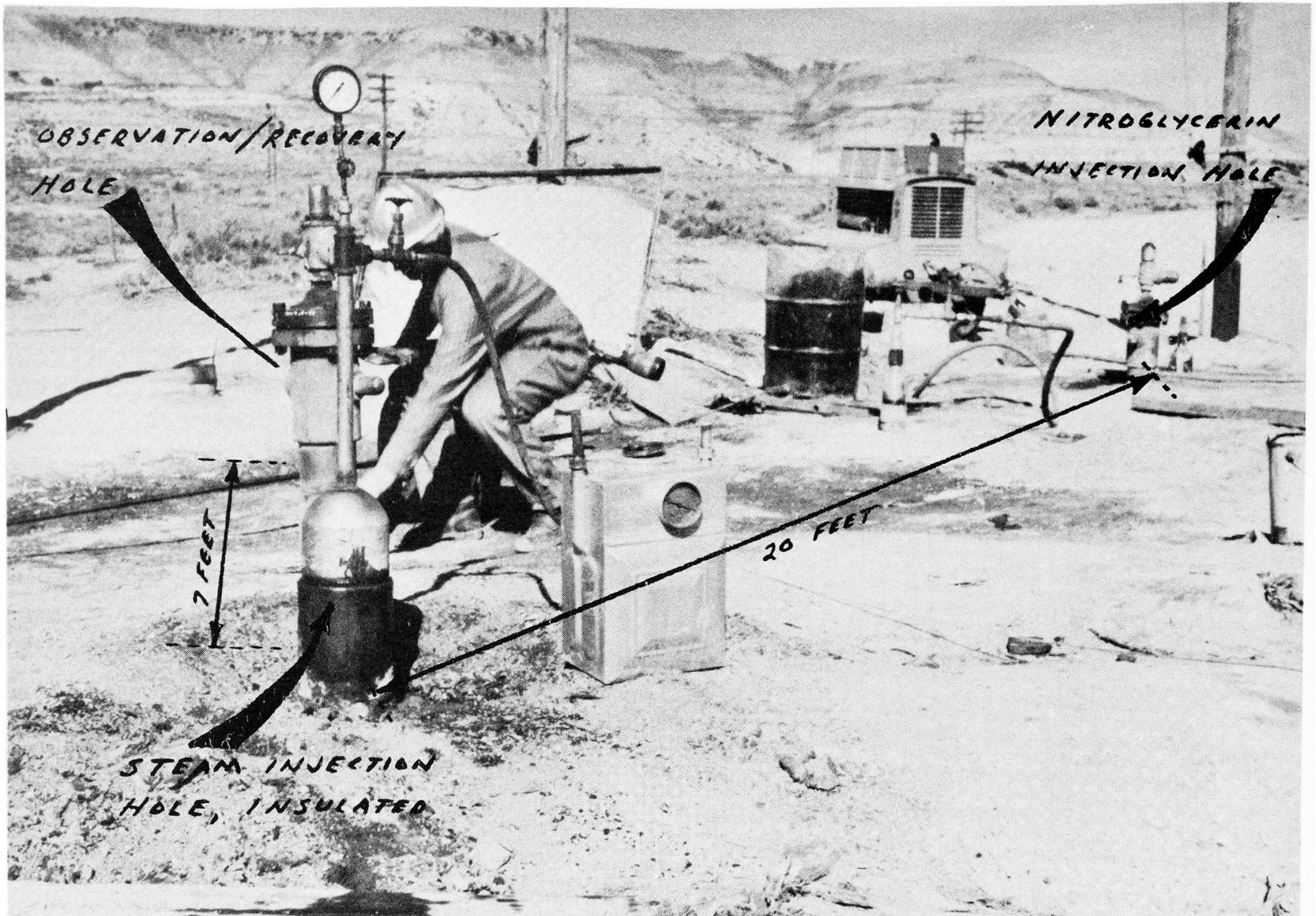
Electro-Fracing, Nitro-Fracing and Thermal In-Situ  
Projects Underway at Bu Mines Field Test Site near  
Rock Springs (continued)

were injected into the permeable layer of tuff through one injection well which was cased and cemented to a level about one foot above the layer of tuff. A bottom plug was poured to fill the bottom of the injection well to a level about one foot below the layer of tuff. Flow rates were established before and after the detonation of the nitroglycerin, utilizing nearby observation wells. The post shot flow rates between the injection well and observation wells was 2 to 19 times greater than the pre-shot flow rates. Core holes were drilled in the blast zone in an attempt to gain more data.

Tests at Site No. 2:

Six test holes, 125 feet deep, were drilled in an unsymmetrical pattern in which it was possible to install Electro-Fracing process electrodes at separation distances ranging from about 25 feet (a practical minimum) to about 130 feet (about as much as could be expected for the process). Electro-Fracing tests were made at various electrode-separation distances. Test results were evaluated by such means as air-flow measurements, made before and after the tests, and by downhole camera photographs, which allowed visual examination of the formations after the tests. One major problem with the process is apparently that of controlling the flow pattern of electricity between electrodes. Once a pathway has been established, by burning or carbonizing of shale, the current continues to flow along that pathway.

The holes at Site No. 2 encountered various quantities of water, necessitating the casing of the holes for the first 40 feet. A porous zone was also encountered. Sealing off the wet and porous zones represented additional problems and made it difficult to truly evaluate permeability increases attributable to the Electro-Fracing process.



U.S.B.M. Field Test Area, Wyoming

View of Portion of Test Site No. 2

Shown are relative positions of holes to be utilized in a steam-thermal test for the in situ recovery of oil from oil shale.



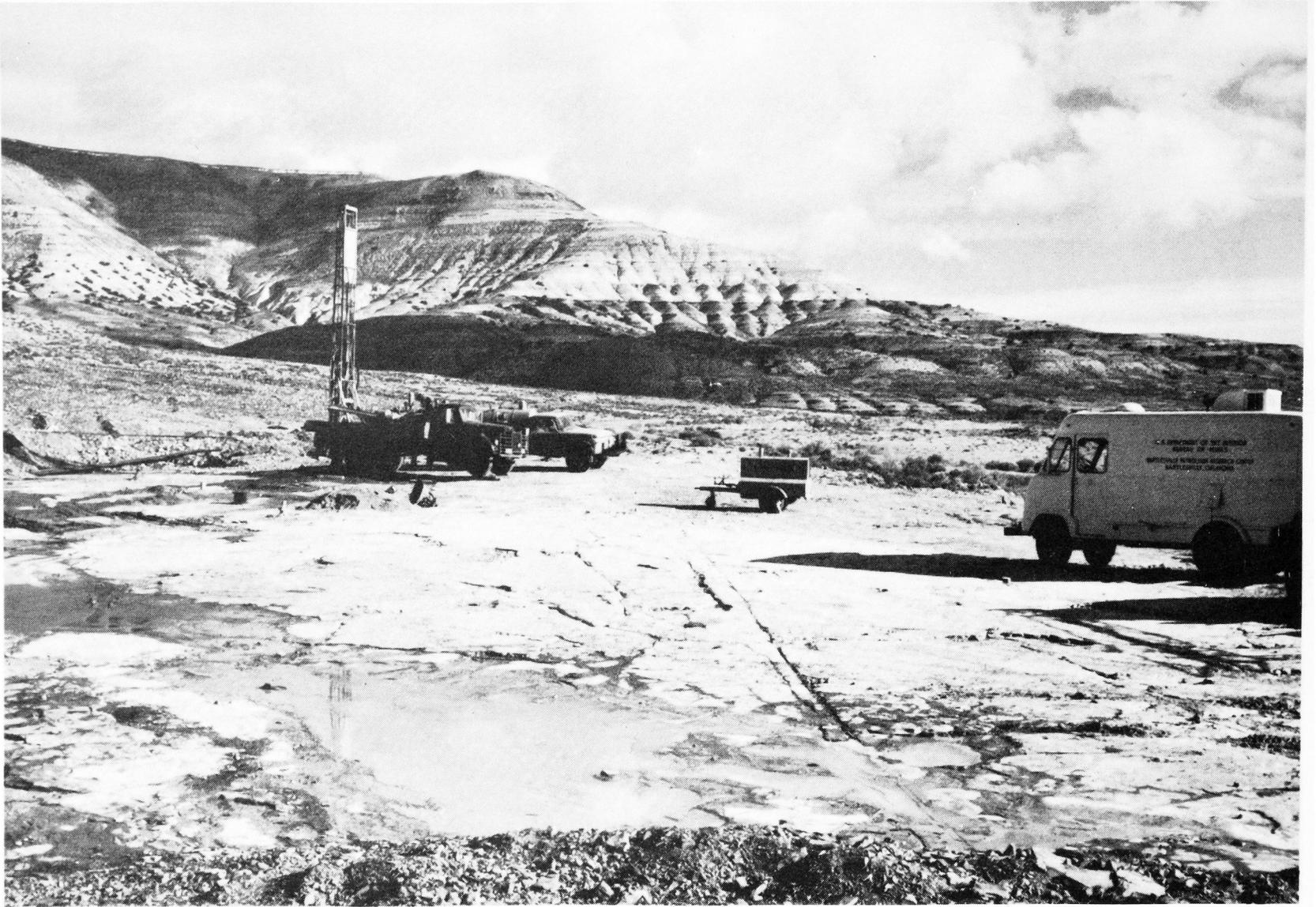
Electro-Fracing, Nitro-Fracing and Thermal In-Situ  
Projects Underway at Bu Mines Field Test Site near  
Rock Springs (continued)

A steam-thermal project will be conducted at Site No. 2. Test preparations are now underway. A steam-injection hole has been drilled to about 70 feet, has been cased and insulated. Superheated steam (1000°F) will be injected into the oil shale formations that have already had some Electro-Fracing and some Nitro-Fracing work done to increase their permeability. About 16 quarts of nitroglycerin were recently pressure-injected into the formations at the 70-foot level through an injection hole located about 20 feet from the steam-injection hole. An observation recovery hole exists at a distance of about 7 feet from the steam-injection hole. In the photograph on the page that follows, a Bu Mines engineer is setting up a flow measurement test just prior to the detonation of the nitroglycerin. Such tests were repeated after the detonation.

Superheated steam (1000°F) will be introduced into the formations through the cased and insulated hole. Steam condensate and oil, if any, will be recovered from the nearby observation well. The steam-thermal project will provide additional data concerning the kind of permeability that exists in the formation. Also, if oil is recovered, its characteristics can be studied and the amount of heat required will be noted.

Tests at Site No. 3:

Loose soil and overburden were scraped away to provide a level site on hard oil shale formations for continuing tests of the Nitro-Fracing process. Eleven holes have been drilled at this site, to date, and two Nitro-Fracing tests have been made. Late in October, a Nitro-Fracing test was made which involved the detonation of 190 quarts of nitroglycerin which had been injected into permeable zones of the formation through one injection hole believed to be about 140 feet deep. This test was well instrumented. Work to evaluate the effectiveness of the detonation is now in progress.



U.S.B.M. Field Test Area, Wyoming

View of Test Site No. 3

Rig is cleaning sand plug out of nitroglycerin injection hole following detonation of 190 quarts of nitroglycerin which had been forced into fractures within the oil shale formation.



U.S.B.M. Field Test Area, Wyoming

#### View of Test Site No. 4 Preparations

A new series of Electro-Fracing tests will be conducted here, utilizing holes now being prepared.

Test Site No. 2 appears in the background.

Electro-Fracing, Nitro-Fracing and Thermal In-Situ  
Projects Underway at Bu Mines Field Test Site near  
Rock Springs (continued)

Tests at Site No. 4:

Test holes are now being drilled at this site for a new series of Electro-Fracing experiments. The formation characteristics have not been evaluated. It is believed that these holes may be deeper than at the other test sites.

Chief Geologist of Union Pacific R.R. Discusses the  
Railroad's Raw Material Program and Oil Shale Properties

James A. Marsh, Chief Geologist for the Union Pacific Railroad presented a paper, Union Pacific's Raw Material Program, before the 1966 Mining Convention of the American Mining Congress at Salt Lake City, Utah, during September.

Marsh noted that the Union Pacific owns mineral rights to approximately 8 million acres of land consisting of the odd-numbered sections extending in a checkerboard pattern for 20 miles on each side of its line of railroad through Wyoming, Colorado and Utah.

During 1957-1958, Union Pacific geologists made a reconnaissance investigation of the areal extent and quality of oil shales within the Land Grant area of Wyoming. From this survey, Marsh estimated that Union Pacific owns approximately 650 sections of land underlain by oil shales averaging about 40 feet in thickness, and capable of yielding 15 gallons of oil per ton of shale. On this basis, the estimated oil in place would be about 20 billion barrels. Most of this shale would have to be mined by underground operations.

Marsh depicted the Union Pacific Railroad as being an energy company because of its reserves of coal, oil and gas, oil shale and potential uranium-bearing lands. As a matter of interest, Marsh stated that Union Pacific consumes about 20,000 barrels of diesel and turbine fuel per day, yet produces crude oil in a volume that exceeds this by a considerable amount.



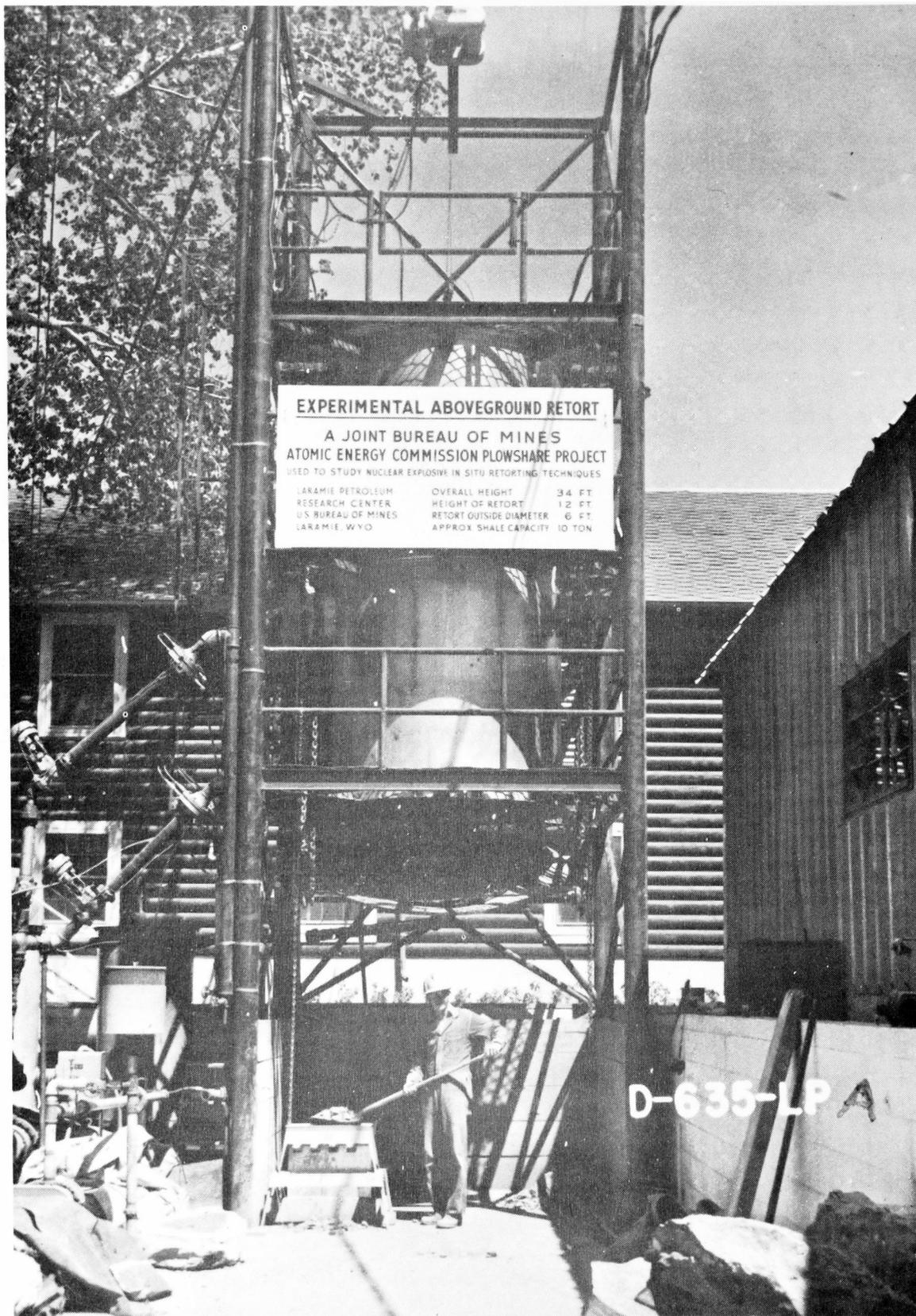
## Retorting of Large Fragments of Oil Shale at Laramie

The Laramie Petroleum Research Center of the U. S. Bureau of Mines is continuing its retorting tests on large fragments of oil shale in an experimental above-ground retort designed for this purpose. These tests were reported in our March 1, 1966 report, beginning on page 41. Results of preliminary retorting tests were reported by Lombard in, Retorting Oil Shale in a Nuclear Chimney, a paper reviewed in our September 1, 1966 report beginning on page 19. The A.E.C. is participating with the Bureau of Mines in these tests. The objective of the tests is to obtain data useful for evaluation of processes for retorting the large-size fragments of shale resulting from a contained nuclear detonation in oil shale.

Shown on the page that follows is a view of the special retort used. The retort has an inside-the-refractory diameter of five feet, at the bottom of the retort. The refractory walls taper slightly, leaving an inside diameter of 4-1/2 feet at the top of the retort. The metal shell of the retort is 6 feet in diameter.

When the retort is filled with coarse, ungraded fragments of oil shale, a dome shaped free space of 18 inches maximum height is left above the surface of the shale. Shale is placed in the retort from the top, and is discharged from the bottom. Upper and bottom plates are hinged. The largest fragment of oil shale retorted to date in these experiments had a maximum dimension of about two feet. This particular fragment is shown in the photograph on a page that follows. Thermocouples are imbedded within large fragments, prior to retorting, as an aid in studying the heat penetration rates.

The early retorting tests were controlled by temperature measurements within the bed, a method that proved unreliable. At the very low gas flow rates, the fire could go out and not be noticed for several hours. The later retorting tests have all been controlled by off-gas analyses. The oxygen content of the exit gas is monitored. Should the fire go out, the oxygen content of the exit gas stream increases quickly.



Bureau of Mines Photograph of the Batch-Type Retort Used at Laramie in Retorting of Ungraded Oil Shale of Large Fragment Size.



This photograph, furnished by the Laramie Petroleum Research Center of the U. S. Bureau of Mines, shows one of the largest fragments of oil shale to be retorted in the experimental "ungraded shale" retort at Laramie. The retorted fragment has been split open along a bedding plane to disclose an inner zone of residual carbon which remained unoxidized during the retorting operation.

Retorting of Large Fragments of Oil Shale at Laramie  
(continued)

The combustion front travels downward through the bed of shale. The fire front is started by the use of air and natural gas introduced into the upper portion of the dome-shaped roof of the retort. Difficulties have been experienced in getting the fire and flame front started.

Various ratios of recycle gas and combustion air have been used in the tests. The ratios have ranged from 1.5 recycle gas/ 1.0 air to 0.0 recycle/1.0 air. It normally takes about a week to conduct one retorting test. As the inside height of the retort is 12 feet, the rate of travel of the heat front through the bed of shale calculates to about 1.7 feet/day, but rates as low as 0.4 feet/day have been attempted.

A minimum of about 1.5 cubic feet of air/minute/square foot of cross sectional area has been used, but air requirements probably will be close to 3 cubic feet of air/minute/square foot of cross sectional kiln area.

In the early tests, retorting temperatures of about 900°F were sought. In later tests, retorting temperatures of 1200°F were found to be more suitable.

The large fragments of oil shale heat up much more quickly than would be expected from calculations. They cool off more slowly than expected, according to Laramie spokesmen.

While the retorting tests at Laramie can be observed by visitors, specific data are appropriately reserved by the Bureau.



THE OIL SHALE RESEARCH PROGRAM  
AT THE LARAMIE PETROLEUM RESEARCH CENTER  
FISCAL YEAR 1967  
(July 1, 1966-June 30, 1967)

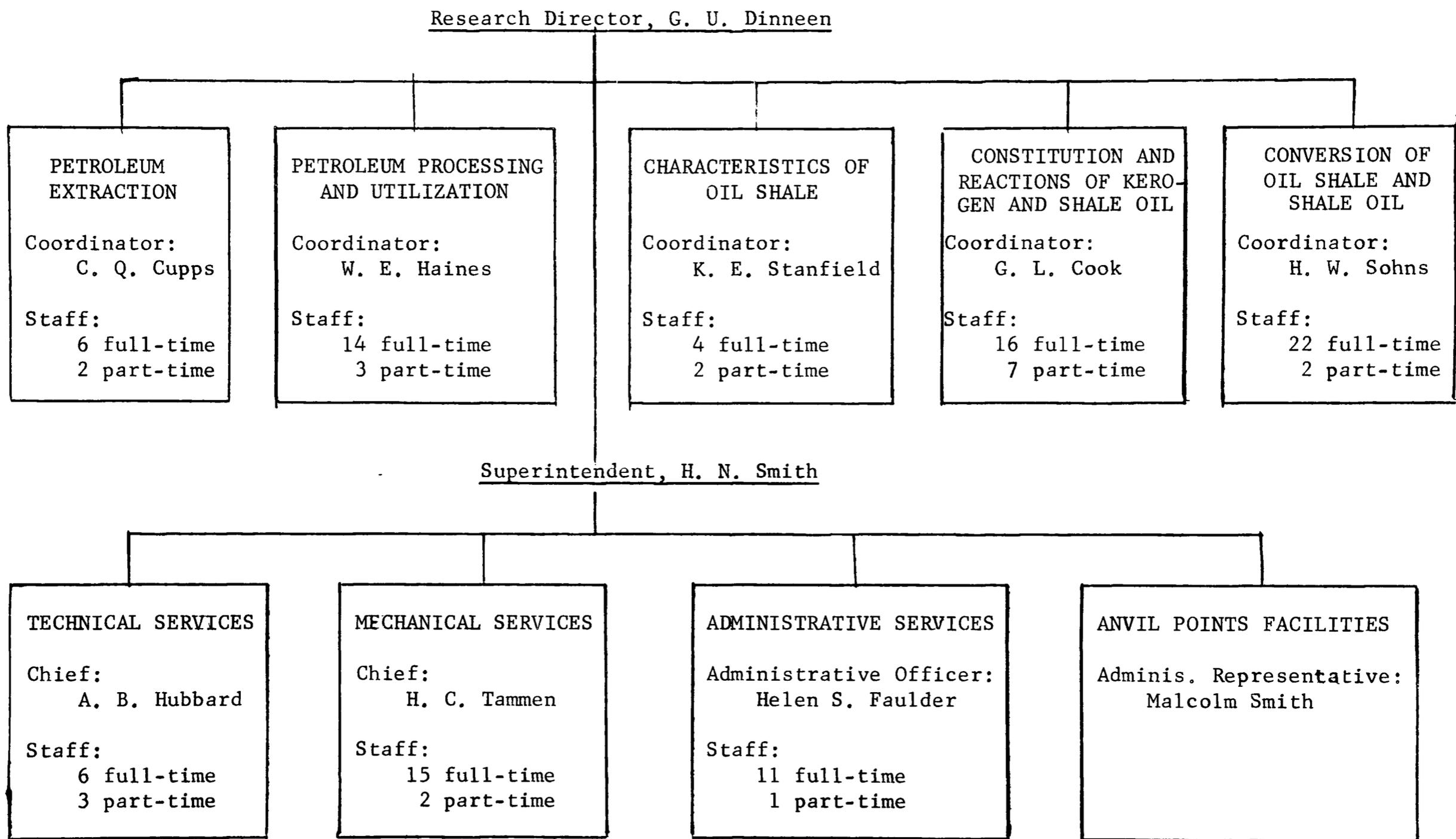
Introduction

The U. S. Bureau of Mines maintains the Laramie Petroleum Research Center on the campus of the University of Wyoming, in Laramie, Wyoming. For Fiscal Year 1967 the Laramie Petroleum Research Center was allocated about \$1.5 million from the \$3.4 million total appropriation to the Bureau of Mines for conducting research on petroleum and oil shale. These figures represent a slight increase over those for Fiscal Year 1966 when \$1.2 million was allocated to the Center from the Bureau's appropriation of \$3.3 million. In addition to the \$1.5 million allocation for Fiscal Year 1967, about \$120,000 is being contributed by other Government agencies and by industry for cooperative programs being conducted at the Center.

The total research effort at the Center is devoted about one-fourth to petroleum research and about three-fourths to oil shale research. That portion of the Laramie Center's research program that concerns oil shale and on which work has been authorized for Fiscal Year 1967 will be discussed in detail.

The Organization of the Laramie Petroleum Research Center

The organization diagram for the Laramie Petroleum Research Center is presented on the page that follows. The manpower resources that should be available to the Center during Fiscal Year 1967 for support of the various research efforts are indicated on the diagram. This is essentially the same organization that has been maintained for the past few years. While the number of personnel involved theoretically should be increased during Fiscal Year 1967, present policies of the Bureau keep this number essentially unchanged over Fiscal Year 1966.



Organization of the Laramie Petroleum Research Center.



## The Oil Shale Research Program

All research programs at the Laramie Center are developed through a project proposal system whereby research ideas are evaluated by Bureau officials at Laramie and in Washington on the basis of such factors as pertinence to established policies, scientific value, extent of interest in results, technical feasibility, and possibility of success.

### CHARACTERISTICS OF OIL SHALE

The work of this group has been a continuous effort since 1945, involving the sampling of oil shale deposits, determining the nature of representative samples and publishing these data in a continuing series of Reports of Investigations. Oil yields have been determined on more than 120,000 samples. Most of the samples used in the studies have been drill cuttings and cores contributed by private companies.

A study presently being emphasized by this group--the geochemistry of oil shale--should provide additional data for correlating and interpreting the oil shale characteristics for the purpose of appraising the source deposits. The studies of this group have been concentrated on oil shales derived from the Green River formations in Colorado, Utah and Wyoming.

During the past year, emphasis has been placed on the sampling, analysis and evaluation of sites for proposed Bureau experiments to process oil shale in place. In this particular effort, the Bureau of Mines and the AEC have collaborated in the drilling of two coreholes in Colorado. The Bureau has drilled an additional corehole in Wyoming. The analyses of these cores has taken precedence over other phases of the group's normal project effort. The Bureau's progress in drilling these three coreholes has been discussed in the regular issues of

this quarterly report. These particular studies may be continued by drilling one additional corehole during Fiscal Year 1967.

This group's efforts also include studies regarding the composition and properties of oil shales. Analytical research is performed to determine the elemental composition of many oil shale samples, the thermal properties of the oil shale, and physical properties such as its character, bedding, porosity, joints, permeability, specific gravity, strength, etc. Emphasis is now placed on the determination, occurrence and properties of the mineral dawsonite, recently noted in quantity in the central portion of the Piceance Basin. J. Ward Smith of the Laramie Center and Charles Milton of the U.S.G.S. prepared an interesting paper, Dawsonite in the Green River Formation of Colorado, which appeared in the *Journal of Economic Geology*, V. 61, 1966. A review of this paper is presented in this quarterly report in the chapter entitled "Sodium Mineral Occurrences Within the Green River Formation".

A special assignment to this group concerns the role of domestic tar sands for inclusion in the Department of Interior's petroleum energy study, A Survey of Factors Affecting Future Availability of Liquid Hydrocarbons and Natural Gas to Meet United States Requirements.

#### CONSTITUTION AND REACTIONS OF KEROGEN AND SHALE OIL

This research group is concerned with determining the constitution and reactions of fractions, components, and products from kerogen and from shale oil. The group's efforts are divided into four projects, each of which is discussed briefly.

1. The Constitution of Kerogen: This project has the objective of describing the raw material "kerogen". Emphasis is placed on the identifi-



cation of chemical structures that can be associated with ancient living organisms, as an aid in explaining the origin of the organic matter in oil shale. The changes in the kero-gen functional groups with stratigraphic depth are being studied. This project includes the studies of the pyrolysis of oil shale under controlled temperatures, pressures and several types of atmospheres.

2. The Composition of Shale Oil Products: This project has the objective of providing data on the composition of shale oil and shale oil fractions.
3. Reactions of Oil Shale Components: This project has the objective of exploiting differences between shale oil and petroleum. It is desired to demonstrate that components in shale oil can be changed in specific ways, such as by the application of ultra-violet light, to initiate specific reactions.
4. Spectroscopic Research: This project includes the performance of all non-routine spectral analysis methods and for the development of techniques useful to other research groups at the Center.

#### CONVERSION OF OIL SHALE AND SHALE OIL

This area of work is concerned with methods for converting the organic portions of oil shale to shale oil, and with methods for converting shale oil to an oil, for which refining methods are available, and to other useful products. The primary efforts of the Laramie Center in oil shale conversion research are currently concentrated in studies of in situ techniques for producing shale oil. Specific current studies underway at the Center will be discussed briefly under separate headings.

1. Laboratory Studies of In Situ Retorting Problems: Thermal conductivities of various grades of raw shale have been determined, both parallel and perpendicular to the bedding planes. Conductivities of spent and burned shales are being studied. Operation of a 300 pound-per-hour spent-shale-burning retort has been improved recently after modifications to the equipment. Maximum feed rates compatible with efficient burning in this equipment have been determined. Studies will continue in an effort to determine data on diffusivities of raw shale and on the effects of air and shale rates and other variables on the combustion of the residual organic matter deposited on spent shale.
  
2. In Situ Retorting of Oil Shale: The purpose of this project is to investigate non-nuclear methods of creating permeability in oil shale. Small-scale field tests are being conducted near Green River, Wyoming to determine the potentialities of utilizing high-voltage electricity (the Electro-Fracing process) and utilizing nitro-glycerine (the Nitro-Fracing process) for creating permeability and/or to induce massive fracturing of the oil shale. At the time of this writing, the Laramie Center is setting up a thermal (steam) oil recovery project for the in situ processing of oil shale at the site of the Electro-Fracing and Nitro-Fracing field tests in Wyoming.

As these field tests are being conducted in Wyoming, the more detailed discussions of the tests are presented in the Wyoming Oil Shale Developments chapter of this quarterly report.



3. Use of Nuclear Explosives in Processing Oil Shale: The Bureau of Mines, in cooperation with the AEC, is investigating the feasibility of processing oil shale by in situ recovery of oil from shale fractured by a nuclear detonation. The Bureau has drilled two coreholes in oil shale formations in Colorado and one corehole in Wyoming. Final selection of a suitable site for a nuclear detonation test is yet to be made. Reports on results of analyses of the three coreholes are in the process of preparation and publication.

For evaluating the retorting characteristics of large fragments of oil shale, the Laramie Center has been conducting tests in a specially-designed "ungraded shale" retort. The status of this test program is reported in this quarterly report in the chapter entitled, "Wyoming Oil Shale Developments".

4. Physical Chemistry of Oil Shale: The purpose of these studies is to develop a body of information which will provide a better understanding of the structure and physical chemistry of oil shale.
5. Observation of Research Operations at the Anvil Points Oil Shale Research Center, Rifle, Colorado: Pursuant to the terms of the lease agreement between the Colorado School of Mines Research Foundation and the Department of the Interior, the Laramie Center stations observers at the Anvil Points Oil Shale Research Center near Rifle, Colorado to observe the research being conducted there. Companies participating in the research effort at Anvil Points are:

Project Manager --- Socony Mobil Oil  
Participants --- Humble Oil & Refining  
Continental Oil  
Pan American Petroleum  
Phillips Petroleum  
Sinclair Research

### Conclusions

The oil shale research program at the Laramie Center points up the emphasis placed by the Department of the Interior on the development of in-situ techniques for processing oil shale. The Electro-Fracing tests, the Nitro-Fracing tests, the retorting tests on ungraded, large-size fragments of oil shale, the AEC/BuMines core drilling program and the new thermal recovery project at the field test site near Green River are all designed to investigate various aspects of in-situ processes.



## THE OIL SHALE CORPORATION (TOSCO)

### TOSCO President Reveals Additional Details of the Colony Project Realignment

In an October 10, 1966 letter to shareholders, Hein Koolsbergen, president of The Oil Shale Corporation, informed the shareholders of the changes in operational responsibilities at the Colony Development Company's "semi-works" facility near Grand Valley, Colorado. For reference purposes, Koolsbergen's letter is reproduced as pages A-34 and A-35 of the Appendix section of this quarterly report.

Koolsbergen disclosed that Colony Development Company's oil shale mine would be operated by Cleveland Cliffs Iron, a 30 percent owner of Colony, but the cost of its operation will be assumed by the three Colony partners in proportion to their ownership interests in the venture. The retort will be operated by TOSCO, a 30 percent owner of Colony, but the costs will be borne entirely by TOSCO. Colony Development Company will cease to have responsibility for field operations.

These new arrangements carry on the program for commercial production, according to Koolsbergen. They provide a period during which the three companies will continue their appraisal of data obtained from operations and will review technological alternatives. Such new alternatives were said to range from variations in the present semi-works plant to investigation of other processes.

The last paragraph of Koolsbergen's letter states that TOSCO's increased responsibilities in connection with the operation of the semi-works plant will require substantial funds, which TOSCO intends to acquire from private sources either by loan, which may be secured by certain reserves or by issuance of equity securities.

## TOSCO Loses Utah Land Option Suit

A suit filed two years ago by TOSCO against Fred V. Larson, and others, has been decided in favor of the Larsons. The issues involved in this civil action are discussed in detail in the Utah Oil Shale Developments chapter of this quarterly report.

## Miscellanea

The most recent monthly report, Form 8-K, filed by TOSCO with the Securities and Exchange Commission was dated July 18, 1966. This report announced an increase in the amount of securities outstanding, namely, a Demand Note wherein TOSCO agrees to repay \$750 thousand borrowed on June 10, 1966 from the First National City Bank of New York.

TOSCO is dismantling its 1-ton-per-hour pilot retort which was operated for several years at the Zuni Street site in south Denver.

TOSCO is reportedly attempting to sell its interests in the Ertl oil shale property, a group of unpatented claims in T4S, R95 and 96W., 6th P.M., Garfield County, Colorado.



## NUCLEAR DEVELOPMENTS

A group of twenty-four companies, representing about 80 percent of the petroleum industry in the United States plus others interested in oil shale development, have organized under the promotional efforts of CER Geonuclear Corp. to negotiate an operating agreement --among themselves-- and a participation agreement with the Federal government for the purpose of conducting an experiment with a nuclear bomb to be detonated in oil shale in western Colorado. The objective of the experiment is to fracture the tight oil shale formation and to retort the broken rock in place in order to demonstrate the production of oil from shale by a method which would be competitive in cost with conventional petroleum cost.

### The Background Developments in Brief Review

CER Geonuclear Corporation presented its "Feasibility Study" of the nuclear in-situ oil shale project to industry at an oil shale conference held in Washington, D.C. in July of 1966. For specific details concerning the July conference and the proposed project, your reference is invited to the September 1, 1966 quarterly report, pages 9-21. In summary form, the proposed project would be conducted in three phases and would include the features listed in the time schedule shown below.

<u>Time Period</u>	<u>Activity</u>	<u>AEC Cost</u>	<u>Industry Cost</u>
July through December, 1966	Formation of consortium and negotiation with government agencies	none	\$ 100,000
January through October, 1967	Site selection and pre-shot studies - Phase IA	640 acres	395,000
Late Fall 1967	Detonation - Phase IB	\$670,000	none

The Background Developments in Brief Review (cont'd)

<u>Time Period</u>	<u>Activity</u>	<u>AEC Cost</u>	<u>Industry Cost</u>
January through December 1968	Post-shot investigations and planning of Phase II - Phase IC	\$195,000	\$1,435,000
January 1969 through March 1970	<u>In-situ</u> retorting of nuclear chimney - Phase II	none	2,055,000
April through December 1970	<u>In-situ</u> retorting of fractures around nuclear chimney - Phase III	none	1,470,000
4-1/2 Years	Total Program	\$865,000 plus land	\$5,455,000

Additional features of the program proposed by CER Geonuclear Corporation were that the explosion of the nuclear device would be carried out under the direction and at the expense of the Atomic Energy Commission as another step in its Plowshare program to develop peaceful uses for atomic explosions. The private industry group would have the primary responsibility of determining, through a full scale experimental program, whether or not shale oil can be produced economically by retorting the broken shale produced by the blast.

Conference Held in September on Oil Shale Research Project Details

Representatives of 24 organizing companies met at the Dunes Hotel in Las Vegas, Nevada on September 29-30 and took first action on a proposed "Operating Agreement". As now drafted, this agreement would become operative only when (a) CER Geonuclear Corporation has negotiated an



Conference Held in September on Oil Shale Research Project  
Details (continued)

agreement with the government regarding the Research and Development Program which is acceptable to the industrial participants, and (b) the participants are assured that there are at least ten participating parties in the program.

The Operating Agreement is between CER Geonuclear Corporation and the companies listed below.

Atlantic Richfield Company  
Cameron and Jones, Incorporated  
Cities Service Oil Company  
Continental Oil Company  
El Paso Natural Gas Company  
Equity Oil Company  
Getty Oil Company  
Humble Oil & Refining Company  
Marathon Oil Company  
Mobil Oil Corporation  
Murphy Oil Corporation  
Pan American Petroleum Corporation  
Shell Oil Company  
Sinclair Oil & Gas Company  
SOHIO Petroleum Company  
Sun Oil Company  
Tenneco Oil Company  
Texaco, Inc.  
The Cleveland-Cliffs Iron Company  
The Oil Shale Corporation  
The Superior Oil Company  
Western Oil Shale Corporation  
Wolf Ridge Minerals Corporation

The industrial participants in the program will receive: (a) royalty-free licenses to use any primary patents developed during the course of the program, (b) access on a reasonable royalty basis to any secondary patents which are made available by any of the participants and which are found to be necessary to the success of the project, and (c) a three-year lead time in obtaining the technology for producing shale oil by this method.

Conference Held in September on Oil Shale Research Project  
Details (continued)

The draft agreement has provisions which permit other organizations to enter the program by paying a pro-rated share of past expenses plus a late charge of 30 percent of these expenses. It provides for a group of individuals or companies, all of which were in existence prior to December 31, 1965, and none of which have total assets exceeding \$50 million, to band together to share the cost of participation by acting as a single participant.

According to CER, two basic relationships are to be established: first, already under way, the framework within which CER will work with Industry; and, second, the framework within which the group, represented by CER, will work with the Government--the objective being to achieve a resolution that will allow a single cooperative approach to the experiment. CER expressed its conviction that the experiment will have an excellent chance of success utilizing the talents of both Industry and Government.

One vital point has not yet been clarified--the matter of site location. CER has held discussions with Lawrence Radiation Laboratory (LRL), and the consensus of opinion is that no particular technical preference exists, so long as the selected site meets the necessary criteria--sufficient depth, thickness of shale, and distance from habitation. There are some 100,000 acres from which to choose the site of this first shot. The matter will be discussed further with LRL and the Bureau of Land Management, and a site acceptable to all concerned should be selected shortly. CER spokesman stated hopefully that the contracts can be finalized by the end of the year.

Considerable time was devoted to discussion of the point of participation by the smaller companies. It included such viewpoints as--any Participant should be a full-fledged Participant; how does one govern the distribution of rights? large companies contribute more through their research and technology than the smaller companies since the latter do not have the available talents; experience as well as monetary contributions should be considered;



Conference Held in September on Oil Shale Research Project  
Details (continued)

by excluding small companies, they could get together and form their own group; small companies may not be able to afford participation later; politically, CER has to include smaller companies; Government approvals will be more likely if the smaller companies are included. The majority of Participants voted to support participation by the small companies by means of Organizations.

The project is expected to be a four-to-five-year program. With 24 companies participating, the cost for one full ticket over such period would be \$223,125 of a total estimated cost of \$5,355,000. Participants were told to plan on expenditures the first year of between \$30,000 and \$50,000.

The matter of Patents and Publications was summarized by D. P. Cullen, the patent attorney who drafted the provisions of the Operating Agreement. It was determined that these patent discussions, since the people at the meeting are not experts in this area, should properly be handled by legal counsel of the Participants. If necessary, a patent lawyers' meeting will be held.

The concept of operation of the project was discussed. During Phase 1, the actual control will undoubtedly lie in the hands of the AEC. The Commission will be responsible, by law, to assure that everything is conducted in a safe manner during the firing of the nuclear device. (Any radiation hazard is a continuing AEC responsibility). The revised minimum size of the site (160 acres) was felt by the group to be inadequate. It was decided CER should request 640 acres and, since the site criterion from the Bureau of Mines was for 1,280 acres, CER has justification for this 640-acre request. CER would then be covered in the event that additional experimentation is directed by the Operating Committee.

Conference Held in September on Oil Shale Research Project  
Details (continued)

It was proposed, and agreed to by the group, that there is a definite need to establish various Subcommittees to the Operating Committee, in such categories as Product Recovery, Underground Phenomena, etc., each comprised of about five members, to work with the staff. An Executive Committee is needed to evaluate the technical progress and give guidance to the Operating Committee.

The suggestion was offered that the group contract for only one phase of the experiment at a time, since there are so many "unknowns" in subsequent phases. After discussion, it was felt that a total contract was necessary to establish intent and a framework. CER advised that the Operating Committee's authority and responsibility are such that the Participants would establish the program and be afforded opportunity for modification or control.

It was suggested that clearer provision be made for evaluation and right to revise estimates for subsequent phases following the end of each phase. It was recommended that costs be reviewed at the end of Phase 1, as a revised programmatic concept will emerge in any event at such time. The Operating Committee will set the budget of work, and will be required to have semi-annual meetings. The Agreement will be redrafted to clarify and modify those sections under discussion and the legal representatives of the Participants were invited to send in their comments.

Guidelines for negotiations with the Government were discussed. CER believed that the Government would be responsible for the costs of firing, and a discussion was held concerning the desirability of Government monetary contributions in the processing step. Since the land is all Government owned, it was felt that this might be appropriate. Some of the Participants believed it would be acceptable for Phase 1, but not for subsequent phases. However, a lengthy discussion as to participation in this project (financial and/or technical) by the Government led to the decision that it be invited to



### Conference Held in September on Oil Shale Research Project Details (continued)

participate, but only as a technical contributor. Suggestions were made that a representative of the Bureau of Mines would be welcome to serve on the Operating Committee. This would satisfy the Bureau's wish to be considered a technical contributor to the project.

CER stated that a monthly progress report will be issued to all Participants. The group determined that the next general meeting of Participants, for the purposes of reviewing the revised Agreement and Feasibility Study, and discussing progress on CER's pertinent activities, will be held in Dallas, Texas, around the first week of December.

### Other Nuclear Projects are Proposed

CER disclosed at its September 29 meeting in Las Vegas, Nevada, that it is a member in two joint proposals before the AEC--Dragontrail (Continental Oil Company) and Rulison (Austral Oil Company). Dragontrail could be fired within two-to-three months following Gasbuggy. Rulison, located near Rifle, Colorado, is a much larger explosion, and data from Gasbuggy and Dragontrail are needed to assure that the concepts are correct prior to proceeding with the Rulison detonation. Both of these projects are "follow-on" projects related to the Gasbuggy project.

Bronco is the name given by government agencies to the AEC and BuMines feasibility studies to be made jointly with the CER Geonuclear group.

Sloop is a feasibility study of a proposal by Kennecott Copper Corporation for in situ leaching of copper ore, aided by an underground nuclear detonation.

Ketch is the name given to a proposed project for providing underground gas storage facilities through the use of a controlled nuclear detonation.

Gasbuggy, officially approved by the Budget Bureau on November 4, will involve an underground nuclear detonation to stimulate recovery of natural gas.

## OIL SHALE TECHNOLOGY

### Texaco Patents, Publicizes Hydrotorting Process for the Recovery of Oil From Shale

Hydrotorting is the name given by Texaco to the recently-patented process which consists essentially of contacting oil shale with 800-950°F hydrogen gas in a pressure vessel operating at pressures ranging from 1000 to 2000 psig. All but a few tenths of a percent of the organic carbon in the shale are reportedly converted to hydrocarbons by this process, providing yields of oil ranging from 105 to 115 percent of Fischer assay. Hydrotorting process details have been disclosed by W. G. Schlinger of Texaco in U. S. Patent 3,224,954 (a copy is reproduced beginning on Page A-25 of the Appendix) and in Schlinger's paper, Hydrotorting of Oil Shale, presented at the September 11-16, 1966 meeting of the American Chemical Society in New York City. The process details will be reviewed here.

In accordance with Schlinger's patent, oil shale fragments having a maximum size of about 2 inches are charged into a pressure vessel and are contacted with 800-950°F hydrogen-rich gas under pressures within the range of 1000 to 2500 psig. The gas stream passes upward through the bed of oil shale. Oil, presumably in mist form, is entrained in the gas stream and is carried from the pressure vessel for recovery by conventional methods. Following recovery of oil from the effluent gas, hydrogen-rich gas is recirculated to the retorting vessel.

