

SHELF

2303004

OIL SHALE
COAL
OIL SANDS

synthetic fuels

VOLUME 12 • NUMBER 4

DECEMBER, 1975

quarterly report

Tell Ertl Repository
Albert Lakes Library
University of Illinois

CAMERON ENGINEERS, INC.

synthetic fuels[®]

OIL SHALE



COAL



OIL SANDS

VOLUME 12— NUMBER 4 DECEMBER, 1975

quarterly report

Text Printed on Recycled Paper

© CAMERON ENGINEERS, INC. 1975

[®] Reg. U.S. Pat. OFF.

CAMERON ENGINEERS, INC.

John S. Hutchins, President

SYNTHETIC FUELS STAFF

Dick Prouty

Gary Baughman	Craig Moseley
Jim Hylton	Gaylord Kirkham
Tom Hendrickson	Ken Stanfield
Carl Sandberg	Sandra Blackstone

ARTWORK & REPRODUCTION

Eugene Jojola

John Schaffer

Jerry Medford

Lucy Padilla

Rebecca Green

1315 SOUTH CLARKSON
DENVER, COLORADO 80210
TELEPHONE 303-777-2525
TWX 910-931-2699

CONTENTS

HIGHLIGHTS AND SPECIAL FEATURE	A-1
STATUS OF SYNFUELS PROJECTS	B-1
COMING EVENTS	C-1
RECENT PUBLICATIONS	D-1

I. SYNFUELS: GENERAL

ECONOMICS

Conference Focuses on Financing Western Energy Development	1-1
----------------------------------------------------------------------	-----

ENVIRONMENT

API Assesses Impact of EPA Air Quality Regulations on Energy Development	1-5
Energy Boom Town Problems to Be Studied in Four Western States	1-15

WATER

Interior Sets Guidelines on Water Facts Needed to Get Permits, Licenses, Leases, and Contracts	1-18
Water Resources Council Hikes Percent Level	1-18

GOVERNMENT

Proposed Colorado Severance Tax Considered by Legislative Committee	1-19
Synthetic Fuels Task Force Recommends Informational Program	1-20
Federal Funding, Incentives Outlook Good -- At the Moment	1-23
Outline of Ford Administration Section 103 Proposal on Synthetic Fuels	1-24
Commentary on Synthetic Fuels Loan Guarantee Program	1-26
Federal Procurement Notices and Contract Awards Published	1-29

II. OIL SHALE

TECHNOLOGY

Union Oil Proposes to Demonstrate Its "Retort B" Process at 7,000 Barrel/Day Rate	2-1
ARCO Patents Methods of Removing Catalyst-Poisoning Impurities From Synthetic Crude Oil	2-7
Costs of Producing In Situ Retorts In Oil Shale By Mining Methods Are Studied	2-8
Report Describes An Oil Shale Conversion Process Which Uses CO and H ₂ O	2-8
LERC Studies The Anomalous Heating Behavior of Large Shale Blocks	2-10
Underground Mining of Oil Shale In The Piceance Basin Study	2-12

LAND

Court Orders Full Hearings By Interior On Obstacles to Patenting Oil Shale Claims	2-20
------------------------------------------------------------------------------------------------	------

WATER

Oil Shale In Situ Tests Effect On Groundwater Reported	2-24
------------------------------------------------------------------	------

ENVIRONMENT

Union Oil Company's Revegetation Studies Described	2-29
Environmental Oil Shale Symposium At CSM Is Disappointing	2-34
In Situ Oil Shale Lease Nominations Hit Snag	2-36

GOVERNMENT

Congressional Hearings In Colorado On Oil Shale	2-39
Nine In Situ Oil Shale Tracts Nominated Under Interior Prototype Leasing Program: Two Sites Recommended For Leasing, Final Selection Uncertain	2-42