Hydrogen feed rates of the order of 25,000 to 150,000 scf per ton of oil shale per hour may be employed. Hydrogen consumption is reported within the range of 500 to 3000 scf per barrel of oil produced. The hydrogen pressure in the system is at least 1000 psig, but preferably in the range of 1500 to 2000 psig. Satisfactory oil recovery can generally be obtained within 30 minutes at reaction temperatures above 800°F. Schlinger's patent



Texaco Patents, Publicizes Hydrotorting Process for the  
Recovery of Oil From Shale (continued)

discloses that the hydrotorting process would operate in combination with a vapor-phase hydrogenation process. Vaporous products from the hydrotorting operations would pass directly into contact with one or more beds of solid catalytic material, for example, cobalt molybdate on a suitable support. Process flowsheets are shown on pages A-27 and A-28 of the Appendix of this report.

A material balance for a typical batch test of the hydrotorting process, based on the use of one ton of raw shale feed, is presented below.

BATCH HYDROTORTING OF OIL SHALE  
MATERIAL BALANCE

<u>Feed Streams</u>	<u>Lbs.</u>	<u>Gals.*</u>	<u>SCF</u>
Raw Shale*	2000.000		
Hydrogen(as 100%)	8.467		1594
TOTAL	2008.467		
<u>Product Streams</u>			
Spent Shale	1659.700		
Oil Product	279.200	37.1	
Water	25.000	3.0	
Hydrogen Sulfide	0.886		10
Ammonia	2.863		64
Methane	19.836		470
Ethane	10.494		132
Propane	7.690		66
Butylenes	0.440		3
Butanes	2.000		13
Pentanes	0.358		2
TOTAL	2008.467		

\* Fischer Assay: 33.4 gallons of oil per ton;  
3.0 gallons of water per ton.

Texaco Patents, Publicizes Hydrotorting Process for the Recovery of Oil From Shale (continued)

Properties reported by Schlinger for shale oil produced by the hydrotorting process, by "air retorting", and by the conventional Fischer assay are shown below.

PROPERTIES OF SHALE OIL  
FISCHER ASSAY - AIR RETORT - HYDROTORT

	<u>Fischer</u> <u>Assay</u>	<u>Air</u> <u>Retort(6)</u>	<u>Hydrotort</u>
Gravity, °API	24.1	20.7	24.5
Viscosity, SUS at 100°F	73	223	61
Viscosity, SUS at 210°F	36	46	34
Sulfur, Wt.%	0.98	0.77	0.56
Nitrogen, Wt.%	1.80	2.01	1.88
Carbon, Wt. %	85.23	--	85.44
Hydrogen, Wt.%	11.33	--	11.12
Conradson Carbon, Wt.%	2.33	4.57	4.28
Pour Point, °F	75	90	65
Characterization Factor(K)	11.42	11.45	11.37

ASTM DISTILLATION

IBP	192	402	160
10%	336	536	278
20%	430	622	354
30%	518	692	430
40%	600	764	506
50%	655	814	568
60%	685	836	634
70%	705	865	682
80%	Cracked	889-	712-
		Cracked	Cracked

The condition of the spent shale is reported to be such that it has no strength, being easily crushed to a dust whose particles will pass through a 200-mesh sieve. Schlinger attributes this characteristic to the



Texaco Patents, Publicizes Hydrotorting Process for the  
Recovery of Oil From Shale (continued)

near-complete removal of the kerogen from the shale, leaving nothing to cement the sedimentary particles together.

Obvious problems to be faced by a commercial-scale hydrotorting plant would include those associated with disposal of large tonnages of the powdery spent shale product and would also include the problems associated with the high-pressure retorting of large tonnages of shale having fragment sizes of up to 4 inches.

## THE NAVAL OIL SHALE RESERVES

### Commander Butterfield Reviews the Origins, the Management and Potentials of the Naval Petroleum and Oil Shale Reserves

In his presentation to the Society of Petroleum Engineers in Dallas in October entitled, Management of the Naval Petroleum and Oil Shale Reserves: Maintaining a Potential, Commander Butterfield, CEC, USN, reviewed the Navy's interests in these reserves. We review here just those portions of Commander Butterfield's presentation which concern the Naval Oil Shale Reserves.

The Naval Oil Shale Reserves were created by several Executive Orders. President Wilson, by an Executive Order dated December 6, 1916, designated 44,500 acres of public lands in Colorado as Naval Oil Shale Reserve No. 1. This reserve was established as a further guarantee of oil for the Navy in view of the fact that future drainage could occur in the already-established conventional petroleum reserves. Naval Oil Shale Reserve No. 2, located in Utah, was also established by President Wilson by a second Executive Order dated December 6, 1916. Naval Oil Shale Reserve No. 3 was established by an Executive Order dated September 27, 1924. It borders Oil Shale Reserve No. 1 on the east, south and west. While less than 15 percent of Reserve No. 3 contains oil shale, its withdrawal was considered necessary to afford working space and waste disposal areas necessary for operation on Oil Shale Reserve No. 1. Subsequent Executive Orders modified slightly the areas covered by the Oil Shale Reserves, which currently are:

<u>Naval Oil Shale Reserve</u>	<u>Acreage</u>
No. 1	40,760
No. 2	90,440
No. 3	22,600



Commander Butterfield Reviews the Origins, the  
Management and Potentials of the Naval Petroleum and  
Oil Shale Reserves (continued)

Prior to enactment of the Mineral Leasing Act of 1920, the Navy had no authority to explore or develop the Petroleum or Oil Shale Reserves. By the Act of June 4, 1920 (41 stat. 813), the Secretary of the Navy was directed to take possession, conserve, develop, use and operate the Naval Petroleum Reserves in his discretion, directly or by contract, and to use, store, exchange or sell the oil and gas produced for the benefit of the United States. However, he still had no authority for the development and operation of the oil shale reserves.

In 1921, Executive Order 3473 transferred the administration of the Petroleum and Oil Shale Reserves to the Secretary of the Interior. The period which followed was highlighted by the notorious Teapot Dome scandal and by Congressional investigations into the circumstances of the leasing of portions of Naval Petroleum Reserves. In March of 1927, the Petroleum and Oil Shale Reserves were returned to the jurisdiction of the Navy pursuant to Executive Order No. 4614.

From 1944 to 1956, the Bureau of Mines conducted experimental work at the Rifle Oil Shale Demonstration Plant on Oil Shale Reserve Nos. 1 and 3, under the Synthetic Liquid Fuel Act.

The enactment of Public Law 87-796 of October 11, 1962, gave the Secretary of the Navy the same powers over the shale reserves as he has over the petroleum reserves. The law governing the Naval Petroleum and Oil Shale Reserves is now codified in Title 10, United States Code, Sections 7421-7438.

Public Law 87-796 also enabled the Department of the Interior to lease the idle research facility at Rifle, Colorado, for research purposes. Leasing of the facility was accomplished on April 29, 1964, and at the

Commander Butterfield Reviews the Origins, the  
Management and Potentials of the Naval Petroleum and  
Oil Shale Reserves (continued)

present time research in oil shale continues under the auspices of the Colorado School of Mines Research Foundation.

Special Note: Your reference is invited to pages 35-42 of the June 1, 1965 issue of Oil Shale and Related Fuels for additional data on the Naval Oil Shale Reserves.



## SODIUM MINERAL OCCURRENCES IN THE GREEN RIVER OIL SHALE FORMATION

### Wolf Ridge Minerals Discloses Information on Its Saline Mineral Deposits in the Piceance Basin

In a presentation before the 16th annual meeting of the American Association of Petroleum Geologists in Denver on October 24, 1966. Irvin Nielsen, geologist and vice president of Wolf Ridge Minerals Corporation discussed Economics of Oil Shale. The paper is of interest here because of Nielsen's first-hand knowledge of the saline mineral deposits in the central portion of the Piceance Basin. Wolf Ridge minerals has conducted an exploratory drilling program with the objective of determining the characteristics of the saline minerals contained on an area held under Federal sodium prospecting permits. Nielsen includes the economic values of soda, and alumina products as well as the value of shale oil in his evaluations. His data, based on actual analyses of exploratory drill cores from his company's sodium prospecting permit add authority to his economic evaluations.

Nielsen illustrates the effect that saline mineral by-products of value can have on the the apparent value of oil shale. He provides an analysis for an oil shale that could be mined from a specific zone that contains the minerals nahcolite and dawsonite. Using this analysis, he calculates a value for the mined shale as being \$11.23 per ton.

For reference purposes, Nielsen's paper is reproduced and is presented in the Appendix section of this report, beginning on page A-1.

### Western Oil Shale Corporation Drills Utah Oil Shales, Seeks Saline Mineral Deposits

Western Oil Shale Corporation (WOSCO), an affiliate of Texas American Oil Company of Midland, Texas, holds state leases on 56,000 acres of oil shale land in Utah. Nash J. Dowdle, president of WOSCO, announced in October

Western Oil Shale Corporation Drills Utah Oil Shales,  
Seeks Saline Mineral Deposits (continued)

that exploratory drilling would commence about 45 miles south of Vernal, Utah, and stated his company's intention to analyze the cores obtained for their possible content of the mineral dawsonite. Apparently-commercial saline mineral deposits are now known to occur in Wyoming and Colorado portions of the Green River formation, but have not yet been delineated in the Utah portions of the Green River formation.

BuMines and USGS Authors Report on Dawsonite in the  
Green River Formation of Colorado

J. Ward Smith, project leader at the Bureau of Mines Laramie Petroleum Research Center, and Charles Milton, geologist with the U. S. Geological Survey at Washington, D. C. co-authored, Dawsonite in the Green River Formation of Colorado. This paper, published in the September, 1966 issue of Economic Geology, compiles much of the available data concerning the character and extent of the deposits of dawsonite in Colorado's Piceance Creek Basin.

The authors report that dawsonite,  $\text{NaAl}(\text{OH})_2\text{CO}_3$ , is now known to occur through 700 feet of oil shale which averages 25 gallons per ton and extends over hundreds of square miles of area. In places, the mineral dawsonite is reported to make up one-fourth of the oil shale, by weight.

Concerning the identification of dawsonite, the authors state that dawsonite is difficult to recognize in the oil shales of the Piceance Creek Basin because the crystals are usually so small that visual detection is usually impossible. Because nahcolite, analcite, calcite, quartz and other minerals also occur in these shales as minute disseminations, they may be easily confused with dawsonite. The authors present data, shown on the page that follows, which indicate that index of refraction measurements by the usual oil immersion methods will readily differentiate dawsonite



BuMines and USGS Authors Report on Dawsonite in the  
Green River Formation of Colorado (continued)

of oil shale can be detected with certainty, according to the authors. However, precise methods for quantity determination of dawsonite have yet to be worked out. As yet, sufficient well-crystallized pure dawsonite for use as comparative standards has not been available. Dawsonite prepared by published methods is poorly crystallized and yields diffuse and unsatisfactory patterns. The authors present comparative data obtained from x-ray analyses of synthetic dawsonite and of dawsonite from Colorado, Montreal and Italy.

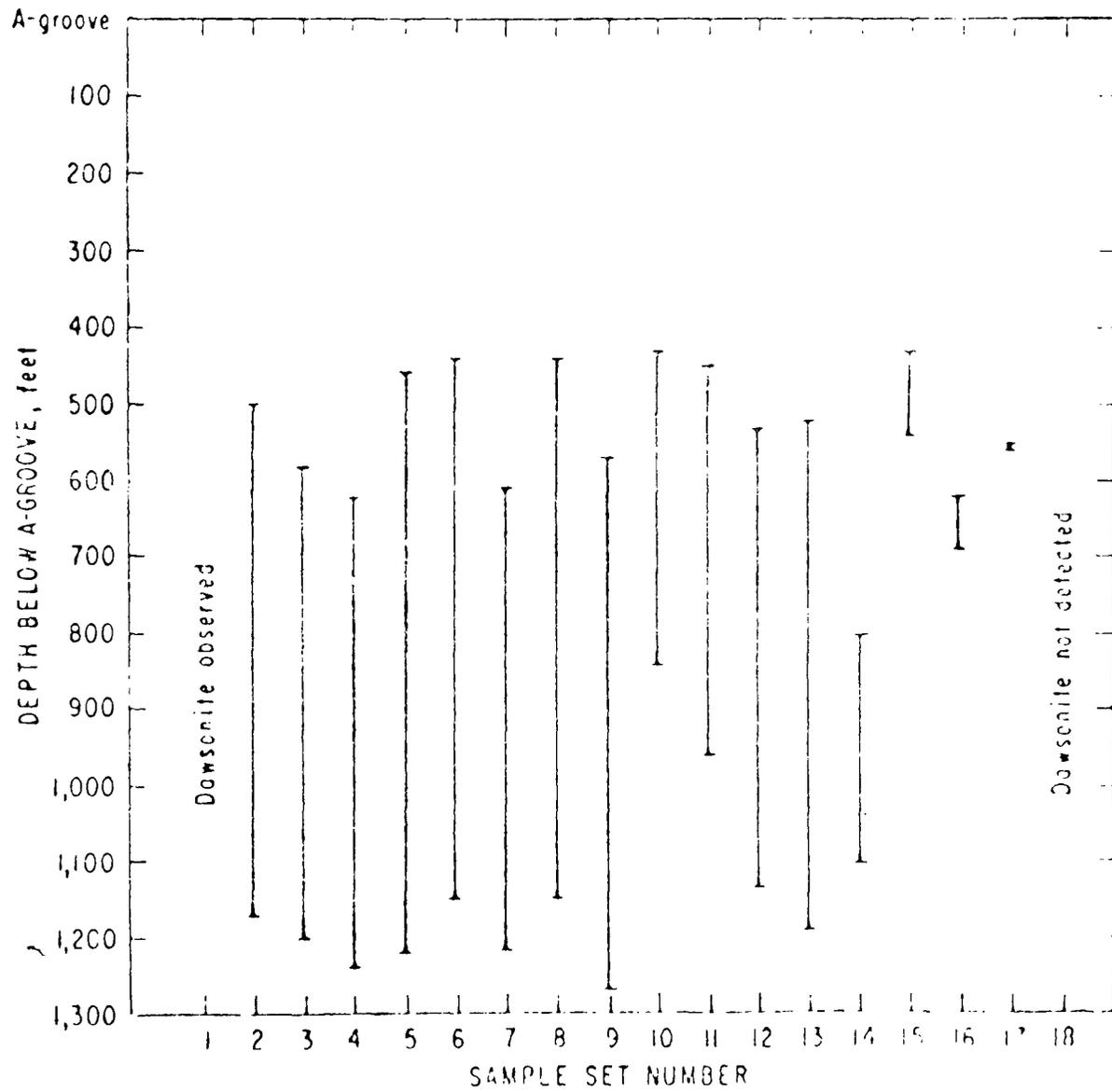
The occurrence of dawsonite in the Green River formation is usually as disseminations throughout the host rock or as thin lenses on sheets parallel to bedding. It has been observed as thin sheets transverse to the bedding, partially or wholly filling fissures at high angles to the bedding. Small vugs, almost microscopic in size, may be lined with well-developed crystals of dawsonite. Fibrous aggregates of dawsonite are commonly radial.

Dawsonite is known to occur only in the Piceance Creek Basin of the Green River formation. The mineral has been identified by x-ray diffraction in 5 drill cores and 13 sets of cuttings obtained at the locations shown in the listing on the page that follows.

SAMPLE SET NO.	COMPANY OR AGENCY	HOLE	LOCATION			SAMPLE A-GROOVE DEPTH, TYPE	DEPTH, FEET	DAWSONITE SECTION	
			SEC.	T	R			FROM FEET BELOW A-GROOVE	TO FEET BELOW A-GROOVE
1	U.S. BUREAU MINES	COLO. COREHOLE 1	13	1 N	98 W	CORE	1076	EXTENSIVE DAWSONITE SECTION <sup>1/</sup>	
2	EQUITY OIL Co.	SULFUR CREEK 11	9	2 S	98 W	CUTTINGS	770	500	1170
3	GREAT YELLOWSTONE Co.	SULFUR CREEK 1	21	2 S	98 W	CUTTINGS	900	580	1200
4	EQUITY OIL Co.	SULFUR CREEK 9	13	2 S	98 W	CUTTINGS	1010	620	1240
5	EQUITY OIL Co.	BOIES 1	19	2 S	97 W	CORE	600	458	1220
6	EQUITY OIL Co.	JOHNSON 2	21	2 S	97 W	CUTTINGS	560	440	1150
7	MOBIL OIL Co.	68-11	11	2 S	97 W	CUTTINGS	810	610	1220
8	MOBIL OIL Co.	54-13	13	2 S	97 W	CUTTINGS	960	440	1150
9	MOBIL OIL Co.	63-17	17	2 S	96 W	CUTTINGS	1130	570	1270
10	EQUITY OIL Co.	RYAN 1	27	2 S	99 W	CUTTINGS	770	430	840
11	HYLAND OIL Co.	1-33	33	2 S	98 W	CUTTINGS	750	450	960
12	SHELL OIL Co.	GREENO 4-4	4	3 S	97 W	CUTTINGS	1070	530	1135
13	SHELL OIL Co.	GREENO 1-4	4	3 S	97 W	CORE	1070	520	1190
14	EQUITY OIL Co.	OLDLAND 3	10	3 S	96 W	CORE	700	801	1106
15	THE TEXAS Co.	FAWN CREEK 3	27	3 S	98 W	CUTTINGS	470	430	540
16	EQUITY OIL Co.	EBLER 1	30	3 S	97 W	CORE	700	620	690
17	EQUITY OIL Co.	SO. PICEANCE CK 10	25	3 S	96 W	CUTTINGS	1100	550	560
18	SKELLY OIL Co.	DRY FORK 1	25	4 S	97 W	CUTTINGS	680	DAWSONITE NOT FOUND	

BuMines and USGS Authors Report on Dawsonite in the  
Green River Formation of Colorado (continued)

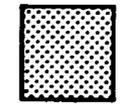
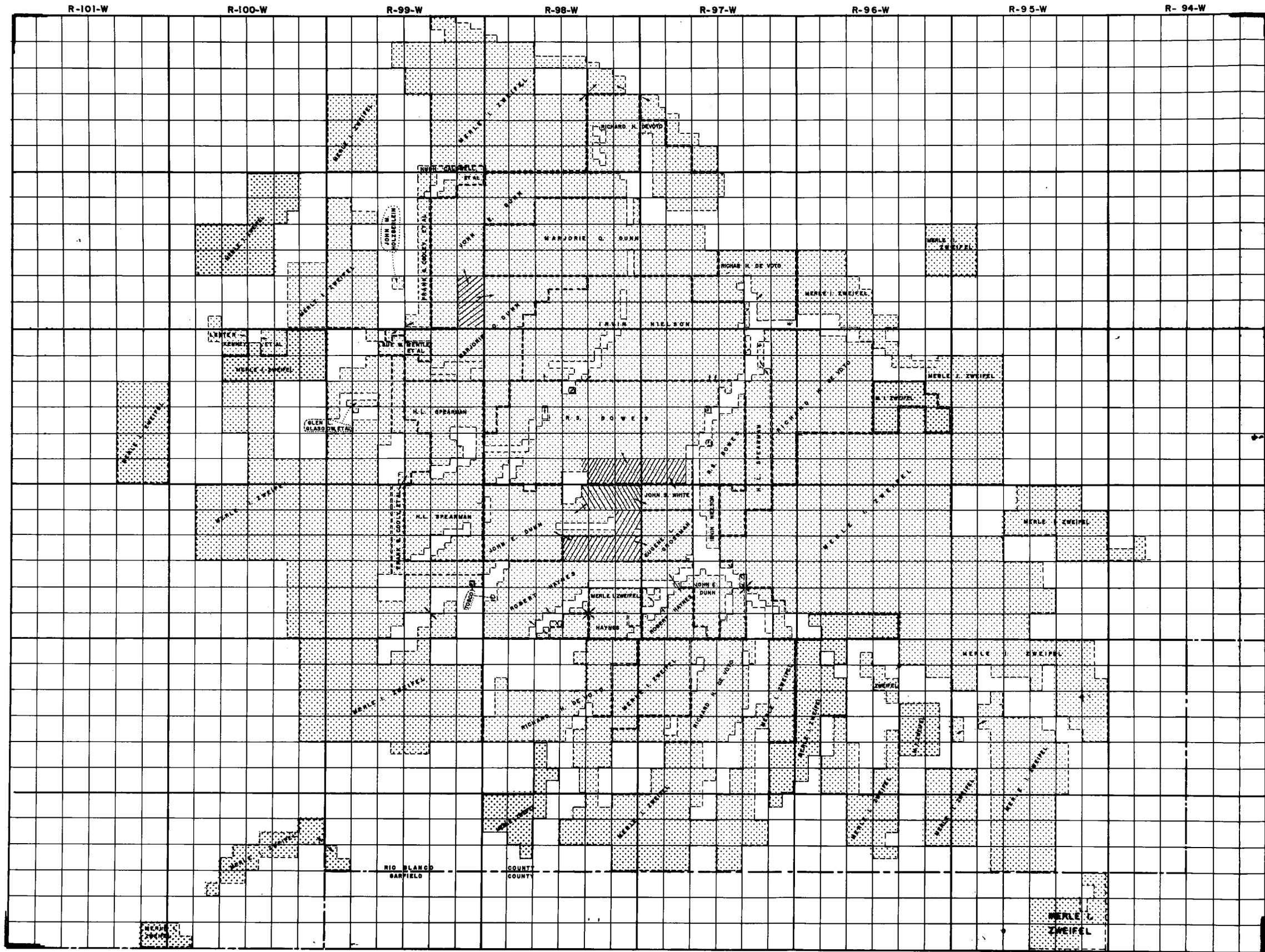
The stratigraphic location of the section of the formation in which dawsonite occurs is shown below, the data being based on the sample sets just shown.



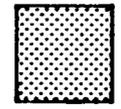
Stratigraphic location of dawsonite section  
in Piceance Creek Basin.

Additional Mining Claims Filed in the Dawsonite Area

The status of mining claim filings in the dawsonite mineral area of the Piceance Basin is shown on the fold-out map which follows this page.



Mining Claims Filed  
After Sept. 1, 1966



Mining Claims Filed  
Before Sept. 1, 1966

LOCATION OF MINING CLAIMS FILED ON OIL SHALE  
LANDS PRESUMED TO CONTAIN DAWSONITE MINERAL DEPOSITS  
RIO BLANCO COUNTY, COLORADO





## GENERAL INTEREST

### Federal Energy Study Calls for Increased Government-Sponsored Research on Oil Shale and Coal

A long-awaited interdepartmental energy study by various Federal agencies, released in November, spells out an increasingly important role for the Federal government in energy research. Two reports actually were issued, a summary report of findings and conclusions, and a comprehensive compendium of information on all sources of energy. The title of both reports is the same, Energy R&D and National Progress.

Those parts of each report dealing with oil shale, tar sands, and coal as a source of oil are reproduced and are presented in excerpt form beginning on page A-45 of the Appendix of this quarterly report. A brief discussion of the content of the study follows.

Energy R&D and National Progress together with other related studies being conducted by various Federal agencies, apparently will become the fabric for broad Federal policy on matters relating to energy. This report treats the subject of energy research and development but actually is much more far-ranging, delving into national policy aspects of the subject beyond the elementary concept of research and development.

As background for its recommendations the task force assembled data on supply and demand, resources, technology, economics and the like. For the most part the information is not original and has appeared elsewhere. In the case of oil shale, the data are behind the time and in some respects are even misleading. For instance, the economics of shale oil production are based on an up-dating of a 1951 National Petroleum Council study.

In its classification of oil shale reserves the report does not differentiate the rich oil shale of the Piceance Basin from the very lean Devonian shales of the eastern

Federal Energy Study Calls for Increased Government-Sponsored Research on Oil Shale and Coal (Continued)

United States. By including oil shales yielding 5 gallons per ton, 170 trillion barrels of oil are estimated to be recoverable from both known and undiscovered oil shale deposits. Such a resource estimate has no practical meaning. However, the 170 trillion barrel figure has focused attention on oil shale because of the enormity of its potential. At the same time the utilization of very lean shale magnifies the need for R&D to make oil shale a practical source of energy.

Particular emphasis is placed on the "serious obstacles due to its (oil shale's) impact on the natural environment". The primary recommendation of the report is for R&D on in situ extraction methods and "mining and recovery systems that will be compatible with sound principles of environmental management".

Coal is given secondary consideration as a source of oil or gas. Ultimate reserves from coal are shown to be only a fraction of those from oil shale, due to inclusion of 5 gallon-per-ton shale in the estimated shale reserves. However, continued government support of research in the conversion of coal to petroleum products is recommended as well as research on methods to lower production and "other costs" of coal processing.

Pollution abatement is given the highest priority for R&D by the Federal investigators. The ultimate replacement of fossil fuels by nuclear energy is suggested to be a worthwhile research objective.

The report draws the general conclusion that there is sufficient energy from conventional sources using technology already developed (including a small contribution of liquids and gases from oil shale, coal and tar sands) to supply United States needs for the 20th century. Federal R&D should be focused therefore on the long-range problems. Research on nuclear energy, already largely in the Federal domain, should come in for even greater emphasis. The relatively new field of environmental control, where little



Federal Energy Study Calls for Increased Government-Sponsored Research on Oil Shale and Coal (Continued)

or no profit motive appears to exist to stimulate private research, deserves massive Federal support. The predicted short-term depletion of natural gas and only a few years later, of crude oil, needs Federal effort to develop the presumed large reserves of oil shale by technologies that do not add to existing problems of pollution and despoilment.

This report in its entirety is worthy of detailed study owing to its probable impact on Federal energy policy. This study supports the thesis of Kenneth W. Galbraith and others who suggest a long period of government-sponsored research before making Federal oil shale lands available for development. However, much deeper and more subtle meaning may be attached to the strong R&D program recommended for environmental control and the use of nuclear energy as a substitute for fossil fuels.

We again invite your attention to the excerpts from Energy R&D and National Progress concerning oil shale, coal and tar sands which are reproduced beginning on page A-45 of the Appendix.

Domestic Crude Oil Production Sufficiency of Major Oil Companies

For its general interest value, data published in the 1965 annual reports of the major oil companies have been arranged to illustrate the domestic crude oil production sufficiency of the major oil companies. The tabulation of data, presented on the following page, shows net liquids production by the various companies as percent of refinery feed.

DOMESTIC CRUDE OIL PRODUCTION SUFFICIENCY

DATA FROM 1965 ANNUAL REPORTS

RANK	COMPANY	BARRELS PER DAY			PRODUCTION AS % OF	
		PRODUCTION	REFINERY FEED	SALES	REFINERY FEED	SALES
1.	ASHLAND OIL & REFINING COMPANY	19,305	166,325	194,587	11.6	9.9
2.	THE STANDARD OIL COMPANY (OHIO)	26,671	162,955	162,472	16.4	16.4
3.	SINCLAIR OIL CORPORATION	167,215	420,592	443,364	39.7	37.8
4.	SUNRAY DX OIL COMPANY	71,358	159,159	164,000	44.7	43.5
5.	ATLANTIC RICHFIELD COMPANY	168,552	352,660	367,703	47.8	54.0
6.	MOBIL OIL CORPORATION (INCL. CANADA)	327,000	672,000	760,000	48.6	43.0
7.	STANDARD OIL COMPANY (IND.)	389,642	756,516	811,870	51.5	48.0
8.	SUN OIL COMPANY (INCL. CANADA)	49,000	93,515	99,800	52.4	49.1
9.	UNION OIL COMPANY (CALIF.)	207,000	348,700	366,700	59.4	56.4
10.	CITIES SERVICE COMPANY	153,200	252,000	320,000	60.8	47.9
11.	SHELL OIL COMPANY	431,000	700,000	846,000	61.7	51.0
12.	STANDARD OIL COMPANY (CALIF.)	473,417	754,500	---	62.7	--
13.	CONTINENTAL OIL COMPANY	156,093	234,777	289,903	66.5	54.0
14.	GULF OIL CORPORATION	432,100	633,500	---	68.2	--
15.	SIGNAL OIL AND GAS COMPANY	74,190	104,700	---	70.8	--
16.	TIDEWATER OIL COMPANY	149,000	202,000	226,000	73.7	66.0
17.	MARATHON OIL COMPANY	112,118	139,110	147,841	80.1	75.9
18.	TEXACO, INC.	700,838	757,387	739,000	92.6	94.8
19.	HUMBLE (STD. OIL N. J.)	746,000	805,000	900,000	92.7	82.9
20.	PHILLIPS PETROLEUM COMPANY	241,700	249,000	462,000	97.0	52.3
21.	SKELLY OIL COMPANY	89,434	48,898	90,401	183.	98.9



OIL SHALE ACTIVITIES OF THE  
INTER-ASSOCIATION PUBLIC LANDS STEERING COMMITTEE

Oil Shale Subcommittee Reports to the Inter-Association  
Steering Committee

The 21st Annual Convention of the Rocky Mountain Oil and Gas Association was held in Denver on September 28, 29 and 30, 1966. During the convention, the Inter-Association Steering Committee presented the reports made to it by its various subcommittees. The Oil Shale Subcommittee report consisted of a listing of the members' points of agreement, of disagreement, and recommendations. The oil shale subcommittee members were essentially in agreement as follows:

- A. Policy. The Industry recognizes a significant future for the development of oil shale resources on the Public Domain and further believes development in the most efficient and effective manner would be by private industry operating within the traditional system of free, competitive enterprise.
- B. Is new legislation necessary? Yes. The present law relating to the leasing of oil shale lands is inadequate to properly encourage wide participation by private industry to an extent necessary to assure competitive development.
  - 1. Since the Public Domain lands were closed to oil shale entry under the Mining Law, no lease has been granted; and, further, the lands were withdrawn from leasing by Executive Order, April 15, 1930.
  - 2. Recent attempts to secure lifting of the withdrawal order and leasing under the Act of 1920 were unsuccessful. Industry reaction, Interior hearings and public hearings indicate Congressional review and new legislation are in order prior to Industry and the Department of the Interior moving ahead with confidence that the path toward development is clear.

Oil Shale Subcommittee Reports to the Inter-Association  
Steering Committee (continued)

- C. Recommendations. Drafting of legislation is recommended to establish a new leasing act for oil shale on Public Domain land. Such act to cover the following considerations and such others as may be deemed appropriate.
1. Provision for nominations and selection of lands to be put up for bid.
  2. Bidding to be competitive.
  3. Terms of lease should be sufficient to encourage development.
  4. Royalty rate should be such to encourage development by private enterprise.
  5. The allowable acreage and size of lease should be such to encourage the heavy investment required for development.
  6. Unitization provisions should be designed to assure development in most efficient manner.
  7. Rental rate should be established for primary term prior to production.
  8. Multiple use of lands should be recognized.
- D. Controversial areas of general oil shale subject are set forth as follows:
1. Depletion allowance. General industry agreement that rate is satisfactory but there is a question as to the point of application. Industry believes it should be applied through the retort in conventional mining and retorting process.



Oil Shale Subcommittee Reports to the Inter-Association  
Steering Committee (continued)

2. Leasing policy.

- a. A debate as to oral versus sealed bidding.
- b. Royalty rate - little experience to guide.
- c. Development clause - a debate as to desirability. Some say would speed development; some say would hinder as development will only progress as general economics dictate.
- d. Acreage allowance. Needs study as cited reserve figures may distort the picture as to profitable production.
- e. Limited offering of leases for research and development. A debate as to such a proposal without access to remaining lands under known conditions.

NOTE: At a meeting of the Board of Directors, during the RMOGA Annual Meeting, the Association's by-laws were amended so as to establish a standing committee (No. 15) to be known as the "Oil Shale and Synthetic Fuels Committee".

This committee has now been formed. It's present members are:

* A. J. Gravitt	Phillips Petroleum, Denver
Ted Hannon	Sun Oil Company
Frank Castleberry	Atlantic Richfield
S. J. Tryan	Mobil Oil
Walter E. Will	Texaco
Max Eliason	Skyline Oil
Wm. S. Livingston	Humble Oil & Refining
R. H. Volk	Plains Exploration

\* Chairman

Oil Shale Subcommittee Reports to the Inter-Association Steering Committee (continued)

James B. Rose	Continental Oil
Dean Nickell	Sinclair Oil
D. L. Black	Shell Oil
J. B. Tweedy	Tweedy, Mosely and Young
Bruno Lukens	Pacific Oil
Bob Burch	Independent
John Wold	Independent
Dan Meyer	Independent

Present Membership of the Oil Shale Subcommittee of the Inter-Association Public Lands Steering Committee

The names of the present members of the Oil Shale Subcommittee of the Inter-Association Public Lands Steering Committee are listed below.

<u>Oil Shale Subcommittee</u> <u>Member's Name</u>	<u>Member's Organization</u>
F. W. McWilliams, of Continental Oil Co.	Rocky Mountain Oil and Gas Association
John R. Pownall, of Union Oil Company	Western Oil and Gas Association
John D. Knodell, Jr., of Humble Oil and Refining	New Mexico Oil and Gas Association
Walter E. Will, of Texaco, Inc.	American Petroleum Institute
Kye Trout, Independent	Independent Petroleum Association
John S. Miller, of Amerada Petroleum Corporation	Mid-Continent Oil and Gas Association



## THE UNITED STATES CONGRESS

### Sen. Long Recommends That End Use Should Determine Depletion Rate

Senator Russell B. Long (Louisiana), speaking in the Senate on October 22, recommended that depletion rates be adjusted in a manner which allows for the competitive nature of the products. As recorded in the Congressional Record of November 10, 1966, Sen. Long stated, "Where two or more products are used for essentially the same purpose, good tax treatment--namely, the considerations of equity and fair completion--demands that they receive approximately the same depletion deduction." Long was speaking in support of HR 13103 which included two depletion allowances riders. One rider raised depletion rate for clay from its present 15% rate to 23% (the rate applicable to bauxite) to make clay and bauxite competitive sources of alumina. The second rider raised the depletion rate on oyster shells from its present 5% rate to 15% (the rate applicable to limestone) to make oyster shells a competitive cement raw material. There were no references in Long's bill to depletion rates for oil, oil shale, or tar sands.

HR-13103 was approved by the 89th Congress and is now Public Law 89-809, 80 STAT. 1539. Senator Long's depletion riders are a part of that law.

Even though the depletion allowance changes do not apply to oil, oil shale, or coal, the legislation was enacted by the Congress after consideration of many factors that relate to depletion allowances assigned to these mineral fuels.

For reference purposes, Sen. Long's remarks are reproduced from the Congressional Record of November 10, 1966, and are presented on page A-44 of the Appendix section of this quarterly report.

Public Land Law Review Commission Holds Regional Meetings in Denver and Albuquerque - Sets Study Program

The Public Land Law Review Commission continued its series of regional meetings, holding a two-day meeting in Denver, September 16-17, and a two-day meeting in Albuquerque, November 10-11. While in Colorado, the Commission viewed the public domain sections of the State from the air.

Staff director Milton Pearl announced on November 10 that the Commission's study program will involve 25 individual studies on lands and resources, namely:

- History of Public Land Laws
- Revenue Sharing and Payments in Lieu of Taxes
- Forage and Brouse
- Administrative Rule-making and Adjudication
- Land Exchanges and Acquisitions
- Withdrawals and Reservations
- Digest of Public Land Laws
- Alaska
- Demand Studies
- Timber
- Non-fuel Minerals
- Energy Fuels
- Water
- Regional and Local Land Use Planning
- Outdoor Recreation
- Land Grants to States
- Use and Occupancy of Public Lands
- Fish and Wildlife
- Intensive Agriculture
- Outer Continental Shelf
- Organization, Administration and Budgetary Policy
- Impact of Public Ownership on Local and Regional Economies
- Non-economic Aspects and Implications of Public Land Ownership on Local and Regional Areas
- User Fees and Charges
- Criteria by Which to Determine Maximum Benefit to The General Public



## Senate Hearings Set for Creation of a Department of Natural Resources

Senator Abraham Ribicoff has announced his plans to hold hearings in January on a Bill proposed by Utah's Senator Moss which would replace the Department of the Interior with a Department of Natural Resources. The Moss Bill would give the new Department of Natural Resources full responsibility for federal action in the management of water resources and power generation, as well as transferring the non-military functions of the Army Corps of Engineers to the new department.

## THE STATUS OF FILINGS AND ADJUDICATIONS OF OIL SHALE WATER RIGHTS IN COLORADO

### Introduction

Data were presented in the September 1, 1964 issue of Oil Shale and Related Fuels concerning the availability of water supplies in the oil shale area of Colorado and concerning the types of water rights obtainable, how to file for water rights, the present costs of water supplies and concerning the water customs, compacts, and laws of the State of Colorado. It suffices here to state that in Colorado water rights are granted by the Courts and are administered by the State Engineer. Applications or filings for water rights are submitted to the State Engineer, and are accompanied by complete engineering data concerning all works, such as dams, pumps, pipelines, etc., associated with the proposed use of the water.

The State of Colorado has been marked off into Water Districts, whose boundaries are shown on the fold-out map which follows this page. Also shown on the map are the areas within which the Green River (oil shale) formations occur. Most of the water adjudications of importance here, those that concern the use of water for oil shale purposes, have been found to be in State Water Districts 39, 43 and 70.

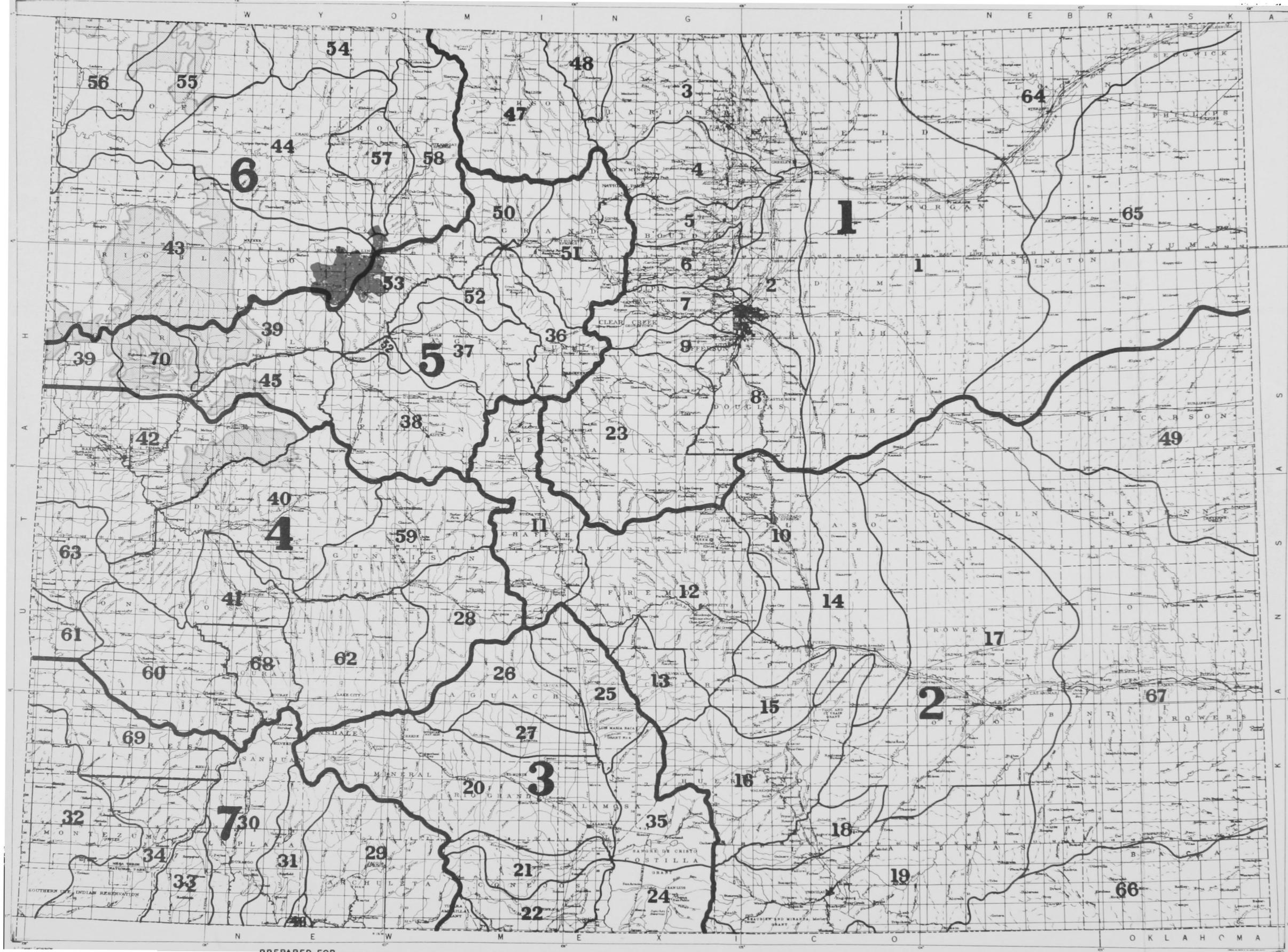
When court adjudication proceedings are opened for any Water District, the District Court having jurisdiction for that Water District orders from State Engineer a listing of all outstanding unadjudicated water filings within the Water District. The court then considers each water filing, and its adjudication is for the priority of water rights.

### Objectives and Scope of This Review

During this reporting period, court adjudications proceedings were completed in two of the State Water Districts within the oil shale area of Colorado. The objective of this review is to present available data concerning the new status of water right filings and adjudications in the oil shale area.

# STATE OF COLORADO

STATEMENT OF THE STATE ENGINEER  
U. S. GEOLOGICAL SURVEY



Areal extent of the proposed Flat Tops Wilderness is indicated by red coloring.

Areal extent of the Green River oil shale formation is indicated by green coloring.

PREPARED FOR  
DEPARTMENT OF NATURAL RESOURCES  
BY  
STATE ENGINEER  
1961



IRRIGATION DIVISION BOUNDARIES **—————**  
WATER DISTRICT BOUNDARIES **—————**





## Schedule for Water Adjudication Proceedings

In recent years, water adjudication proceedings have been initiated in the State Water Districts shown in the listing presented below.

<u>State Water District No.</u>	<u>Location of District Court, County</u>	<u>Date Opened</u>	<u>Date of Adjudication</u>
39	Garfield	1957	Nov. 1966
56	Moffatt	1960	
53	Eagle	1961	Oct. 1962
68	Ouray	1961	
51	Grand	1961	
58	Routt	1961	April, 1964
43	Rio Blanco	1961	Nov. 1966
6	Boulder	1962	
11	Chaffee	1962	
42	Mesa	1963	
59	Gunnison	1963	Dec. 1965
12	Fremont	1963	
60	Montrose	1964	
19	Las Animas	1964	
1	Weld	1965	
37	Eagle	1965	Feb. 1966
53	Eagle	1965	
69	San Miguel	1966	
44	Moffatt	1966	
55	Moffatt	1966	
29	Archuleta	1966	
51	Grand	1966	
14	Pueblo	1966	
38	Garfield	1966	
17	Bent	1966	

From the listing shown above it can be concluded that the courts act rather slowly, that many years may elapse before a district is opened for adjudication, and that adjudication procedures can be time-consuming.

For the water districts of importance to oil shale developers, the status of adjudication procedures is:

Schedule for Water Adjudication Proceedings (continued)

<u>State Water District No.</u>	<u>Location of Court, County</u>	<u>Status of Adjudication Proceedings</u>
38	Garfield	Opened by petitioners, August, 1966.
39	Garfield	Opened by petitioners in 1957. Court adjudication decree issued on November 18, 1966
43	Rio Blanco	Opened in 1961, Courts adjudication decree issued on November 21, 1966.
45	Garfield	Was closed last summer.
70	Garfield	Has been closed for years.

STATE WATER DISTRICT NO. 38:

State Water District 38 was opened in August of 1966 for court adjudication proceedings on petition of the Janss Colorado Corporation, as Civil Action No. 5884 in the District Court for the County of Garfield, Colorado. The District generally encompasses the drainage area of the Roaring Fork River and its tributaries, and is located upstream from the oil shale area.

A complete listing of all unadjudicated claims (record of September 13, 1966) to water in District 38 was obtained from the Colorado State Engineer. Examination of the listing discloses no filings for water intended specifically for use in the development of oil shale. As the list is quite long, it will not be reproduced here but is presented in the Appendix section of this report, beginning on page A-37.



## STATE WATER DISTRICT NO. 39

State Water District No. 39 was opened in November of 1957 for court adjudication proceedings as Civil Action No. 4914 in the District Court for the County of Garfield, Colorado.

During this reporting period the Court issued its adjudication findings, made in the form of a Decree issued on November 18, 1966. Because of its interest to oil shale developers, a complete listing of the water adjudications contained in the Decree are presented on the pages that follow.

WATER ADJUDICATIONS -- DECREE OF NOVEMBER 18, 1966  
 COLORADO STATE WATER DISTRICT NO. 39  
 DISTRICT COURT FOR GARFIELD COUNTY, COLORADO

<u>PRIORITY NUMBER</u>	<u>NAME</u>	<u>APPROPRIATION DATE</u>	<u>PRIORITY DATE</u>	<u>AMOUNT ADJUDICATED</u>
268	PERRY SPRINGS AND DITCH	1890	10/12/51	1.0 CFS
269	GRASS VALLEY CANAL	1891	10/13/51	15 CFS
270	GRASS VALLEY CANAL (STORAGE)	1891	10/14/51	9 A.F.
271	GLENWOOD SPGS PIPELINE #1	1905	10/15/51	2.20 CFS
272	GLENWOOD SPGS PIPELINE #2	1905	10/16/51	1.8 CFS
273	GLENWOOD SPGS PIPELINE #3	1905	10/17/51	1.8 CFS
274	GLENWOOD SPGS PIPELINE #4	1905	10/18/51	0.15 CFS
275	SAMPLE #1 DITCH	1906	10/19/51	4.5 CFS
276	ROCK-N-PINES #2	1910	10/20/51	2.0 CFS
277	1ST ENLARGEMENT - BAXTER #1 DITCH	1910	10/21/51	6.4 CFS
278	1ST ENLARGEMENT - BAXTER #2 DITCH	1910	10/22/51	1.39 CFS
279	1ST ENLARGEMENT - BAXTER #5 DITCH	1910	10/23/51	3.0 CFS
280	JACKSON SPRING AND PIPELINE	1911	10/24/51	1.01 CFS
281	THODE WASTE WATER DITCH	1911	10/25/51	1.23 CFS
282	WOODTICK DITCH	1911	10/26/51	5.6 CFS
283	REES DITCH	1914	10/27/51	4.26 CFS CONDITIONAL-2.72 CFS
284	W. E. DITCH	1917	10/26/51	1.0 CFS
285	LANGSTAFF DITCH	1917	10/29/51	1.04 CFS
286	THODE WASTE WATER DITCH	1920	10/30/51	1.77 CFS
287	BUSTER No. 1 DITCH	1920	10/31/51	1.48 CFS
288	POSSUM No. 1 DITCH	1920	11/ 1/51	2.14 CFS
289	1ST ENLARGEMENT - LEWIS #1 DITCH	1920	11/ 2/51	1.0 CFS
290	1ST ENLARGEMENT - LEWIS #2 DITCH	1920	11/ 3/51	1.10 CFS



<u>PRIORITY NUMBER</u>	<u>NAME</u>	<u>APPROPRIA- TION DATE</u>	<u>PRIORITY DATE</u>	<u>AMOUNT ADJUDICATED</u>
291	1ST ENLARGEMENT - WARNER DITCH	1920	11/ 4/51	4.65 CFS
292	U. S. VANADIUM RIFLE MILL PUMPS, SLUICING PUMPS, AND MILL PIPELINE	1924	11/ 5/51	4307. CFS
293	CLOUGH STOCK WATER DITCH AND POND	1929	11/ 6/51	.30 CFS 1 A.F. STORAGE
294	CLOUGH #2 STOCK WATER DITCH	1929	11/ 7/51	.30 CFS
295	ANDERSON STOCK WATER PIPELINE	1930	11/ 8/51	.21 CFS
296	THE CAMPBELL DITCH	1934	11/ 9/51	2.5 CFS
297	MINNIE-HA-HA SPRING & DITCH	1935	11/10/51	1.0 CFS
298	HARRIS NO. 2 DITCH	1937	11/11/51	3.8 CFS
299	JEWELL NO. 1 SEEPAGE DITCH	1946	11/12/51	3.0 CFS
300	JEWELL NO. 2 SEEPAGE DITCH	1946	11/13/51	1.0 CFS
301	1ST ENLARGEMENT - GRASS VALLEY RESERVOIR	1946	11/14/51	3087.20 A.F.
302	1ST ENLARGEMENT - DAVIE DITCH	1949	11/15/51	9.34 CFS CONDITIONAL
303	THE DRAGERT PUMPING PLANT AND PIPELINE	1950	11/16/51	94.0 CFS CONDITIONAL
304	2ND ENLARGEMENT - KEYSER DITCH	1950	11/17/51	3.2 CFS
305	2ND ENLARGEMENT - URQUHART DITCH	1950	11/18/51	2.0 CFS
306	PUMPING PIPELINE OF THE PACIFIC WESTERN OIL CORP.	1950	11/19/51	56.0 CFS CONDITIONAL
307	RIFLE GAP RESERVOIR	1951	11/20/51	14,000 A.F. CONDITIONAL
308	EATON PUMPING PLANT AND PIPELINE	1951	11/21/51	100. CFS CONDITIONAL
309	DOMESTIC SPRING No. 1	3/10/53	3/10/53	0.50 CFS
310	DOMESTIC SPRING No. 2	3/10/53	3/11/53	0.30 CFS
311	EAST RIFLE CREEK PIPELINE No. 2	3/10/53	3/12/53	90.0 CFS

WATER ADJUDICATIONS - STATE WATER DISTRICT No. 39 (CONTINUED)

<u>PRIORITY NUMBER</u>	<u>NAME</u>	<u>APPROPRIATION DATE</u>	<u>PRIORITY DATE</u>	<u>AMOUNT ADJUDICATED</u>
312	ELK CLIFFS No. 1 DITCH	5/15/53	5/15/53	1.0 CFS
313	1ST ENLARGEMENT - JOHNSON DITCH	5/ 1/54	5/ 1/54	2.1 CFS
314 314A 314B 314C	FLATTOPS PROJECT	6/28/54	6/28/54	
315	2ND ENLARGEMENT - DEWEESE DITCH	7/ 1/54	7/ 1/54	19.8 CFS
316	MEADOW CREEK RESERVOIR	9/13/54	9/13/54	2.0 CFS STORAGE - 984.02 A.F.
317	DOW EAST MIDDLE FORK PIPELINE	10/19/54	10/19/54	20.0 CFS CONDITIONAL
318	DOW MIDDLE FORK PIPELINE	10/20/54	10/20/54	10.0 CFS CONDITIONAL
319	DOW PUMPING PLANT AND PIPELINE	1/24/55	1/24/55	178.0 CFS CONDITIONAL
320	U. S. VANADIUM RIFLE MILL PUMPS, SLUCING PUMPS AND MILL PIPELINE	3/ 8/56	3/ 8/56	1837. CFS CONDITIONAL
321	GRAND VALLEY PIPELINE	6/18/56	6/18/56	30.0 CFS CONDITIONAL
322	BEANE SPRING & PIPELINE	6/24/56	6/24/56	0.00223 CFS
323	THE SILT PUMP CANAL	11/21/56	11/21/56	36.0 CFS CONDITIONAL
324	SINCLAIR OIL AND GAS Co. PUMPING PLANT & PIPELINE	11/29/56	11/29/56	33.0 CFS CONDITIONAL
325	OIL SHALE CORP. PIPELINE AND PUMPING PLANT	12/ 3/56	12/ 3/56	100.0 CFS CONDITIONAL
326	THE BLUESTONE PROJECT	3/27/58	3/27/58	220. CFS CONDITIONAL
327	1ST ENLARGEMENT - THE CLOUGH No. 1 DITCH	8/28/58	8/28/56	13.2 CFS CONDITIONAL
328	ROCK-N-PINES No. 1 DITCH	11/11/58	11/11/58	7.0 CFS CONDITIONAL



<u>PRIORITY NUMBER</u>	<u>NAME</u>	<u>APPROPRIATION DATE</u>	<u>PRIORITY DATE</u>	<u>AMOUNT ADJUDICATED</u>
329	BUSTER PUMP & PIPELINE	6/ 1/59	6/ 1/59	3.0 CFS
330	THE CLOUGH NO. 2 DITCH	7/24/59	7/24/59	12.0 CFS CONDITIONAL
331	ESHE PUMP AND PIPELINE #1	9/ 1/59	9/ 1/59	1.10 CFS CONDITIONAL
332	ESHE PUMP AND PIPELINE #2	9/ 1/59	9/ 2/59	14.0 CFS CONDITIONAL
333	ESHE PUMP AND PIPELINE #3	9/ 1/59	9/ 3/59	3.0 CFS CONDITIONAL
334	ESHE PUMP AND PIPELINE #4	9/ 1/59	9/ 4/59	16.0 CFS CONDITIONAL
335	DAVIS GULCH RESERVOIR	9/15/59	9/15/59	204.0 A.F. CONDITIONAL
336	MIDDLE FORK RESERVOIR	9/17/59	9/17/59	171.622 A.F. CONDITIONAL
337	EAST MIDDLE FORK RESERVOIR	9/17/59	9/18/59	130.558 A.F. CONDITIONAL
338	SHALE PUMPS AND PIPELINE	10/ 7/59	10/ 7/59	11.11 CFS CONDITIONAL
339	WHORL SPRING AND PIPELINE	10/ 8/59	10/ 8/59	.022 CONDITIONAL
340	1ST ENLARGEMENT - NEW HARRIS DITCH	5/11/60	5/11/60	0.5 SCF
341	ADAMS LAKE RESERVOIR	9/12/60	9/12/60	763.94 A.F. CONDITIONAL
342	MAIN ELK-WHEELER GULCH PIPELINE	6/19/63	6/19/63	40.0 SFC
343	MAIN ELK RESERVOIR	6/19/63	6/19/63	34.922 A.F. CONDITIONAL
344				
344A				
344B				
344C				
344D				
344E	ELK-RIFLE WATER SUPPLY PROJECT	6/28/63	6/28/63	
344F				
344G				
345				
345A				

WATER ADJUDICATIONS - STATE WATER DISTRICT No. 39 (CONTINUED)

<u>PRIORITY NUMBER</u>	<u>NAME</u>	<u>APPROPRIA- TION DATE</u>	<u>PRIORITY DATE</u>	<u>AMOUNT ADJUDICATED</u>
346	ROAN PLATEAU PUMPING PIPELINE	5/27/64	5/27/64	100. cfs CONDITIONAL
347	VALLEY FARMS WATER WELL	5/31/64	5/31/64	0.18 cfs
348	UNA RESERVOIR & POWER CONDUIT	3/16/65	3/16/65	
349	HUMBLE DIVERSION FOREBAY AND PUMPING PLANT	5/22/65	5/22/65	8582. A.F. CONDITIONAL



## Adjudications That Relate to Oil Shale

Many of these water adjudications concern water supplies for possible use in oil shale developments. As an example, priority number 349, the Humble Diversion Forebay and Pumping Plant, is part of a complex inter-related system of storage reservoirs, pipelines, dams and pumping plants proposed by Humble Oil and Refining Company and by the Fourteen Mile Land Company. These inter-related facilities are proposed for construction in State Water Districts 39 and 43, and would derive their water supplies from several sources.

In our next quarterly report we plan to include a review of all of the adjudications that concern water supplies from oil shale, and to include a description of all facilities proposed by the oil companies for providing the water supplies at the various oil shale properties.

### STATE WATER DISTRICT NO. 43

State Water District No. 43 was opened in 1961 for court adjudication proceedings as Civil Action No. 1269 in the District Court for Rio Blanco County, Colorado.

During this reporting period the Court issued its adjudication findings, made in the form of a Decree issued on November 21, 1966. A complete listing of the water adjudications contained in the Decree are presented on the pages that follow.

WATER ADJUDICATIONS -- DECREE OF NOVEMBER 21, 1966  
 COLORADO STATE WATER DISTRICT NO. 43  
 DISTRICT COURT FOR RIO BLANCO COUNTY, COLORADO

<u>PRIORITY NUMBER</u>	<u>NAME</u>	<u>APPROPRIATION DATE</u>	<u>PRIORITY DATE</u>	<u>AMOUNT ADJUDICATED</u>
603	DAUM DITCH	1887	10/23/57	2.73 CFS
604	MCGRUDER No. 1 DITCH	1899	10/24/57	5.25 CFS
605	BIG LICK RESERVOIR AND FIRST ENLARGEMENT	1903	10/25/57	21.93 A.F.
606	BLACK GULCH RESERVOIR	1910	10/26/57	40.75 A.F.
607	BLACK & TSCHUDY GULCH IRRIGATION SYSTEM	1910	10/27/57	7.8 CFS
608	JONES SPRING & PIPELINE	1910	10/28/57	0.5 CFS
609		1911	57	3.0 CFS
610		1912	10/30/57	2.03 CFS
611	DAUM DITCH No. 2	1912	11/ 1/57	1.4 CFS
612	DAUM DITCH No. 3	1912	10/31/57	
613	OAK RIDGE PARK DITCH	1915	11/ 2/57	10.0 CFS
614	GREENSTREET DITCH No. 2	1916	11/ 3/57	6.1 CFS
615	LYNN-LEE DITCH	1916	11/ 4/57	0.5 CFS
616	GREENSTREET DITCH EXTENSION	1917	11/ 5/57	8.9 CFS
617	POWELL PARK DITCH & POWELL PARK DITCH 1ST & 2ND ENLARGEMENT	1917	11/ 6/57	15.0 CFS
618	WHEELER ENLARGEMENT OF GEORGE S. WITTER DITCH	1917	11/ 7/57	7.9 CFS CONDITIONAL
619	DORRELL DITCH No. 1	1920	11/ 8/57	0.5 CFS
620	DORRELL DITCH No. 2	1920	11/ 9/57	2.4 CFS
621	MARVINE No. 1 DITCH	1928	11/10/57	7.59 CFS
622	JOE FOX DITCH & PIPELINE	1933	11/11/57	2.22 CFS
623	GOFF'S RUN SPRING No. 1	1933	11/12/57	0.002CFS
624	GOFF'S RUN SPRING No. 2	1933	11/13/57	0.002CFS
625	FRASER DITCH	1934	11/14/57	1.0 CFS



## WATER ADJUDICATIONS - STATE WATER DISTRICT NO. 43 (CONTINUED)

<u>PRIORITY NUMBER</u>	<u>NAME</u>	<u>APPROPRIA- TION DATE</u>	<u>PRIORITY DATE</u>	<u>AMOUNT ADJUDICATED</u>
626	BEL AIRE HATCHERY WATER SUPPLY	1935	11/15/57	8.9 CFS
627	OAK RIDGE PARK DITCH (THIRD ENLARGEMENT)	1935	11/16/57	22.21 CFS
628	WATSON PLACE DITCH	1936	11/17/57	1.0 CFS
629	IMES & REYNOLDS DITCH (ENLARGEMENT)	1936	11/18/57	1.0 CFS
630	HERRELL DITCH	1936	11/19/57	0.50 CFS
631	IMES, REYNOLDS & MCKELL DITCH (WHEELER ENLARGEMENT)	1936	11/20/57	3.7 CFS CONDITIONAL
632	NEW ARCHER WARNER DITCH (POLLARD ENLARGEMENT)	1937	11/21/57	0.69 CFS CONDITIONAL
633	BAILEY LAKE RETAINING POND	1941	11/22/57	22.81 A.F. .2 CFS
634	DRIEFUSS DITCH (K-K ENLARGEMENT)	1942	11/23/57	5.58 CFS
635	BAER SPOT WELL	1942	11/24/57	7 GALLONS PER MINUTE
636	Ivo E. SHULTS DITCH & PUMPING PLANT	1944	11/25/57	5.0 CFS
637	CALHOUN DITCH	1945	11/26/57	0.86 CFS
638	OAK RIDGE PARK DITCH (FOURTH ENLARGEMENT)	1946	11/27/57	
639	K-K WELL	1946	11/28/57	18 GALLONS PER MINUTE
640	FISH POND DITCH	1946	11/29/57 11/30/57	3.0 CFS 12 GALLONS PER MINUTE
642	DREYFUSS DITCH	1947	12/ 1/57 57	2.49 CFS 32.0 CFS CONDITIONAL
643	MCGINNIS MEADOWS RESERVOIR			,
641	CARSTENS WELL	1947&1947	12/ 2/57	87. A.F. 0.1 CFS

WATER ADJUDICATIONS - STATE WATER DISTRICT NO. 43 (CONTINUED)

<u>PRIORITY NUMBER</u>	<u>NAME</u>	<u>APPROPRIATION DATE</u>	<u>PRIORITY DATE</u>	<u>AMOUNT ADJUDICATED</u>
644	GOVREAU WELL	1947	12/ 3/57	7 GALLONS PER MINUTE
645	THOMAS DITCH (1ST ENLARGEMENT)	1950	12/ 4/57	6.0 CFS
646	K-K STOCK WATER WELL	1951	12/ 5/57	0.02 CFS
647	LAWRENCE DITCH No. 1	1951	12/ 6/57	5.0 CFS
648	UINTAH OIL REFINING Co. PIPELINE	1951	12/7 /57	3.15 CFS CONDITIONAL-2.15
649	THE BIG FISH No. 1	1952	12/ 8/57	0.5 CFS
650	THOMAS No. 3 DITCH	1953	12/ 9/57	2.5 CFS
651	SMITH WATER SYSTEM	1953	12/10/57	0.04 CFS
652	YELLOW JACKET PROJECT YELLOW JACKET CANAL RIPPLE CREEK RESERVOIR LOST PARK RESERVOIR	1953	12/11/57	500. CFS 27,991.7 A.F. 33,541.3 A.F. (ALL CONDITIONAL)
653	GOOSMAN RESERVOIR	1954	12/12/57	SUFFICIENT WATER TO MAINTAIN SURFACE AREA OF 1.8 ACRES AT ALL TIMES.
654	THE HIGHLAND DITCH	1956	12/13/57	33.0 CFS
655	BRADY GULCH STOCK WATER POND	1957	12/14/57	1.0 A.F.
656	VEACH-GULCH STOCK WATER POND No. 1	1956	12/15/57	1.0 A.F.
657	URRUTY STOCK WATER TANK	3/15/57	12/16/57	.50 A.F.
658	ERTL PIPELINE	5/26/57	12/17/57	30.0 CFS CONDITIONAL
659	BUCK CREEK RESERVOIR	9/ 7/57	12/18/57	1293.41 A.F. CONDITIONAL
660	BUCK CREEK DIVERSION CANAL	9/ 7/57	12/18/57	50.0 CFS
661	MEADOWS RESERVOIR	9/ 7/57	12/18/57	77,395.18A.F. CONDITIONAL
662	FIRST ENLARGEMENT MEADOWS RESERVOIR	9/ 7/57	12/18/57	21,391.82A.F. CONDITIONAL
663	WAGON WHEEL CREEK DIVERSION PIPE	9/ 7/57	12/18/57	100. CFS CONDITIONAL



## WATER ADJUDICATIONS - STATE WATER DISTRICT No. 43 (CONTINUED)

<u>PRIORITY NUMBER</u>	<u>NAME</u>	<u>APPROPRIA- TION DATE</u>	<u>PRIORITY DATE</u>	<u>AMOUNT ADJUDICATED</u>
664	PLATEAU TUNNEL	9/ 7/57	12/18/57	200. CFS CONDITIONAL
665	FIRST ENLARGEMENT OF THE PLATEAU TUNNEL	9/ 7/57	12/18/57	60. CFS
666	PATTERSON CREEK DIVERSION PIPE	9/ 7/57	12/18/57	160.0 CFS CONDITIONAL
NUMBERS 659-666 ARE PART OF THE SWEETWATER HYDROELECTRIC PROJECT				
667	MONUMENT MOUNTAIN STOCK WATER POND	9/12/57	12/19/57	1.0 A.F.
668	VEACH GULCH WATER POND #2	9/12/57	12/20/57	1.0 A.F.
669	CALDWELL DITCH	10/11/57	12/21/57	8.0 CFS CONDITIONAL
670	SEVENTH LAKE (FIRST ENLARGEMENT)	2/15/58	2/15/58	29.51 A.F.
671	SECOND ENLARGEMENT THOMAS No. 2 DITCH	7/ 1/58	7/ 1/58	6.0 CFS
672	BEL AIRE HATCHERY WATER SUPPLY	7/ 2/58	7/ 2/58	0.16 CFS
673	JEAN URRUTY No. 2 RESERVOIR	7/10/58	7/10/58	1.0 A.F.
674	JEAN URRUTY No. 1 RESERVOIR	8/10/58	8/10/58	1.0 A.F.
675	TUCKER DITCH No. 1	9/ 6/58	9/ 6/58	1.0 CFS
676	DRIEFUSS DITCH (K-K ENLARGEMENT)	1/ 9/59	1/ 9/59	1.5 CFS
677	NEAL WELL	7/ 1/59	7/ 1/59	7 GALLONS PER MINUTE
678	NONAME STOCK WATER POND	9/30/59	9/30/59	1. A.F.
679	MARCOTT DITCH (FULTON ENLG.)	7/26/60	7/26/60	1.0 CFS
680	CAMPBELL CREEK DITCH	8/ 2/60	8/ 2/60	8.0 CFS
681	PALMER PIPELINE	10/20/60	10/20/60	0.021CFS
682	PONCA CITY PUBLISHING Co. PIPELINE	10/21/60	10/21/60	0.011CFS
683	PONCA CITY PUBLISHING Co. PIPELINE	10/22/60	10/22/60	1.12 CFS CONDITIONAL

WATER ADJUDICATIONS - STATE WATER DISTRICT NO. 43 (CONTINUED)

<u>PRIORITY NUMBER</u>	<u>NAME</u>	<u>APPROPRIATION DATE</u>	<u>PRIORITY DATE</u>	<u>AMOUNT ADJUDICATED</u>
684	PONCA CITY PUBLISHING Co. DITCH	10/23/60	10/23/60	1.73 CFS
685	JOHNY JOHNSON RESERVOIR	11/ 2/60	11/ 2/60	1036. A.F. & .60 CFS (BOTH CONDITIONAL)
686	URRIOLA No. 1 RESERVOIR	5/ 4/60	5/ 4/61	4.0 A.F.
687	LYNN-LEE DITCH (FIRST ENLARGEMENT)	5/31/61	5/31/61	0.5 CFS
688	MOBLEY PIPELINE No. 1	6/ 3/61	6/ 3/61	8.0 CFS CONDITIONAL
689	URRUTY No. 3 RESERVOIR	6/15/61	6/15/61	0.75A.F.
690	MCLAUGHLIN PIPELINE	6/21/61	6/21/61	8.0 CFS CONDITIONAL
691 691A	BOIES RESERVOIR, PICEANCE PIPELINE & PICEANCE CANAL	7/10/61	7/10/61	50. CFS 31,020.8A.F. (BOTH CONDITIONAL)
692	FRANK MORISON DITCH	7/15/61	7/15/61	2.5 CFS
693	CROSS L. PUMP LINE (AN ENLARGEMENT OF THE NIBLOCK DITCH	7/22/61	7/22/61	0.60 CFS
694	HERRELL DITCH No. 2 AND FISH POND	8/23/61	8/23/61	0.50 CFS 2.5 A.F. STORAGE
695	HERRELL PIPELINE	8/26/61	8/26/61	0.50 CFS
696	MCDOWELL No. 1 DITCH	8/24/60	8/24/61	8.0 CFS
697	JOY, JOY & WATSON RESERVOIR AND DITCH	8/25/61	8/25/61	2.0 CFS 5.88A.F. STORAGE
698	POLFER DITCH & PIPELINE	8/28/61	8/28/61	0.25 CFS CONDITIONAL
699	BEAVER LAKE RESERVOIR (FIRST ENLARGEMENT)	8/29/61	8/29/60	58.96A.F.
700	RIDGE PUMPING PLANT	8/31/61	8/31/61	6.5 GALLONS PER MINUTE



WATER ADJUDICATIONS - STATE WATER DISTRICT NO. 43 (CONTINUED)

<u>PRIORITY NUMBER</u>	<u>NAME</u>	<u>APPROPRIA- TION DATE</u>	<u>PRIORITY DATE</u>	<u>AMOUNT ADJUDICATED</u>
701	HIGHLAND DITCH (FOURTH ENLARGEMENT)	9/ 6/61	9/ 6/61	61.0 CFS CONDITIONAL
702	HIGHLAND DITCH (FIFTH ENLARGEMENT)	9/ 6/61	9/ 6/61	180.0 CFS CONDITIONAL
703	SEELY PIPELINES	9/ 8/61	9/ 8/61	2.0 CFS CONDITIONAL

The Flat Tops Wilderness Proposal and Its Effect on Oil  
Shale Water Supplies

The U. S. Forest Service is proposing that 99,713 acres of the Flat Tops Primitive area and 53,532 acres of adjacent National Forest lands in Colorado are suitable for Wilderness classification and should be added to the National Wilderness Preservation System. The area would be named the Flat Top Wilderness and would total 153,245 acres, according to the Forest Service proposal. The proposed Flat Tops Wilderness area is shown in red on the fold out map which also shows the relative position of the oil shale area and the boundaries of Colorado's state water districts.

A public hearing on the proposal was held in Glenwood Springs, Colorado, during October. Present were representatives from such diverse groups as the U. S. Forest Service, Humble Oil, Rocky Mountain Power, Colorado Open Space Coordinating Council, Colorado Game, Fish and Parks Dept., Rio Blanco County Stock Growers Assn., etc.

Under the Forest Service proposal, the Flat Tops Wilderness would be a land for foot or horseback travel only. No vehicles would be permitted. No campsites or other recreational facilities would be developed. No water diversion, reclamation, or hydro-power facilities would be allowed.

## FOREIGN OIL SHALE

### CANADA :

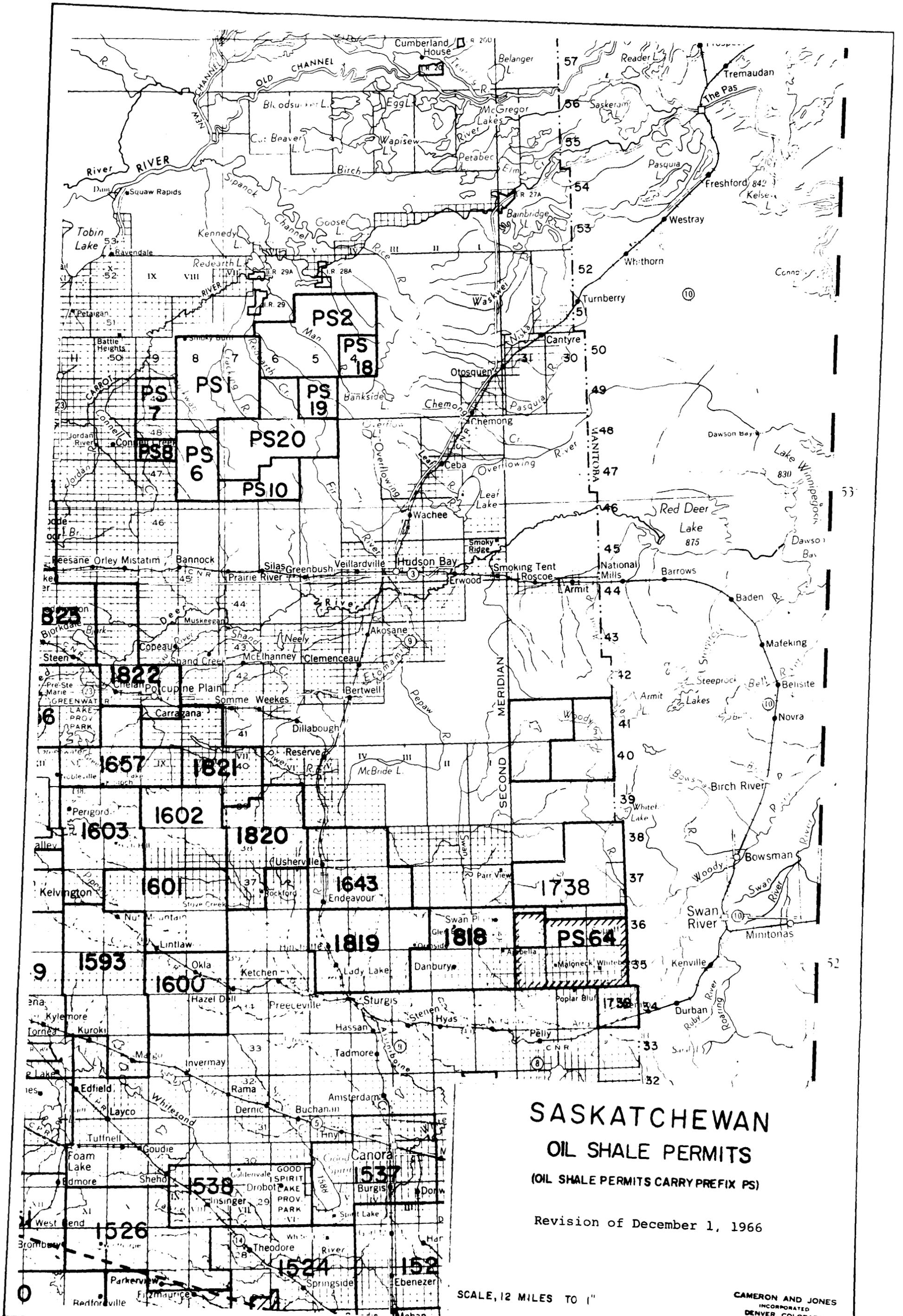
#### Interest in Canadian Oil Shale Deposits Continues to Decline

All oil shale reservations in Manitoba have expired and have been cancelled in the records of that Province. In the span of two years an oil shale land play began and ended, affecting seven million acres. Interest in Manitoba's oil shale deposits has declined to the vanishing point.

In the Province of Saskatchewan, where an oil shale land play was in progress simultaneously with that in Manitoba, a maximum of three million acres were held under oil shale permits. Interest in Saskatchewan's oil shale deposits has declined also. The only permits remaining in effect now total 557,334 acres, most of which are held by Sun Oil Company. The permits for Saskatchewan are presented in the listing below and are shown on the fold-out map which follows this page.

#### SASKATCHEWAN OIL SHALE PERMITS

<u>Permit</u>	<u>Holder</u>	<u>Acreage</u>	<u>Date</u>
PS1	Sun Oil Company	99,840	20-3-64
PS2	Sun Oil Company	99,840	20-3-64
PS6	Sun Oil Company	36,640	1-6-64
PS7	Sun Oil Company	34,560	1-6-64
PS8	Sun Oil Company	11,520	1-6-64
PS 10	Sun Oil Company	31,360	1-6-64
PS 18	Sun Oil Company	21,760	1-6-64
PS 19	Sun Oil Company	21,920	1-6-64
PS 20	Sun Oil Company	100,000	1-6-64
PS 64	Husky Oil Canada Ltd.	99,994	9-7-65



# SASKATCHEWAN OIL SHALE PERMITS

(OIL SHALE PERMITS CARRY PREFIX PS)

Revision of December 1, 1966

SCALE, 12 MILES TO 1"

CAMERON AND JONES  
INCORPORATED  
DENVER, COLORADO



**TAR SANDS**

**BITUMINOUS SANDS**





## TAR SANDS/BITUMINOUS SANDS

UTAH:

### State Land Board Still Undecided on Tar Sands Leasing Policy

Since 1951 the Utah State Land Board has been issuing two types of hydrocarbon leases, a bituminous sands lease and an oil and gas lease. Late in 1965, the State Land Board directed its staff not to receive any new applications for bituminous sands leases of state land until the Board reviewed and possibly revised its leasing policies. The Board was convinced that it was not a good idea to issue two types of leases, as the rights of the lessees could not be defined. The Board requested recommendations from the Rocky Mountain Oil and Gas Association which could be used in aiding the formulation of a new leasing policy.

A special RMOGA subcommittee submitted its recommendations, which were reviewed in our September 1, 1966 report beginning on page 86.

Since September 1st, the State Land Board has considered the RMOGA recommendations and has prepared a new and different lease form which calls for a single hydrocarbon lease and which was submitted to the Governor. State Land Board director, Max Gardner, stated last August that if the Governor supported the new form, industry approval would be sought prior to the preparation of any necessary legislation. Gardner stated that the new form was essentially a single lease form which amounted to an oil and gas lease plus a mining lease. Gardner stated his belief that any hydrocarbon taken out of the ground as a liquid should be subject to a different royalty than hydrocarbons taken out as solids. He believed also that, under the lease form tentatively proposed, the State would not lose revenue and that the State's position would be consistent with that of Utah's Senator Moss, who had submitted S.3622 in the U. S.

State Land Board Still Undecided on Tar Sands Leasing Policy (continued)

Senate last year to establish a single hydrocarbon lease for Federal lands. Moss' bill was not enacted into law by the 89th Congress. Gardner also stated that industry reaction is now being sought, through RMOGA, for the new lease form which has been proposed and which would provide for a single hydrocarbon lease.

CANADA:

Queens University Offers Process Design Courses in Tar Sands Extraction

The Department of Chemical Engineering of Queens University, Kingston, Ontario, now offers 4th. year courses concerning in situ and conventional plant extraction processes for recovery of oil from tar sands.

Current Listing of Alberta Bituminous Sands Leases and Prospecting Permits

A listing of all current bituminous sands leases and prospecting permits in Alberta, and a fold-out map showing the areas involved, are presented on the pages that follow.

TAR SANDS LEASES AND PROSPECTING PERMITS IN THE  
ATHABASCA TAR SANDS AREA OF ALBERTA, CANADA

TAR SAND LEASES

<u>COMPANY NAME</u>	<u>LEASE NUMBER</u>	<u>ACREAGE</u>	<u>COMPANY NAME</u>	<u>LEASE NUMBER</u>	<u>ACREAGE</u>
AQUITAINE COMPANY OF CANADA, LTD.	39	49,742	CANADIAN FINA OIL LTD.	6	6,440
ARROWHEAD EXPLORATION COMPANY, LTD.	23	36,937		7	2,866
ATLANTIC RICHFIELD COMPANY	40	22,054		8	1,393
	54	49,483		9	5,601
	55	26,002		11	2,483
	56	23,377		12	4,174
	57	49,451		33	22,700
	58	36,042		34	9,129
	59	45,414	CANADIAN HUSKY OIL LTD. <u>AND</u>	82	48,489
	60	31,250	HUSKY OIL COMPANY	35	49,904
	61	26,641			
	63	43,562	CANEX GAS LTD.	15	2,094
	65	49,467			
	66	49,419	CITIES SERVICE ATHABASCA, INC. <u>AND</u>	17	49,788
	70	46,802	ATLANTIC RICHFIELD COMPANY <u>AND</u>	22	49,591
	71	36,492	IMPERIAL OIL LTD. <u>AND</u> ROYALITE	29	49,722
	72	41,613	OIL COMPANY LTD., <u>C/O</u> SYNCRUDE	31	49,870
			CANADA, LTD.	32	11,365
ATLANTIC RICHFIELD COMPANY <u>AND</u>	79	27,265		41	13,491
IMPERIAL OIL LTD. <u>AND</u> CITIES	81	41,954		78	36,086
SERVICE ATHABASCA LTD.					
BAILEY SELBURN OIL & GAS LTD.	42	21,729	COLORADO OIL AND GAS CORPORATION (SEE GREAT PLAINS		
			PETROLEUM LTD.)		
BAILEY SELBURN OIL & GAS LTD., <u>AND</u>	19	18,758	FRENCH PETROLEUM COMPANY OF CANADA LTD.	50	32,824
WHITEHALL CANADIAN OILS LTD.	20	13,657			
			GREAT CANADIAN OIL SANDS LTD.	14	4,177
GREAT PLAINS PETROLEUM LTD., <u>AND</u>					
COLORADO OIL & GAS CORPORATION	25	49,964	HOME OIL COMPANY LTD.	30	37,715
CAN-AMERA OIL SANDS DEVELOPMENT LTD.	5	5,874	HUSKY OIL COMPANY		SEE CANADIAN HUSKY OIL LTD.
	43	49,784	IMPERIAL OIL LTD.		SEE CITIES SERVICE ATHABASCA, INC.

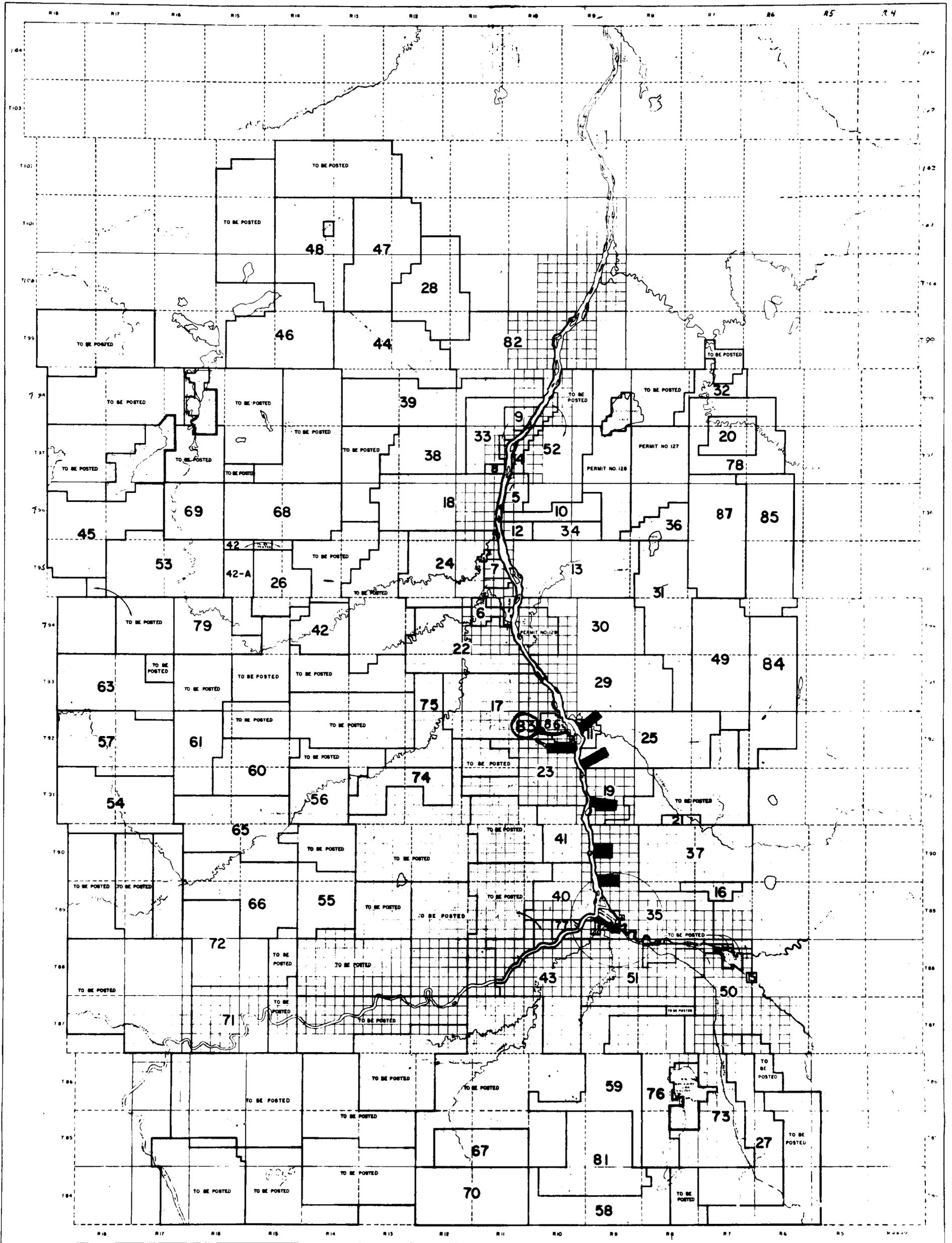
<u>COMPANY NAME</u>	<u>LEASE NUMBER</u>	<u>ACREAGE</u>
MIC MAC OILS LTD.	18	49,969
MOBIL OIL OF CANADA, LTD.	16	5,824
	21	2,584
	36	12,156
	37	49,751
	38	26,339
PAN AMERICAN PETROLEUM CORPORATION	73	49,931
	76	49,837
REGENT REFINING LTD.	67	25,969
	68	46,154
	69	23,377
ROYALITE OIL Co., LTD.	(SEE CITIES SERVICE ATHABASCA)	
SHELL CANADA LTD.	13	49,872
	26	23,506
	28	40,642
	42-A	16,209
	45	49,731
	53	49,419
SINCLAIR CANADA OIL COMPANY	52	35,109
	74	23,353
	75	25,945
SUN OIL COMPANY, LTD.	10	11,227
	27	49,994
	83	624
	84	49,379
	85	49,419
	86*	3,898
SUPERTEST PETROLEUM CORPORATION	24	49,941

<u>COMPANY NAME</u>	<u>LEASE NUMBER</u>	<u>ACREAGE</u>
SYNCRUDE CANADA LTD.	(SEE CITIES SERVICE ATHABASCA)	
TENNECO OIL COMPANY	87	49,427
TEXACO EXPLORATION COMPANY	44	49,775
	46	49,751
	47	49,735
	48	49,763
	49	49,727
	51	49,503
WHITEHALL CANADIAN OIL LTD.	(SEE BAILEY SELBURN OIL)	
WOOD OIL COMPANY	77	6,792

TAR SANDS PROSPECTING PERMITS

<u>COMPANY NAME</u>	<u>PERMIT No.</u>	<u>ACREAGE</u>
AMERADA PETROLEUM CORP.	127	35,258
	128	28,734
	129	11,918

\* FORMERLY LEASE No. 4, RENEWED AS LEASE No. 86



**LEGEND**

Bituminous Sands Leases 22

Bituminous Sands Permits 23

Patented 24

Indian Reserves 25

Road Allowance Surveys 26

Road Allowance Unsurveyed 27

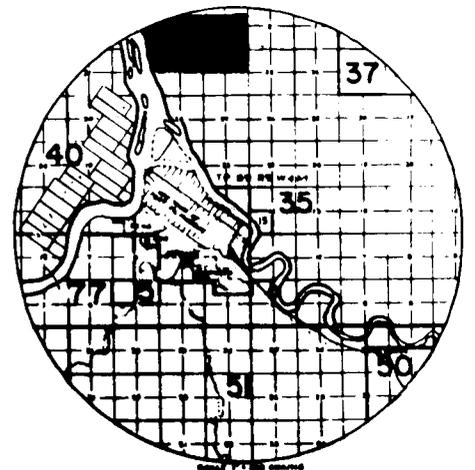
Town Boundaries 28

Railways 29

Lakes 30

NOTE: BALANCE OF AREA AVAILABLE FOR BITUMINOUS SANDS APPLICATIONS

MAP OF  
**BITUMINOUS SANDS AREA**  
ALBERTA



Dec. 1966





Prompt Development of Athabasca Tar Sands Viewed as  
"The Canadian Challenge"--Spragins, Syncrude Canada Ltd.

A delay in initiating plans for a continuing development of the tar sands would simply invite serious future competition from other sources of oil, such as the liquefaction of coal and the development of shale oil. Canada must take advantage of the present lead enjoyed by Athabasca. Wasted time will allow technology for recovery of oil from shale and from coal to catch up and supply markets that might have been supplied more economically from tar sands oil. With these statements, Mr. Frank Spragins, President of Syncrude Canada Ltd., urged Canadians to continue development of Athabasca tar sands. Spragins presentation, The Canadian Challenge, was made to the Canadian Institute of Mining and Metallurgy at the Institute's annual meeting in Calgary on October 18, 1966.

Spragins noted also that the U. S. years of reserve supply has been steadily declining since 1958 and expressed doubts that future exploration trends will improve to a point where discovery rates in the U. S. can keep up with demand. Canada, he noted, is in a fortunate position because it has the ability to provide the insurance of a large supply of liquid fuels. Spragins stated that tar sands technology, today, has advanced to the stage where it can be safely assumed that oil is producible at currently competitive prices. To meet the increasing demand forecast for the mid 70's, Spragins cited the need for increased action today to develop the new industry capable of meeting foreseeable needs. Only the Athabasca tar sands has the potential of filling the huge future requirements after 1975.



# **COAL and LIGNITE**





## NATIONAL DEVELOPMENTS

### Coal Production Running Ahead of Last Year

Coal production so far this year, through November 4, has been 443,169,000 tons compared to 429,792,000 tons during the comparable period in 1965. This amounts to an increase of 13,377,000 tons, or about 3.1 percent.

### Consol/Conoco Merger Completed

Consolidation Coal Company was merged into Continental Oil Company on September 14 and has become a division of the latter. Conoco's chairman stated, "The most important aspect of this acquisition is the tremendous potential for coal and oil working together to meet the world-wide demand. It is no longer a question of one source of energy pushing out another source. By 1980, the free world's need for economic sources of fossil energies for electricity generation, transportation and other basic industries will be doubled."

### Peabody/Kennecott Merger Plans Unchanged

It will still be well into next year before plans can be consummated to merge Peabody Coal Company into Kennecott Copper Company.

### General Dynamics Attempts to Buy More United Electric Coal Stock

General Dynamics Corporation announced that it will buy shares of common stock in United Electric Coal Companies for \$50 a share. General Dynamics already owns 445,773 shares, about 66 percent of those outstanding and is trying to buy up a minimum of 170,000 more, for a total of about 91 percent of the outstanding shares.

## General Dynamics Attempts to Buy More United Electric Coal Stock (continued)

United Electric Coal produced 5,409,814 tons of coal in 1965, all in Illinois. In 1966, it obtained coal properties in New Mexico.

## Kerr-McGee to Build Coking Units

Kerr-McGee Corporation announced on November 23, 1966, that it will begin construction of 50 coke ovens near Stigler, Haskell County, Oklahoma. They will be sole-heated and will not have gas recovery facilities. Construction will begin in January 1967. The first three units will be completed about April 1967 and the remaining units are scheduled for completion by July 1, 1967. Each oven will be 34 feet long, 9 feet wide and 8 feet high. The capacity of each unit will be 14-1/2 tons, with a daily yield of 10 tons.

Kerr-McGee will sink its own mine shafts starting in January 1968 and expects to be in production by December 1968. Two shafts, each 20 feet in diameter, will be sunk to the coal seams about 1,300 feet below the surface. The company owns about 35 million tons of recoverable reserves of metallurgical coke in the Arkansas River Basin. D. A. McGee, president and chairman of the board of Kerr-McGee stated, "With the beginning of this first phase of coal mining and processing operations, Kerr-McGee expresses its faith in the future of the coal industry in the Arkansas River Basin." He also said that by utilizing modern methods of coal recovery and taking advantage of low-cost water transportation when the Arkansas River becomes navigable, Oklahoma coal will be competitive with other fossil fuels (gas and oil).