CORPORATIONS

C-b Lessees Submit Draft of Detailed Development Plan	2-46
Oil Shale Environmental Panel Reviews Draft of C-b Detailed Development Plan . . .	2-47
Occidental Moves Ahead on Modified In Situ	2-48
Geokinetics Still Seeking Federal Shale Tract	2-49
American Lurgi Seeks Industry Support For 4,000 T/D Lurgi-Rurhgas Process Demonstration Plant	2-50
Superior Oil Company's Multiple Product Process Reviewed	2-52
Status of Oil Shale Legal Proceedings Noted	2-53

III. OIL SANDS

TECHNOLOGY

A Closed Cycle, Single-Stage Separatory Process On Alberta Oil Sands is Patented . .	3-1
Patent Describes Use of Disc-Type Centrifuge to Upgrade Oil Sands Froth Product	3-1
Texaco Patents Process Which Combines In Situ Solvent Deasphalting With Subsequent In Situ Combustion	3-2
GCOS Patents Method For Clarifying Water Discharged From Hot Water Separation Process	3-3
Imperial Releases Information On In Situ Project	3-3
NDC Publishes Volume of Oil Sands and Shale Patent Reviews	3-5

LAND

Study Details Utah Oil Sands	3-6
Alberta Indians Threaten Lawsuit Over Land Claims	3-6

GOVERNMENT

Athabasca Oil Sands Index Service	3-9
Alberta Reserves Described In ERCB Report	3-9

CORPORATIONS

Lurgi Seeks Industry Sponsors For \$15 MM L-R Process Pilot Plant	3-14
Recent Nominations For GCOS Syncrude Listed	3-14
Roosevelt, Utah, Refinery Modifications Follow Tax Sale: Expansion Anticipated . .	3-15

IV. COAL

TECHNOLOGY

Oak Ridge Presents Phase I Report to ERDA on Coal Hydrocarbonization	4-1
Alternative Solvents Tested in the Solvent Refined Coal Process	4-3
Coal-Derived Synthesis Gas Assuming New Importance in Many Industries	4-5
University of North Dakota Appraises Coal Conversion Processes	4-5
Six Processes For Drying Western Coal Described	4-8
North Dakota PSC Makes Final Decision on ANG Project	4-10
1,000 Tons of COED Process Chars Gasified In Koppers-Totzek Plant in Spain	4-10
SRC Pilot Plant Construction Reported	4-11
SRC Reporting Plan Revealed	4-13
Project Lignite PDU Described	4-13
EPRI Reports On Operating Performance of Wilsonville SRC Process Pilot Plant . . .	4-14
ERDA Dedicates Synthane Pilot Plant	4-19
LURGI Slagging Gasifier-Status Reported	4-22
BI-GAS Pilot Plant Nearing Completion	4-25

WATER

Scenic Upper Missouri River Status Would Bar Water Development	4-28
Westwide Study Released	4-29
Madison Formation Study Planned	4-29

ENVIRONMENT

Final Environmental Impact Statement Issued By U.S. Department of Interior On Proposed Federal Coal Leasing Program	4-31
ERDA Report Concerns The Social, Economic, and Land-Use Impacts Of A Fort Union Coal Processing Complex	4-35
Suit Filed To Block Renewed Federal Coal Leasing	4-40

GOVERNMENT

Kaiparowits Project Summarized	4-42
Interior Proposes Surface Coal Mining/Leasing Regulations	4-48
Coal Feeding Systems Studied By Lockheed	4-49
Fluor To Evaluate H-Coal Process	4-49
Rocketdyne Process Tests For Coal Conversion Announced	4-49
ERDA To Report Coal Conversion Research Quarterly	4-50
Synfuels Consulting Contract Let By ERDA	4-50
Montana Studies Possible State Role In Coal Gasification Plant	4-51
Energy Authority Temporarily Shelved	4-51

CORPORATIONS

Riley Stoker Corp. Offers Commercial Model Coal Gasifier	4-53
Synfuels Loan Guarantee Supported	4-53