## CONTRACTS AWARDED BY THE OFFICE OF COAL RESEARCH

### Coal De-Ashing Pilot Plant to be Built

The Office of Coal Research announced on November 9, 1966, that it had awarded a contract to Pittsburg & Midway Coal Company to pilot plant the coal de-ashing process developed by Spencer Chemical Company. Both of these organizations are subsidiaries of Gulf Oil Corporation. Spencer worked from August, 1962 to March, 1965 under a \$1,240,000 OCR contract to develop a process for de-ashing coal in a bench scale pilot plant. A report by Spencer, Solvent Processing of Coal to Produce a De-Ashed Product, was released by OCR on June 22, 1965 and was summarized in *Oil Shale and Related Fuels*, September 1, 1965 (Vol. 2 No. 3).

The previous work was done under the supervision of Willard C. Bull. He is now affiliated with Pittsburg & Midway and presumably will head the new pilot plant investigation. The pilot plant is expected to be capable of processing two tons of coal per hour to a de-ashed product and will cost about \$4,000,000. It will be located in Tacoma, Washington. The contract is for a five-year period and includes the design, construction and operation of the pilot plant, evaluation of the data, preparation of a final report, and preliminary design of a semi-commercial unit. Adequate de-ashed product will be made for testing in commercial facilities. Of added interest will be the availability of sizable quantities of mineral matter from coal. This will be a by-product of the process and probably will not resemble the ash which is the residue from coal when it is combusted. It is not oxidized and has never before been available in quantity for investigation. The total cost of the current project is expected to be \$7,600,000.

Possible uses for de-ashed coal are discussed in an article by R. M. Jameson, *Utilizing Solvent Refined Coal in Power Plants*, in *Chemical Engineering Progress*, Vol. 62, No. 10 (Oct. 1966), pages 53 to 60.

## Extension of Another Gasification Project Announced

"Project Gasification" was given a 15-month extension and an additional \$1,000,000 by an amendment to the contract between OCR and Bituminous Coal Research, Inc. The announcement was made on October 31, 1966.

This project was originally a three-year research program to select the best gasification approach after a study by BCR which extended throughout the United States and into Europe. A report to OCR prepared by BCR titled, Gas Generator Research Survey and Evaluation, Phase One, was released by OCR on August 17, 1965. This report was quite extensive but recommended two processes as being most attractive: 1, the two-stage entrained gasifier operating at 1,000 psig or higher; and 2, a new conceptual process (now being investigated by the Institute of Gas Technology under contract to the OCR and the American Gas Association) of catalytic steam methanization. After the study was made, BCR constructed a small pilot plant to investigate the two-stage entrained gasifier and has been operating it during the past year.

The additional funds will provide for the construction and operation of a 100-pound per hour "process development" unit that will operate under conditions similar to those used in the smaller unit and determine the factors involved in scale-up. The new plant will utilize a novel coal feeder to continuously inject pulverized coal against the pressure in the gasifier.

In the announcement of the extension, statements were made that the two-stage generator has low oxygen consumption, produces a gas under pressure that can be further processed for pipeline distribution and entertains the hope that the system will be available for commercial use in ten years.



### Anthracite Culm Banks to be Investigated

On September 6, 1966, OCR announced that a contract has been awarded to Dorr-Oliver, Incorporated, to develop methods to upgrade both burned and unburned anthracite culm (fine coal in eastern Pennsylvania) banks into high quality road base materials and other potentially valuable products. The contract is for \$386,100 for a 27-month effort. The Commonwealth of Pennsylvania will pay one-fourth of the costs of the work performed.

### West Virginia University Receives OCR Grant

A grant of \$21,000 to the University of West Virginia by OCR was announced October 31, 1966. The grant will finance the first year of a three-year study into methods for converting molten coal ash slag into mineral wool for insulation applications.

### Not Yet, But Soon, A Lignite Gasification Pilot Plant

The Black Hills of South Dakota has been "semi-selected" as the location for the lignite gasification pilot plant. George Fumich, Jr., OCR Director, stated in late October, "We've narrowed down the area to the Black Hills, but we're still checking on two locations. Belle Fourche is the first choice, with Rapid City as an alternate." An announcement of the site and awarding of a contract is expected from the Interior Secretary's office shortly.

The proposed gasification pilot plant will use the CO<sub>2</sub>-Acceptor process investigated by Consolidation Coal Company under an earlier OCR contract. The process and the estimated economics of making pipeline gas from lignite was presented in Oil Shale and Related Fuels, December 1, 1965, Vol. 2 No. 4, pages 84 to 86. The cost of the new pilot plant will be about \$2,500,000. It is anticipated that the contract, when awarded, will go to Consolidation Coal Company, now a subsidiary of Continental Oil Company.

Not Yet, But Soon, A Lignite Gasification Pilot Plant  
(continued)

In a letter dated November 21, 1966, Neal Cochran of the Office of Coal Research wrote that the CO<sub>2</sub>-Acceptor pilot plant has been under design by the M. W. Kellogg Company for about eight months.

Coal Gasification Processes to be Evaluated by West Virginia University

Interior Secretary Udall announced on November 21, 1966, that a contract had been awarded by the Office of Coal Research to West Virginia University to investigate mathematical optimization of processes that can be applied to coal gasification. Cost of the three-year project was estimated to be \$165,000.

The work to be done under this contract includes obtaining data from laboratories where coal gasification is being performed and collecting data to evaluate the process economics. These data will be transposed into appropriate reaction equations and programmed into a computer. The effect of coal price, rank, capital investment and operating costs, and by-products, on the product gas will be determined by the computer. Precise determination will be made of those process areas likely to greatly influence the cost of the product gas. No laboratory research will be undertaken.

Penn State University to Identify Coals for Special Uses

On September 28, 1966, OCR announced that a contract for \$459,800 had been signed with Pennsylvania State University. Under the contract, which is financed 90.2% by Federal funds and 9.8% by the University, the latter will endeavor to identify coal types and constituents which are best suited for conversion to liquids, to gases, for use in sewage treatment, and for other special products which OCR is attempting to develop under its research program.



Penn State University to Identify Coals for Special Uses  
(continued)

It is believed that certain coal types and compositions are best suited for steam generation only, while others are more reactive and can be converted to various chemicals and fluid fuels. The University will attempt to evaluate present and potential methods by which desirable coal constituents may be separated on an economic and commercial basis. Work under this contract is expected to be completed in 28 months, or about March, 1969.

REPORTS RELEASED BY OFFICE OF COAL RESEARCH

Reactions of Coal with Various Gases at Plasma Temperatures Reported

The Office of Coal Research released a report, Plasma Reactions with Powdered Coal, on August 30, 1966. This report summarizes the work done at the University of Utah by Edward McDonald. Plasma temperatures from 4950°F to 14,100°F were achieved. Four gases, argon, helium, hydrogen and nitrogen, were used separately and in combination as a carrier gas. Experiments were made using coal, coke, oil shale, activated charcoal and methane. Products were hydrogen, acetylene and hydrogen cyanide. The maximum yield of acetylene was from high-volatile Utah coal. Yields from subbituminous coal were lower. Coke and activated charcoal were unreactive in the plasma. No catalysts were found to improve the yields. The yield under a certain condition with coal as feedstock was: 1.37% hydrogen; 1.68% methane; 14.36% acetylene; 1.0% hydrogen cyanide; and 26.3% carbon monoxide. Power input was 24 KWH per pound of products (about 12¢ per pound of impure gases). Scale up and certain modifications might improve the economics, but they are not bright now.

## Midwestern and Alaskan Coal and Lignite Evaluated

A report by Robert R. Nathan, Inc. on the potential market for coal and lignite in the Midwest States and Alaska was announced to OCR on November 11, 1966. The potential for Alaskan coal was considered to be indeterminate at this time. The indicated potential for midwestern coal was 6-1/2 times the tonnage consumed in that area in 1964.

The Midwest study is Part II of a comprehensive study of the market potential for western coal and completes the contract awarded to the Nathan firm by OCR in October, 1964. Part I, The Potential Market for Far Western Coal and Lignite, was published in January, 1966.

The largest increase in coal consumption in the Midwestern States (Minnesota, Iowa, Missouri, North Dakota, South Dakota, Nebraska, Kansas, Arkansas, Oklahoma, Texas and Louisiana) between 1964 and 1980 will be for electric power generation. About 6.4 million tons of coal were used for this purpose in 1964 and in 1980 about 49.8 million tons will be burned. The report recommends that industry should: 1, study the opportunities for coal-derived electric generation identified in the report; 2, examine the possibilities of Oklahoma metallurgical grade coal; 3, consider the added long-term investments in coal production; 4, study the economics in all steps from mining through transport and utilization; and, 5, cooperate with Government and private research organizations. The report recommends the following actions by the Government: 1, increase the support for research into conventional and new types of electric generation; 2, improve the Government reports on U. S. coal resources by adopting geological criteria related to economic factors, make more private resource data public, and perform more exploration; and, 3, change existing policy to encourage exploration and development of coal resources.



## Midwestern and Alaskan Coal and Lignite Evaluated (cont'd)

Copies of Part II of the Nathan Report will soon be available for individual ownership. They may be ordered from the Office of Coal Research, Department of the Interior, Washington, D. C., 20240. Check for \$5.00 per copy should be made payable to "Interior, Office of Secretary".

### STATUS OF PROPOSED SOUTHWESTERN COAL-FIRED POWER PLANTS

There are three areas in the Southwestern United States where coal will be mined to supply fuel for major steam-electric power plants. One of these, the Four Corners area near Farmington, New Mexico, has already been put into production. The Navajo Mine, owned and operated by Utah Construction and Mining Company, is producing about two and one-half million tons of subbituminous coal per year. This coal is hauled by trucks to the adjacent Four Corners power plant owned by Arizona Public Service Company where it is burned as fuel.

#### The Four Corners Area

The Four Corners power plant is to be enlarged by 1,510 Mw. Construction of the addition was started last summer and it should be in complete operation by the middle of 1970. The addition is being built by Western Energy Supply and Transmission Associates (W.E.S.T.). Fuel for this addition will come from the Navajo Mine and requirements will be six million tons per year by 1970. Then, the mine will be producing eight and one-half million tons per year and will be the largest coal mine in the world. The coal is of poor quality, barely over 9,000 Btu per pound delivered and containing about 22 percent ash. However, it lies near the surface and is easily recovered by strip-mining and delivers to the plant for about 12¢ per million Btu. The low cost makes

### The Four Corners Area (Continued)

it very attractive and plans seem to be underway to double the size of both the plant and mine, to about 4,000 Mw and 16 million tons per year, respectively, by about 1974.

Adjoining the property containing the Navajo Mine on the south is a coal-bearing area leased to El Paso Natural Gas Company. There has been no official statement, but Consolidation Coal Company has apparently joined El Paso to develop a coal mine which is expected to supply the fuel requirements of a power plant with a capacity of about 1,500 Mw. This indicates a mining rate of about six million tons of coal per year and is expected to be in production by 1972.

Both Utah Construction and El Paso have their coal properties on the Navajo Indian Reservation. Public Service Company of New Mexico has no known coal leases on the Navajo reservation, but does have some on public lands both north of Utah's and east of El Paso's holdings. In a statement accompanying its request for water rights Public Service states that it intends to use the water for cooling purposes in a coal-fired power plant with a capacity of 1,000 Mw. No time or location has been fixed.

### The Black Mesa of Arizona

About 100 miles west of the Navajo Mine is the Black Mesa of Arizona. It is an island of Cretaceous geologic remains projecting high above the surrounding landscape in a sparsely inhabited area just south of Monument Valley. The northern edge of the mesa is a steep escarpment often 1,500 feet high. Trees growing in this shaded area give it a dark appearance and probably account for the name, Black Mesa. The top of the mesa is geographically rough, sparsely vegetated, almost devoid of people. The mesa is about forty miles across. During the past six years, Sentry Royalty Company, a wholly owned subsidiary of Peabody Coal Company, found large deposits of coal recoverable by strip mining methods toward the northern tip of the mesa. A letter of agreement was signed with Southern



### The Black Mesa of Arizona (Continued)

California Edison Company to deliver coal to a W.E.S.T. power plant to be constructed in southern Nevada. The construction of this plant is scheduled to start in early 1967 and it should be producing its full power rating of 1,500 Mw by mid-1971. At that time it should be consuming about five million tons of Black Mesa coal per year. Present plans are to pump the pulverized coal through a 270-mile pipeline as a water slurry. Formal announcement of the method of delivery and who will build the pipeline, if that is still the plan, is expected on December 1, 1966 by Southern California Edison Company, the project manager. However, it is anticipated that the coal will be slurried with its own weight of water, pumped to its destination in a 16-inch pipeline, and dewatered, pulverized and dried before burning.

### The Kaiparowits Plateau-Lake Powell Area of Utah

About 75 miles northwest of the Black Mesa coal deposits is the Kaiparowits Plateau of Utah, just north of Lake Powell. See the discussion of the Resources Company project on page 123 and the map on page 127, Oil Shale and Related Fuels Report, September 1, 1966 (Vol. 3, No. 3). There have been no further announcements and no more known progress on this proposed 5,000 Mw power project and none is expected until the end of February 1967, when coal company bids for supplying fuel to the plant are opened. Actual construction of the plant will not start until about 1971. The several generators will be installed one at a time and will be ready for service over the period from 1974 to 1980. When the plant is completed, the coal requirements will be about 14.6 million tons per year. The coal beds lie from 400 feet to 1,000 feet below the top of the plateau, inferring that coal will be recovered by underground mining techniques. Ultimately, about eight mines will be in operation. The coal, after washing, is low in ash, has a heating value of about 12,000 Btu per pound, and is bituminous in rank.

## WESTERN COAL AND LIGNITE

### NEW MEXICO:

#### Coal Mines in New Mexico

The Bureau of Mines reported that there were eleven coal mines active in the State of New Mexico in 1964. On an annual basis, one produced over 500,000 tons, two produced more than 200,000 tons but less than 500,000 tons, and eight produced less than 50,000 tons.

The Navajo Mine of Utah Construction and Mining Company is located in the San Juan Basin of northwestern New Mexico near Farmington. It is the largest mine in the state and produced 2,398,000 tons of coal in 1965. A detailed description and a graphic representation of the mine are shown on the fold-out page which follows.

The coal produced is used as fuel at the adjacent Four Corners power plant owned and operated by Arizona Public Service Company. The coal is of relatively poor quality. It averages about 9,000 Btu per pound and contains 22 percent ash. But, it is mined cheaply from seams from about 20 feet to 100 feet below the surface. Coal is mined from three seams; the No. 6 which is 10 feet to 14 feet thick, the No. 7 which is about 4 feet thick, and the No. 8 which is about 8 feet thick. Coal reserves are in excess of 500,000,000 tons and even with the announced increase in mining rate to 8 1/2 million tons per year the supply should last almost 60 years.

The McKinley Mine of Pittsburg & Midway Coal Company is located at the extreme western edge of the state northwest of Gallup. In 1965, this mine produced 368,600 tons of coal. It has a potential capacity of one million tons per year.

Most of the coal produced is shipped by rail to the Cholla Plant of Arizona Public Service Company near Joseph

- DRAGLINE FOR REMOVING OVERBURDEN**
1. DUMPING HEIGHT = 125 FEET
  2. HOISTS TOTAL OF 200,000 LBS. OR 100 TONS WEIGHT EACH TIME
  3. DIAMETER OF HOIST ROPES = 2-5/8"
  4. DIAMETER OF DRAG ROPES = 3-3/8"
  5. TOTAL ELECTRICAL MOTORS = 3,200 HP - FOUR HOIST, TWO DRAG, FIVE SWING AND TWO BOOM HOIST MOTORS
  6. WALKING SPEED = 0.15 MPH OR 800 FT. P.H.
  7. TOTAL WEIGHT OF THE MACHINE = 3-1/2 MILLION LBS. OR 1,750 TONS

**THE NAVAJO MINE**

By 1970 the Navajo Mine will be the largest coal mine in the United States, producing some eight and one-half million tons of power plant fuel each year. The story of the development of this mine and a description of the mining methods required for an operation of this magnitude are briefly outlined for you on the pages here.

Utah Construction & Mining Co. October, 1966  
 2000 K.V.A. 7,200 V. MARION DRAGLINE

POWDER TRUCK  
 40-R B.E. DRILL  
 AMMONIUM NITRATE AND FUEL OIL EXPLOSIVE  
 MARION 151-M SHOVEL

History of the Navajo Mine  
 The existence of coal in the San Juan Basin of New Mexico and southern Colorado has been known for many years, and it is believed that the Indians burned it in their kivas along the San Juan River some 1,000 years ago. Yet, until recently, for the lack of a substantial market located reasonably close to this area, little interest was shown in these vast reserves.

Then, in the early 1950's, Utah Construction & Mining Co., a San Francisco based firm, known primarily for its heavy construction, mining, and land development activities, began its search for large strippable coal deposits in the western United States. Utah's efforts were then motivated by the belief that substantial reserves of steam coal could provide an attractive base for meeting the expanding electrical energy requirements of the growing Southwest. At that time the principal sources of electricity in this part of the country were thermal plants fueled by oil or natural gas, and hydro-electric units.

By 1953 Utah had obtained a permit from the Navajo Tribe to prospect for coal on the tribal lands located in the Four Corners Area of New Mexico. In the years that followed, attention was directed toward determining the extent and quality of coal within the area embraced by the prospecting permit. Other members of the Utah staff concentrated on acquiring the necessary rights for the use of waters from the nearby San Juan River for purposes of operating a thermal electric power plant in the vicinity of the coal deposits.

In 1957, the Navajo Tribe granted to Utah a mining lease covering some 24,000 acres of coal-bearing lands. This lease, which has since been increased to more than 30,000 acres, holds in excess of 750 million tons of coal which can be extracted by strip mining methods.

The year following the acquisition of the mining lease was marked by the receipt of a permit from the State of New Mexico to appropriate certain quantities of water from the San Juan River.

THE COAL WAS FORMED IN CRETACEOUS PERIOD - 95 MILLION YEARS AGO, AND IS NOW PRESERVED IN FRUITLAND FORMATION.

Armed then with abundant coal reserves, available water, and detailed economic studies, the Utah staff set out to find, among the major power companies of the Southwest, a customer for whom this energy source could be developed.

Arizona Public Service Company displayed considerable interest in a mine mouth power plant venture of the type proposed and in 1960 a coal sales agreement between the two companies was executed. Under that agreement Utah was to supply the coal needs of Arizona Public Service Company's new Four Corners Power Plant, two 175,000 kilowatt units to be constructed within a few miles of the coal lease. The term of the agreement is for 35 years and there are provisions for a 15-year extension to the term, at the option of the utility company. An additional option set forth the terms under which coal would be supplied should a decision be made to increase the size of the power plant. Arizona Public Service Company exercised a portion of this latter option in 1963 with the addition of a 225,000 kilowatt generating unit, bringing the total generating capacity of the Four Corners Power Plant to its present size of 575,000 kilowatts.

fuel deliveries to Arizona Public Service Company commenced in January of 1963 and, since the completion of the third generating unit in the summer of 1964, the power plant has required approximately two and one-half million tons of coal annually. As the contract price for the delivered coal ranks among the cheapest power plant fuels in the nation it was necessary for Utah, in order to conduct its operation on a profitable basis, to equip the Navajo Mine with the most modern high capacity earth moving and materials handling machinery available.

The co-operation of the Navajo people was received throughout the development of these resources, and since the commencement of operations the Navajo Tribe has received a royalty for each ton of coal sold. In addition, the mine has an established hiring policy which gives preference to Navajos, with the result that Navajos now comprise 60% of the present employment. Most of these men have been trained on the job, and have since advanced into positions requiring a greater degree of skill.

**SHOVEL FOR MINING COAL**

1. BOOM LENGTH = 41' @ 45° ANGLE
2. DUMPING HEIGHT = 23 FEET
3. HOIST CABLE DIA. = 1-5/8" (DOUBLE LINES)
4. TOTAL ELECTRICAL POWER = 450 HP ONE HOIST, TWO SWING AND ONE CROWD MOTOR
5. TRAVEL SPEED = 1.3 MPH
6. TOTAL WEIGHT = 472,000 LBS. OR 236 TONS

Stripping consists of removing the earth, or overburden, which overlies the coal seam. For the coal to be produced at the Navajo Mine this overburden ranges from 20 to 120 feet in depth and is composed primarily of sandstone and shales.

Generally, the stripping operation is performed in such a manner that a long strip of coal, approximately 100 feet wide, is exposed. After this coal is removed, another strip of coal, adjacent to the first, is similarly exposed and the overburden from this second strip is placed in the cavity created by the removal of the first coal strip. This process is repeated, with each cut being deeper than its predecessor, until the overburden depth finally becomes so great that it is no longer feasible to recover the coal in that area.

In the first phase of the stripping operation the overburden is blasted in order to facilitate its removal. This is accomplished by first drilling a series of 12 1/4" diameter holes from the surface, through the overburden, to the coal seam. These holes are generally spaced every 35 feet and are drilled in several rows, which are also 35 feet apart. The holes are then charged with an explosive mixture of ammonium nitrate and fuel oil which is detonated by means of a primacord network leading to a dynamite primer in the bottom of each hole.

Once the material has been fractured by the blast, a 7900 Marion walking dragline removes the overburden and casts it into the adjacent strip, from which the coal has been mined previously. This dragline, weighing almost 4 million pounds, has a 250 foot boom and a bucket which can excavate 48 cubic yards of earth with each bite. At the time of its construction, in 1962, it was the largest dragline in the world.

With the completion of the stripping operation, the mining phase, consisting of the removal of the exposed portion of the coal seam, may commence. In the current area of operations only one

coal seam is present, averaging 10' to 14' in thickness. However, in later years as mining operations proceed to the South, within the lease boundary, a number of seam branches of varied thicknesses will be encountered.

As in the case of the overburden, the coal must first be fractured by blasting. This is performed by drilling 4" diameter holes through the coal seam with a truck mounted unit which drills two such holes simultaneously. These holes are spaced every 15 feet and blasted in a manner similar to that employed in the stripping phase.

A 151 Marion power shovel, equipped with an 11 cubic yard loading bucket, then loads the fractured coal into trucks. As the power plant requires coal of a uniform quality, it is necessary to operate two of these power shovels, in areas of differing coal quality, in order to achieve the desired final product through blending.

Once the coal has been mined it must be hauled to the processing facilities, a distance of two to five miles depending upon the location of the mining operation at the time. This function is performed by a fleet of bottom-dump trucks, headed by a twin-trailer unit capable of transporting 150 tons of coal with each trip and two 120 ton single-trailer trucks.

When the trucks reach the processing facilities, located near the power plant, their loads are discharged into a 400 ton hopper. From the hopper the coal passes through a primary crushing stage and is fed into the secondary crusher by a conveyor belt. Upon leaving the second crushing stage the coal is sampled and then conveyed to a stacking unit. This unit travels back and forth continuously along a set of rails, discharging the coal into a long narrow pile. While various grades of coal constitute its construction, when the pile is completed it contains better than 30,000 tons of coal and the average grade is that required by the power plant. At the processing plant there are four such blending piles, and while one pile is in the building stage, a pile which was previously built in one of the other three piles is picked up and delivered to the power plant by a reclaimer. The reclaimer unit, which picks up the coal, is a conveyor that it mixes the coals

of various grades which were placed in the pile. This assures the delivery of a product of uniform quality.

**The Years Ahead**

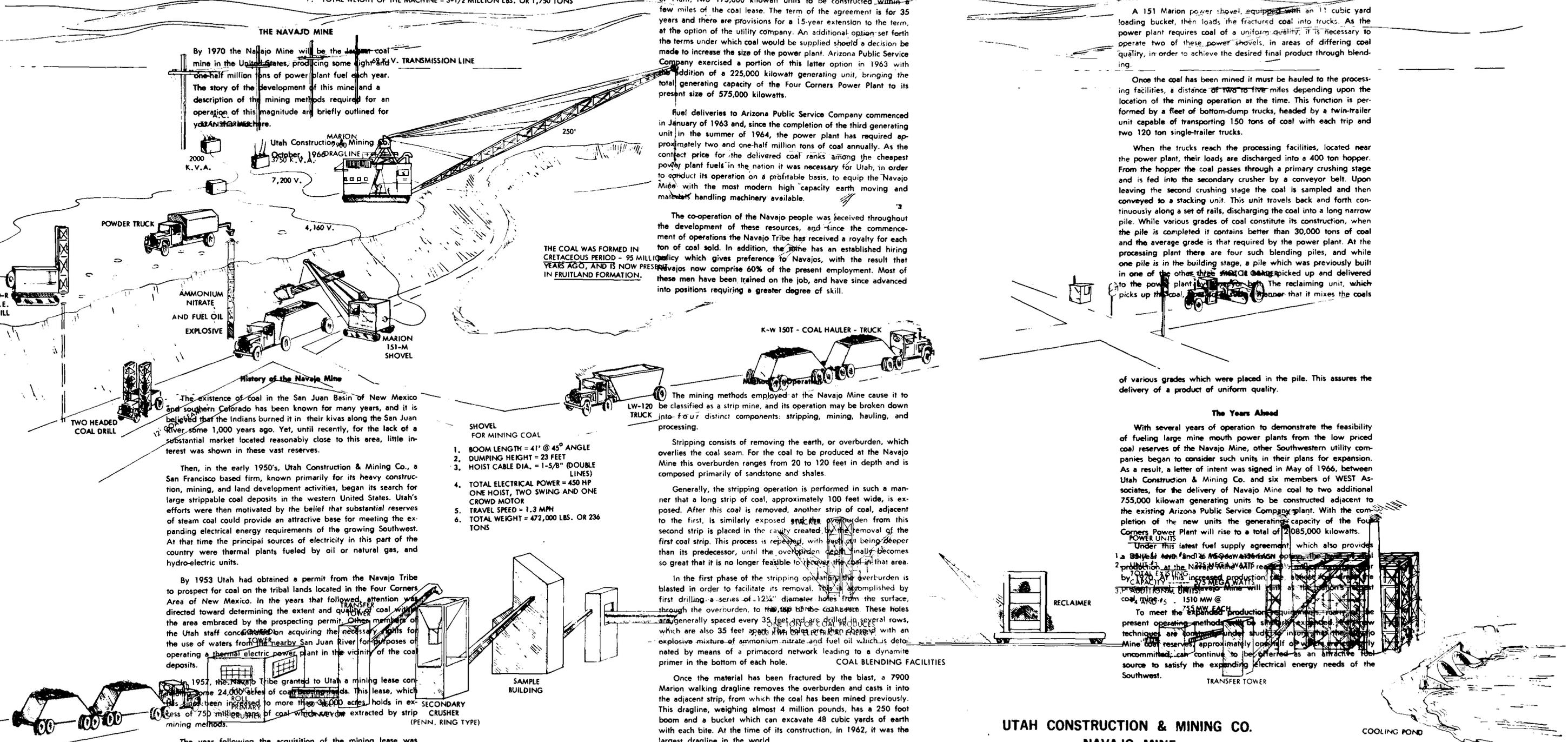
With several years of operation to demonstrate the feasibility of fueling large mine mouth power plants from the low priced coal reserves of the Navajo Mine, other Southwestern utility companies began to consider such units in their plans for expansion. As a result, a letter of intent was signed in May of 1966, between Utah Construction & Mining Co. and six members of WEST Associates, for the delivery of Navajo Mine coal to two additional 755,000 kilowatt generating units to be constructed adjacent to the existing Arizona Public Service Company plant. With the completion of the new units the generating capacity of the Four Corners Power Plant will rise to a total of 2,085,000 kilowatts.

Under this latest fuel supply agreement, which also provides for a 15% increase in production at the Navajo Mine, the total capacity of the Four Corners Power Plant will be increased to 2,085,000 kilowatts. The new units will consist of two 755,000 kilowatt units and two 575,000 kilowatt units. The total capacity of the Four Corners Power Plant will be 2,085,000 kilowatts.

To meet the expanded production requirements, the present operating methods will be studied and new techniques are being developed. Studies are being conducted to determine if the Navajo Mine coal reserves, approximately one-half of which are currently uncommitted, can continue to be offered as an attractive fuel source to satisfy the expanding electrical energy needs of the Southwest.

**UTAH CONSTRUCTION & MINING CO. NAVAJO MINE FRUITLAND, NEW MEXICO, U.S.A.**

THIS IS LARGEST OPEN PIT COAL MINE IN THE WEST PRODUCING 2-1/2 MILLION TONS OF COAL PER YEAR. BY 1970 THIS MINE BECOMES THE LARGEST COAL MINE IN THE NATION WHEN 8-1/2 MILLION TONS OF COAL WILL BE MINED ANNUALLY.







### Coal Mines in New Mexico (continued)

City, Arizona, about 100 miles distant. Mining equipment includes a stripping shovel, loading shovel, two bulldozers, seven haulage units and an overburden drill. The coal has a heating value about 10,300 Btu. The coal producing area is leased from the Bureau of Land Management (see map on the next page) and from the Santa Fe Railroad. Reserves, at the present rate of production, are sufficient to last 50 years.

The Kaiser Steel Corporation has been operating a mine near Raton. The mine has a capacity of 2,000 tons per day of bituminous coal. It is a drift (underground) mine and employs six continuous mining machines, ten shuttle cars, 11 locomotives and 94 steel mine cars. In September, 1966, the new York Canyon Mine was opened and dedicated. It will furnish metallurgical grade coal to the Kaiser Steel plant at Fontana, California. Santa Fe built 37 miles of new spur line to connect the mine to the main line and is operating a 84-car unit train over the 1,100 miles from the mine to the plant. Special facilities provide for loading the unit train with 100 tons of coal in each car in about two hours.

### Coal Land Ownership Map Presented

The recent activity for coal lands in New Mexico has been in the San Juan Basin in the northwestern portion of the state. Kaiser has opened a large mine near Raton, but this was to obtain coking coal rather than fuel coal and it is the exception. The two major mines in the San Juan Basin are the Navajo Mine and the McKinley Mine. They have been discussed above.

The map, Coal Leases and Permits on Public and Indian Lands, NW New Mexico, is presented on page 129. The outcropping of the Fruitland coal seams is marked by leases and permits by Public Service Company, Utah Construction and Mining Company, El Paso Natural Gas Company, Public Service Company, Mitchell, Faust, United Electric Coal Companies, and Consolidation Coal Company. The deeper

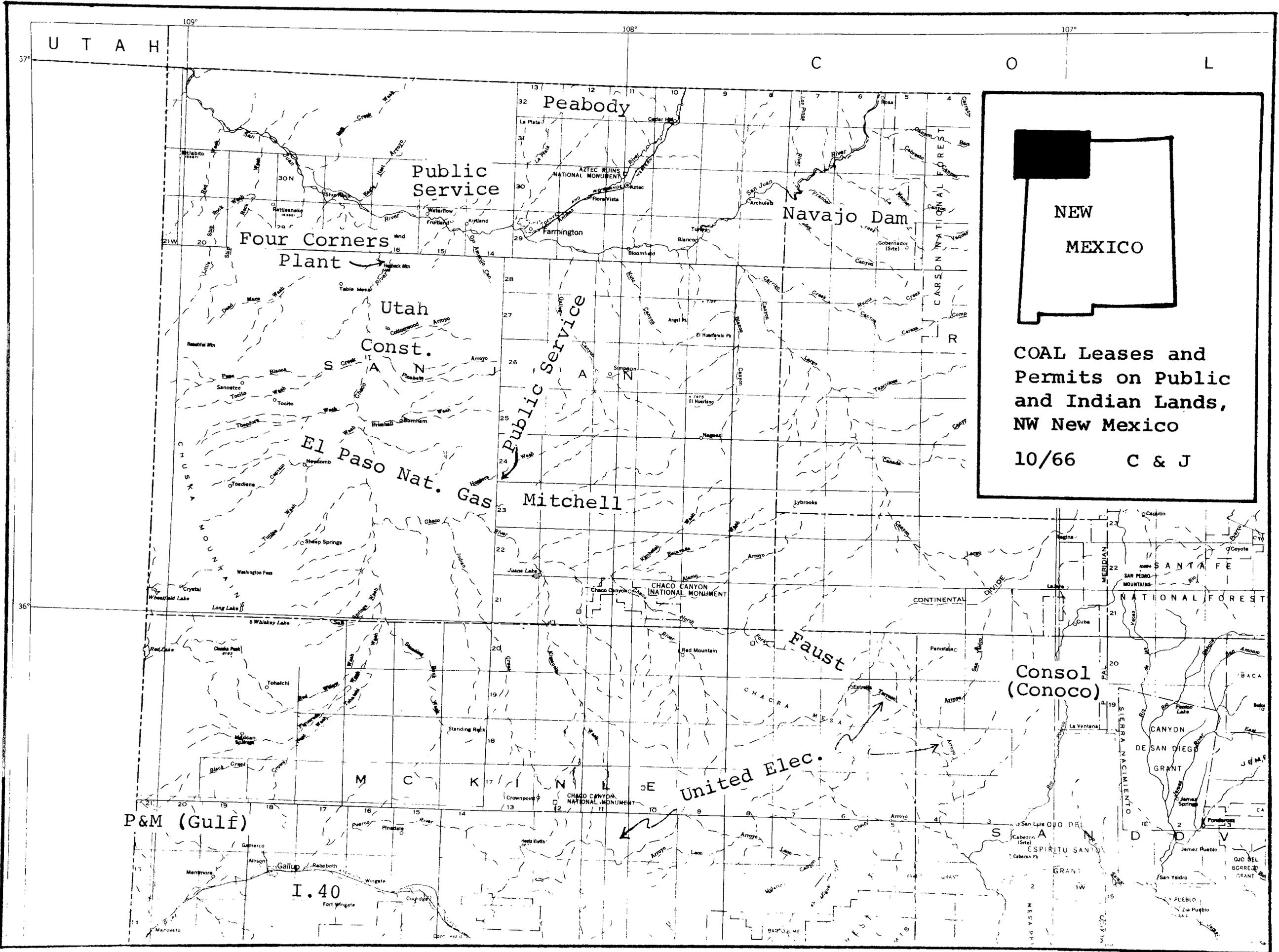
Coal Land Ownership Map Presented (continued)

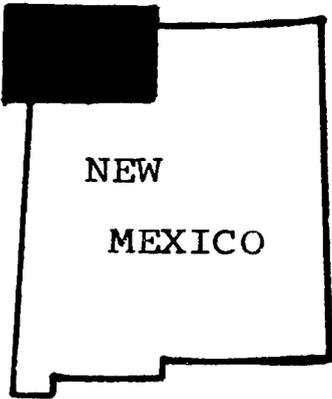
coal beds of the Mesa Verde outcrop further from the center of the basin and are marked by leases of Peabody Coal Company on the north and Pittsburg & Midway and United Electric Coal Companies on the south. Navajo dam and reservoir are shown near the top of the map. This reservoir is the principal source of water available for future plant development in this area. Leases on private lands are not indicated except those on the Navajo Indian reservation, and those are approximated. In the following paragraphs, the coal land holdings will be discussed in detail, beginning with the Fruitland holdings, followed by the Mesa Verde.

Public Service Company of New Mexico has leases on about 440 acres of State coal lands in T.24N, R13W. and T.30N, R15W. It has leases totalling 10,930 acres of Federal lands, mostly in T.30N, R.15W. The exact location of some of these leases was not available when the map was prepared. These actions were taken between late 1961 and late 1963. The total area covered by these leases and permits is 12,720 acres. It is presumed that sufficient coal reserves are included in these leases and permits to fuel a 1,000 Mw power plant Public Service has referenced in requests to the Bureau of Reclamation for water rights.

Utah Construction and Mining Company holds a lease on about 24,000 acres of coal land on the Navajo Indian reservation and reputedly has asked for a lease on an additional 16,000 acres. The location of their leases is approximated on the ownership map. The Navajo Mine, owned and operated by Utah, is working the northern part of the lease in the vicinity of the Four Corners power plant.

El Paso Natural Gas Company obtained a lease from the Navajo Indians on coal lands south of Utah's lease in about 1962. This year, with the lease about to expire, El Paso and Consolidation Coal Company jointly requested a lease on the area formerly held plus some additional area. Apparently, this coal would be used to





NEW  
MEXICO

COAL Leases and  
Permits on Public  
and Indian Lands,  
NW New Mexico

10/66      C & J

129

Coal Land Ownership Map Presented (continued)

fuel a power plant with a capacity of 1,500 Mw, as mentioned in the joint request by the two companies to the Interior Department for water from the Navajo Reservoir. With Consolidation Coal joining El Paso, there is speculation that fluid fuels might be extracted from the coal before it is burned in a power plant. At this writing, the possibility of renewing El Paso's lease with the Navajo Tribe is obscure. At least one member of the Tribe stated unofficially that he thought El Paso had forfeited its privilege of renewing its lease and that the Tribe might auction off the coal land in the same way as they do oil land.

Public Service Company of New Mexico applied for a coal exploration permit just east of the Navajo Reservation on May 10, 1966. The area involved is T.23N, R12W, sections 6 and 7, covering 1,350 acres.

Mr. Hugh J. Mitchell, of Farmington, N. M., has applied for coal exploration permits on state sections totalling 6,040 acres and three sections of federal land totalling 1,920 acres. Mitchell's applications follow the coal outcrops generally eastward from the Navajo Reservation. All of the applications were made during the period July through September, 1966. The scattered areas seem to indicate that the applicant is speculating.

Paul F. Faust, 2806 South St. Paul St., Denver, Colorado, has applied for coal exploration permits on 2,240 acres of state land and 19,828 acres of federal land east of Chaco Canyon National Monument. The applications were filed during the period from February to July, 1966. The applicant declined to comment on the possible use for the coal. He was formerly a land man with Pan-American Oil Company but claims he is now an independent agent.

United Electric Coal Companies obtained coal leases on 641 acres of state land in 1965 and applied for coal exploration permits covering 20,880 acres of federal land in September, 1966. These actions involve land in T.19N, R3W, 4W, 5W, and 6W.



Coal Land Ownership Map Presented (continued)

Consolidation Coal Company, now a subsidiary of Continental Oil Company, has applied for coal exploration permits on 6,808 acres of federal land and has bought 2,206 acres of coal leases on federal land south of Cuba. The actions were taken in 1964 and 1965. The leases were purchased at \$2.05 an acre.

Mesa Verde coal has been mined on a relatively small scale in the Gallup area for many years. Pittsburg & Midway Coal Company, a subsidiary of Gulf Oil Company, started large-scale mining at their McKinley Mine in 1962. The mine is about 20 miles northwest of Gallup on coal lands leased from the Santa Fe Pacific Railroad Company and from the Federal Government. These lands are part of the Checkerboard area resulting from the Government giving alternate sections to the railroad as an inducement to build in the nineteenth century. Only the federal lands are shown on the map. Santa Fe did not furnish exact locations of their lease agreements with Gulf, but stated that they were in T.16N, R20W and 21W. The federal leases total 8,995 acres and were obtained in 1964. Over 5,000 acres of this was obtained by assignment, perhaps from Spencer Chemical Company, Pittsburg & Midway's associate before both were absorbed by Gulf.

United Electric Coal Companies bought coal exploration permits on 5,967 acres of federal lands near the Mesa Verde outcropping from William E. Roope (their agent?) in January 1966. The resemblance of checkerboarding is noticeable in the area covered by the permits, but Santa Fe Pacific states that they have granted no permits or leases to United Electric.

Sentry Royalty Company, a subsidiary of Peabody Coal Company, obtained a lease on 2,044 acres of federal land at the northern border of the state in 1963. The coal reserves contained in this area probably could fuel a power plant if the Animas-La Plata Project is built to supply the necessary cooling water.

Water for Industrial Development in Northwestern New Mexico

The water supply for northwestern New Mexico is, simply, the San Juan River. And, for all practical purposes, all of the water in the San Juan River has been allocated. For industrial purposes, some water is available for "short term" use. This means from now until about the year 2005. Until that date, it is thought that other states will allow sufficient water to flow to Lee's Ferry, Arizona, to satisfy the Upper Colorado River Compact, and the San Juan River contribution can be short of its legal share without harm. Secretary Udall of the Interior Department has said, informally, that 200,000 acre-feet per year may be diverted and 100,000 acre-feet per year depleted during the next forty years. This water would come, at least in effect, from the Navajo Reservoir. Water applications filed for this "short term" water include the following:

<u>Company</u>	<u>Purpose</u>	<u>Diversion AF/yr</u>	<u>Depletion AF/yr</u>
Utah Construction & Mining Company	Power	48,000	43,000
El Paso Gas-Consolidation Coal	Power	30,000	27,000
Humble Oil & Refining Company	Water-flood	25,000	15,000
Public Service Co. of New Mexico	Power	22,000	20,000
Southern Union Gas Company	Plant cooling	50	50
		<hr/>	<hr/>
		125,050	105,050

Utah seems to have sufficient water for the Four Corners Power Plant even after its present expansion to 2,025 Mw is completed. A further expansion of perhaps 2,000 Mw appears to be the purpose behind the current request. El Paso Natural Gas-Consolidation Coal Company has requested sufficient water for a 1,500 Mw power



Water for Industrial Development in Northwestern New Mexico (continued)

plant and Public Service Company of New Mexico has requested enough for a 1,000 Mw plant. Humble's request for water stated that the water would be used for recovery of oil by water-flooding.

The Navajo Indian Tribe has an allocation of 508,000 acre-feet per year from Navajo Reservoir. Apparently, Secretary Udall appointed a task force on March 4, 1966, to evaluate the ultimate use of this water. It is earmarked for irrigation only, and there is the possibility that some of the water could be more beneficially used for industrial purposes. There appears to be concern that the vast coal deposits on the Navajo Reservation cannot be completely utilized in the remaining period before nuclear fuel supersedes coal unless Navajo water is made available. The task force has submitted a report which states:

"6,975 megawatts of existing, scheduled and tentatively planned generating capacity" (in mine-mouth steam plants in the area) "will, if constructed, use an estimated 28 - 30 million tons of coal annually."

"---an additional generating capacity of about 1,275 Mw increasing the total to 8,250 Mw would be desirable. Generating capacity of this magnitude operating at an annual load factor of 90 percent would consume approximately 36 million tons of coal per year. This rate of use would exhaust the known economical reserves in about 40 years."

"Since full development of the irrigation project will likely be spread out over a rather long period of time," (it is recommended that the) "temporary assignment of 26,000 acre-feet of water by the Indians for this use would be both desirable and beneficial for the Tribe."

Water for Industrial Development in Northwestern New Mexico (continued)

The task force report concluded that "development of a large percentage of this capacity" (required by W E.S.T.) "in the Four Corners area is entirely logical and likely, provided construction in this area remains competitive with alternative sites and sufficient water available."

The Navajo Tribal Council went on record April 27, 1966, opposing any re-evaluation of the Navajo Project by a vote of 58 - 0. The resolution stated, among other things, "No use in New Mexico of water of the San Juan River (a tributary of the Colorado River) not heretofore authorized (should) be given priority ahead of the Navajo irrigation project."

UTAH:

Coal Land Activities Continue Brisk

Recent applications for coal exploration permits and leases on public lands include: Mid-Western Minerals, Inc., assignment of permits and extensions to June, 1967 on 25,542 acres in Kane County just east of Atlantic's major holdings on the Kaiparowits Plateau; Utah Construction and Mining Co., a state lease issued on 160 acres, a Federal lease purchased on 560 acres for \$3.50 per acre, and a Federal permit applied for on 560 acres, all in Kane County in the Pink Cliffs area; Heiner Coal Co., purchased a Federal lease on 2,212 acres for \$3.00 per acre in Carbon County; Otto G. Green, a coal permit issued on 4,480 acres in Kane County; Independent Coal and Coke Co., bought a Federal lease on 1,240 acres in Carbon County; United States Fuel Co., applied for a Federal coal lease on 2,560 acres in Emery and Carbon Counties; Alan C. F. Dille', Federal permit issued on 12,750 acres in Kane County, and, Consolidation Coal Co., a subsidiary of Conoco, bought state leases from Kemerer Coal Co. covering 4,464 acres in Emery and Sevier Counties.



COLORADO:

U. S. Supreme Court Denies Colorado-Ute Appeal

The Hayden plant of the Colorado-Ute Electric Association continues to operate, but the facility has been declared illegally built. This generating plant, in northwestern Colorado, was built under the authorization of the Colorado Public Utilities Commission. However, the Colorado Supreme Court found, in February, 1966, that the authorizing certificate was not legal. The U. S. Supreme Court, on October 24, 1966, denied hearing an appeal, and substantiated the Colorado court's finding. The plant will probably continue to operate during further litigation. Legislation will be introduced at the next session of the Colorado legislature to correct the legal tangle.

Land Activity is Modest

Recent applications for coal exploration permits and for leases on public lands include: Western Nuclear, Inc., 1,920 acres, state lease issued in Moffat County; Page T. Jenkins, permit issued for 5,104 acres in Elbert County; Grassy Creek Coal Co., state lease by assignment from Contract Engineering, 1,872 acres in Routt County; Kemmerer Coal Co. bought Federal coal lease at \$1.00 per acre, 1,707 acres in Jackson County; James C. Goodwin, Federal permit issued on 8,666 acres in Rio Blanco County; Sentry Royalty Co. (Peabody), state coal lease issued, for 6,450 acres in LaPlata County; Gerald T. Tresner, Federal permit issued, for 14,729 acres in Garfield and Mesa Counties.

WYOMING:

Northeastern Wyoming is Scene of Coal Land Activity

Most of the recent coal land activity in Wyoming has been in Campbell, Sheridan, and Converse Counties in the northeastern part of the state. Activities covered almost 27,000 acres in Campbell County, over 16,000 acres in Converse County, and about 22,000 acres in Sheridan County.

Some of the names involved in the transactions are noteworthy. In Campbell County, Texaco, Inc. applied for a coal exploration permit on 5,122 acres in Township 51N, Range 72W. Sun Oil Company was an unsuccessful bidder for a coal lease on 5,884 acres in Campbell County. Also unsuccessful bidders for this lease were Sentry Royalty (Peabody), T. C. Woodward and Pacific Power and Light. This area, in Townships 42N and 43N, Range 70W, went to Paul Faust for the relatively high price of \$31.33 per acre.

Just south of the Faust lease area, Sentry Royalty (Peabody) bought two lease parcels totalling 11,141 acres for \$30.05 an acre. Unsuccessful bidders were PP & L and Woodward.

In Converse County, southeast of the above Sentry Royalty lease, Pacific Power and Light bought a lease on 2,908 acres for \$1.17 per acre. There were no other bidders.

Between the Sentry Royalty lease and the Pacific Power and Light lease, James R. Learned picked up a total of 1,879 acres in two leases for \$2.00 an acre.

All of the above were the result of an auction for Federal coal leases held September 27, 1966, and are on lands about 50 to 60 miles south of Gillette.

Sentry Royalty applied for a coal exploration permit in Converse County on 11,680 acres about ten miles southeast of their above-mentioned lease. This action



Northeastern Wyoming is Scene of Coal Land Activity  
(continued)

was dated August 17, 1966. They have a coal exploration permit further north in Campbell County on 5,060 acres about 8 miles north of Wyodak.

Texaco's application for a coal exploration permit is for land almost adjacent to the Sentry Royalty land north of Wyodak.

H. B. Renfro applied for a lease on 22,440 acres straddling the Powder River about 15 miles from the northern border of the state.

Frank M. Gallivan was issued state leases on parts or all of scattered state sections at the eastern edge of Campbell County northwest of Moorcroft. A total of 13,145 acres were involved in 22 separate leases.

Page Jenkins of Casper, Wyoming, applied for coal prospecting permits on 25,373 acres in Campbell and Johnson Counties.

In October, Fred Blume of Cheyenne, Wyoming, was issued state coal leases on 4,481 acres in Sweetwater County.

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# **APPENDIX**



"ECONOMICS OF OIL SHALE"

by

Irvin Nielsen

Wolf Ridge Minerals Corporation  
Glenwood Springs, Colorado

Presentation to the  
16th Annual Meeting

of the

Rocky Mountain Section

of the

American Association of Petroleum Geologists

Denver, Colorado

October 24, 1966

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The "Beyond the Borehole" theme of this meeting is especially appropriate for a discussion of oil shale economics. Those who have studied the subject are in general agreement that shale oil can be produced for less than \$2.10 per barrel, at a profit, if optimum conditions of land, operator, process, market, and tax treatment can be incorporated. The proposed nuclear-in-situ process may reduce costs of shale oil to the cheapest fuel available in the United States. And, a recent discovery of saline minerals promises to make the rock an ore of aluminum and a host of chemicals.

Those interested in oil shale should carefully consider these new concepts. An illustration of the time required for a new idea to be tested and developed to a point where it had a considerable impact on the energy market is found in nuclear power. Just nine years after the first plant was built, 60% of all new power plants planned are nuclear.

The subject of the "economics of oil shale" is complex. The fundamental process is simply to heat oil shale rock to 500°C, capture the retorted vapors and condense them to liquid oil. Two basic methods are proposed to accomplish this feat. The most thoroughly researched and most advocated is to mine and crush the shale, pass it through a retort and dispose of the ash. The other method is in-place or in-situ retorting, where the rock is heated in the ground and the oil drawn off of the retorting mass of shale. The complexities result from the possible number of combinations of the variables. In a conventional mining-retorting system, some of the variables are: the choice of deposit; the interval within the deposit; the location of the mine site; the ownership; the royalties; the mining method; the operator; the retorting method; the ash disposal system; the market for the oil; the stability of imports, etc. An evaluation of the in-situ system, with its numerous variables, is equally difficult to analyze. No matter which system is used, the process must produce a barrel of oil for about \$1.75, and each ton of rock must be heated to 500°C to yield a maximum of 38 gallons of oil.

This paper will attempt to show some of the combinations of variables tried in Colorado in recent years, to show some of the proposed processes, and to summarize the resulting economic data that have been published. You should realize, however, that an accurate estimate of the economics of producing shale oil from a particular site would require expensive and exhaustive studies.

### GEOLOGY OF THE DEPOSITS

The deposits are located between the Colorado and White Rivers and between the Grand Hogback and the Douglas Arch. The area is drained by Piceance, Yellow, Parachute and Roan Creeks as shown on Figure 1.

During the middle Eocene epoch, an arm of Lake Uintah existed in this area. In it were deposited a sequence of sand, shale, oil shale and evaporites in a general transgressive and regressive cycle, with intermediate cycles as shown on Figure 2.

We have recently learned that the oil shales of the epi-center of the basin contain beds and concentrations of evaporites. This sub-unit is akin to the saline sections of Utah and Wyoming and deserves study and classification as a distinct stratigraphic unit. The saline zone can generally be divided into a total rich oil shale zone with sub-units. These sub-units, starting from the base, are rich in nahcolite, dawsonite, nahcolite, halite, richest oil shale, halite, and finally a bed of nahcolite. Above the saline zone is a 450-foot-thick section of highly-fractured medium-grade shale. Then there is the Mahogany Ledge, which is rich in oil shale, and which contains some dawsonite. The strata above the Mahogany Ledge contains a high concentration of analcitized volcanic ash. The highest concentration of saline materials occurs in an area coincident with the areal extent of the two salt beds shown on Figure 3.

Until recently, the only sequence of oil shale considered important from a business standpoint was the "Mahogany Ledge". This is a sequence of rich oil shale varying from 50 to 100 feet thick and averaging from about 20 to 33 gallons of oil per ton for the total section as shown on Figure 4. It is possible to select sections of 30 feet or so that average up to 40 gallons per ton.

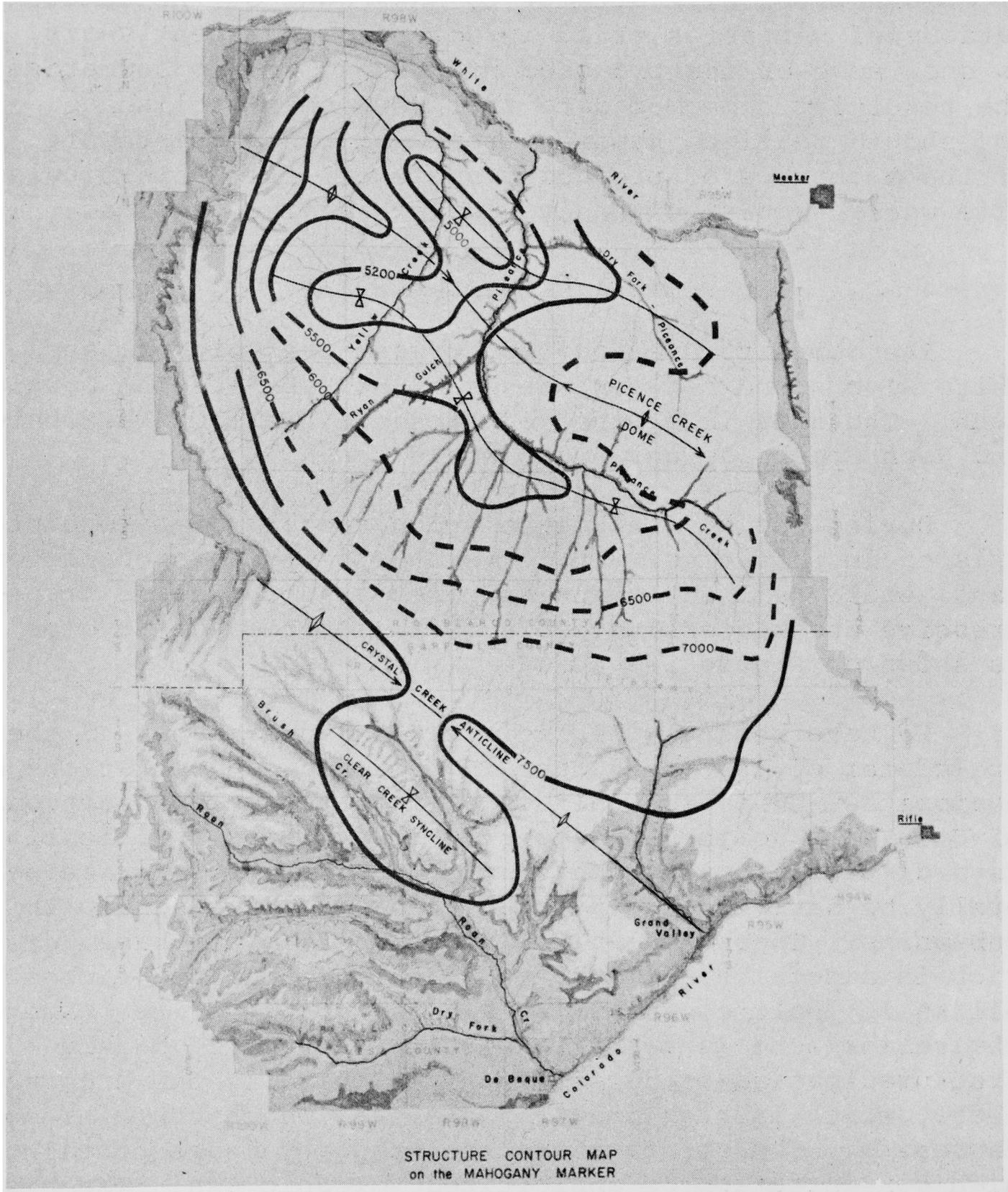


Figure 1

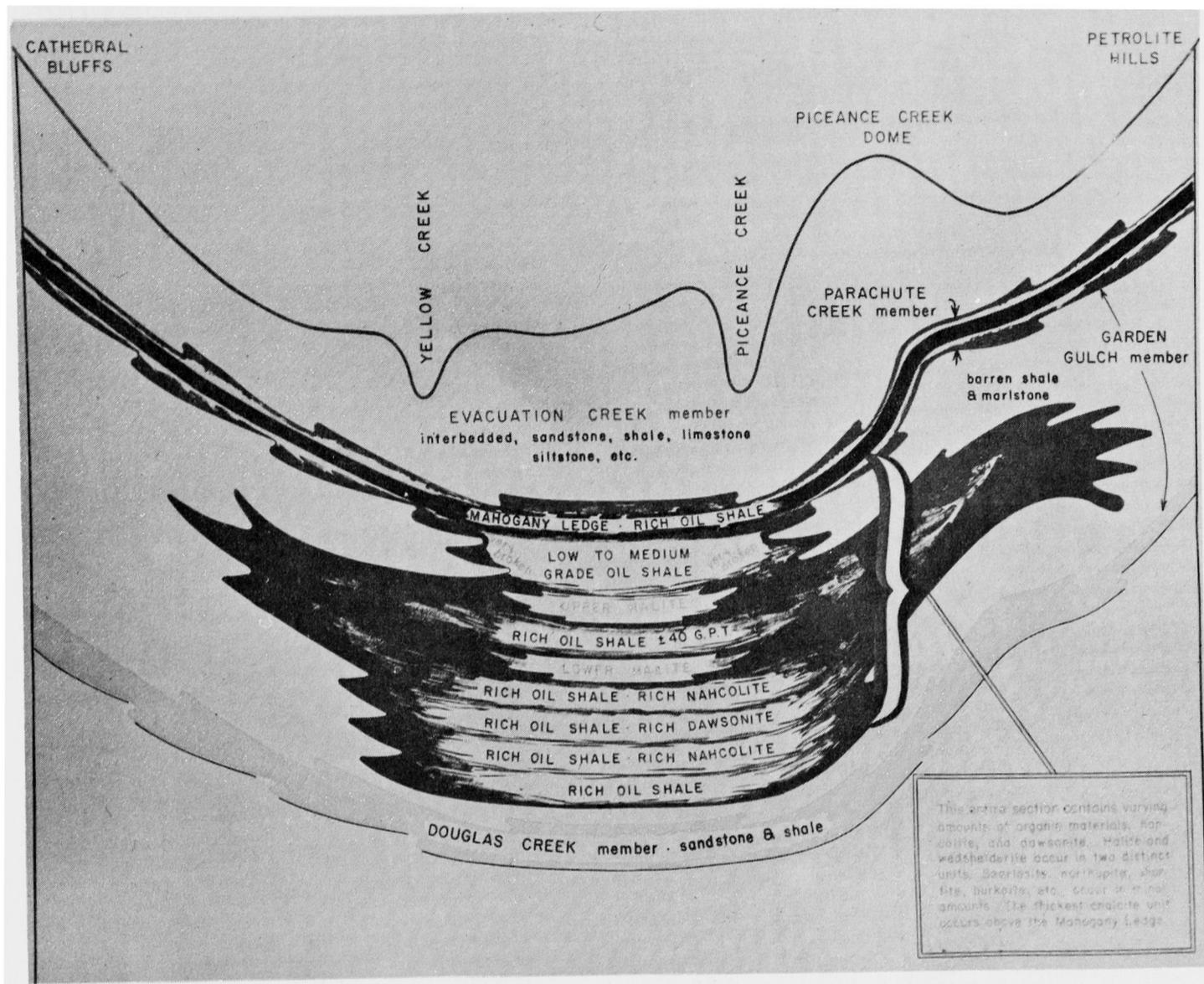


Figure 2

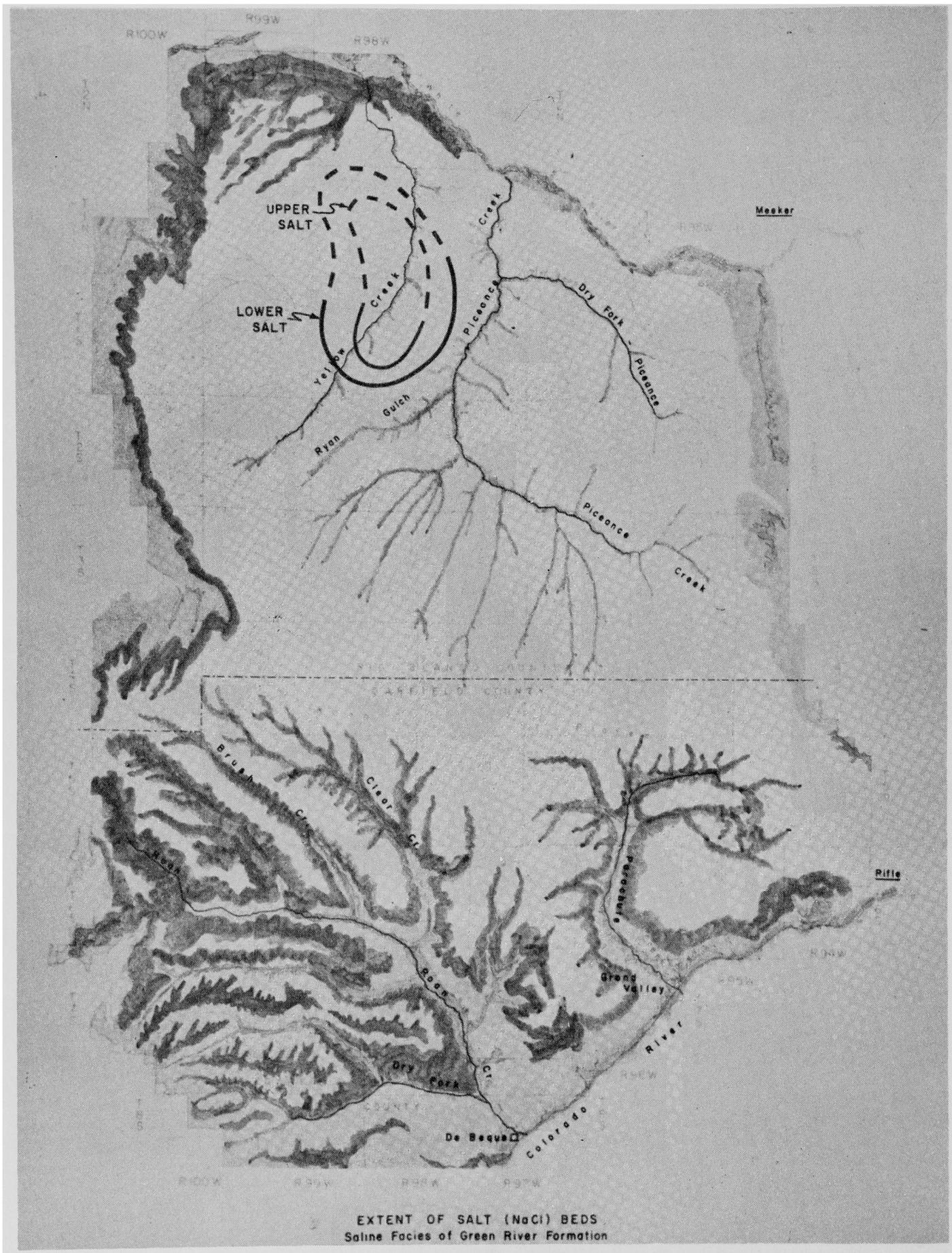


Figure 3

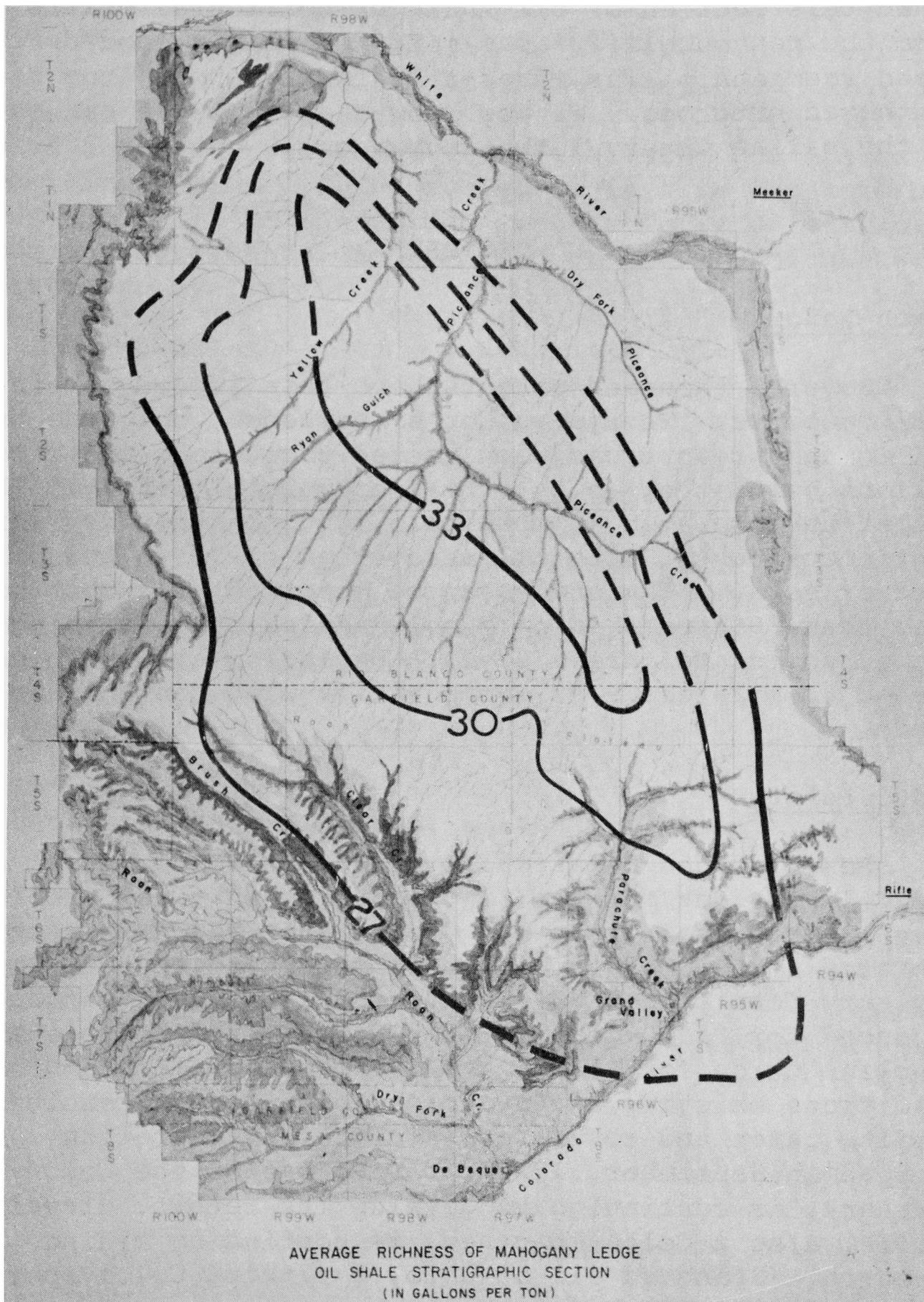


Figure 4

Union Oil, Colony, and the Anvil Points project have all mined this section of oil shale by horizontal drifts from the canyon cliff faces into the strata, and developed room and pillar mines at safe distances from the weathered outcrops. We now know that there is one section in the saline interval that averages 39 gpt for 200 feet.

## RETORTS

### Union Retort

Several thousand patents have been issued on oil shale retorts. To the author's knowledge, only the Union Oil Company retort has been tested adequately under conditions simulating an on-stream commercial retort. The retort has operated at more than 1000 tons per day for continuous tests, with oil recoveries of 75 to 80% of Fischer assay. The shale can be retorted at a cost of less than 30¢/ton. Union's only admission concerning the economics is that a 27-1/2% depletion allowance is needed to make shale oil competitive with conventional crude.

### TOSCO Retort

Research has been conducted on the TOSCO retort at the Colony Plant for the last year. Mechanical problems have plagued the retort and it has just recently been operated. TOSCO stated in their report to the Oil Shale Advisory Committee (1964) that crude shale oil can be produced for \$1.10 to \$1.15 per barrel, and hydrogenated pipeline curde for \$1.25 to \$1.30 per barrel, based on conditions existing at the Colony plant lands, excluding profit, taxes and royalties. The Colony operation stopped in September, 1966. TOSCO, one of the Colony partners, is continuing to develop its retort. Cleveland Cliffs, also a Colony partner, is continuing mining research. Standard Oil of Ohio, the third Colony partner, is inactive in the Colony venture.

## Anvil Points Project

The six companies doing joint research on mining and retorting at Anvil Points have completed their Phase I tests of the pilot-scale gas combustion retorts and have entered Phase II of their announced test program, wherein retorts will be scaled up in size and some mining research will be conducted. Because of the interlocking company agreements, none of the data concerning these tests are available.

## C&J-Petrosix

Cameron (65) outlined the principles and economics of the C&J-Petrosix retort, designed and tested on a pilot plant scale. Cameron's projected cost for an oil shale retorting facility are \$225 per daily ton capacity, and his operating cost is 15¢ per ton of throughput. The latter figure excludes royalties, taxes or allocated administrative expense. For our purposes, Cameron's operating cost figure is adjusted to 25¢ per ton to cover the latter costs.

## SITE PREPARATION, ACCESS, AND UTILITIES

Each proposed shale operation must allow some amount of money for site preparation, access and utilities. The amounts can vary widely because of location, type of process, etc. Although no accurate estimate of these costs can be made without knowing the site and process, a figure of \$100 per daily barrel is allocated to site preparation.

## MINING

### Room and Pillar Mining

The U. S. Bureau of Mines, Union Oil Company and Colony Development Company have experimented with "room and pillar" mining. The Bureau of Mines estimated

operating mining costs to be \$0.4263 per ton of crushed shale delivered to the retort. Capital investment for the mine will be \$250/ton. More recent experience by Union Oil Company, and by Cleveland Cliffs Iron Mining Company at the Colony Plant, proved that the U. S. Bureau of Mines' operating costs were reasonable and are reasonable today. The newer higher capacity equipment and other mining advances have offset inflation. East's figure is raised 16 cents per ton to 58 cents per ton to cover ad valorem taxes, depreciation, administrative overhead, and interest.

### Open Pit Mining

East (1964) and Ertl (1965) visualized a magnificent open pit to exploit the 2,000 foot thick section of rich oil shale in the depositional center of the basin. At one stage in development, Ertl's open pit characteristics would be:

1. 1.3 billion cubic yards overburden, removed at 25 cents per yard for a total cost of \$325 million.
2. 3.1 billion tons of "ore", mined at 25 cents per ton, for a total of \$775 million.
3. Cost of 3.1 billion tons would be \$1.1 billion or 35 cents per ton.

The Ertl concept is basically a mental exercise to see how the deep deposits might be mined. The exercise becomes much more plausible when one considers that products other than shale oil would be produced. Ertl showed that 1.8 billion barrels of oil, worth about 3.25 billion dollars, would be produced by this method, at 60 cents per barrel cost for mining and waste disposal. If we add to that the adjusted Cameron (65) retorting costs of about 25 cents per ton of shale feed, and assume that two tons of shale are necessary to yield one barrel of oil, then the open pit oil would cost \$1.10 per barrel. If located in one area, the retort waste from the lower 800 foot section of this mine would yield 136 million tons of soda ash and 44 million tons of alumina, and would

multiply the gross value of products by three times, based on today's prices for these commodities. The economics of this concept warrants a much more detailed analysis.

### Ash Disposal

The retort ash can be stacked or disposed of for less than five cents per ton, assuming that the ash is similar to that produced by the Union Oil Company.

### In-Situ Field Tests

Mobil, Equity, Sinclair, Humble and Shell have all conducted field tests directed toward in-situ retorting of oil shale. Equity Oil Company seems to have had the greatest success and is currently retorting shale by circulating 1000°F methane at about 1000 psi through a five-spot drill hole configuration. The hot gas travels from the in-put hole, or holes, along fractures to the exhaust holes. The other companies' projects were similar, but apparently were not as successful as Equity's project has been.

### NUCLEAR BLAST - IN-SITU RETORT PROPOSAL

The Atomic Energy Commission, the U. S. Bureau of Mines, CER Geonuclear and 20 oil companies are advocating the use of nuclear explosives to create a volume of fragmented and permeable oil shale in the deep thick deposits of Colorado. The volume of shale would then be retorted by in-situ methods. The method, according to Lekas (65 & 66), will utilize 3,000 cu. ft. of air (at 50 psi) per ton of shale. The retorting advance would be 2 feet per day, and the recovery is estimated at 75%. The Bureau of Mines is conducting retorting tests on large fragments of shale at Laramie. Data for the air volume, pressure, advance rates and the recovery factors were derived from that plant. However, scaling up these pilot plant test data for application in an in-situ retort having a number of acres in cross-sectional area, instead of the 5 foot diameter retort used in the pilot plant, will cause some problems. Those that are most obvious are:

1. Channeling, which may occur in the retorting zone, so that only a part of the chamber will be retorted.
2. Oil shale is several times more elastic than similar rock types and consequently may not fragment to form underground crushed rock chimneys as expected.
3. Although the shale is considered impervious, gas and water are found in the section where the first blast is proposed. It may not be possible to retort the chimney if it floods with water.
4. A 400-foot zone of shale is already fractured by nature and is a notorious "lost circulation" zone. What will happen if the blast breaks into that zone?
5. How will the other valuable minerals be recovered?

Despite the obvious problems that may be associated with nuclear in-situ projects, one must admit that if responsible men say shale oil can be produced for 29 cents per barrel, then research must be conducted to test the theory. Oil at this price would be equated to 5 cents per million Btu, 20 to 25% of today's cost.

The economics of open pit mining of shales in the center of the basin have not been adequately examined, but should be, in light of the other mineral discoveries. Similarly, the nuclear blast may offer the breakthrough necessary to create permeability for in-situ (and cheap) shale oil production. Projected costs are wildly speculative, but should be researched to determine if they are anywhere near correct.

SUMMARY OF SHALE OIL PRODUCING COSTS

Assumptions:

1. Conventional Room and Pillar Mine
2. Shale Assay 38 gpt.
3. Overall Recovery 85%
4. Adjusted costs include taxes, interest, depreciation and administrative overhead
5. 50,000 B/D capacity
6. No royalties are included, and no credits for coke and LPG are taken

Costs:

	<u>Adjusted</u>	<u>Cost/Barrel</u>
A. Mining (East 42¢/T)	58¢/T	\$0.804
B. Retorting (Cameron 15¢/T)	25¢/T	0.325
C. Ash Disposal (Est. 5¢/T)		0.065
D. Plant Site (Est Int. & deprec.)		0.030
E. Hydrogenation		0.750
F. Pipeline Chgs. (Common Carrier)		<u>0.500</u>
	Delivered Cost	\$2.474

Profit:

	<u>High</u>	<u>Low</u>
A. Value at Market	\$3.75/B	\$3.25/B
B. Delivered Cost	<u>2.47/B</u>	<u>2.47/B</u>
C. Net Profit	\$1.28/B	\$0.78/B
D. Percent of Sales	34%	24%
E. Percent on Investment	26.7%	16.3%

CAPITAL INVESTMENT

(Shale Oil Plant in Dollars per Daily Barrel)

A. Mining	\$325/DB
B. Retorting	293/DB
C. Ash Disposal (Est.)	32/DB
D. Plant Site and Utilities (Est.)	100/DB
E. Hydrogenation	1,000/DB
F. Pipeline (by Common Carrier)	---
	<hr/>
Total	\$1,750/DB

Conclusion:

A 50,000 B/D plant will cost \$87.5 million assuming optimum conditions can be incorporated.

## TAXES

A depletion allowance of 15% is now given on oil shale rock. Therefore, the depletion allowance is negligible. Since the depletion allowance cannot be greater than one-half of the net profit, a 15% depletion on the crude shale oil could be fully utilized if the profit were 30% of total income. A company would have to produce shale oil for \$0.79 per barrel to get the maximum benefit of a 27-1/2% depletion.

## SODIUM MINERALS

The deposits of sodium minerals in the Piceance Creek basin must seem to be a grand design to the few chemical engineers who have had the opportunity to study them. In one particular area, the minerals nahcolite, ( $\text{NaHCO}_3$ ) and dawsonite, ( $\text{NaAlCO}_3(\text{OH})_2$ ), occur intermingled in oil shale. The conditions of association of organic material, nahcolite and dawsonite are such that it is necessary to heat the rock to  $500^\circ\text{C}$  to:

1. Volatilize the organic matter
2. Expose the inorganic matter for leaching
3. Reduce the  $\text{NaHCO}_3$  to a more soluble  $\text{Na}_2\text{O}$
4. Reduce the  $\text{NaAlCO}_3(\text{OH})_2$  to  $\text{NaAlO}_2$  or soluble sodium aluminate.

Higher temperatures will reduce the other carbonates, consume unnecessary fuel, and cause adverse reactions of the aluminates. Lesser temperatures will not retort the shale adequately or convert the dawsonite to sodium aluminate.

Once properly retorted, the calcine can be leached with water to remove the aluminate and soda. The products  $\text{Al}(\text{OH})_3$  and  $\text{NaHCO}_3$  can then be precipitated by adding crystals of  $\text{Al}(\text{OH})_3$  and by bubbling  $\text{CO}_2$  through the liquor. This phase is chemically similar to part of the presently-used Bayer red-mud process for removing alumina tri-hydrate from the lime-soda-bauxite sinter leach solutions. Alumina is produced by calcining the aluminum tri-hydrate, and

aluminum metal is made from alumina by the electrolytic process. In our case, the energy available from the volatilized organic matter could be totally utilized to generate electricity to reduce the alumina to aluminum.

The primary raw materials for producing soda ash, other chemicals of value, and aluminum metal are available from the same acre of ground, and the secondary raw materials are available locally.

The economics of the sodium minerals are about as complex as those of oil shale and cannot be defined without setting up various assumptions. Dr. J. M. Ehrhorn (1966), director of industrial development of U. S. Smelting and Refining, has stated that saline minerals may add \$20 per ton (for aluminum) and \$6 per ton (for soda ash) to the \$2 per ton for shale oil from the same rock. While the source of Dr. Ehrhorn's figures is not known, they can be computed by the figures given below, and are realistic in principle.

For the purposes of illustration we can say that energy is worth 25 cents per million Btu, soda ash is worth \$32 per ton, alumina is worth \$65 per ton and aluminum is worth 24.5 cents per pound. Then the ultimate value of shale having an assay of 15% nahcolite, 20% dawsonite and 35 gallons oil per ton is as follows:

- |                                    |   |             |
|------------------------------------|---|-------------|
| 1. Energy; 6.5 x \$0.25/MMBtu      | = | \$1.63      |
| 2. Soda Ash; 300 lbs. x \$0.016/lb | = | 4.80        |
| 3. Alumina; 150 lbs. x \$0.032/lb  | = | <u>4.80</u> |

\$11.23

At the stage where soda ash and alumina are produced, 55% of the rock, by weight, has been consumed, and the products are valued at \$11.23 per ton. Carrying the alumina through the electrolytic reduction stage, the value of products will have increased to \$23.18 per ton. The economics of sodium minerals look better than those of oil shale, particularly in light of the recent Colony project. It should be emphasized that leaching of rock is an everyday practice. There are no serious technical barriers to converting the saline minerals in oil shale to usable products.

## POWER

Since the automobile manufacturers have begun to design electric cars, as an anti-pollution measure, we should consider what will happen if the electric car partially replaces the internal combustion engine. Power to charge the car batteries will have to be produced from nuclear or fossil fuels. Nuclear fuels are in short supply...without adding the burden of the electric car requirements. Therefore, it is reasonable to assume that coal and oil will be used to generate power to supply smog-prone populous areas. The generation plants will be located in areas not conducive to smog formation, and the power will be transmitted to the people. Assuming that breakthroughs will make shale oil competitive with other fuels, the oil shale fuels will have a share of the power generation market.

## Conclusions

The main problems for producing shale oil, sodium minerals, or aluminum are the lack of positive government actions to permit development of these resources. We need constructive policies on depletion allowance, mining claims, oil shale leases, mineral leases, etc. It is incongruous not to encourage the development of such inexhaustible reserves of oil, chemicals and aluminum when we are dependent on imports of oil and aluminum. The attendant strategic balance of payments and employment considerations would seemingly demand government encouragement of these industries. The government can always include protective provisions in leases to safeguard the interests of the United States. The industry cannot be started until the government stabilizes imports, clarifies the depletion allowance and the legal status of lands, and adopts a progressive policy aimed at helping or at least not obstructing the industry.

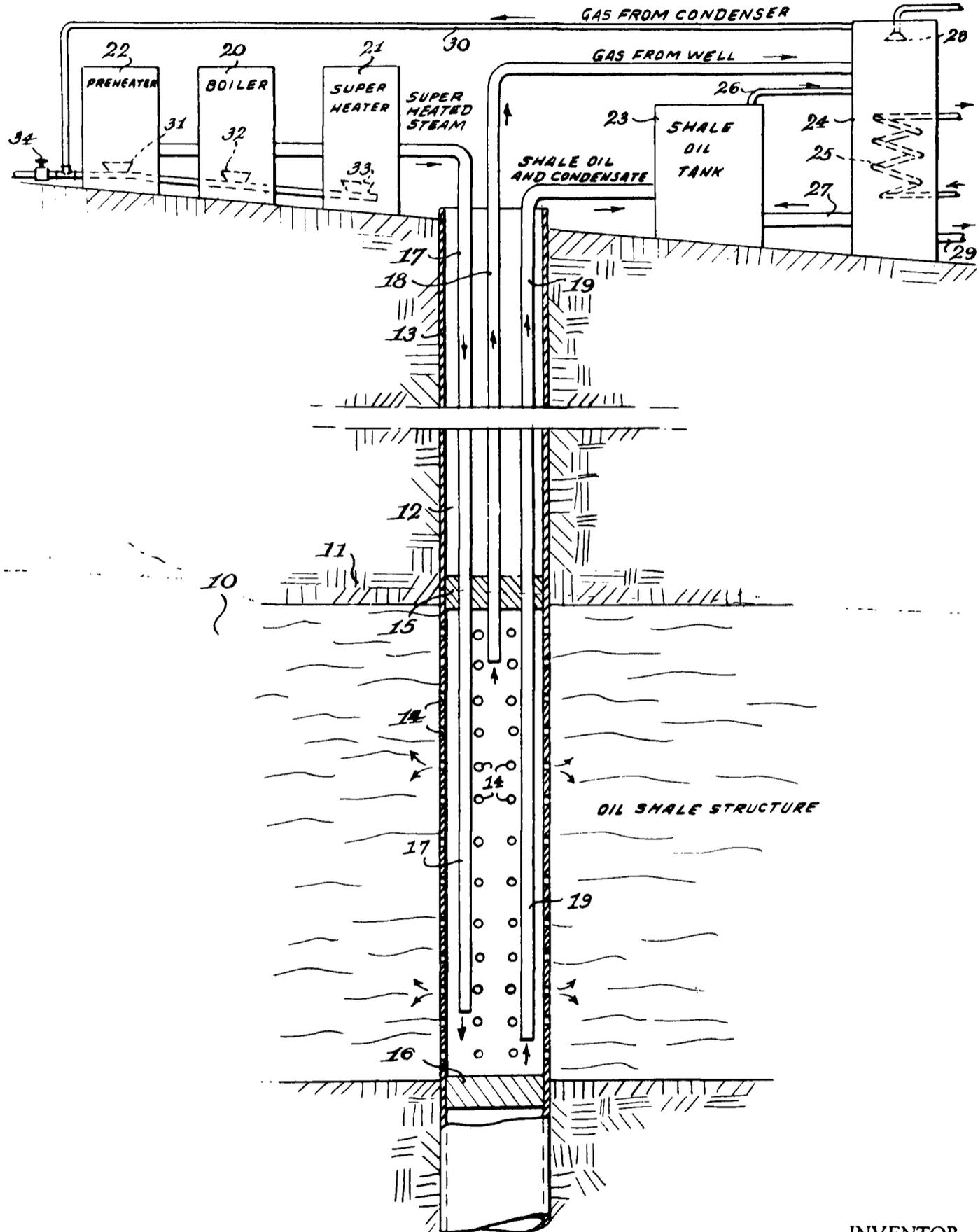
Dec. 6, 1955

C. BELSER

2,725,939

APPARATUS FOR PRODUCING OIL FROM OIL SHALE IN SITU

Filed June 19, 1953



INVENTOR

CARL BELSER

BY

*Mc Morrow, Berman + Davidson*  
ATTORNEYS

1

2,725,939

**APPARATUS FOR PRODUCING OIL FROM OIL SHALE IN SITU**

Carl Belser, Boulder, Colo.

Application June 19, 1953, Serial No. 362,797

1 Claim. (Cl. 166—57)

This invention relates to a method and apparatus for producing oil from oil shale or oil bearing rock without removing the oil bearing shale or rock from its location in the ground.

It is among the objects of the invention to provide an improved method and apparatus for producing oil from oil bearing shale or rock which provides for heating the carbonaceous material in the shale or rock to a temperature at which the material separates into its liquid and gaseous components and flowing these components through separate conduits from the production level in a well; which utilizes at least a portion of the production gas from the well to produce the necessary heat; which may use either superheated steam or combustion gas as the formation heating medium; which removes the liquid and most of the gas from the well through separate conduits; and which is simple in arrangement, economical to operate, and effective and efficient in operation.

Other objects and advantages will become apparent from a consideration of the following description and the appended claim in conjunction with the accompanying drawing wherein the single figure is a diagrammatic illustration of an oil well and apparatus for carrying out the method of the invention for producing oil and gas from a formation carrying a carbonaceous material which is non-flowable at normal temperatures.

In the arrangement illustrated, the numeral 10 designates a bed or strata of oil bearing formation, such as shale or limestone, carrying a carbonaceous material, known as kerogen, which is non-flowable at normal temperatures, but which, when heated to a predetermined temperature, breaks down into freely flowable liquid and gaseous components, and the numeral 11 designates the overburden overlying the oil carrying formation 10. A well 12 extends through the overburden 11 and into or through the formation 10 and has a well casing 13, the portion of which extending into or through the formation 10 is provided with a large number of apertures 14. Suitable plugs 15 and 16, formed of concrete or other suitable material, are disposed in the well at the top and bottom surfaces respectively of the formation 10 and separate conduits 17, 18 and 19 extend downwardly of the well through the top plug 15. The conduit 19 terminates at its lower end adjacent the top surface of the bottom plug 16, the conduit 17 terminates at its lower end adjacent the bottom plug 16, but somewhat above the bottom end of the conduit 19, and the conduit 18 terminates at its lower end above the lower ends of the conduits 17 and 19 and near the bottom surface of the top plug 15.

A plant for heating fluid to a temperature above that at which the carbonaceous material in the formation 10 breaks down into its liquid and gaseous components is shown as including a boiler 20, for producing steam, a steam superheater 21 connected to the boiler 20 and to the conduit 17 and a water preheater 22 connected to the water inlet of the boiler 20. While this plant will produce steam and superheat the steam to a tempera-

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ture above the predetermined temperature at which the carbonaceous material in the formation 10 is broken down into its gaseous and liquid components, it is to be understood that a suitable plant may be provided for producing heated combustion gas and that such heated combustion gas may be forced downwardly into the well through the conduit 17 without in any way exceeding the scope of the invention.

An oil storage tank 23 is provided on the surface near the head of the well and the upper end of the conduit 19 is connected into this tank. A condensing and gas washing device 24 having a water cooled condenser coil 25 therein is connected to the storage tank 23 through conduits 26 and 27 for receiving any gas accumulating in the storage tank 23, condensing any condensible material in this gas and returning the liquid condensate to the storage tank. The upper end of the conduit 18 is connected to the condensing and washing apparatus 24 near the top of this apparatus for introducing gas from the well into the washer and condenser. In addition to the condenser coil 25, the device 24 has at its upper end a suitable sprayhead 28 for directing a spray of water downwardly through the gas in the device to remove any water soluble contents from the gas, the water with the soluble contents of the gas therein being removed from the device 24 through the water outlet conduit 29. A gas pipe 30 leads from the upper portion of the gas washing and condensing device 24 to the burner 31 disposed in the water preheater 22 and to burners 32 and 33 disposed in the boiler 20 and the superheater 21 respectively, to generate and superheat the steam used as the heating medium for the carbonaceous material in the oil bearing formation. Obviously, the steam generating equipment may be eliminated, if desired, and the combustion products of the gas forced directly to the bottom portion of the well through the conduit 17.

In order to start the well, a connection 34 is provided on the pipe 30, so that an external source of gaseous fuel can be temporarily connected to the burners 31, 32 and 33 to produce a sufficient quantity of heated fluid to start the production of oil and gas from the well.

With the position of the bottom ends of the conduits 17, 18 and 19, it will be noted that the heated fluid is released into the well near the bottom of the oil bearing formation 10 and that the oil from the formation flows into the bottom end of the conduit 19 near the bottom end of the well, while the gas produced from the formation rises in this portion of the well and flows into the bottom end of the conduit 18 above the bottom ends of the conduits 17 and 19, so that the gas and liquid components of the carbonaceous material are substantially separated in the well and are delivered to the storage and processing equipment at the surface in separated condition.

The invention may be embodied in other specific forms without departing from the spirit or essential characteristics thereof. The present embodiment is, therefore, to be considered in all respects as illustrative and not restrictive, the scope of the invention being indicated by the appended claim rather than by the foregoing description, and all changes which come within the meaning and range of equivalency of the claim are, therefore, intended to be embraced therein.

What is claimed is:

65 Apparatus for producing oil from a stratum of oil shale in situ comprising; a well casing extending from top to bottom of said stratum; sealing plugs extending transversely of said casing at the top and bottom of the stratum, the casing being freely perforated throughout its circumference for the full portion of its length extending between said plugs; a pipe for supplying steam to the portion of the casing between the plugs, a second pipe

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for leading off gaseous components of the raw shale product, and a third pipe for leading off liquid components of said product. all of said pipes extending from the surface and opening within the casing, the first at a location near the bottom of the stratum above the lower plug, 5 the second at the top of the stratum below the upper plug, and the third near the bottom of the stratum above the lower plug but at an elevation below the first pipe; means connected with the upper end of the second pipe for breaking down the gaseous component flowing 10 through the same into liquid and gaseous parts; means connected with the third pipe for breaking down the liquid component flowing therethrough into liquid and gaseous parts; means for supplying steam through the first pipe for passage into the stratum through said per-

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forations for breaking down the product thereof into said liquid and gaseous components, for passage of the liquid and gaseous components into the casing through said perforations; means for uniting the gaseous parts of the liquid and gaseous components; and means for uniting the liquid parts of said liquid and gaseous components.

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IN THE UNITED STATES DISTRICT COURT

FOR THE DISTRICT OF COLORADO

CIVIL ACTION NO. 8682

FILED  
United States District Court  
Denver, Colorado

JUL 10 1964  
+ 95 PM

SOCONY MOBIL OIL COMPANY, INC., )  
a New York corporation, )

Plaintiff, )

vs. )

WASATCH DEVELOPMENT CO., )  
a Colorado corporation, )

Defendant. )

G. WALTER BOWMAN  
CLERK

BY \_\_\_\_\_  
DEP. CLERK

COMPLAINT

8682

Plaintiff, by its attorneys, Haskell, Helmick, Carpenter & Evans, for a claim against Defendant, states:

1. Jurisdiction is founded on diversity of citizenship and amount. Plaintiff is a New York corporation with its principal place of business in New York and is the successor by merger on December 31, 1959, of General Petroleum Corporation, a Delaware corporation (hereinafter referred to as "General"). The principal place of business of General was not in Colorado. As a result of such merger Plaintiff has succeeded to all of the rights and assumed all of the obligations of General. Defendant, Wasatch Development Co. (hereinafter referred to as "Wasatch"), is a Colorado corporation with its principal place of business in the State of Colorado. The amount in controversy, exclusive of interest and costs, exceeds the sum of Ten Thousand Dollars (\$10,000.00).