LAND

Crow Indians Sue Interior to Invalidate Coal Leases And Permits On Montana Reservation	4-55
Leasing Activity Reported	4-56

APPENDIX

Copy of "Order of Remand" by U.S. Court of Appeals in Combined Oil Shale Civil Action Cases	5-1
Interior's Recommendations Regarding In Situ Oil Shale Tract Nominations	5-6
Interior Sponsors Bill Authorizing Leasing of Off-Tract Oil Shale Disposal Lands	5-19
Proposed Severance Tax Legislation May Become Model for Several States	5-20

highlights
and

special features

H I G H L I G H T S

U.S. Bureau of Mines Test Well in Piceance Basin Finds Simple-Appearing Fault is Complex, Water-logged

A core-hole was drilled in September and October 1975, to 2,382 feet a mile west of the mouth of Ryan's Gulch in the SW 1/4 of the SE 1/4, Section 31, T1S, R97W by the Bureau of Mines. The location since has been named Fault Draw. The well encountered considerable quantities of both fresh and saline water in the course of a study seeking a location for an experimental deep mine shaft. The well was plugged back to 750 feet and completed as a fresh water well for the Bureau of Land Management.

The contractor, Brinkerhoff Drilling, moved its rig to a Horse Draw location in the NW 1/4 of the SW 1/4, Section 29, T1S, R97W, some two miles away and in mid-November was drilling at a depth in excess of 1400 feet. The work is preparatory to a Bureau of Mines experimental mine in the basin.

West River Study Final Report Issued

The North Dakota State Water Commission has published the final West River Area Diversion Study for the lignite-rich southwest region of the state. Its conclusion and recommendations are essentially the same as the draft version. (*See June 1975 Synthetic Fuels*). Extensive background data have been included in 11 appendices. Copies are available from the North Dakota State Water Commission, State Office Building, 900 East Boulevard, Bismarck, North Dakota, 58505.

Sierra Club Granted Extension of Time to Answer Interior's U.S. Supreme Court Petition in Northern Great Plains Dispute

The Sierra Club received an extension from Nov. 8 to Dec. 3, 1975, to answer the Interior Department's appeal of the federal appellate court decision in the Northern Great Plains case.

The Appellate Court favored the Sierra Club arguments in a 2-1 decision issued in June 1975 case known as *Sierra Club vs. Morton*. (*See pages 4-42 and A-34 in the September 1975 issue*). The effect of the suit has been to block private coal development and related federal activity in the region until it is decided whether a regional environmental impact statement is needed.

It will be at least mid-December before the Supreme Court will decide whether to hear the appeal. If it does, a hearing date is months away. The philosophy of a new justice succeeding William O. Douglas could be a key factor.

H I G H L I G H T S

Interior has balked at the appeals court direction to prepare a regional EIS or show cause why it shouldn't. It contends a court ordered regional EIS under the National Environmental Policy Act would then be applicable to scores of development projects on the basis of geography alone. One would be oil shale.

As a case in-point, the Sierra Club in November filed suit in California obliquely seeking a regional EIS as applicable to the proposed Kaiparowits power plant in southern Utah. Coal gasification related projects in Arizona and New Mexico and Utah would be affected by requirements for regional EIS, especially in view of the regulatory questions raised in the California suit.

The federal role of making money available through incentive programs could also be construed as applying to a synthetic fuels program in the east, to off shore petroleum development and other endeavors in which federal action is on a "regional basis." The list of imagined horrors is endless.

At the moment there is no indication the Sierra Club Great Plains suit will be settled out of court as suggested by Wyoming Gov. Ed Herschler. He advocated the Sierra Club and Interior obtain a court stipulation allowing planned coal operations to proceed while maintaining the court injunction on new developments. The unofficial proposal has been greeted with official silence.