2. On or about November 19, 1958, Wasatch and General entered into an Option Agreement covering certain unpatented mining claims owned by Wasatch and located on certain lands in Rio Blanco County and Garfield County, Colorado. A copy of said Option Agreement is attached hereto as Exhibit 1 and by this reference made a part hereof.

3. Under the terms of said Option Agreement, it was provided, among other things, that:

(a) General would pay Wasatch Two Hundred Seventy-eight Thousand Dollars (\$278,000.00) at the time of execution of the Agreement; and General was given the exclusive right and option to acquire all lands subject to the Agreement upon agreeing to pay therefor a purchase price, based on land values set forth therein, totaling approximately Two Million Four Hundred Fifty-two Thousand Dollars (\$2,452,000.00), which option was exercisable in any event on or before October 1, 1964. Under the terms of the Agreement, payment in cash of any portion of the purchase price over and above the original payment of \$278,000.00 would be deferred for various periods of time, depending upon the satisfaction of certain conditions by Wasatch; and, in effect, if any portion of the purchase price in excess of the original payment of \$278,000.00 is never represented by patents on lands subject to the Agreement, the deferment of such portion of the purchase price would result in abatement of the purchase price to the extent of the value of the lands not patented.

(b) Wasatch would promptly file patent applications on the lands subject to the Agreement which were not already covered by such applications, and would diligently pursue the processing of patent applications, both filed and to be filed, and advise General when the patents on such applications issued.

(c) In the event of exercise of the option by General, Wasatch would convey by Warranty Deed to General all lands on which patents were then issued, and would thereafter convey lands as patents were issued.

4. Plaintiff exercised its option under the Agreement on February 14, 1964, by letter to Wasatch and requested Wasatch to convey presently patented lands subject to the Agreement to Plaintiff. A copy of the letter from Plaintiff to Wasatch dated February 14, 1964, is attached hereto as Exhibit 2.

5. Wasatch refused, on May 13, 1964, to recognize the exercise of Plaintiff's option by letter to Plaintiff, and has refused to deliver to Plaintiff Warranty Deeds covering the lands upon which patents have already issued. Wasatch has further advised Plaintiff that it intends to return to Plaintiff on or before October 1, 1964, the \$278,000.00 previously paid pursuant to the Option Agreement and that it will consider the Option Agreement terminated on said date. A copy of the letter from Wasatch to Plaintiff dated May 13, 1964, is attached hereto as Exhibit 3.

6. All conditions precedent to the exercise of the option by Plaintiff pursuant to said Agreement have been satisfied; and Plaintiff has been and is ready, willing and able to perform its obligations under said Agreement.

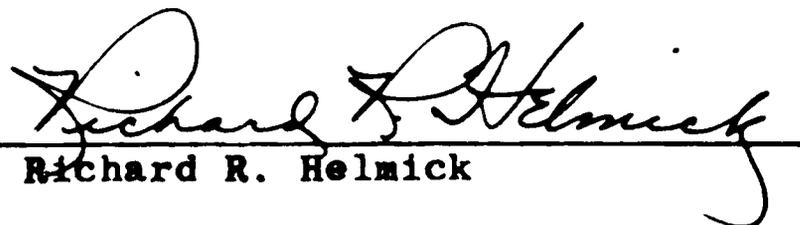
7. An actual controversy exists between Plaintiff and Defendant as to their rights and obligations under said Option Agreement and Plaintiff is entitled to a declaratory judgment adjudicating its rights under the provisions of 28 United States Code, Section 2201, and of Rule 57 of the Federal Rules of Civil Procedure. A declaratory judgment declaring the

rights and other legal relations of the parties is the most efficient means of terminating the controversy between the parties.

WHEREFORE, Plaintiff prays that this Court interpret and construe the Option Agreement of November 19, 1958, between Plaintiff and Defendant; adjudicate the rights and obligations contained therein; declare that Plaintiff has exercised its option to purchase lands subject to the Agreement; declare that Defendant is bound to diligently apply for and process patent applications, to convey by Warranty Deed those lands on which patents have issued, and otherwise to perform its obligations under the Agreement; enter judgment for Plaintiff for damages suffered by reason of the acts of Defendant; and provide such other and further relief as to the Court may seem proper.

HASKELL, HELMICK, CARPENTER & EVANS

By

  
Richard R. Helmick

By

  
John R. Evans  
Attorneys for Plaintiff  
1110 Denver Club Building  
Denver, Colorado  
Telephone: 222-5751

Address of Plaintiff:

Socony Mobil Oil Company, Inc.  
150 East 42nd Street  
New York 17, New York

1

3,224,954

RECOVERY OF OIL FROM OIL SHALE  
AND THE LIKE

Warren G. Schlinger, Pasadena, Calif., and Du Bois Eastman, deceased, late of Whittier, Calif., by Security First National Bank of Los Angeles, Calif., executor, assignors to Texaco Inc., New York, N.Y., a corporation of Delaware

Continuation of application Ser. No. 816,755, May 29, 1959. This application Feb. 3, 1964, Ser. No. 342,852  
7 Claims. (Cl. 208—11)

This application is a continuation of our copending patent application, Serial Number 816,755 now abandoned, filed May 29, 1959.

The present invention relates to the production of oil from oil-bearing minerals. The process of this invention involves recovery of oil from oil-bearing minerals, for example, oil shale, oil sand, and tar sand, and simultaneous treatment of said recovered oil with hydrogen. The process results in the production of recovered oil in high yield having relatively low viscosity, low sulfur content, and good refinability, particularly in comparison with oil recovered from these same oil-bearing materials by conventional retorting or by extraction with solvents.

In carrying out the process of this invention, an oil-bearing mineral is subjected to treatment with hydrogen containing gas at a pressure in the range of 1000 to 2500 pounds per square inch gauge and at a temperature in the range of about 800 to 950° F. for a period of about 20 minutes to 5 hours, preferably not more than 2 hours. High oil yields are obtained. Oil yields of more than 100 percent, and typically 125 to 135 percent, by volume, in comparison with the standard Fischer Assay, are obtained from commercial grade oil shales. The quantity of oil remaining in the residue is too small to support combustion. In addition, the recovered oil has lower viscosity, lower specific gravity and lower carbon residue than oils recovered by conventional retorting procedures.

It is known that certain oil-bearing minerals, called oil shales, contain certain substances known as kerogens which may be converted to hydrocarbon oil by the application of heat. Other oil-bearing minerals, such as oil sands or tar sands, contain hydrocarbons which may be distilled or extracted from the mineral residue, or displaced by means of liquids, particularly at elevated temperatures. As is well known, however, oil recovered from oil shale and tar sands, is generally of poor quality as compared with most crude petroleum oils. In particular, the oil from such oil-bearing minerals generally is of low API gravity and contains relatively little material boiling in the distillate boiling range. In addition, the oil has a relatively high content of organic sulfur and organic nitrogen compounds. Yields of motor fuels from these oils by conventional petroleum refining process are comparatively poor. Extensive treating and refining operations are necessary to remove nitrogen and sulfur and to obtain maximum yields of commercially desirable products from the crude oil.

The process of this invention provides a method for direct recovery of oil of improved product quality from oil shales and tar sands by hydrotorting, a combination hydrogenation and heat treatment, under carefully controlled conditions of time, temperature and pressure. In addition, some ammonia is produced which may be recovered as a valuable by-product.

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We are aware of the fact that it has been proposed heretofore to upgrade crude oil recovered from oil shale or tar sand by treatment with hydrogen, either catalytically or non-catalytically, for the express purpose of improving product quality. We are also aware that it has been proposed heretofore to retort oil shale in the presence of hydrogen. Usually such processes are carried out at pressures below about 1000 p.s.i.g. at relatively mild temperatures, e.g. below about 1000° F., or at higher temperature and pressure. We have found that much improved results may be obtained by retorting the oil shale under relatively mild temperatures of 800 to 950° F. in the presence of hydrogen at a pressure above about 1000 p.s.i.g. and in the range of 1000 to 2500 p.s.i.g.

One major disadvantage of prior processes for treating oil-bearing minerals with hydrogen is the large volume-time relationship required in such processes. For example, the time required for treatment of a batch of oil shale by conventional processes ranges from about 6 to 24 hours, thus requiring extensive installations of retorts capable of holding a large volume of material for a period of several hours. When it is appreciated that the oil contents of commercial oil shales range from about 15 to about 40 gallons per ton, the immense investment in equipment required for a plant designed to produce, for example, 10,000 barrels of crude shale oil per day becomes immediately apparent.

As pointed out above, the time required for processing oil-bearing minerals by the process of this invention is short in comparison with other processes. In general, it is only necessary to raise the temperature of the material to 800° F. or above by heat exchange with the hot gas and hold the particles at a temperature in the range of 800 to 950° F. in the presence of the high pressure hydrogen for a period of about 20 minutes to two hours. The external heat required for the hydrotorting operation is comparatively low and is easily supplied by the hot hydrogen stream itself without the necessity for supplemental heating by heat exchange through the walls of the vessel or by means of a heated circulating solid. The relatively mild temperature prevents decomposition of the carbonate, primarily calcium carbonate, in oil shale. A large part of the heat required in conventional shale retorting processes is required for decomposition of the carbonates, liberating carbon dioxide which generally serves no useful purpose in the process, and is actually detrimental.

The extent of recovery of hydrocarbon from oil shale by the process of this invention is such that there is not sufficient fuel value in the residual shale to support combustion. This is in sharp contrast with conventional processes which burn the residual shale. Shale residue obtained in a number of test runs was largely in the form of an impalpable powder or soft lumps easily disintegrated to powder. These residues appear to be suitable as raw material for the production of Portland cement.

In accordance with a preferred embodiment of the present invention, tar sand, or oil shale lumps or pieces having a maximum size of about 1½ to 2 inches, is charged into a pressure vessel, preferably a series of such vessels, and contacted with a hydrogen-rich gas stream which is passed upwardly through said vessel under a pressure within the range of 1000 to 2500 p.s.i.g. and a temperature within the range of 800 to 950° F. It is not necessary to preheat the mineral prior to contact with hydrogen. As the hydrogen passes up through the re-

tort, a fairly sharp temperature profile is observed, above which the temperature is less than retorting temperature, probably as a result of condensation of oil vapors on the cooler material. Oil is entrained in the hydrogen-rich gas passing through the mineral and carried from the vessel where it is recovered by conventional methods, e.g. condensation and/or adsorption. Following recovery of the oil from the effluent gas, the hydrogen-rich gas is recirculated to the retorting vessel. The recirculated gas may be processed for recovery of ammonia and for removal of sulfur-containing gas, e.g. hydrogen sulfide, contained therein but this is not essential to the operation. It is not essential that the gas pass upward through the retort; horizontal flow (cross flow) or down flow may be used with suitable retorts.

Hydrogen feed rates of the order of 25,000 to 150,000 standard cubic feet (60° F. and atmospheric pressure) per ton of mineral per hour may be employed. Generally the hydrogen consumption is within the range of about 500 to about 3,000 standard cubic feet per barrel of oil produced. Hydrogen preferably is supplied in relatively pure form, e.g. 90 volume percent or higher, but may be supplied as a gas mixture having a hydrogen concentration in the range of from about 25 to about 99 percent hydrogen by volume. The hydrogen pressure in the system preferably is at least 1000 p.s.i.g. and preferably within the range of 1500 to 2000 p.s.i.g. Treating time may range from about 20 minutes to 5 hours, although generally satisfactory recovery may be obtained within 30 minutes at reaction temperatures above 800° F. The holding time in the reaction vessel may be somewhat longer, depending upon the size of the vessel and the gas feed rate.

A preferred embodiment of the present invention involves the combination of hydroretorting the mineral under specified pressure-time-temperature conditions followed by passing the total effluent from the hydroretorting reactor in vapor phase directed over a hydrogenation catalyst, for example, a cobalt-molybdenum hydrogenation catalyst. Catalysts which are effective for use in the present process are those which promote hydrogenation of hydrocarbons. In general, the oxides of the Group VI metals and of the first transition series of Group VIII of the Periodic Table of the Elements are effective catalysts. Solid catalyst, such as oxides or sulfides of molybdenum, tungsten, zirconium, chromium, vanadium, iron, cobalt or nickel on a suitable carrier material, for example, silica, magnesia, alumina, bauxite, aluminum silicate or clay, are suitable known hydrogenation catalysts. A preferred catalyst comprises 1.5 to 5 weight percent cobalt oxide and 7 to 14 weight percent molybdenum oxide on an alumina support. Preferably, the vaporous products of the hydroretorting operation are passed directly into contact with one or more beds of solid catalytic material, for example, cobalt molybdate on a suitable support.

The hydrocarbon products are suitably recovered from the fixed gases by condensation, absorption or a combination thereof. The remaining gases may be recycled to the process as desired, together with fresh feed hydrogen from a suitable source.

The fresh feed hydrogen may be produced economically by partial oxidation of a portion of the gas or oil product of the process. Partial oxidation of carbonaceous fuels to carbon monoxide has recently been developed commercially. Gaseous, liquid or solid carbonaceous fuels may be converted to carbon monoxide and hydrogen by reaction at elevated temperature and pressure with free oxygen in a compact reaction zone free from catalyst and packing. The resulting carbon monoxide may be converted to hydrogen by reaction with steam in the water gas shift reaction to produce carbon dioxide and hydrogen. Removal of carbon dioxide from the resulting gas stream yields relatively pure hydrogen. From about 3 to about 13 percent of the recovered oil is sufficient to supply all

the hydrogen required for the process, the lower figure corresponding to hydrogen consumption of about 600 s.c.f. per barrel, and the higher, to about 2600 s.c.f. per barrel.

5 The process of this invention will be more readily understood from the following detailed description taken in conjunction with the attached drawing.

FIG. 1 illustrates diagrammatically an arrangement of apparatus suitable for carrying out the present process.

10 FIG. 2 illustrates schematically an arrangement of apparatus wherein a plurality of retorts are employed.

FIG. 3 illustrates diagrammatically, a retorting vessel suitable for carrying out the process of this invention on a commercial scale.

15 With reference to FIG. 1 of the drawing, oil shale crushed to a particle size not greater than 2 inches in diameter is charged into a retort 1 in the form of a pressure vessel, wherein it is contacted with hydrogen-rich gas at elevated pressure and temperature, hereinafter specified, for a period of time sufficient to effect substantially complete recovery of hydrocarbons from the oil shale. The shale in the retort is maintained in a settled bed condition, as distinguished from a fluid bed or a suspension or entrainment operation. The shale may be processed batchwise in a stationary bed or continuously in a downwardly moving bed or in an upwardly moving bed.

20 In a continuous processing operation, shale is introduced continuously or intermittently into the upper portion of retort 1 while residue is removed continuously or intermittently from its lower portion. The rate of introduction of oil shale and withdrawal of residue is regulated so that the time of contact between the hydrogen-rich gas and the oil shale is within the range of about 25 20 minutes to 5 hours and sufficient to effect substantially complete recovery of hydrocarbons from the shale. The incoming oil shale may be preheated to about 700° F. or higher, suitably by contact with a hot gas substantially inert with respect to the oil shale and its hydrocarbon content, for example nitrogen, steam, or flue gas although preheating of the shale is not essential.

Hydrogen-rich gas is preheated in heater 2 to a temperature in the range of about 850 to 1,000° F. and introduced into the retort. The hydrogen-rich gas passes upwardly through the particles of oil shale in the retort at a velocity below that required to expand the bed of shale, or fluidize the particles, and insufficient to entrain more than a minor amount of solid particles in the gas stream. Hydrogen-rich gas containing recovered hydrocarbons from the oil shale is passed to catalyst chamber 3 containing a hydrogenation catalyst effective for hydrogenation of hydrocarbons in vapor phase.

Heater unit 4 may be provided to maintain the temperature of the gases and vapors reaching the catalyst chamber within the desired operating range for optimum improvement of the retorted oil by the vapor phase hydrogenation reaction taking place in catalyst chamber 3. Generally, in batch operations, it is desirable to pass the gases and oil vapors through heater 4, at least during that period of the cycle in which oil vapors carried over from the retort in the gas stream in appreciable amounts are at a temperature below about 700° F. When the retort is operated in a continuous manner, heater 4 may be used or not depending upon the temperature of the gas stream containing oil vapors leaving the upper portion of the retort. Since the temperature of the effluent stream from the retort is dependent to a large extent upon the temperature of the shale at the gas outlet from chamber 1, it will be evident that by preheating the incoming oil shale the temperature of the oil at the gas outlet point may be maintained sufficiently high that heater 4 is unnecessary. In latter case, the hydrogen-rich gas and accompanying oil vapors may be passed directly to catalyst chamber 3 via line 6.

75 The unit 4 may take the form of a turbulent-flow hy-

RECOVERY OF OIL FROM OIL SHALE AND THE LIKE

Original Filed May 29, 1959

2 Sheets-Sheet 1

Fig. 1.

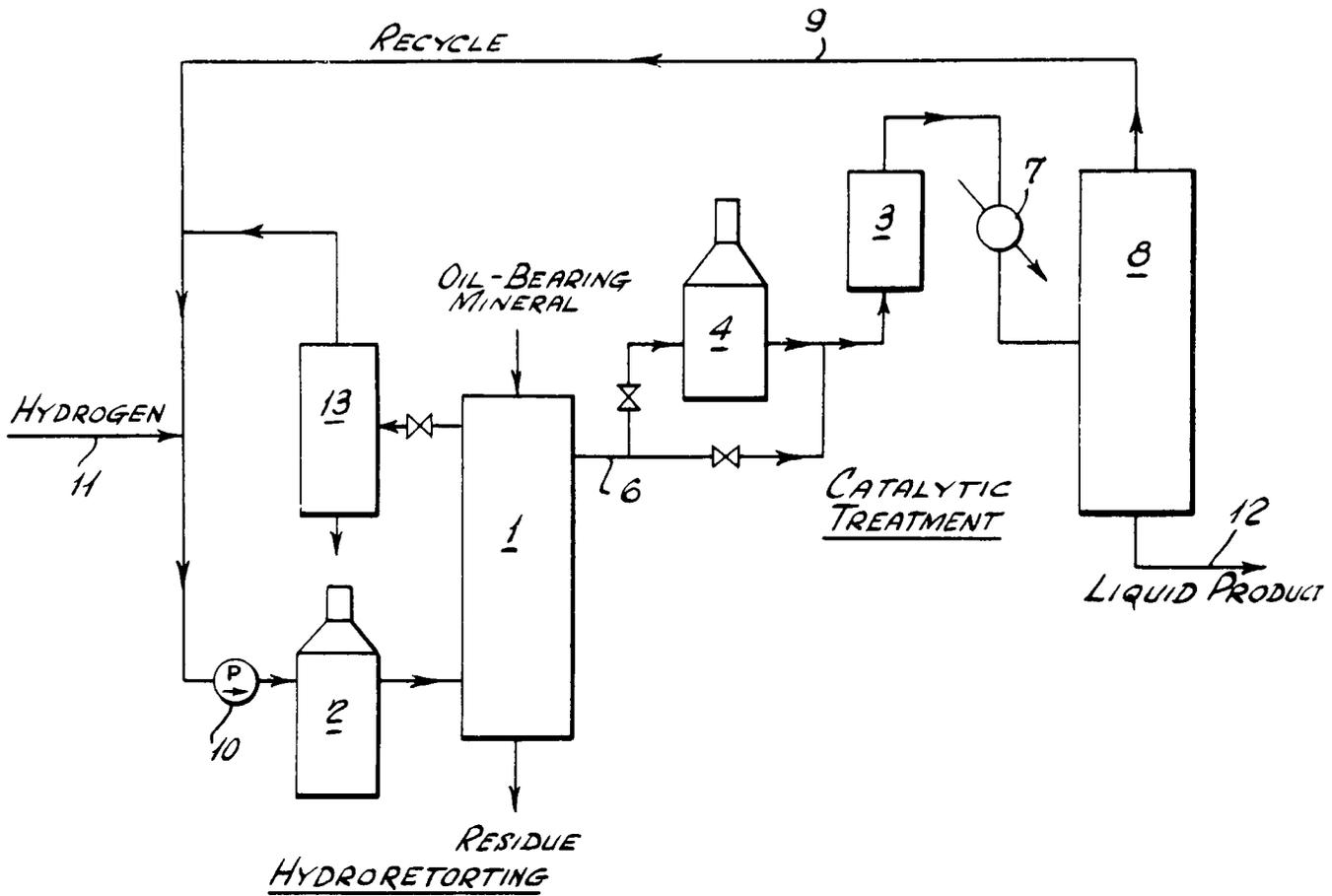
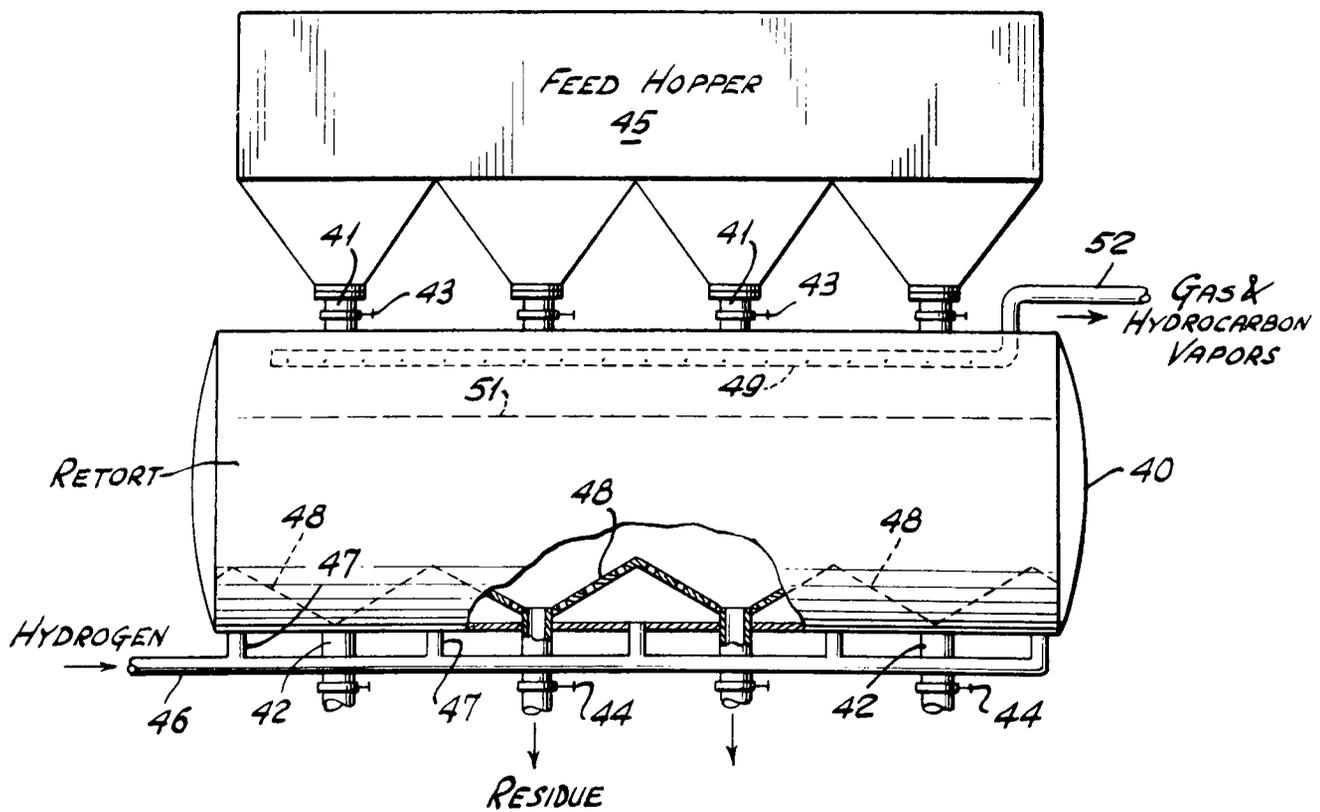


Fig. 3.





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drogenation unit in which the oil and hydrogen are subjected to highly turbulent flow in a conduit at a temperature in the range of 800 to 1500° F. and a pressure in the range of 1000 to 2500 pounds per square inch gauge for a reaction time of at last five seconds. Turbulent flow hydrogenation is described in my copending application, Serial No. 740,138, filed June 5, 1958. In turbulent flow hydrogenation, the flow rate of hydrogen and oil are correlated with conduit diameter and reaction temperature and pressure to give the desired turbulence level. It has been found that the ratio

$$\frac{\bar{E}_m}{\mu}$$

of average apparent viscosity of the flowing stream,  $\bar{E}_m$ , to the molecular or kinematic viscosity  $\mu$  should be at least 25 and preferably in the range of 50 to 1000.  $\bar{E}_m$  may be defined in terms which may be determined by physical measurements by the following equation:

$$\bar{E}_m = \frac{r_0}{15} \sqrt{\frac{r_0 g}{2\sigma} \frac{dp}{dx}}$$

Wherein  $dp/dx$  is the pressure drop in pounds per square foot per foot of conduit length;  $g$  is the acceleration of gravity in feet per second;  $r_0$  is the radius of the conduit in feet; and  $\sigma$  is the specific weight of the flowing fluid in pounds per cubic foot.

The gases and vapors from the catalyst chamber 3 are passed to cooler 7 for condensation of the readily liquefiable hydrocarbon from the gas stream. Gas and liquid are separated from one another in separator 8. The gas is recycled via line 9 to compressor 10 where it is returned to heater 2 and to retort 1. Hydrogen required for the process is supplied from a suitable source through line 11. Liquid is withdrawn through line 12.

If desired, catalyst chamber 3 and cooler 7 may be bypassed. Thus in batch processing oil shale, effluent gases from the retort may be passed through line 6 directly to separator 8 and recycled without cooling during a portion of the cycle. If desired, gases from retort 1 may be drawn through a suitable guard separator 13, to effect removal of solid particles and entrained liquid, directly to recycle line 9. This latter procedure may be desirable in batchwise processing of the oil shale during the preheating period, i.e. during the period in which the charge of oil shale in the retort is being heated up to a temperature of about 600° F.

In the continuous processing of oil shale, as outlined hereinabove, it may also sometimes be desirable to withdraw a portion of the gaseous effluent from retort 1 from a point above the point of product withdrawal, e.g. via separator 13 for direct recycle. By this means the temperature of the effluent stream withdrawn through line 6 may be maintained at the temperature level desirable in catalyst chamber 3 without the necessity for preheating the incoming oil shale or alternatively the use of heater 4. When gases are withdrawn to separator 13, readily condensable hydrocarbons contained in the gas stream are condensed on the relatively cool oil shale, serving to preheat the shale. Hydrocarbons so condensed are revaporized at a lower point in the retort and recovered through product line 6.

In batch processing operations a series of retorts may be used with suitable switching arrangements to permit the retorting vessels to be connected with various inlet and outlet lines in sequence to preheat the shale, retort the shale, and cool the residue.

FIG. 2 of the drawing illustrates diagrammatically an arrangement of apparatus for carrying out a batchwise hydroretorting of oil shale in a series of retorts in accordance with the present invention. As illustrated, pressure vessels 16, 17, 18, 19, 20 and 21 are arranged for treatment in sequence in the order illustrated. The piping is arranged so that the various pressure vessels may be

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connected in a cyclic manner to provide the flow pattern illustrated in the figure. It is to be understood that neither of the specific arrangements illustrated nor the specific number of vessels is to be taken as limiting our invention.

In operation, retort 16 is charged or recharged, while the remaining retorts are connected for gas circulation. Residue from a previous retorting operation is discharged from retort 16 and fresh oil shale in the form of particle no larger than 2 inches in average diameter is charged to the retort. Numeral 17 designates a pressure vessel which has been charged with fresh shale and is undergoing preheating. Preheating of the fresh shale may be accomplished in a number of ways. In the specific embodiment illustrated in FIG. 2, the preheating is accomplished by means of circulating hydrogen-rich gas preheated by contact with hot residual shale resulting from the hydroretorting operation. In this particular example, hydrogen-rich gas is passed through spent or residual shale in retort 21 where it is heated to a temperature, of the order of 500° F. for example, and then passed over the fresh shale in retort 17 to preheat the fresh shale. Gas discharged from retort 17 is passed to cooler 22, then through separator 23 to compressor 24 for recirculation.

Following preheat of the oil shale (as illustrated, in retort 17), the shale is preheated further and retorting started by passing hot hydrogen-rich gas, for example, at a temperature of the order of 900° F., over the shale particles. Effluent gas from retort 18 may be processed directly for recovery of oil or passed through a second retort 20 from which a considerable portion of the hydrocarbons have been retorted, depending upon the temperature and hydrocarbon content of the effluent. The retorting is completed in retort 20 to which heated gas or cold recycle gas may be supplied as required. In retort 20, retorting is completed and the residual shale is cooled moderately, e.g. to a temperature of the order of 500 to 600° F. Effluent gas containing hydrocarbon vapors from retort 20 passed to catalyst reactor 26 in which the hydrocarbons recovered from the oil shale are subjected to catalytic treatment with hydrogen at reactor pressure and a temperature above 800° F. Some vapor phase hydrogenation of the hydrocarbons takes place in reactor 26 in which the catalyst preferably is disposed in a series of beds 27.

Hydrogen-rich gas and hydrocarbon leaving the catalyst chamber 26 pass through heat exchanger 28, wherein they are cooled by heat exchange with cold hydrogen-rich gas, and through cooler 22 for further cooling sufficient to effect condensation of readily condensable hydrocarbons, and are then passed to separator 23 maintained at substantially retort pressure. In separator 23, condensed liquid is separated from residual gases comprising hydrogen and gaseous hydrocarbons recovered from the oil shale. The gases pass to compressor 24 and are recirculated to the retorts.

Hydrogen from a suitable source, preferably in relatively pure form, is introduced to the system as required through line 29. From compressor 24, a part of the hydrogen-rich gas is passed to retort 21 as previously mentioned. A further portion of the hydrogen-rich gas passes through heat exchanger 28 where it is heated by indirect heat exchange with the product from catalytic reactor 26, for example, to a temperature of the order of 600 to 700° F. and then passed through heater 31 wherein it is heated to a temperature in the range of 800 to 950° F. A part of the gas from heater 31 is passed to retort 18 in which recovery of hydrocarbons from the shale is initiated and further portion of the heated gas is passed to retort 19 in which recovery of hydrocarbons from previously heated and partially retorted shale is continued. Gaseous effluent from retort 19 containing hydrocarbon vapors is passed to catalytic reactor 26. The mixture of shale oil vapors and hydrogen from the retorts may be subjected to turbulent flow hydrogenation (not

illustrated) as described hereinabove in connection with FIG. 1.

In the sequence illustrated, a period of time for each operation in the range of 15 to 45 minutes is usually adequate. It will be appreciated that the time requirements will depend to some extent on the particle sizes of the oil shale and the depth of the shale bed in each of the retorts. It will be evident that the larger particle sizes require longer heating times than do the smaller particles. The minimum time requirement, therefore, is largely dependent upon the time required to process the largest shale particles in the charge to the retorts. As previously indicated, a period of two hours above 800° F. is generally adequate for pieces up to 2 inches in diameter. During the retorting periods proper, i.e. the period following the preheat, during which hydrocarbons are vaporized from the shale particles, the bed depth has considerable effect upon the time required for retorting a given amount of shale. The results of a number of trial runs, data for which are reported in the following examples, indicate that it is possible to recover the hydrocarbon from oil shale substantially completely in about 20 minutes at a temperature in the range of 800 to 950° F. with hydrogen at a pressure in the range of 1,000 to 2,500 p.s.i.g. It will be appreciated however that in a bed several feet in depth, the zone of actual retorting extends over only a portion of the entire shale bed. For example, in retort 19 of FIG. 2, shale in the lowermost portion of the vessel is completely retorted. As the hot gas from the heater ascends through the portion of the shale bed in which retorting is complete, the temperature of the hot gases remains essentially constant and the residual shale particles are substantially inert with respect to the processing gas stream. At a somewhat higher level in the bed, hydrocarbons liberated from the oil shale are undergoing vaporization from the shale and simultaneous reaction with hydrogen contained in the processing gas stream. The net effect of these reactions is an endothermic one. Consequently, the temperature of the gas stream beings to fall as it ascends through that portion of the bed in which hydrocarbon vapors are liberated from the shale. In this connection it should be noted that the liquid product from the oil shale has an atmospheric boiling range of from about 140 to about 725° F. (Example 1). As the processing gas containing these hydrocarbon vapors ascends to a still higher level in the shale bed, a part of the oil vapor is condensed by contact with the cooler shale in the upper portion of the retort. The high temperature retorting zone moves slowly up through the bed of oil shale. It will be apparent that the depth of the bed has an appreciable effect on the length of time required for retorting. The superficial linear gas velocity in the retorts generally is in the range of 0.005 to 0.5 feet per second, preferably 0.01 to 0.25 feet per second. Low gas velocities prevent entrainment of fine particles of residue in the processing gas stream. At the same time, the temperature of the processing gas stream is limited to a maximum of about 950° F. Consequently, relatively shallow large beds of shale are preferred for retorting. A preferred retort is illustrated in FIG. 3.

With reference to FIG. 3, the numeral 40 designates a pressure vessel shell adapted to withstand operating pressure and provided with a liner of refractory insulating material. The preferred form of retort is a horizontal cylinder as illustrated with a plurality of loading nozzles 41 along its topmost surface and a plurality of ash discharge nozzles 42 along its lowermost surface. Nozzles 41 and 42 are provided with suitable valves 43 and 44 to permit the flow of crushed shale into the retort and the withdrawal of residue from the retort and to effectively seal the nozzles against pressure during the retorting operation. Crushed oil shale of a suitable size for retorting is applied to nozzle 41 from feed hopper 45. Hydrogen-rich gas is introduced to the retort through line 46 and nozzles 47 and distributed throughout the

shale bed by perforated plates 48. Processing gas and hydrocarbon vapors are collected by a perforated header 49 in the upper portion of the retort above the normal level, indicated by dashed line 51, of the oil shale during the retorting operations. Effluent gas and hydrocarbon vapors from the retorts are discharged through line 52 for further processing, for example as illustrated in FIG. 2.

The process of this invention is further illustrated in the following examples reporting data from a number of runs made in accordance with the above described process.

#### EXAMPLE 1

Colorado oil shale having a Fischer Assay of about 43.5 gallons per ton was crushed to 1½ inch maximum size and treated with hydrogen in a vertical reactor 6 inches in diameter by 12 feet long. Runs A and B, reported in Table 1 below, represent composite data from several batches of shale. The reactor was charged with 100 to 150 pounds shale per batch, pressured with hydrogen, and circulation established. The gas at a rate of about 7,000 s.c.f.h., was passed through a preheater, up through the reactor, through a cooler and a condensate separator and back to the heater. Makeup hydrogen was added as required to maintain pressure. The temperature of the hydrogen was then raised to 800 to 900° F. and circulation continued 3 to 4 hours. When the temperature of the gas stream at the top of the reactor reached 800° F., circulation of the gas stream was continued for two hours. Inspection of the residual shale from the reactor showed no apparent difference from top of the reactor to the hydrogen inlet, evidencing that shale treated for the minimum period of time (at the top of the reactor) was as effectively extracted as that treated for the entire period.

Operating conditions and results are shown in Table 1, in comparison with the standard Fischer Assay described in U.S. Bureau of Mines, R.I. 3977 (October 1946). Each run represents several batches of shale processed in the reactor. The characterization factor, K.V., an index of the type hydrocarbon recovered, is described by Watson, Nelson, and Murphy, Ind. Eng. Chem. 25,880 (1933); 27, 1460 (1935).

These data show the substantial increase in oil yields over the Fischer Assay and improvement in API Gravity, pour point and yield of distillate, as compared with oil from the Fischer Assay.

#### EXAMPLE 2

A series of runs were made with the same oil shale and retorting apparatus as was used for Runs A and B of Example 1. Substantially pure hydrogen was used as the retorting gas in each case. The total effluent from the shale was passed without condensation or separation of vapors, into direct contact with a hydrogenation catalyst in the form of ⅛ inch pellets comprising 3.1 weight percent cobalt oxide and 8.5 weight percent molybdenum oxide on alumina. In Run C, 15 pounds of catalyst was placed in the reactor, directly above the shale bed. The catalyst bed was approximately 15 inches in depth. In Runs D and E the catalyst was contained in a separate vessel, four feet long and three inches inside diameter filled with the catalyst (a total of about 12 pounds). The total effluent from the hydroretorting reactor was passed directly to the catalyst chamber without heating or cooling. In Run F, the total effluent from the retort was heated before contacting the catalyst in the catalyst vessel. Runs E and F illustrate the effect of the temperature of the catalytic treatment of the hydrocarbon vapors on product quality. In each case, the bulk of the oil vapors from each batch of shale passed over the catalyst in a relatively short period of time (estimated at about 15 minutes) so that the space velocity of oil vapors over the catalyst was relatively high. Operating conditions and results are shown in Table 2.

Table 1

	Fischer Assay		Run A	Run B
	None ( <sup>1</sup> )	None ( <sup>2</sup> )	H <sub>2</sub> 4	H <sub>2</sub> 3
Retorting Gas.....				
Retorting Period, Hrs./Batch.....				
Operating Conditions:				
Pressure, p.s.i.g.....			1,802	1,803
Temperature, °F.....				
Preheater Outlet.....			875	915
Overhead.....			642	662
Gas Flow, s.c.f.h.....			7,000	7,000
Yields, Product, Lbs.:				
Ash.....			570	329
Oil.....			133.1	86.0
Water.....			16.0	4.7
Gas.....			3.7	3.3
Loss.....			16.7	16.0
Total Shale Charged, Lbs.....			739.5	439.0
Recovery, Wt. Percent.....			97.7	96.4
Oil:				
Gals./Ton.....		43.29	48.17	52.85
Percent Fischer Assay.....		100.0	<sup>3</sup> 111	<sup>3</sup> 122
Water:				
Gals./Ton.....		3.50	5.19	2.55
Percent Fischer Assay.....		100.0	<sup>3</sup> 148	<sup>3</sup> 73
Hydrogen Consumption, s.c.f./bbl. (Est.).....			600-800	600-800
Product Oil:				
Gravity, °API.....	25.2	24.5	25.9	27.1
Viscosity, SSU at 122° F.....	58.0	54.2	80.0	59.4
Carbon Residue, Wt. Percent.....				
Percent.....	2.48	2.23	1.10	1.05
Sulfur, Wt. Percent.....	0.88	0.92	0.63	0.88
Nitrogen, Wt. Percent.....	1.65	1.94	1.42	1.26
Pour Point, °F.....	75	80	90	85
Distillation, °F.:				
IBP.....	170		153	140
10%.....	370		397	358
50%.....	650		676	664
90%.....	700 (80%)		724	715
EP.....				
K.V.....	11.6	11.51	11.78	11.77
Recovery, Percent.....	80		92.5	93.0
Residue.....			7.5	7.0
Ash, Carbon Content, Wt. Percent.....	~5	4-5	2.00	0.83

<sup>1</sup> Composite from Fischer Assays.<sup>2</sup> Typical Fischer Assay—10 Samples.<sup>3</sup> Based on Typical Fischer Assay (2).

Table 2

	Run C	Run D	Run E	Run F
Retorting Gas.....	H <sub>2</sub> 3	H <sub>2</sub> ~5	H <sub>2</sub> 4	H <sub>2</sub> 3
Retorting Period, Hr.....				
Catalyst.....	Cobalt Molybdate	Cobalt Molybdate	Cobalt Molybdate	Cobalt Molybdate
Operating Conditions:				
Pressure, p.s.i.g.....	1,800	~2,000	1,900	2,000
Temperature, °F.:				
Preheater Outlet, Avg.....	900	920	910	930
Overhead, Avg.....	670	660	720	730
Catalyst Chamber Inlet.....			685	825
Gas Flow, s.c.f.h., Avg.....	7,000		6,450	6,000
Yields: Product, Lbs.—				
Ash.....	591.8	1,628.5	305.5	288.0
Oil.....	153.2	407.1	81.3	71.6
Water.....	25.3	82.8	9.2	16.9
Gas.....	11.3	35.3	4.2	7.2
Loss.....	6.4	11.8	10.8	22.8
Total Shale Charged, Lbs.....	788.0	2,165.5	411.0	406.5
Recovery, Wt. Percent.....	92.2	99.5	97.5	94.4
Oil:				
Gals./Ton.....	54.11	52.94		
Percent Fischer Assay.....	<sup>1</sup> 125	<sup>2</sup> 134	<sup>3</sup> 128	<sup>3</sup> 120
Water:				
Gals./Ton.....	7.72	9.18	7.53	
Percent Fischer Assay.....	<sup>1</sup> 220	<sup>2</sup> 223	<sup>3</sup> 128	<sup>3</sup> 239
Hydrogen Consumption, s.c.f./ bbl. (Est.).....	1,000-1,400	2,500	2,700	4,000
Product Oil:				
Gravity, °API.....	32.3	34.5	32.2	39.4
Viscosity, SSU at 122° F.....	40.9	41.2	47.3	33.7
Carbon Residue, Wt. Per- cent.....	0.37	0.03	Trace	0.06
Sulfur, Wt. Percent.....	0.43	0.12	0.13	0.06
Nitrogen, Wt. Percent.....	0.60	0.77	1.20	0.49
Pour, °F.....	80	80	90	45
Distillation, °F.:				
IBP.....	152	166	144	126
10%.....	316	359	358	256
50%.....	704	710 (80%)	728 (70%)	640 (80%)
EP.....				
K.V.....	11.8	11.9	12.0	11.7
Recovery, Percent.....	91.0			94.0
Residue.....	9.0			6.0
Ash, Carbon Content, Wt. Percent.....	0.95	0.86	1.07	0.57

<sup>1</sup> Based on Typical Fischer Assay (2), Example 1.<sup>2</sup> Based on Fischer Assay avg. of 7 runs.<sup>3</sup> Based on Fischer Assay of 42.86 and 4.19 lbs. oil and H<sub>2</sub>O, respectively.

In all of the runs in this example, preheated hydrogen is passed up through the retorting vessel. Circulation was continued for a period of two hours after the temperature at the top of the shale bed reached 800° F. From one half to one hour was required to bring this temperature up to 800° F. At the conclusion of the two-hour period, the fire in the preheater was cut out and the cool hydrogen circulated through the reactor until the temperature of the effluent gases from the reactor had dropped to less than 150° F.

## EXAMPLE 3

Runs were made with the same oil shale as in the foregoing examples using mixtures of hydrogen and carbon monoxide, and hydrogen and carbon dioxide as stripping gases. In each of the following runs, the procedure was the same as in Run F of Example 2. In Run G, the composition of gas initially supplied to the reactor and added as make up gas in the processing of each batch contained 69 mole percent hydrogen and 30 mole percent carbon dioxide. In Run H, the gas supplied to the reactor contained 57 mole percent hydrogen and 42 mole percent carbon monoxide. Operating conditions and results are shown in Table 3.

Table 3

	Run G	Run H
Retorting Gas.....	H <sub>2</sub> +CO <sub>2</sub>	H <sub>2</sub> +CO
Retorting Period, Hrs.....	3 to 4	~2
Catalyst.....	Cobalt Molybdate	Cobalt Molybdate
Operating Conditions:		
Pressure, p.s.i.g.....	1,935	1,930
Temperature, F.—		
Preheater Outlet.....	926	930
Overhead.....		
Catalyst Chamber Inlet.....	699	740
Gas Flow, s.c.f.h.....	>5,000	>5,000
Yields, Product, Lbs.:		
Ash.....	197.5	411
Oil.....	53.5	96.6
Water.....	44.5	39.4
Gas.....	5.6	15.8
Total Shale Charged, Lbs.....		
Oil:		
Gals./Ton.....	55.39	48.69
Percent Fischer Assay.....	<sup>1</sup> 129	<sup>1</sup> 114
Water:		
Gals./Ton.....	40.58	17.60
Percent Fischer Assay.....	<sup>1</sup> 968	<sup>1</sup> 420
Hydrogen Consumption, s.c.f./bbl. (est.)...	6,550	6,500
Product Oil:		
Gravity, ° API.....	28.8	29.6
Viscosity, SSU at 122° F.....	49.7	45.2
Carbon Residue, Wt. Percent.....	0.38	0.65
Sulfur, Wt. Percent.....	0.32	0.46
Nitrogen, Wt. Percent.....	1.46	1.44
Pour Point, ° F.....	85	85
Distillation, ° F.:		
IBP.....	170	168
10%.....	384	360
50%.....	675	628
90%.....	719 (70%)	700 (80%)
EP.....		
K. V.....	11.8	11.7
Recovery, Percent.....	71.5	65.5
Ash, Carbon Content—Wt. Percent.....	1.01	1.38

<sup>1</sup> Based on Fischer Assay of 42.86 and 4.19 Lbs. Oil and H<sub>2</sub>O, respectively.

It will be noted from the above data that there is a considerable increase in the relative quantity of gas and water produced. This indicates reaction between the carbon oxides and hydrogen. Hydrogen consumption in these runs was exceptionally high as compared with Runs C, D and E, of Example 2. The increase in water yield is particularly noticeable in the case of the carbon dioxide-hydrogen mixture. Water production is generally undesirable since it represents a direct loss of hydrogen to no useful product. The quality of the oil from Runs G and H was not as high as that from Runs C, D and E. Run H however, shows a considerable increase in gas yield as compared with Runs C, D and E. Where gas is a desired product, e.g. for heating gas, operation as illustrated by Run H may be desirable.