Meanwhile Interior has allowed AMAX Coal Co. to mine federal coal under AMAX owned surface at the Belle Ayr mine south of Gillette, Wyoming. Strict environmental stipulations were imposed by Interior. Interior noted AMAX is not a party to the lawsuit, hence its operations initiated prior to the lawsuit could continue from private to federal coal.

It is possible the Sierra Club will challenge the action as a violation of the court injunction by Interior. This in turn could open up the Sierra Club to litigation by AMAX.

(Synthetic Fuels reported on the Sierra Club suit in the September 1973, and subsequent issues.)

Off-Site Disposal of Spent Shale from Federal Leases Faces Uphill Climb in Congress

It will take an act of Congress to get approval of off-site spent oil shale disposal for federal prototype oil shale leases in Colorado and Utah. The logical man to introduce such legislation on the House side of Congress, Colorado's Fourth District Rep. James

H I G H L I G H T S

Johnson (R) has been reluctant about introducing such a measure.

Such legislation would need Johnson's approval if not his sponsorship since the tract for which off-site disposal approval is being sought, Tract C-a, held by Gulf and Standard of Indiana, is in Johnson's district. Such measures almost never pass over the affected member's objections. Even with Johnson's endorsement, a bill still faces difficulty in the House.

A bill probably would be assigned to the House Interior Committee's Subcommittee on Mines and Mining chaired by Rep. Patsy Mink, D-Hawaii. Interior legislation has always had long gestation periods. Johnson's bill introduced more than two years ago to amend the Mineral Leasing Act of 1920 and allow states to use mineral lease royalties for needs in addition to roads and schools only recently surfaced from the Mines and Mining Subcommittee, wrapped in a broader piece of legislation to amend federal coal leasing laws. The latter narrowly averted having the twice vetoed strip mine bill attached to it in a 21-20 committee vote Nov. 12.

An off-site disposal bill, S. 2413, has been introduced in the Senate by Sen. Henry M. Jackson, D. Wash., but it is in the House that the measure will face its toughest test.

Participants in both C-a and C-b favor off site disposal authorization in their Piceance Basin locations. It has been C-a sponsors, however, who have been lobbying for it. They consider off-site dumping of spent shale and pit mining overburden "essential" to the economic viability of their mining plan.

Energy Companies Backing Off High BTU Coal Gasification Programs as Cash Flow Shrinks and Expenses Soar; Fuel Gas Projects Pushed

While reluctant to announce it publicly, a number of firms are backing away from coal gasification projects designed to produce pipeline quality gas. Instead, they are concentrating efforts and increasingly limited investment dollars on projects promising a quicker return. Suppliers of coal gasification capital are looking with increasing interest at processes and locations for manufacture of low-BTU gas primarily for serving-groups of small industrial users who face prospects of winter shutdowns due to interruptions of natural gas service. The synthetic gas would be expensive, but be less so than pipeline quality synthetic gas. Still, sponsors of some proposed commercial gasification projects presently seeking FPC certification have shown no signs of reduced enthusiasm.

H I G H L I G H T S

In a related vein, an August memorandum to the Energy Resources Council from the Secretary of Interior contains pessimistic assessments of the state of the art regarding high BTU synthetic gas.

"The technology for producing low/medium BTU sulfur-free gases from coal and other solid fuels is established and the operation of commercial plants would introduce no unknown factors. However, the conversion and methanation of low/medium BTU gases to high BTU gas is still far from commercial...The existing technology that could be employed in the production of low/medium BTU gas is currently applied in 14 commercial plants outside the United States...The production of low/medium BTU gas involves a minimal technical risk and time for implementation.

"Technologies are available to produce high BTU gas from coal by appending shift conversion and methanation operations onto medium BTU gasification facilities...The shift conversion and methanation steps allegedly have been proven feasible during insignificant periods of operating time in laboratory and pilot plant tests. To date, careful appraisals would probably reveal that technical risks currently are abundant.

"Coal gasification and liquefaction cannot become a practical reality until recognized problems with materials are solved."

An attachment by the U.S. Bureau of