While the process of this invention has been described and illustrated with specific reference to the treatment of oil shale, it is to be understood that it is equally effective for the processing of tar sands or oil sands.

Obviously, many modifications and variations of the invention, as hereinbefore set forth, may be made without departing from the spirit and scope thereof, and therefore only such limitations should be imposed as are indicated in the appended claims.

We claim:

1. A continuous process for the production of hydrocarbon oils from oil shale by retorting with hydrogen which comprises maintaining a downwardly moving settled bed of oil shale particles in a vertically extended retorting zone, introducing hydrogen into the lower portion of said zone and passing hydrogen at a temperature within the range of from about 800 to about 950° F. at a rate of from about 25,000 to about 150,000 standard cubic feet per ton of shale per hour at a pressure within the range of about 1,000 to about 2,500 pounds per square inch gauge upwardly through said bed effecting retorting of hydrocarbons from said shale, withdrawing said hydrocarbons solely in vapor phase in admixture with unreacted hydrogen from said zone at an intermediate point below the top of said bed and passing resulting mixture at a temperature above about 700° F. directly from said retorting zone into contact with a bed of solid catalyst effective for promoting vapor phase hydrogenation of said hydrocarbons, recovering resulting hydrocarbons from the vaporous effluent of said bed of catalyst, recycling unconverted hydrogen to said process, withdrawing residual oil shale substantially free from carbon from the lower end of said retorting zone, introducing cold raw shale in particle form into the upper end of said zone as said residual shale is withdrawn from said zone to maintain said bed of shale particles therein, withdrawing hydrogen-rich gas substantially free from readily condensable hydrocarbon vapors from the upper portion of said zone above the point of withdrawal of said hydrocarbons in vapor phase, and recycling said hydrogen-rich gas to the lower portion of said zone.

2. A process for the production of hydrocarbon oils from the oil shale by retorting with hydrogen in a settled bed of oil shale particles in a vertically extended retorting zone, which comprises introducing hydrogen into the lower portion of said zone and passing said hydrogen at a temperature in the range of 800° F. to 950° F. and at a pressure within the range of about 1,000 to about 2,500 pounds per square inch gauge upwardly through said bed at a rate of from about 25,000 to about 150,000 standard cubic feet per ton of oil shale per hour for a period of time within the range of 20 minutes to 5 hours effecting retorting of hydrocarbons from said shale as hydrocarbon vapors mixed with said hydrogen, and passing said mixture solely in vapor phase at a temperature above 700° F. over a bed of solid catalyst effective for promoting vapor phase hydrogenation of said hydrocarbons, recovering resulting hydrocarbons from the vaporous effluent of said catalyst, recycling unconverted hydrogen to said process, and discharging residual oil shale substantially free from carbon from said retorting zone.

3. A process according to claim 2 wherein said catalyst is selected from the group consisting of the oxides and sulfides of molybdenum, tungsten, zirconium, chromium, vanadium, iron, cobalt and nickel.

4. A process according to claim 2 wherein said catalyst is cobalt molybdate.

5. A process according to claim 2 wherein said catalyst comprises 1.5 to 5 weight percent cobalt oxide and 7 to 14 weight percent molybdenum oxide on alumina.

6. A process according to claim 2 wherein said catalyst comprises molybdenum sulfide.

7. A process according to claim 1 wherein said cata-

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lyst consists essentially of oxides of cobalt and molybdenum.

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PAUL M. COUGHLAN, *Primary Examiner*.  
ALPHONSO D. SULLIVAN, *Examiner*.

THE OIL SHALE CORPORATION  
680 FIFTH AVENUE  
NEW YORK, NEW YORK 10019

1700 BROADWAY  
DENVER 2, COLORADO

October 10, 1966

**To Our Shareholders:**

Last week TOSCO, Sohio Petroleum Company (Sohio) and The Cleveland-Cliffs Iron Company (Cliffs) announced certain changes in operational responsibilities at their jointly owned semi-works facilities at Grand Valley, Colorado. Although the press carried some reports of these changes, I would like to inform you directly of what the changes are and what they mean to your Company.

Operation of the semi-works facilities is continuing. The mine will now be operated by Cliffs, and the cost of the operation will be assumed by each of the three companies in proportion to their ownership interests in the Venture. The semi-works plant will now be operated by TOSCO, for the time being at its own cost. We expect that full operation of the plant facility, which is presently undergoing maintenance and repair, will be resumed about November 1. Personnel of all three companies will continue joint evaluations of past results, continuing operations, process modifications and alternatives, and commercial economics.

These new arrangements do not affect the common objective of the three participating companies to proceed toward commercial production of shale oil from our jointly owned shale reserves. In other words, the underlying Venture Agreements of 1964 remain in full force and effect, and continue to define the common objectives of the companies.

The present arrangements carry on the program for commercial production. First, they provide a period during which the three companies will continue both their appraisal of the data obtained from prototype operations, and their review of technological alternatives. Such alternatives range from variations in the present semi-works plant to investigation of other processes, including the TOSCO V Process, which has been under intensive development by us. Second, the mining program continues under Cliffs. Finally, TOSCO will operate the prototype plant. Our operation will provide additional data which we believe to be necessary for definitive evaluation of the TOSCO II Process for comparison with systems which we are developing, as well as with other technologies.

The companies have agreed that, for the present, Colony Development Company, as agent for the three companies, will cease to have responsibility for field operations. These revisions of operating responsibility, and the present joint program of evaluation, are constructive steps toward the realization of our fundamental objectives.

In the last three months significant operating data and information has been obtained from sustained semi-works plant operations at Grand Valley. We are pleased with the results, which on basic criteria thus far examined are within the performance established by TOSCO for the TOSCO II Process in its own pilot plant operations conducted over the past several years.

TOSCO's own operating program for the semi-works plant is designed, during an operating period of several months, for further confirmation of the operation of the TOSCO II Process on the semi-works scale to allow optimum commercial design and to minimize potential problems of scale-up. Simultaneously, we have intensified our continuing engineering and economic evaluation of a complete commercial complex.

Our program for integration of the TOSCO II pilot plant with our new research center facilities at Rocky Flats is now nearly complete and during our operation of the semi-works facilities we look forward to a high level of efficiency in pilot plant support of those operations.

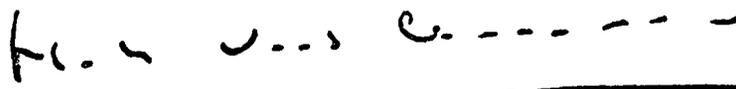
TOSCO's development of the TOSCO V Process, about which I have previously written to you, has been and is proceeding encouragingly. Preliminary engineering and economic evaluation of the commercial scale application of this process has begun. The system, which was originally conceived for the processing of tar sands and certain foreign oil shales, has also been found to be of great interest for the Colorado and Utah oil shales.

Although the principal purpose of this letter is to report to you on the recent operational changes at Grand Valley, it is appropriate to add that we continue to be vitally interested in our other programs in oil shale and other materials here and abroad.

Your Company owns or controls substantial interests in oil shale reserves in western Colorado and eastern Utah, and in a variety of water sources for use in the operation of production facilities and for community purposes. Our holdings include reserves and water rights held jointly with Cliffs and Sohio, as well as other valuable properties held by TOSCO alone or with others. We are continuing with the evaluation of reserves by core drilling and related programs.

Our increased responsibilities in connection with the semi-works facilities as well as our continuing programs and operations will require substantial funds. We presently intend to acquire such funds from private sources either by loan, which may be secured by certain of our reserves, or by the issuance of equity securities. Several of our major stockholders have already made available to us a portion of these funds for interim use. While there is no assurance that these methods of obtaining funds will provide all our needs, we are confident that our programs will go forward.

Sincerely,



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H. I. KOOLSBERGEN

*President*



COLORADO STATE WATER DISTRICT NO. 38  
COURT ADJUDICATION PROCEEDINGS

LIST OF CLAIMS TO WATER IN WATER DISTRICT NO. 38

File No.	Name of Feature	Claimant	Address
80	Spring Creek Ditch	S. P. Sloss	Sloss, Colorado
84	Goodwin Ditch	Anton Shufca	Aspen, Colorado
151	McLean Res. Nos. 1 & 2	Mary McLean	Carbondale, Colo.
165	Peterson Ditch	Mrs. Enoch Olsen	Basalt, Colorado
199	Tie Camp Ditch	S. P. Sloss	Sloss, Colorado
200	McLachlin Ditch	Walter McKenzie	Aspen, Colorado
210	Sunshine Placer Ditch	Charles O. Johnson	Denver, Colorado
2386	Corwin Ditch & Pipeline	Colo. Marble Company	Kansas City, Mo.
3057	Myser Pipelines 1, 2, 3, 4, 5, 6 & 7	J. F. Myser E. E. Drach	Denver, Colorado Denver, Colorado
3088	Myser Pipelines 8 & 9	J. F. Myser E. E. Drach	Denver, Colorado Denver, Colorado
3305	J. F. Barnes Irr. Ditch	J. F. Barnes	Marble, Colorado
3823	McKenzie Reservoir	James McKenzie Mrs. Ann McKenzie	Snow Mass, Colorado Snow Mass, Colorado
3882	Swede Ditch	N. J. Jacobson Albert Maurin	Snow Mass, Colorado Snow Mass, Colorado
4205	Corwin Ditch & Pipe Line, Amended	Colo. Marble Company	Kansas City, Mo.
5136	Saloon Ditch	S. P. Sloss	Sloss, Colorado
5193	Treasury Springs Pipe Line	Colo. Marble Company	Kansas City, Mo.
6162	Vagneur Ditch	James J. Vagneur Lewis Vagneur Dellore Vagneur	Aspen, Colorado Aspen, Colorado Aspen, Colorado
6689	Homestake, Hagerman & & Ivanhoe Ditch	W. A. Colt	Las Animas, Colo.
6927	Roaring Fork Reservoir	Harry A. House	Pueblo, Colorado
7425	Wurtz Ditch	Henry Wurtz	Aspen, Colorado
7744	Jordan Ditch	Mary Jordan Wm. Jordan	Aspen, Colorado Aspen, Colorado

List of Claims to Water in Water District No. 38 (continued)

<u>File No.</u>	<u>Name of Feature</u>	<u>Claimant</u>	<u>Address</u>
9494	Red Mountain Ditch, Gavin Enl.	James H. Gavin	Aspen, Colorado
10107	Savage Ditch	Chas. A. Savage	Aspen, Colorado
10811	Hope Ditch	Hope Mng., Milling & Leasing Co.	Aspen, Colorado
11042	Landis Creek Reservoir	Charles Schleicher Mary Schleicher Hopkins Bros. & Tillie Forker	Glenwood Spgs., Colo. Glenwood Spgs., Colo. Glenwood Spgs., Colo. Glenwood Spgs., Colo.
11679	Anna Sandy Ditch	Theodore Zadra	Carbondale, Colorado
11680	Peiser Spring & Pipe Line	E. L. Peiser	Glenwood Spgs., Colo.
12128	Renstrom Highline Ditch	S. B. Mansfield (Agent)	Carbondale, Colorado
12187	Flogaus Ditch	Charles H. Flogaus	Carbondale, Colorado
12364	Independent Ditch	Daniel McCarthy	Carbondale, Colorado
12585	Smuggler Ditch & Pipe Line	Smuggler Leasing Co.	Aspen, Colorado
12595	Rossi Edgerton Crk. Ditch	Thomas Rossi	Carbondale, Colorado
12710	Ben Hotz Ditch	Benjamin M. Hotz	Carbondale, Colorado
13139	Nettle Creek, Tank & Inlet	Crystal River Railroad Company	Denver, Colorado
13145	Cardiff Pipe Line	Colo. Fuel & Iron Corp.	Denver, Colorado
13370	Prentiss Ditches (W. & E.)	Chas. E. & Grace E. Prentiss	Glenwood Spgs., Colo.
13889	Genter Power Pipe Line	E. W. Genter	Carbondale, Colorado
13936	Yule Crk. Pipe Line, Lost Trail Crk. Ditch & Pipe Line, Kline Falls Pipe Line	John S. Macbeth Carrara Yule Marble Co.	Denver, Colorado
14094	Lyle Reservoir	L. G. Carlton	Colo. Spgs., Colo.
14095	Lake Fork Res., Preliminary	L. G. Carlton	Colo. Spgs., Colo.
14172	Crystal River Power Project	W. Porter Nelson	Denver, Colorado
14405	Hot Springs Power Pipe Line	H. L. Johnson	Marble, Colorado

List of Claims to Water in Water District No. 38 (continued)

<u>File No.</u>	<u>Name of Feature</u>	<u>Claimant</u>	<u>Address</u>
14815	Roarding Fork Trans-Mtn. Water Diversion System	G. A. Taff	Denver, Colorado
14981	Hercules Pipe Line	E. P. Simpson	Crested Butte, Colo.
15158	Lead Queen Mines Power Pipe Line	Lead Queen Mines Co.	Marble, Colorado
15159	Snow Mass Lake Reservoir	Lead Queen Mines Co.	Marble, Colorado
15198	Basalt Power Pipe Line	W. W. Frey G. B. Lucksinger	Basalt, Colorado Basalt, Colorado
15347	Twin Lakes Ditches #1&2	Twin Lakes Res. & Canal Company	Ordway, Colorado
15366	Valley Mesa Ditch	August Vallet	Carbondale, Colorado
15487	A. Usel Pipe Line & Irrigation System	Antoine Usel	Carbondale, Colorado
15503	Twin Lakes Ditches 1 & 2 Amended	Twin Lake Res. & Canal Company	Ordway, Colorado
15705	Hidden Lake Creek Ditch Ext.	Busk-Ivanhoe Co.	Colo. Spgs., Colo.
15763	Crystal Falls Pipe Line	W. Porter Nelson	Denver, Colorado
15783	Newkirk Ditch	F. D. Newkirk	Meridith, Colorado
15843	Highland Mines, Inc. Power Ditch, Famous Ditch & Ext.	Highland Mines, Inc. E. L. Grover, Sec.	Aspen, Colorado
15900	Twin Lakes Ditches, Amended	Twin Lakes Res. & Canal Company	Ordway, Colorado
16036	Bean Power & Irrigation Ditch	Concer H. Phillips	Woody Creek, Colo.
16390	Baler Park Irr. Ditches Nos. 1 & 2	U. S. Forest Service	Denver, Colorado
16469	Lewis Reservoir	Charles Thomas	Carbondale, Colorado
16493	Bob Sewell Thompson Creek Ditch	R. O. Sewell	Carbondale, Colorado
16501	Taylor Cr. Ranger St. Pipe Line	U. S. Forest Service	Denver, Colorado
16502	Capitol Cr. Ranger St. Pipe Line	U. S. Forest Service	Denver, Colorado

List of Claims to Water in Water District No. 38 (continued)

<u>File No.</u>	<u>Name of Feature</u>	<u>Claimant</u>	<u>Address</u>
16503	Lily Lake Ranger St. Pipe Line	U. S. Forest Service	Denver, Colorado
16568	Maroon Lake Pipe Line	U. S. Forest Service	Denver, Colorado
16570	Chapman Pipe Line	U. S. Forest Service	Denver, Colorado
16573	Rocky Fork Campground Pipe Line	U. S. Forest Service	Denver, Colorado
16574	Thompson Ck. Ranger St. Pipe Line	U. S. Forest Service	Denver, Colorado
16575	Aspen Park Ditch & Retaining Pond	U. S. Forest Service	Denver, Colorado
16579	Norrie Ranger St. Pipe Line	U. S. Forest Service	Denver, Colorado
16580	Conundrum Hot Spgs. Pipe Line Nos. 1 & 2	U. S. Forest Service	Denver, Colorado
16590	Chapman Reservoir & Ditch	U. S. Forest Service	Denver, Colorado
16834	Fourmile Reservoir	Colorado River Water Conservation District	Glenwood Spgs., Colo.
16888	Edgerton Gulch Ditch	Metropolitan Life Insurance Company	New York, New York
16947	G. & G. Pipe Line	Highland Mines, Inc.	Aspen, Colorado
17145	Cattle Creek Ranger St. Pipe Line	U. S. Forest Service	Denver, Colorado
17287	Gold Pan Power Ditch & Pipe Line	Wilfred C. Parry Guy C. Sperry	Carbondale, Colorado
17418	Nora E. Jackman Pipe Line	Nora E. Jackman	Wichita, Kansas
17577	Miller Domestic Pipe Line	C. W. Miller	Carbondale, Colorado
17578	Squires Domestic Pipe Line	Mary T. Squires	Carbondale, Colorado
17630	Crooked Creek Reservoir	Ralph B. Saffeels	Eagle, Colorado
17641	Miller Domestic Pipe Line	C. W. Miller	Carbondale, Colorado
17760	Dossigny Ditch	Joe Dossigny Crest Gerbaz Kenneth R. Whittlesey Posic Cerise Oscar & Amie Diemoz	Glenwood Spg., Colo. Emma, Colorado Emma, Colorado Emma, Colorado Emma, Colorado

List of Claims to Water in Water District No. 38 (continued)

<u>File No.</u>	<u>Name of Feature</u>	<u>Claimant</u>	<u>Address</u>
17878	Burgin Spring & Pipe Line	Howard N. & Evelyn W. Burgin	Ft. McPherson, Ga.
17949	Coryell Spring & Pipe Line	Josephine Coryell	Glenwood Spgs., Colo.
18035	Walck Pump & Pipe Line	Clay Walck	Glenwood Spgs., Colo.
18144	Bohan Ditch	E. C & F. O. Redman	Snow Mass, Colorado
18303	Warren Creek Ditch	J. H. Smith, Jr.	Aspen, Colorado
18575	Gaumer Spring	G. B. Gaumer & Della B. Gaumer	Glenwood Spgs., Colo.
19942	Wood Spring	Elaine & George M. Woods	Glenwood Spgs., Colo.
20669	Coke Oven Reservoir	Colo. Game & Fish Comm.	Denver, Colorado
20741	Diemer Reservoir	U. S. Forest Service	Denver, Colorado
20876	Polly Spring No. 2 & Pipeline	Ollie & Lawrence E. Hartzell	Glenwood Spgs., Colo.
20877	Polly Spring No. 3 & Pipeline	Ollie & Lawrence E. Hartzell	Glenwood Spgs., Colo.
21228	Davies Spring & Pipeline	David Davies	Glenwood Spgs., Colo.
21488	Ashcroft Reservoir	Colo. River Water Conservation District	Glenwood Spgs., Colo.
21541	Mineral Spring & Ditch	Alex & Rose Creton	Carbondale, Colorado
21577	Redstone Campground Pipeline	U. S. Forest Service	Denver, Colorado
21711	Barbers Gulch Ditches	Ray R. & Lois J. Fender	Carbondale, Colorado
21763	Yule Creek Ditch	Charles & Marjorie A. Orlosky	Marble, Colorado
21804	West Marble Pipeline & Water System	Elmer O. & Ida L. Bair George T. Harris	Carbondale, Colorado Denver, Colorado
21956	Castle View Ditch & Pond	Phil W. & Barbara L. Streker	Basalt, Colorado
21974	Beaver Lake	Colorado Game, Fish & Parks Commission	Denver, Colorado
22036	Learn Spring & Pipeline	John Learn	Glenwood Spgs., Colo.
22053	Cator Spring	Bert Cator	Glenwood Spgs., Colo.

List of Claims to Water in Water District No. 38 (continued)

<u>File No.</u>	<u>Name of Feature</u>	<u>Claimant</u>	<u>Address</u>
22056	Yule Creek Reservoir	Scott W. Heckman Ivan P. Kladder Frank Misley	Grand Junction, Colo. Grand Junction, Colo. Grand Junction, Colo.
22095	Black Spring	G. B. Gaumer	Glenwood Spgs., Colo.
22278	Hinderliter Pipeline	Virginia Hinderliter	Basalt, Colorado
22280	Nelson Springs & Pipeline	Vinance Favre Glenn A. Leonard Earl V. Nelson	Basalt, Colorado Basalt, Colorado Basalt, Colorado
22288	Twining-Harbour Ditch	Betty Jane Harbour Stanford H. Johnson Wm. J. Clearey W. C. & H. E. Stroud James & Susan Drais W. A. & S. O. Shattuck	Aspen, Colorado Aspen, Colorado Aspen, Colorado Aspen, Colorado Topeka, Kansas Ashland, Kansas
22295	Norrie Colony Water Pipeline	W. C. Kurtz	Norrie Colony Meredith, Colorado
22333	White Horse Springs Collection System & Storage Tanks	White Horse Springs Ranch Syndicate	Aspen, Colorado
22334	Aspen Skiing Corp. Springs Collection System & Storage Tanks	Aspen Skiing Corp.	Aspen, Colorado
22462	Highland Ditch No. 1	Highland Mines Inc.	Glendale, California
22494	Nast Summer Home Group Spring Pipeline	U. S. Forest Service	Denver, Colorado
22517	Trentaz Corral Springs Collection System & Storage Tanks	Starwood Land Corp.	Aspen, Colorado
22526	Highland Richmond Spring & Pipeline	Keating & Virginia M. Coffey	Aspen, Colorado
22527	Highland Hope Spring & Ditch	Keating & Virginia M. Coffey	Aspen, Colorado
22538	Owl No. 1 Stock Pond Spring	U. S. Forest Service	Denver, Colorado
22636	Ray-Mar No. 1 Well	R. A. & M. D. Morgan	Glenwood Spgs., Colo.
22726	Jammaron Spring Pipeline	Joe & Leo Jammaron	Glenwood Spgs., Colo.
22737	Castle Creek Res. & Pipeline	City of Aspen	Aspen, Colorado

List of Claims to Water in Water District No. 38 (continued)

<u>File No.</u>	<u>Name of Feature</u>	<u>Claimant</u>	<u>Address</u>
22738	Maroon Creek Res. & Pipeline	City of Aspen	Aspen, Colorado
22760	Moore, K. N. C. B., Ditch	K. N. C. B. Moore	Aspen, Colorado
22761	Moore, K.N.C.B., Fish Pond	K. N. C. B. Moore	Aspen, Colorado
22773	La Moy Pipeline	Gordon M. La Moy	Snow Mass, Colorado
22799	Snowmass Project	Colorado River Water Conservation District	Glenwood Spgs., Colo
22808	Colorado Outward Bound School Pipeline	Colorado Outward Bound School	Marble, Colorado
22809	Twin Meadows Reservoir	Colorado Game, Fish & Parks Commission	Denver, Colorado
22811	Upper Chapman Reservoir	Colorado Game, Fish & Parks Commission	Denver, Colorado
22832	Snowmass Reservoir	Janss Colorado Corp.	Aspen, Colorado

Approved, but no Filing No. assigned, as of the above date.

Frank Ditch	Mary K. Frank	Snow Mass, Colorado
Doremus Pipeline	John F. Doremus	Aspen, Colorado

EXTENSION OF REMARKS  
OF**HON. RUSSELL B. LONG**

OF LOUISIANA

IN THE SENATE OF THE UNITED STATES

*Saturday, October 22, 1966*

## PERCENTAGE DEPLETION

The fourth area of complaint is concerned with the provisions relating to percentage depletion. Of course, there are people who fundamentally disapprove of percentage depletion, as such. To them any amendment in the area of percentage depletion is automatically wrong if it gives one cent more of deduction to anyone, simply because they do not agree with the underlying principle involved in percentage depletion.

It seems to me that as long as we have percentage depletion in our tax system—and parenthetically I might add from my point of view this is something I hope is here for a long time to come—it is entirely appropriate that the percentage depletion rates be adjusted in a manner which allows for the competitive nature of the products. In other words, where two or more products are used for essentially the same purpose, good tax treatment—namely, the considerations of equity and fair competition—demands that they receive approximately the same percentage depletion deduction. This is no new, radical doctrine I am proposing here. This is, instead, the fundamental basis on which most of our percentage depletion rates are based at the present time.

Let us look now at the specific areas where the percentage depletion rates were changed, and I should point out that as a result of the conference committee action it is only a change in rates which occurred. No additional processes were classified as mining processes for any mineral. This is the area that the Senator from Tennessee [Mr. GORE] was so concerned with a number of years ago. We have not in the slightest modified the concepts of the mining processes, on which percentage depletion is based, from the concepts in present law which remains as he provided by legislation in 1960.

The first area in which a percentage depletion rate was made was in the case of domestic deposits of clay, laterite, and nephelite syenite, but only to the extent that they are used for the extraction of alumina or aluminum compounds. The percentage depletion rate for these minerals was raised from 15 to 23 percent. This only seems fair since this is the percentage depletion rate which presently applies to domestic deposits of bauxite, the principal source of alumina and aluminum. It also is the rate which applies to another site to the extent that alumina and aluminum compounds are extracted from it. The Finance Com-

mittee believed that a good case could be made not only for these percentage depletion rate increases but also for more liberal treatment with respect to mining processes. However, the House conferees would not agree to any changes in mining processes. Nevertheless, it is hard for me to see how anyone could object to treating these different sources for alumina and aluminum the same as we already treat the principal source for alumina and aluminum.

The second percentage depletion rate change applies in the case of clam and oyster shells. Now I am aware of the fact that percentage depletion for clam and oyster shells is a source of amusement for many who are unacquainted with the extent to which clam and oyster shells in the entire gulf area are used as a substitute for limestone. The clam and oyster shells referred to in this act are those which have lain at the bottom of the sea for many hundreds or thousands of years. The ownership in these shells is in either the Federal or a State Government. The Government leases to private parties the right to remove these shells from certain specified areas. This gives them a right to property which is exhaustible and which is, therefore, eligible for percentage depletion. This is exactly the same concept which applies generally with respect to percentage depletion.

Clam and oyster shells of the type I have referred to already receive percentage depletion at the rate of 5 percent. However, clam and oyster shells in many cases are ground up and used for their calcium carbonate content in making cement.

Limestone—which also is essentially calcium carbonate—in other areas of the country is used for almost the identical purposes for which clam and oyster shells are used, yet limestone, except when used for road material or similar purposes, receives a 15-percent depletion rate. When it is used as gravel for making roads, the depletion rate is limited to 5 percent. All this amendment does is to give precisely the same treatment to clam and oyster shells which is already available in the other areas of the country where limestone is used for the same purposes. In other words, where clam and oyster shells are used as a substitute for gravel in making roads, the 5-percent depletion rate as at present will continue, but when clam and oyster shells are used for making cement, as in the case of limestone, the 15-percent rate will be available. Realistically, this does no more than give the same treatment to deposits of calcium carbonate found under water as is already accorded deposits of calcium carbonate found on land. This merely removes a competitive discrimination.

The final two percentage depletion rate changes represent very small changes indeed. The Senate action would have added sintering or burning to the processes classified as mining processes in the case of clay, shale, and slate used or sold as lightweight aggregates. These frequently are used for this purpose in concrete or in making cinder blocks. The Senate action, as a

result of a floor amendment, would also have increased from 5 to 15 percent the percentage depletion rate applicable for clay and shale used in making sewer pipe and brick. In these cases the primary consideration was that other products used for similar purposes received a higher percentage depletion rate, or received more favorable treatment in the processes classified as mining processes.

In the case of clay used for sewer pipe, for example, this pipe is in competition with concrete sewer pipe and the materials used in making the cement which goes into the latter is eligible for 15-percent depletion rate. It was on this basis that the increase in the rate from 5 to 15 percent was justified on the Senate floor. In the conference committee consideration of this, however, it was noted that contrary to a clay sewer pipe, only 15 to 20 percent of a concrete sewer pipe consists of cement. The remaining aggregates are sand and gravel which receive a 5-percent depletion rate. Because of this additional information available to the conferees, which was not available at the time this matter was considered on the floor of the Senate, the Senate conferees agreed that the depletion rate should be adjusted upward by merely 2½ percent, rather than by the 10 percent which would have been provided by the Senate amendment. As I have suggested, this was agreed to because of the realization that in the case of the clay pipe, the area of competitive discrimination is limited to 15 to 20 percent of the total value of the pipe. This represents a modest change in the depletion rates and one which is justified on the basis of the present competitive situation.

The Senate amendment relating to lightweight aggregates dealt with the treatment processes which were to be considered part of the cost of mining in working out the percentage depletion allowance. The House conferees, as I have indicated, were not willing to make any change in the treatment process provisions but they could see the merit of a larger deduction for these products when used as lightweight aggregates. The conferees decided to take the direct approach of giving a slightly larger depletion allowance rather than the indirect approach of increasing the base on which the present depletion allowance would be based.

EXCERPTS FROM, ENERGY R & D AND NATIONAL PROGRESS  
An Interdepartmental Study  
September, 1966

## PREFACE

In a memorandum dated February 15, 1963, President Kennedy requested the following nine heads of Federal departments and agencies to undertake a comprehensive study of "the development and utilization of our total energy resources to aid in determining the most effective allocation of our research and development resources."

Director, Office of Science and Technology  
Chairman, Council of Economic Advisers  
Director, Bureau of the Budget  
Director, Office of Emergency Planning  
The Secretary of the Interior  
The Secretary of Commerce  
Chairman, Atomic Energy Commission  
Chairman, Federal Power Commission  
Director, National Science Foundation

The President designated the Director of the Office of Science and Technology and the Chairman of the Council of Economic Advisers as chairman and vice chairman of the steering committee to carry out the study. Subsequently the Secretary of Defense was added to the group because of the Defense Department's varied interests in energy questions. Valuable assistance was also provided by the Departments of Health, Education, and Welfare; State; Labor; and the National Aeronautics and Space Administration.

The steering committee formed an Energy Study Group under the direction of Dr. Ali Bulent Cambel. The Energy Study Group performed a comprehensive, detailed, and thorough analysis, involving more than 500 people both inside and outside the Federal Government and resulting in a report—*Energy R&D and National Progress*.<sup>1</sup> The report has been exposed to detailed scrutiny by all governmental agencies involved in the study, although it should be noted that Dr. Cambel and his staff bear the ultimate responsibility for its content and publication of the report does not imply acceptance or rejection by any of the participating agencies.

The Cambel study, issued concurrently with this statement, is a major source of the data and analysis on which the findings, conclusions, and recommendations in this statement are based. It also provides a more detailed analysis of the many specialized problems associated with the development of particular energy resources. The present statement by the steering committee is directed at principal policy issues of a more general

nature, although it does not deal with a number of important issues of concern to the Federal Government which influence the use of research and development resources, such as regulatory, patent, and foreign trade policies. The committee did not give detailed, specific consideration to potential emergency situations, being aware that other studies of this class of problems have been made and that still others are in progress.

## INTRODUCTION

### The Problem

Advanced industrial societies have developed a high standard of living by utilizing energy on a large scale and replacing human and animal energy with mechanized energy for both industry and personal consumption.

Annual energy consumption in the United States has increased rapidly in the past and is expected to rise from 250 million ( $2.5 \times 10^8$ ) Btu's per capita in 1960—45 quadrillion ( $4.5 \times 10^{16}$ ) Btu's in total—to about 400 million Btu's per capita or 135 quadrillion Btu's in total in the year 2000 (see fig. 1). The total estimated cumulative consumption of 3 quintillion ( $3 \times 10^{18}$ ) Btu's over the 40-year span from 1960 to 2000 is much less than the known recoverable domestic reserves—estimates of which range from about 5 to nearly 25 quintillion Btu's of energy depending on the utilization factors assumed for uranium and thorium. For the projected increase to take place, however, energy must be available at reasonable costs.

From the most reliable information, it seems fairly clear that presently foreseeable total resources will indeed be adequate to meet total energy needs without major cost increases for the remainder of this century, and for a considerable time thereafter. The committee has confined its detailed considerations to the period ending in the year 2000. It has done so with awareness that this is a short period on the scale of human history, but with confidence that critical problems are far enough removed in time so that human ingenuity and imagination can cope with later circumstances as newer information develops. *The main problem is how to meet the growing need in the most effective and least costly way, both in the immediate future and for the long run.*

Secondly, *problems arise in matching energy sources for particular purposes and in assuring competitive availability.* Coal was once the principal energy source for household heating, industrial use, transportation, and electrical power. Today it has been replaced widely by petroleum and natural gas in household heating and industrial uses, and by petroleum for transportation—truck, rail, ship, air, and automobile. It also now shares the market for electric generation with natural gas, oil, nuclear fuel, and waterpower. The economy should retain and expand its flexibility to choose among energy sources for particular application.

In addition, Americans wish to minimize environmental pollution and preserve natural beauty in the course of developing and using energy resources.

The focus of the Energy Study has been on the role of research and development activity in contributing to the solution of these problems, and in particular on the future role of the Federal Government. For most fuels, the private sector has borne an important if not the major part of the cost of R&D in the past, and this pattern is expected to continue. Concurrently

the Government has sponsored important R&D such as that involved in the development and utilization of atomic energy. In the future the Government will need to assist when the development is too large or risky for the private sector, when the benefits of development are too diffused, when they are required for national security and welfare, or when necessary to maintain effective competition among and between energy sources.

### Supply and Demand

The principal foreseeable sources of energy during the next few decades are fossil fuels—coal, oil, shale oil, tar sands, and natural gas—and the fissionable or fertile materials—uranium and thorium. These energy sources occur naturally in the crust of the earth in deposits of widely varying accessibility, depth, size, and quality. As a result of past exploration and research, the nature and extent of some of these deposits are well known. The existence of other similar deposits, discoverable through further exploration, can be inferred from favorable geological conditions known or believed to prevail in those portions of the earth's crust not yet thoroughly explored. In addition to the size of natural deposits, the long-run adequacy of energy resources depends on other factors such as accessibility, quality gradations, processing and extraction techniques, and, importantly, on the particular needs of each consumer. A substantial part of the energy sources contained in both known and unappraised deposits is of submarginal quality, not economically exploitable with present technology, but it is reasonable to assume that technological gains will bring such deposits within economic reach in the future.

The long-run adequacy of our energy resources, therefore, will depend not only on the extent of presently known minable deposits but on R&D that:

- improves knowledge of geology and exploration capability;
- improves processes for extraction from grades now considered marginal and submarginal;
- reduces transportation costs;
- improves efficiency in use; and
- develops substitutes for resources which are being depleted or are increasing in cost.

Also, some energy resources are available abroad at less cost than in the United States. America can benefit from foreign supplies of energy resources, giving in exchange goods in which the United States holds a comparative advantage. Ideally, the appraisal of a nation's total energy resources should reflect its ability to share in the use and production of world energy resources. In order to keep its scope manageable, however, the appraisal here is confined largely to domestic resources, and the conclusions reached are accordingly conservative.

### Energy Resources of the United States

Domestic energy resources and requirements are projected by source from 1960 to 2000 in table I. The projection must be qualified because estimates from various competent authorities differ substantially, and also are quickly outdated by new or improved information. It is evident nonetheless that the Nation's known energy resources are large, and that even greater supply is undiscovered or cannot now be exploited economically. Anticipated requirements exceed "known recoverable resources" from liquid hydrocarbons and natural gas; but "total resources" far exceed anticipated

EXCERPTS FROM, ENERGY R & D AND NATIONAL PROGRESS (continued)

requirements for any and all energy sources. Undoubtedly, the fruits of research and development programs can assure economical and physically exploitable energy resources throughout the 20th century. The well-being of the Nation in the 21st century, however, may well depend on the advances made in the efficiency of utilization of resources and the discovery of new resources.

TABLE I.—Comparison of U.S. energy resources with projected requirements, 1960–2000<sup>1</sup>

[Expressed in terms of energy content, where the unit is 1 Q=1 quintillion (10<sup>18</sup>) Btu]

	Coal <sup>a</sup>	Conventional liquid hydrocarbons <sup>b</sup>	Shale oil <sup>c</sup>	Oil in bituminous rocks <sup>d</sup>	Natural gas <sup>e</sup>	Uranium <sup>f</sup>	Thorium <sup>g</sup>
1. Known reserves recoverable under present economic and technologic conditions.....	4.6	0.3	-----	-----	0.3	0.3	-----
2. Undiscovered deposits recoverable (when found) under present technologic conditions.....	-----	1.3	-----	-----	1.2	0.8	-----
3. Additional known and undiscovered resources possibly recoverable in the future.....	84	2.3	945	0.07	0.9–25	224,000	336,000
4. Total resources (sum of lines 1, 2, and 3).....	88.6	3.9	945	0.07	2.4–26	224,000	336,000
5. Cumulative projection of energy requirements 1960–2000, by source <sup>h</sup> .....	0.6	-----	1.4	-----	1.0	0.2	-----
5.a. As percent of known recoverable resources, assuming present conditions (line 5 divided by line 1).....	13%	470%-----			333%	67%-----	
5.b. As a percent of total recoverable resources (line 5 divided by the sum of lines 1 and 2)....	13%	87%-----			67%	18%-----	
5.c. As percent of total resources (line 5 divided by line 4).....	1%	36%	0.1%	2,000%	42–3.8%	-----	

<sup>1</sup> Derived primarily from Cambel, *Energy R&D and National Progress*, with some modifications in assumptions as to recovery of energy from uranium. Other estimates from competent sources may differ from those used here.

<sup>a</sup> Known recoverable reserves are limited to coal in beds at least 3.5 feet thick and less than 1,000 feet below surface; 50 percent of coal in ground or 220 billion tons is assumed to be recoverable. Undiscovered similar deposits may be assumed to exist but have not been estimated. The additional resources include known and undiscovered beds of 1 foot or more thick largely above a depth of 6,000 feet; 100 percent of coal in ground is assumed to be recoverable.

<sup>b</sup> Known recoverable reserves include 48 billion barrels of crude oil, considered recoverable by primary and secondary recovery methods by Interstate Oil Compact Commission; and 7 billion barrels of natural gas liquids reported as proved reserves by API and AGA. The additional resources include known marginal and submarginal resources and undiscovered resources in producible accumulations, assuming recovery obtainable with present production techniques; eventually 70 to 80 percent recovery of total liquid hydrocarbons in place may be possible.

<sup>c</sup> Shale oil is currently not being produced and hence none is shown as recoverable under present conditions; beds 25 feet or more in thickness and containing 30 gallons or more of oil per ton are considered marginal under present costs and prices, and the more accessible beds of this character contain about 50 billion barrels or 0.3 Q energy equivalent, assuming 50 percent recovery. The additional resources include oil technically extractable from less accessible or lower grade deposits that are capable of yielding 5 gallons or more oil per ton of rock. The estimate includes 170 trillion barrels of oil in known and undiscovered resources. It assumes that about 50 percent of the energy potential of the shale technically could be transformed into hydrocarbon fluid.

<sup>d</sup> Although preparations are being made to recover oil from tar sands in Canada, no oil is currently produced from such deposits in the United States, and hence none is shown here as recoverable under present conditions. Known and accessible deposits contain about 1.3 billion barrels, assuming 50 percent recovery of the rock in place.

<sup>e</sup> Known recoverable reserves (in 1962) represent 268 trillion cubic feet estimated as proved reserves by API and AGA. Undiscovered reservoirs that can be found and produced under present conditions are estimated to contain about 1,200 trillion cubic feet of recoverable gas, or 1.2 Q. The low estimate of additional resources represents undiscovered recoverable and marginal and submarginal natural gas in producible reservoirs as presently recognized. The high figure also includes 24 Q in submarginal known and undiscovered resources of porespace gas in shale and coal; such resources are mostly unappraised as to producibility.

## EXCERPTS FROM, ENERGY R & D AND NATIONAL PROGRESS (continued)

<sup>7</sup> Known recoverable reserves include 142,000 tons of uranium in known producible deposits and 181,000 tons that have already been delivered to the AEC. With present methods about 1.5 percent of potential energy of the uranium can be converted to heat for commercial use; the currently recoverable energy of the 323,000 tons is 0.34 Q. The total theoretical energy of the same material is about 23 Q. If economic methods are developed, e.g., through breeder reactors, to convert about 80 percent of uranium into energy producing fissionable material the recoverable energy would be 18 Q. Undiscovered deposits (recoverable when found) are estimated to contain about 770,000 tons of uranium with a presently recoverable energy equivalent of about 0.81 Q. The total theoretical energy of the same material is about 53 Q, and at 80 percent utilization is 42 Q. The estimate of additional resources includes known lower grade deposits, and unappraised and undiscovered resources in the United States which are estimated to total about 4 billion tons of uranium in deposits containing a few thousandths of a percent or more uranium; the estimate of energy equivalent assumes a theoretical 80 percent recovery.

<sup>8</sup> Technology has not yet been developed which will allow use of thorium in commercial reactors, and hence none is shown as presently recoverable. Thorium, by itself, is not a substitute for other fuels. However, it can be converted into uranium-233 when used in conjunction with fissile material originally provided from natural uranium. Uranium-233 is fissile, and thus can contribute to the overall supply of fuels, when suitable technology is developed. Known deposits of thorium minable at present prices contain about 100,000 tons of thorium with a theoretical energy potential of 5.6 Q, assuming 80 percent energy recovery. Unappraised and undiscovered thorium resources of the same or lower grade are estimated to contain about 6 billion tons of thorium with a theoretical energy potential of 336,000 Q, assuming 80 percent recovery.

<sup>9</sup> Derived from Landsberg et al., *Resources in America's Future*, pp. 856-57 (Medium Projection).

<sup>10</sup> Atomic Energy Commission estimates for these quantities are 96,000 Q for uranium and 152,000 Q for thorium.

<sup>11</sup> The estimated uranium requirements in table I are based on makeup requirements if the overall fuel utilization averaged 1.5 percent of the potential energy content of this fuel (including both uranium-235 and uranium-238). Inventory requirements (in the reactors and the supporting manufacturing operations) are not included, although they are large. This is a relatively low utilization factor which assumes reuse of plutonium created in nuclear reactors of essentially today's technology. It does not take into account the potential gains from advanced converters and reactors of the future with substantially higher conversion ratios.

### Implications

The foregoing comparison of the U.S. energy resources and projected requirements has the following implications:

1. In the light of present day technology, the Nation's total energy resources seem adequate to satisfy expected energy requirements through the remainder of this century at costs near present levels, but technological advances will be required to reduce costs and extend the supply base into the more distant future.
2. Future sources of electric power, especially coal and nuclear fuels, are abundant. All of the estimates indicate that *either* coal or uranium resources *alone* are adequate to take us through the year 2000 and longer.
3. Oil and gas, which now supply 73 percent of our total requirements for energy, are the fuels for which there are the smallest known and potential resources, even on a world basis.
4. In addition to domestic resources, the energy resources of other countries offer increased potential supplies for the United States in exchange for other products of the U.S. economy.

## RECOMMENDATIONS

### Crude Oil and Natural Gas Substitutes

Domestic reserves of gas and petroleum are relatively small enough to warrant governmental interest in the timely availability of additional resources and economical substitutes. Imports from other countries with large reserves and lower production costs, or substitutes in the form of fuel cells or storage batteries, will tend to offset the impact of declining domestic reserves; but it is still desirable to retain the flexibility which domestic liquid and gaseous fuels provide.

The vast supply of shale oil represents one domestic substitute for petroleum. Both private and Government R&D have decreased processing costs. The Government should encourage R&D in extraction techniques, basic geology, and processing and utilization. Advanced mining systems deserve emphasis—particularly *in situ* and other extraction methods which might reduce both costs and damage to environment.

Government support of research in the conversion of coal to petroleum products is desirable as a feasible future substitute. Also, R&D should be encouraged to lower production and other costs of coal processing in general.

### Environmental Pollution Abatement

An important energy issue lies in the extent to which the increasing atmospheric pollution from fossil fuel combustion may require imposition of further regulations on the use of these fuels. Although such a development does not appear imminent, present understanding of environmental pollution problems is rudimentary. Consideration is being given to the research recommendations contained in the report of the Environmental Pollution Panel of the President's Science Advisory Committee (October 1965), and many of these are being implemented. It is entirely possible that our overall R&D program may have to be substantially altered to control pollution.

The trend of pollution regulatory policy will stimulate substantial private research and development directed at cleansing conventional pollution sources, but unfortunately practical and economical results through this approach may not reduce pollution quickly enough. Therefore, the Government should accept its share of responsibility for increasing R&D aimed at reducing damage from ongoing activities as well as developing substitute energy sources and processes that do not pose environmental problems.

The long-run pollution problems—such as heating of streams by powerplants, acid mine drainage, and radioactive and other contamination of water and air—require continuing Government research and surveillance. Existing programs in these areas should be strongly supported.

The aesthetic "pollution" caused by open wire electric transmission in many localities is a special area for Government concern. Except for encouragement via regulation or direct Government purchase, there appears to be sparse private incentive for R&D in overhead direct current or advanced underground high-voltage transmission. Support for R&D in this technology may have to come from the Government.

## OPPORTUNITIES AND INCENTIVES IN RESEARCH AND DEVELOPMENT

The objectives of energy research and development programs are to provide adequate and diverse sources of energy at low costs. The incentives for research and development vary among different fuels, but opportunities for improving technology and extending supplies exist for all of them.

### Oil

As previously shown, potential domestic resources are ample for increased production for many years; the question therefore, is whether exploration and development costs can be reduced sufficiently to attract enough investment to generate this production domestically, or whether needs are to be met from lower cost foreign or synthetic sources. Increased R&D might yield cost-cutting benefits in each of the principal fields related to production—exploration and drilling technology, subsurface geologic mapping and analysis, and secondary recovery.

### Gas

What is said for oil generally applies to natural gas, which is often associated with oil. In addition, some formations not favorable for oil—such as shales and coaly rocks that contain occluded gas—may be favorable for gas. Some of these formations are already yielding gas under artificial fracturing.

### Oil Shales and Bituminous Rocks

Industrial research on the enormous domestic oil shale deposits is increasing with some prospect for competitive production within a few years. Since shale oil is a likely substitute for both gas and oil in some applications, its development is of great importance in extending the supplies of these fuels. Since large-scale production from oil shale faces serious obstacles due to its impact on the natural environment, it is desirable to explore mining and recovery systems that will be compatible with sound principles of environmental management and that might reduce costs as well. *In situ* extraction methods and advanced mining systems offer the most promise.

Further exploration of bituminous rocks, similar to the tar sands of Canada, may also lead to significant discoveries. Some R&D on recovery processes applying to such deposits is in progress and more would appear to be rewarding.

## Coal

Until recently, coal R&D proceeded at low tempo; but the pressure of competition from oil, gas, and most recently nuclear energy, has led to increased expenditures. There has been progress in nearly every phase of the industry—mining, processing, transportation, and utilization—resulting in an overall decrease in the average price of coal. Opportunities for continued advance in extraction and transport technology are still great, and there are gains to be made also from studies of the distribution and quality of coal resources. Also, research and development on processes for extracting substitutes for crude oil and natural gas from coal have progressed in recent years.

## Abatement of Damage to Health and Environment

In the future, development and use of fuel resources will be strongly influenced by the urgent necessity to control critical increases of environmental pollution—such as automobile exhaust gases, SO<sub>2</sub> and other products of fossil fuel burning; excessive heating of rivers and estuaries by powerplant water cooling; acid mine drainage; radioactive wastes; and damage to scenic and land values through mining. Research and development programs aimed at both the assessment of hazards to health and environment and the economical abatement of damages are urgently needed. Atmospheric carbon dioxide is not poisonous but in the long run may affect the temperature of the earth and the weather; research directed toward understanding thoroughly the implications of atmospheric carbon dioxide buildup is particularly necessary to determine with greater certainty the effects that can be anticipated if we continue our present usage of fossil fuels for the next several decades.<sup>2</sup>

Automobile exhaust gas pollution may ultimately limit the use of conventional automotive engines unless a sharp improvement in control is developed. Present technology for limiting pollution, developed in response to official regulation, is inadequate to keep pace with the rate of increase in the number of automobiles. The fuel cell or improved storage batteries may, with sufficient development, provide an alternative power source, even if continuing vigorous research on control of present sources should not be successful.

Nuclear reactors, which do not produce carbon dioxide or other combustion products, provide a potential means of decreasing future air pollution. However, they produce other kinds of deleterious wastes; and continued care will have to be exercised to avoid radioactive contamination in reactor operation, waste product handling, and fuel processing.

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<sup>2</sup> At our projected world rate of fossil fuel consumption, the Panel on Environmental Pollution of the President's Science Advisory Committee, in its report: *Restoring the Quality of Our Environment*, estimates an increase in carbon dioxide content of the atmosphere of 25 percent by the year 2000. It is not yet known whether this would have undesirable consequences. (Tukey, John W., et al., *Restoring the Quality of Our Environment*, U.S. Government Printing Office, Washington, D.C. 1965. Available from Superintendent of Documents, U.S. Government Printing Office, at \$1.25.)

### Fossil Fuels

The energy content of known recoverable domestic reserves of the fossil fuels recoverable at present prices and established technology is about 5.5 Q (quintillion Btu) and that of resources recoverable only under changed economic or technologic conditions is estimated to be as much as 125 Q or more.

TABLE 3-1.—Provisional estimates of fossil-fuel resources of the United States<sup>1</sup>

Fuel	(1) Known recoverable reserves <sup>2</sup>	(2) Undiscovered recoverable resources	(3) Known marginal and submarginal resources that economically recoverable at present	(4) Undiscovered marginal and submarginal resources (not economically recoverable at present)
Coal.....short tons.....	220×10 <sup>9</sup> 3 <sup>4</sup> (4.6 Q)	Not estimated	1,400×10 <sup>9</sup> (29 Q)	2,600×10 <sup>9</sup> (55 Q)
Petroleum.....barrels.....	48×10 <sup>9</sup> (0.278 Q)	3,200×10 <sup>9</sup> (1.16 Q)	40×10 <sup>9</sup> (0.239 Q)	3300×10 <sup>9</sup> (1.74 Q)
Natural gas.....cubic feet.....	208×10 <sup>12</sup> (0.278 Q)	1,200×10 <sup>12</sup> (1.28 Q)	Not estimated	850×10 <sup>12</sup> (0.880 Q)
Natural gas liquids.....barrels.....	7×10 <sup>9</sup> (0.032 Q)	30×10 <sup>9</sup> (0.18 Q)	Not estimated	60×10 <sup>9</sup> (0.28 Q)
Oil in bituminous rocks.....do.....	1.5×10 <sup>10</sup> (0.008 Q)	Not estimated	Not estimated	10×10 <sup>10</sup> (0.058 Q)
Shale oil.....do.....	50×10 <sup>9</sup> (0.29 Q)	Not estimated	2,000×10 <sup>9</sup> (11.6 Q)	4,000×10 <sup>9</sup> (23.2 Q)
Total energy in fossil fuels.....	(5.5 Q)	(2.6 Q)	(41 Q)	(81 Q)

<sup>1</sup> Prepared by D. C. Duncan and V. E. McKelvey of the U.S. Geological Survey.  
<sup>2</sup> As defined here known recoverable reserves include measured, indicated, and inferred reserves. Estimates of indicated and inferred reserves of oil, gas, and natural gas liquids are not available; however, the estimates shown are proved (measured) reserves and therefore not wholly comparable to the estimates shown for the other commodities.  
<sup>3</sup> See text. Other estimates of the size of these reserves vary widely.  
<sup>4</sup> The numbers in parentheses represent the energy equivalent in Q (quintillion Btu) and the total energies are rounded values.

TABLE 3-2.—Other recent estimates of "recoverable" fossil-fuel resources<sup>1,2</sup>

Source	Coal (billion short tons)	Petroleum (billion barrels)	Natural gas liquids (billion barrels)	Natural gas (trillion cubic feet)	Oil in bituminous rocks (billion barrels)	Shale oil (billion barrels)	Total (rounded)
Hubbert, National Academy of Science Publication 1000-D, 1962.....	830 (17.3 Q)	108 (0.63 Q)	24 (0.11 Q)	783 (0.81 Q)	2.6 (0.015 Q)	850+ (4.93 Q)	(23.8 Q)
Averitt, U.S. Geological Survey Bulletin 1136, 1961 <sup>3</sup> .....	830 (17.3 Q)	436 (2.37 Q)		1,842 (1.9 Q)	1.26 (0.007 Q)	700 (4.06 Q)	(25.7 Q)
Lasky et al., National Fuels and Energy Study Group, Senate Document 159, 1962 <sup>4</sup> .....	830 (17.3 Q)	340-440 (1.9-2.46 Q)		1,250 (1.3 Q)	2-3 (0.012-0.017Q)	1,000 (5.8 Q)	(26.3-26.9 Q)

<sup>1</sup> The concepts of "recoverable" differ in the estimates reported. The estimate of recoverable coal (which in all the reports is taken from Averitt) refers to 50 percent of the total measured, indicated, and inferred reserves in the ground; except for the fact that the estimate excludes beds less than 14 inches thick and below a depth of 3,000 feet, the term "recoverable" has no economic implication. The same is true with respect to shale oil and oil in bituminous rocks. As applied to petroleum, natural gas liquids, and natural gas, the term "recoverable" generally refers to amounts that will be ultimately produced, continuing economic and technologic changes are assumed but are unspecified.  
<sup>2</sup> Energy equivalents were reported by Averitt; those for the other estimates have been calculated here.  
<sup>3</sup> Averitt's estimate of coal refers mainly to beds known from detailed mapping and other measurements; because it excludes coal remote from outcrops or points of observation and below a depth of 3,000 feet, the estimate is minimal and "will be increased in the future as additional information is acquired through geologic mapping and physical exploration" (p. 86).  
<sup>4</sup> Lasky made or reported the estimates shown here as amounts that might be ultimately recovered under changed economic or technologic conditions. He considered the most meaningful estimates of reserves, however, to be those in the proved category, minable at present prices. In this category, he estimated or reported reserves as follows: coal, 20 billion tons; petroleum and natural gas liquids, 38 billion barrels; natural gas, 270 trillion cubic feet; and shale oil, 50 billion barrels.

## COAL

## Domestic Resources

The known recoverable reserves are those in thick coalbeds lying at depths of less than 1,000 feet; 50-percent recovery of the coal in place is assumed. The minimum thickness of beds of bituminous and higher rank coal included in the estimate is 3.5 feet, and that of subbituminous and lower rank coal is 10 feet.

The known marginal and submarginal resources include coal left in first mining of known recoverable reserves, coal in thin beds at shallow depths, and coal lying at depths between 1,000 and 3,000 feet below the surface. The estimate assumes complete recovery of coal in place, and includes coal in the measured, indicated, and inferred categories of P. Averitt, with additional data reported by H. Beikman et al., less that reported here in the known recoverable class, rounded to two significant figures.

The undiscovered marginal and submarginal resources refer to coal believed to be in place to depths of 6,000 feet. (A separate estimate of undiscovered thick coal at shallow depths has not been prepared.) The estimates are from work published in 1913 by M. R. Campbell, less the sum of known recoverable reserves and known marginal and submarginal resources, rounded to two significant figures. Campbell's estimates include thin beds of low-rank coal now excluded from coal-reserve estimates, but they are the only ones available that show the distribution of deep coal resources by State and basin. New estimates are in preparation.

Table 3-3 gives estimates of coal resources on a regional basis. (See fig. 8 for regional areas.)

TABLE 3-3.—Coal resources of the United States, by region

Region	Known recoverable reserves (million tons)			Known marginal and submarginal resources <sup>1</sup> (million tons)	Undiscovered marginal and submarginal <sup>2</sup> resources <sup>3</sup> (million tons)
	Measured <sup>1</sup>	Indicated <sup>1</sup>	Inferred <sup>1</sup>		
1.....	None	None	None	Small	Small
2.....	15,000 (0.315 Q)	11,000 (0.231 Q)	16,000 (0.336 Q)	295,000 (6.195 Q)	270,000 (5.67 Q)
3.....	Small	Small	Small	200 (0.004 Q)	1,000 (0.021 Q)
4.....	9,000 (0.189 Q)	17,000 (0.357)	35,000 (0.735)	220,000 (4.62 Q)	85,000 (1.785 Q)
5.....	1,600 (0.034 Q)	3,200 (0.067 Q)	600 (0.013 Q)	35,000 (0.735 Q)	70,000 (1.47 Q)
6.....	14,000 (0.294 Q)	26,000 (0.546 Q)	49,000 (1.03 Q)	600,000 (12.6 Q)	1,200,000 (25.2 Q)
7.....	3,500 (0.073 Q)	4,500 (0.094 Q)	5,600 (0.118 Q)	160,000 (3.36 Q)	880,000 (18.48 Q)
8.....	Small	Small	Small	100 (0.002 Q)	Small
9.....	2,000 (0.042 Q)	3,400 (0.071 Q)	6,500 (0.136 Q)	90,000 (1.89 Q)	60,000 (1.26 Q)
Total resources of coal <sup>4</sup> .....	45,000 (0.95 Q)	65,000 (1.375 Q)	110,000 (2.375 Q)	1,400,000 (29 Q)	2,600,000 (55 Q)

<sup>1</sup> Recompiled from estimates of Averitt and Beikman.

<sup>2</sup> Compiled from estimates of Campbell (less sum of estimates in first four columns).

<sup>3</sup> Includes some undiscovered coal recoverable under present conditions.

<sup>4</sup> The numbers in parentheses represent the energy equivalent in Q.

<sup>5</sup> The totals are rounded values.

NOTE.—The geographical regions are as follows:

Region 1: Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont.

Region 2: Alabama, Delaware, Kentucky, Maryland, Michigan, New Jersey, New York, Ohio, Pennsylvania, Tennessee, Virginia, and West Virginia.

Region 3: Florida, Georgia, North Carolina, and South Carolina.

Region 4: Illinois, Indiana, Iowa, Minnesota, Missouri, and Wisconsin.

Region 5: Arkansas, Kansas, Louisiana, Mississippi, Oklahoma, and Texas.

Region 6: Montana, Nebraska, North Dakota, South Dakota, and Wyoming.

Region 7: Arizona, Colorado, New Mexico, and Utah.

Region 8: California and Nevada.

Region 9: Alaska, Hawaii, Idaho, Oregon, and Washington.

EXCERPTS FROM, ENERGY R & D AND NATIONAL PROGRESS (continued)

The estimates of known coal lying above 3,000 feet are recent State-by-State estimates by State agencies and the U.S. Geological Survey and are based largely on detailed mapping and measurements. The estimate of coal between 3,000 and 6,000 feet made in 1913 doubtless needs revision.

The chief uncertainty in all of these estimates is not in the total quantity of coal—if anything, the estimates are conservative in this regard, for they probably do not allow sufficiently for undiscovered deposits—but in their classification as to recoverability under present economic conditions. For example, the National Fuels and Energy Study Group, while it did not doubt the validity of the estimates of known deposits above a depth of 3,000 feet as estimates of the coal in the ground, questioned their significance as an indication of the amount of coal that could be produced under existing conditions, and attempted instead to acquire an estimate of the coal available to support near term production—the composite tonnage held by individual producers, analogous to the oil controlled by producers and comprising the amount reported by the American Petroleum Institute (API) as proved reserves. A poll of independent coal producers yielded incomplete results but indicated that 20 billion tons are available at 1960 prices and 35 billion tons would be available at a price 25 cents per ton higher.

These estimates probably well represent the reserves controlled by independent producers. Moreover, the estimates of reserves now available are probably comparable to the estimates of proved reserves of oil, gas, and natural gas liquids prepared by industry, and may be about as reliable as national estimates of copper, fluorspar, and other minerals, which (like the oil and gas figures) are also summations of reserves held by individual companies. The National Fuels and Energy Study Group's estimates do not, however, take account of large deposits, both on public domain and privately held, that are not yet controlled by operating companies, but nevertheless could be mined under present conditions. Because coal is in abundant supply compared to present production (the 20 billion tons under control of the independent producers represents a 47-year supply at current rates of consumption), there is not much incentive for private industry to acquire and explore new holdings. Yet a large quantity of coal occurs in situations directly analogous to those in which mining is underway.

According to T. Reed Scollon, Chief of the Bituminous Coal Division of the Bureau of Mines, thick coalbeds lying above a depth of 1,000 feet, and perhaps even 2,000, can be mined at present prices, for mines are already operating profitably over this range. The 220 billion tons, which is 50 percent of the thick coal known to occur above a depth of 1,000 feet, is, therefore, considered to be a conservative estimate of the amount of coal that can be mined under present economic and technologic conditions. No doubt some of the coal in this environment lies in geologically or geographically inaccessible deposits and will be lost to mining; such losses, however, are likely to be more than compensated by more nearly complete recovery of the coal in place elsewhere.

Not only is it probable that the 220 billion tons of reserves can be mined at present costs, but it is likely that much of it can be mined or delivered at lower costs than those prevailing now. Mere application of known technology on a wider scale, for example, should have a more pronounced effect in reducing mining costs.

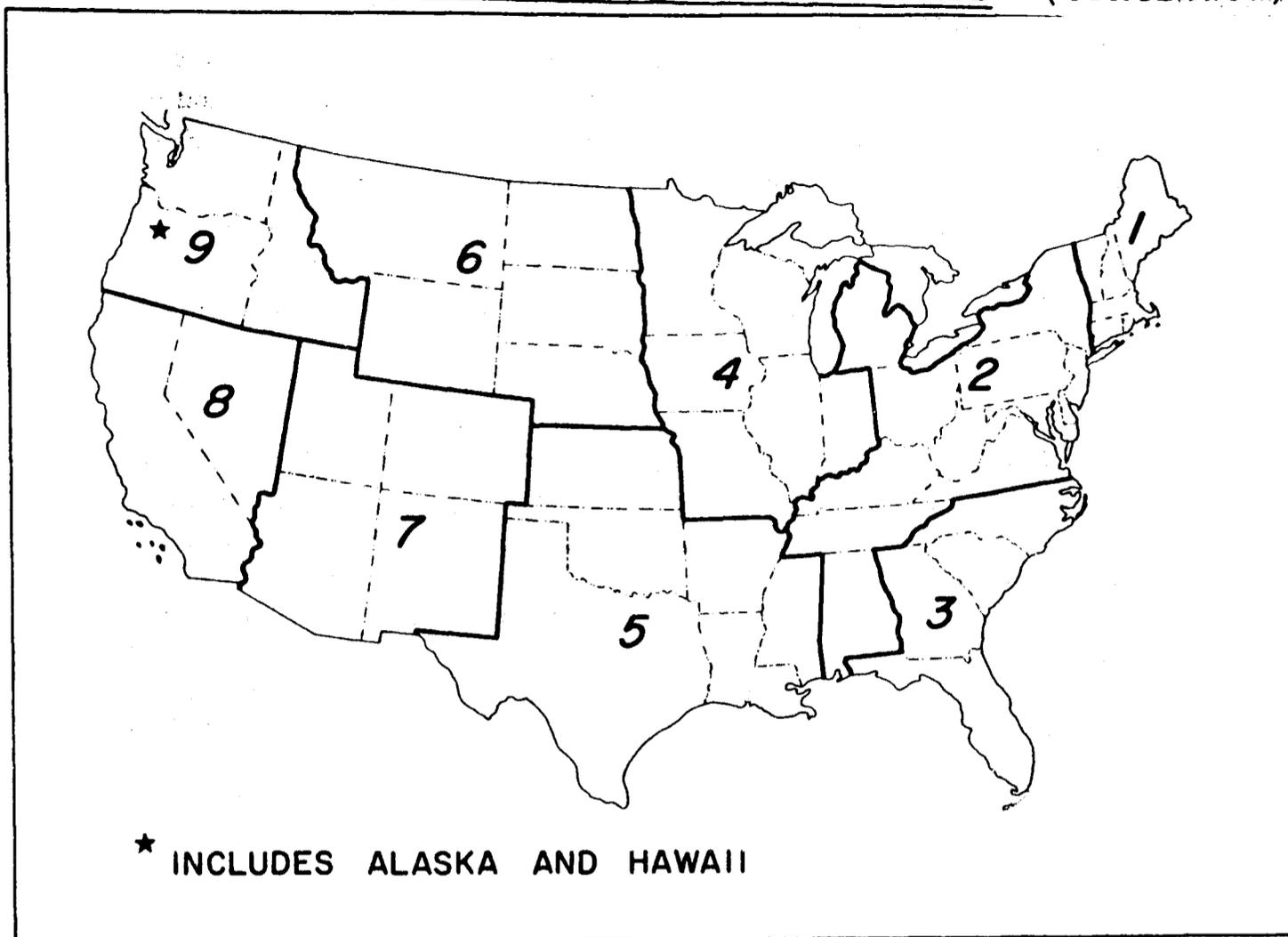


FIGURE 8.—Fuel Resource Regional Areas.

Some indication of the lag in application of modern methods and equipment may be seen in the Bureau of Mines statistics on the use of various types of equipment in operating mines and the variation in output per man-day. Thus, the average output in 1961 in underground mines is 11.4 tons per man-day, but it ranges from about 2.1 to 19.3; in strip mines, the average is 25.0 tons, but the range is 4.4 to 53.3; and in auger mines, the average is 30.6, but the range is from 21.3 to 48.3 tons per man-day. Natural mining advantages and disadvantages of various mines contribute to the wide divergence in output, of course, but in large part it reflects differences in the extent to which modern equipment is used. The average output has been increasing steadily over the years and increase in the use of such equipment as continuous-mining machines (which now account for only 20 percent of the coal mined) and wider application of the auger technique should make it continue to increase for some time in the future.

Much of the coal in known marginal deposits could not be mined at present costs without considerable advance in technology, but it seems safe to assume that the advances required could be brought about by intensive research. Trends in coal prices as a result of improved technology are shown in table 4-2, chapter IV.

**OIL IN SHALE AND BITUMINOUS ROCK****Domestic Resources**

The known recoverable reserves include oil recoverable by destructive distillation of the organic matter from higher grade oil shale in Colorado and Utah, in beds 25 feet or more thick, yielding about 30 gallons of oil per ton of rock, and lying at depths less than 1,000 feet below the surface. The assumed recovery in mining is 50 percent of the shale. The known marginal resources include shale left in the first mining of the known recoverable reserves, similar higher grade deposits at depths greater than 1,000 feet below the surface, and low-grade oil shale, with minimum yield of 10 gallons of oil per ton of rock and minimum thickness of 5 feet, to depths as great as 10,000 feet.

Undiscovered marginal and submarginal resources include a speculative estimate of equivalent oil content of selected shale deposits, yielding 10 gallons or more of oil per ton of rock, to depths as great as 20,000 feet.

Oil shale has been mined only on a local basis, but both the Bureau of Mines and the Union Oil Co. have operated pilot plants for prolonged periods, and as with the tar sands it appears that commercial operation will be feasible in the near future. The known recoverable reserves listed in table 3-1 very likely can be produced at or near present prices. The marginal resources have barely been investigated and it is not possible to estimate the cost of extracting oil from them under present economic and technologic conditions.

The known recoverable resources of oil in bituminous rock include minimal estimates of some deposits for which ready data are at hand; 50-percent recovery of the rock in place is assumed. An estimate by Weeks of 10 billion barrels is the basis for the figure on undiscovered marginal and submarginal resources; it includes a number of known deposits that are unappraised. Other unconfirmed more recent estimates of the tar-sand resources are much larger.

None of the tar-sand deposits in this country or Canada are being mined commercially now and hence it is perhaps premature to class them as reserves minable under present economic and technological conditions. The Canadian deposits are being actively investigated and a group of companies report that they have developed "a process for mining, extraction, and refining that is economically attractive as well as technically feasible." It thus appears that the deposits are on the verge of being competitive with other sources of petroleum, at least in certain areas.

Table 3-6 gives the estimates of the oil yield of selected shale and bituminous rock deposits on a regional basis. A much larger amount of organic-rich shale, which probably would yield little oil with conventional retort processing, is known and assumed to be present in undiscovered deposits. Shales not included in the estimates shown in the tables, but containing 10 percent or more organic matter, probably hold more than 9 trillion tons of organic matter in known and undiscovered deposits to depths as great as 20,000 feet. Their potential energy content is 220 Q, about half of which (110 Q) is technologically convertible to energy in light oil (about 22 trillion barrels) by hydrogenolysis. Shale resources extending to depths of 20,000 feet, containing 5 to 10 percent organic matter, have been roughly estimated to contain 60 trillion tons of organic matter with a total combustion energy potential of 1,600 Q, of which about 800 Q may be convertible to

EXCERPTS FROM, ENERGY R & D AND NATIONAL PROGRESS (continued)

TABLE 3-6.—*Oil resources in selected shale and bituminous rocks of the United States, by region*<sup>1</sup>

Region	Known Recoverable reserves (billion barrels)	Known and undiscovered marginal and submarginal resources (billion barrels)	Region	Known recoverable reserves (billion barrels)	Known and undiscovered marginal and submarginal resources (billion barrels)	
1.....	None	None	8.....	1.3	100	
2.....	None	<sup>2</sup> 500		(0.008 Q)	(0.58 Q)	
3.....	None	<sup>3</sup> (2.9 Q)	9.....	None	500	
4.....	None	Small			(2.9 Q)	
5.....	None	<sup>4</sup> 500	Total energy of oil in shale and bituminous rocks of selected deposits <sup>5</sup>			
6.....	None	(2.9 Q)				
7.....	None	<sup>4</sup> 400				
	None	(2.3 Q)				
	None	<sup>4</sup> 500				
	50	(2.9 Q)		51	6,000	
	(0.29 Q)	<sup>4</sup> 3,500		(0.3 Q)	(35 Q)	
		(20.3 Q)				

<sup>1</sup> Preliminary estimates have been made by D. C. Duncan of the U.S. Geological Survey.  
<sup>2</sup> The appraised parts of the Chattanooga shale and its stratigraphic equivalents probably would yield  $1,050 \times 10^9$  barrels of oil by distillation or  $8 \times 10^{10}$  cubic feet of gas by hydrogenolysis.  
<sup>3</sup> The numbers in parentheses represent the energy equivalent in Q.  
<sup>4</sup> The principal resources in regions 6 and 7 are in the Green River formation in Colorado, Utah, and Wyoming.  
<sup>5</sup> The totals are rounded values.

light-oil product (about 140 trillion barrels) by hydrogenolysis. Some of the undetermined fraction of the energy or oil potential of these deposits may become available as commercial extraction methods are developed.

## Oil Shale

### EXPLORATION

As with other minerals not in commercial demand, oil shale has received little attention, and only a few high-grade deposits have been studied in any detail. The investigations completed thus far have shown that a rather wide variety of rocks will yield oil when they are heated to relatively low temperatures; still others will yield oil or gas under more complex treatment.

The largest oil-shale deposits in this country are lacustrine in origin, but important marine deposits are also known. Some of the carbonaceous shales associated with coal are potentially important sources of oil and gas, in fact, prior to the Drake well, such rocks in the East were exploited as sources of both oil and gas. These deposits appear to be the principal environmental types of rocks that will yield oil or gas under distillation or a related process. However, not enough is known of their origin and geologic setting to guide an intelligent search for new deposits.

Detailed studies of known deposits are made by surface geologic mapping, supplemented by sampling in drill holes. In reconnaissance studies, the procedure has been to sample rocks that appear to be carbonaceous or can be shown by simple field tests to be petroliferous. Not all these rocks are dark colored, and even in areas where oil-shale reconnaissance has been undertaken, there is no assurance that all the rocks that will yield hydrocarbons have been identified.

The amount of oil-shale exploration in the United States is inconsequential. The Geological Survey spends about \$50,000 a year, and excluding

work by oil companies in exploration of high-grade oil shale in Colorado (some of which borders on development), it is doubtful that the expenditure elsewhere is more than a few times this amount. However, these rocks, according to present indications, not only contain the largest potential sources of energy available from fossil fuels, but will be a future source of hydrocarbons. Hence, it is important to learn more about the origin, characteristics, and distribution of oil shales and carbonaceous rocks. In particular, exploration-oriented research is needed on the Green River oil shales in Colorado, Utah, and Wyoming, which probably will be brought into production within the next few years, and which will be the prime source of oil from shales for some time.

## MINING

A low-cost underground mining method for oil shale was developed and successfully demonstrated by the Bureau of Mines at its oil-shale facility near Rifle, Colo., in 1946-56. The method was applied to the Mahogany zone layer of shale, which is about 73 feet thick at the Rifle location and is exposed on the shale cliff face at an altitude of about 8,000 feet. In a room-and-pillar pattern of development, the mined areas (approximately 60 feet square and the full 73 feet high) alternated with 60-foot-square pillars left as roof supports. A coordinated system of heading and benching operations was used; sufficient head and side space at all times permitted use of extremely large equipment so that output per man-shift was high. In the Bureau's demonstration area, 39-foot advance headings and 34-foot benches were chosen as optimum, but these dimensions could be adjusted to meet requirements in other locations without materially affecting mining procedures or efficiency. Outputs of 150 tons of shale per man-shift were attained during normal operating tests.

The Rifle operations emphasized blasting research and the development of equipment particularly suited for large-scale oil-shale mining. The latter included extremely mobile and versatile platforms for use in loading blastholes and in scaling walls and roofs after blasting; multiple-percussion drilling machines and accessory equipment, such as special bits and drill rods; mobile air compressors capable of easy positioning near the drilling sites; and, near the end of the program, rotary-drilling equipment. This last deserves special comment since rotary drilling was considerably cheaper and more rapid than percussion drilling; the quantitative improvement had not been determined when the Rifle plant was shut down. Drilling costs represent a large portion of the overall mining expense, which accents the desirability of further development and evaluation of rotary-drilling techniques. Mining costs, computed on the basis of operations tied to percussion drilling (in terms of 1951 price levels), ranged from 47 to 56 cents per ton and included direct operating costs, depreciation, taxes, and administrative overhead. The cost reduction, where rotary drilling substituted for percussion drilling, was not predicted with certainty but was estimated to be as high as 10 to 15 cents per ton.

The demonstration work at Rifle proved that methods of mining oil shale in the Mahogany zone have been sufficiently developed that they could be applied with assurance in a full-scale industrial development at many

locations along the Colorado River escarpment. An analysis of the operations showed the optimum size for individual mines probably will approximate 20,000 tons per day. Studies indicated, too, that the room-and-pillar mining method may be adaptable to shales other than those of the Mahogany zone, and to separated areas where entry to the shale could be gained through vertical shafts; however, the practicability of such operations has not been demonstrated. Similarly, open pit mining may be practical in some areas where ratio of overburden to shale is not excessive, including the Piceance Creek area of Colorado where the oil shales are deeply buried but extremely thick. Again, comprehensive studies followed by demonstration would be required to assess this possibility.

## PROCESSING

Except in an in situ operation, the mined oil shale must be crushed to a size suitable for retorting. The Rifle operations accumulated experience in crushing oil shale with jaw, gyratory, and roll-type commercial equipment. Sufficient data were obtained for rough-design purposes, but more information is needed for optimum design of oil-shale crushing plants.

Application of heat is the only practical means of producing shale oil so far devised, and numerous mechanical devices (known as retorts) within which to heat oil shale have been developed. Work at Rifle with a number of retorting systems culminated in the development of the gas-combustion process, which to date has proved the most practical method investigated by the Bureau of Mines. Other methods are being investigated on a laboratory scale only. In the gas-combustion process, crushed shale moves down a vertical shaft by gravity; combustion within the vessel of part of the gas produced, as well as of fixed carbon in the shale, supplies heat which is transferred by direct gas-to-solids heat exchange, and the oil is recovered as a mist. This process has high conversion and thermal efficiencies. Pilot plants of three sizes were studied, the largest being operated at about 200 tons of shale per day. An improved rate of throughput, per unit cross section, has been reported by an industrial pilot operation with an adaptation of the gas-combustion process.

Other methods of retorting have been described as being developed to commercial readiness. A large pilot model of a continuous, underfed, countercurrent, internal-combustion retort handled 1,200 tons of shale per day. Tests have been conducted on the TOSCO process, featuring a rotating drum in which retorting is accomplished by transfer of heat to the oil shale from hot ceramic balls which, in turn, are heated in another vessel by combustion of fixed carbon left on the retorted shale.

Undoubtedly, each retorting method described is susceptible to improvements that would reduce processing costs, but the problems of industrial retorting systems are ill defined because detailed information has not been released. However, pertinent research is being done on such fundamental factors as organic and inorganic makeup of shale and the properties of the oil produced under different retort conditions.

The in situ process is a potentially important retorting method because it eliminates the mining and crushing operations. For oil shale, it would involve drilling holes into the shale formation, establishing communication between holes by some fracturing means (for example, by well-developed oilfield hydraulic-fracturing procedures), and igniting the oil shale at selected points in one or more of the drilled holes. Injection

EXCERPTS FROM, ENERGY R & D AND NATIONAL PROGRESS (continued)

of air and possibly gas (logically, part of the gas product) into the ignition holes would move the combustion front toward the others. The hot combustion gases, moving ahead into the formation along with excess air and other gases that might be injected, would effect retorting at some distance forward of the combustion zone. The oil and gas produced would be swept through the formation to the exit holes for recovery by normal rise or artificial lifting as necessary. As in any retorting process, fixed carbon would be left on the retorted shale and should provide all (or at least most) of the fuel needed to support the combustion.

One company field-tested in situ retorting in the early 1950's on oil shale in Colorado. The size of the experiment and results have never been disclosed. More recently, several companies have proposed in situ development programs in the thick shales near Piceance Creek. Preliminary in situ evaluations have been made by two companies, both of which drilled through the overburden to the shale bed, conducted fracturing operations, and made flow tests, using air or other gas. The Bureau of Mines is doing laboratory research on in situ processing, with particular emphasis on the permeability characteristics of Mahogany zone oil shales and on the rate and degree of retorting under conditions simulating an in situ operation. Industrial laboratories are doing similar work, but details are lacking.

The apparent readiness of several oil companies to undertake comprehensive and expensive development programs encourages the belief that in situ retorting has promise. The Bureau of Mines, too, is optimistic enough about the potential value of the method to have proposed expanding its current laboratory studies to field scale, including investigation of the use of conventional or even nuclear explosives to create large volumes of permeable shale as a preparatory step for in situ retorting. In all likelihood, in situ retorting cannot reach a commercial stage of development overnight; the oil companies now proposing development are thinking in terms of reaching commercial feasibility in about 10 years.

Reduction in costs of extracting and processing shale oil is highly important, for shale oil now is considered at least marginally competitive with petroleum. To this end, the gas-combustion retort requires further work on means to regulate gas and shale flows and to accommodate a wide range of shale-particle sizes (to minimize crushing costs) so as to increase the versatility of the overall system. More efficient oil-trapping systems and control of particle size and flow of oil mists also are needed. Too, the in situ approach should be field-tested sufficiently to permit economic evaluations.

While oil shale generally has been considered only as a source of a liquid-petroleum supplement, some laboratory-scale research has been directed toward producing high-Btu gases by hydrogasification of its organic matter, although results of the more recent work have not been reported. Estimates based on earlier work indicate that 1 ton of 22.9-gallon-per-ton Colorado oil shale can be hydrogenated to yield 2,300 to 2,500 std cu ft of 1,000-Btu gas under operating conditions of 1,200° to 1,300° F and about 2,000 psi. In laboratory tests, gasification of the black shales of the Eastern United States gave gas yields approximating those from the Colorado shales, although the oil-yield assay of the former is only about half that of the latter. Thus, although the Eastern shales may not be attractive as a source of oil, they may have value for gas production.

The economics of producing gas from oil shale are not fully known. However, based on the foregoing yield data and using 50 cents and 25 cents per ton of Colorado oil shale as the costs (without profit or income tax) for

mining and crushing, respectively, the raw material cost alone would range from 30 to 33 cents per 1,000 std cu ft of 1,000-Btu gas. Adding operating and depreciation costs for gasification, and allowing for profit and income taxes overall, an onsite cost of gas from shale of about \$1 per 1,000 std cu ft may be a reasonable estimate. Since this is higher than current delivered price for natural gas in many parts of the United States, oil-shale gasification does not appear economically attractive at present.

Other exploratory work on methods of converting the organic matter in oil shale to useful products includes investigation of the possibilities of microbacteriological conversion and of the effects of sonic energy. Meager information also has been obtained on the changes caused in shale by nuclear and other radiation. None of these programs has reached a point where any prediction can be made as to eventual commercial value.

## REFINING

Most of the work on shale-oil refining has been based on adaptations of established petroleum-refining processes. However, the properties and composition of shale oil differ from those of most crude petroleums in several important respects, and these dictate to some degree both the refining processes and the process sequences. A major difference is that the oils produced from retorting are viscous and congeal at about 70° F—a drawback, since it is generally conceded that pipelining the shale oil to an established refining and market center is the most practical approach for shale-oil utilization. Nevertheless, well-known petroleum vis-breaking (viscosity-reduction) and coking processes can produce shale oils suitable for pipelining. The TOSCO method, for example, includes an effective viscosity- and pour-point reduction step in the retorting sequence.

The second difference important to refining is the 2 percent of chemically combined nitrogen in shale oil, which is detrimental to the catalysts used in modern refining processes. However, low-pressure hydrogenation of shale-oil stocks essentially removes nitrogen compounds, as well as sulfur and oxygen compounds and the olefinic compounds that also would interfere with subsequent catalytic processing.

Most of the basic refining techniques, including atmospheric distillation, vis-breaking, coking, recycle cracking, and chemical treating of gasoline and diesel-fuel products, were quite thoroughly evaluated and shown to be technically feasible by the Bureau of Mines operations at Rifle. This work also included preparation of relatively large quantities of motor gasoline, diesel fuel, and various fuel oils, all of which were of comparable quality to their petroleum counterparts in actual equipment operation. Subsequently, smaller scale work on hydrogenation for upgrading of products and stocks for further processing and on various catalytic-conversion processes has shown the practicability of such modern approaches to shale-oil refining. Hydrocracking, one of the most recent petroleum-refining developments, is currently being investigated, and preliminary results are encouraging.

All this work strengthens the conclusion that shale-oil refining techniques are adequate to assure manufacture of a full range of fuels comparable in quality to those in the petroleum family—gasoline, diesel fuel, jet fuel, distillate and residual fuel oils, and coke—although optimum operating conditions need to be defined in certain cases.

## ECONOMICS

No comprehensive, completely original studies of the economics of an oil-shale industry have been made since the 1951 evaluations of the National Petroleum Council and of the Bureau of Mines. Each study showed that a shale-oil industry at that time would be nearly competitive with the petroleum industry. Since then, of course, labor and material costs have risen, oil-shale processes have been improved, a considerably higher return on investment is demanded, and the product-distribution pattern has changed. The costs calculated in 1951 are, therefore, mainly of academic interest today. Nevertheless, to avoid the tremendous job of a new, overall study, the 1951 studies have been taken as a starting point for several subsequent economic estimates that reflect the changes with time. The most recent escalated estimate that has been published was made in 1958 by Cameron and Jones, Inc.; it was based on 1957 dollars and an assumed operation that produced 250,000 barrels per day of crude shale oil. Refining was not considered except for vis-breaking to produce a pipeline oil.

The capital investment of mining and crushing was placed at \$323 million; this figure represented 45 percent of the total capital investment required to prepare crude shale oil and pipe it to California. The estimate attempted a correction for technological development in mining and retorting between 1951 and 1957 and showed the effect of varying return on investment from 6 percent (as assumed in the 1951 studies) to 12 percent (as would be more realistic today). An excerpt from this estimate is given in table 4-23.

The Cameron and Jones estimate also showed the economic effect of a 15-percent depletion allowance, were the present tax laws relaxed to permit depletion to be based on crude shale oil. (At present, the law permits a 15-percent depletion allowance only on the mined oil shale.) With the assumed depletion allowance, the reduction in cost of shale oil delivered to California was estimated to be 30 cents per barrel for the case of 12-percent return on investment.

Simple escalation of the Cameron and Jones estimate from a 1957 to a 1962 dollar basis gives an updated cost figure of approximately \$3.60 per barrel of shale oil delivered to California, allowing a 12-percent return but no depletion allowance. Depletion under existing laws permits an estimated reduction of about 20 cents per barrel, which still would place the delivered shale oil at, roughly, a 40-cent-per-barrel disadvantage relative to current domestic crude-oil prices on the west coast.

The profit factor also has an important bearing: 10-percent return instead of 12 percent would bring the shale-oil cost to \$3.05 per barrel. The argument may be advanced that a more realistic yardstick for measuring the competitive position of shale oil should be the cost of finding, producing, and marketing newly discovered crude oils, for in many cases, such costs may considerably exceed current selling prices.

EXCERPTS FROM, ENERGY R & D AND NATIONAL PROGRESS (continued)TABLE 4-23.—*Economics of crude shale-oil production*<sup>1</sup>

Capital investment:	
Mining and crushing . . . . .	\$323, 000, 000
Retorting . . . . .	201, 000, 000
Pipeline preparation . . . . .	86, 000, 000
Pipeline to California . . . . .	103, 000, 000
<b>Total . . . . .</b>	<b>713, 000, 000</b>
Daily cost, excluding profit . . . . .	356, 000
Cost per barrel of oil delivered in California at 6-percent return on investment after taxes . . . . .	2. 35
At 12-percent return on investment after taxes . . . . .	3. 30

<sup>1</sup> Using Bureau of Mines gas combustion retort.

## SUMMARY

Shale oil appears to be within at least striking distance of competing with petroleum—close enough that the remaining gap could be bridged by any improvement in shale technology that slightly reduced either capital investment or direct operating costs. Since crushing is a relatively unimportant economic factor and well-known petroleum-refining techniques seem appropriate for shale-oil processing, mining and retorting offer the best opportunities for technological advancement. In mining, the greatest promise for economic gain probably lies in further evaluation of rotary-drilling techniques for underground operation. However, because underground mining may not be practical in some areas, open-pit mining also warrants evaluation. In retorting, the most productive improvements are those that would increase rate of shale throughput and oil yield: prevention of gas channeling and erratic shale movement in the retort, and effective control of oil-mist formation and flow. The in situ combination of mining and retorting also appears promising enough to justify evaluation, particularly for areas where underground mining may not be practical. To facilitate advances in processing, much more fundamental information must be obtained on the composition and properties of oil shale and shale oil.

The present knowledge of the economics of oil shale, based largely on studies made more than 10 years ago, is woefully out of date. Cost escalation and estimation of the effects of known technological improvements give updated figures that probably are no better than order-of-magnitude costs. Particularly difficult to assess are the effects of one process change upon another involved process. Because the economic question is of paramount importance to the feasibility of an oil-shale industry, a new and comprehensive economic study, based on up-to-date technology is badly needed.

## *Tar Sands*

Much less well known than other fossil fuels are bituminous rocks (including tar sands), consisting of sandstone or other rocks impregnated with some variety of heavy hydrocarbon. They probably are formed from the natural distillation of lighter hydrocarbons from petroleum, probably most often when caprock was breached by erosion or weathering and the oil-bearing strata were exposed to the atmosphere. Search for bituminous rocks, along with oil seeps, as clues to the presence of petroleum has been extensive, but the rocks themselves, having little commercial value, have been ignored. A notable exception to the disinterest is the Athabaskan tar sands of Canada, which have been explored enough to demonstrate the presence of huge reserves but not sufficiently to determine their origin or the geologic factors controlling their distribution. In short, the enabling knowledge for intelligent exploration of bituminous rocks is primitive and, aside from drilling itself, the tools and methods most widely applied to the exploration for oil and gas are of little help in the search for new deposits.

The Geological Survey now has no work bearing directly on bituminous rocks, and it is doubtful that much is in progress under other organizations. Exploration for bituminous rocks need not be much intensified, but better knowledge is needed to lay the groundwork for future exploration. Moreover, study of such deposits may contribute importantly to an understanding of petroleum reservoirs.

Neither industry nor Government has exerted much more than sporadic efforts to develop tar-sand technology in the United States. In the late 1940's, the Bureau of Mines conducted limited studies of the refining characteristics of tar-sand oils from three different resources and did bench-scale research on the problems of separation of oil, based on a process developed about 1920 by the Scientific and Industrial Research Council of Alberta, Canada. Basically, this process involved a hot-water and diluent oil treatment in an alkaline medium, followed by flotation and settling to effect final separation of oil and sand. The Bureau's studies confirmed that the separation process was technically feasible and demonstrated that the viscosity of tar-sand oil could be reduced to a value low enough for pipeline transport.

In 1956 work was begun on an underground heating method of in-place extraction of oil from tar-sand deposits in California. The process involves sinking two concentric pipes into the deposit. Heat is supplied to the formation by an oil or gas burner in the center pipe, which thins the oil sufficiently to enable it to be raised to the surface through the annular space between the pipes. A small pilot installation yielded 13 barrels of oil per day for an undefined period in 1958. Neither details of the recovery mechanism nor the economics of the process have been disclosed. In 1958 a second pilot operation was conducted in California, but details and results were not disclosed.

Another method envisions use of nuclear explosions to supply the heat required for extracting petroleum from Canadian tar sands. Sample tar sands that were exposed to the strong shocks and radiation of a nuclear explosion in the Plowshare program are now being studied.

Several experimental, large-scale, industrial projects have been underway for some time in Alberta in the Athabasca tar sands, and these will undoubtedly provide a technological base for development of U.S. tar sands when the need arises. One project is designed to produce 31,500 barrels

EXCERPTS FROM, ENERGY R & D AND NATIONAL PROGRESS (continued)

of oil daily at a development cost of \$124 million; it is scheduled for operation in late 1965 or early 1966, using a strip-mining procedure followed by a hot-water separation process.

Another, larger Canadian pilot development has cost about \$19 million since 1959, but an estimated \$10 million more will be needed for the advance to industry-scale operation. The tar sand is mined, and the oil separation is an adaptation of the hot-water extraction process. The viscosity of the oil is reduced in a thermal vis-breaking operation so it can be pipelined to existing refineries. Overall development to full-scale operation, producing 100,000 barrels of tar-sand oil per day, is expected to cost \$356 million.

A third proposed project in Canada anticipates 100,000 barrels of oil daily at an estimated expenditure of \$260 million. This in situ operation would involve several steps: drilling of one injection well and four producing wells on each 4-acre unit to be produced; injection of an aqueous solution of sodium hydroxide into the tar-sand formation, followed by injection of steam at 1,000 psi to separate oil from sand and to emulsify the oil; and use of gas lifting to secure the emulsified oil and aqueous solution from the four production wells. The emulsion would go through a dehydration step and then be vis-broken for pipelining to an existing refinery. Assuming application approval, operations are expected to start in 1969 for 25 years, on the basis of present land holdings. Pay-out is estimated in the first 8 years of the project.

A fourth proposed project, with a daily production of 40,000 barrels, is estimated to cost \$60 million; the only known detail of the process is centrifugal separation of oil from the sand.

None of the groups proposing industrial tar-sand developments in Alberta has released details of its economic evaluations. However, the fact that each is anxious to pursue long-range, high-cost programs indicates full expectation that the operations will prove technically and economically feasible. Disregarding the in situ approach for the moment, oil separation is expected to present the greatest problem and will probably prove the most costly step, followed in decreasing order of cost by mining, preparation of oil suitable for pipeline transport, and actual transporting cost. All that can be said about the economics of the in situ approach is that the overall cost must approximate those for approaches involving mining and oil separation if this method is to be competitive.



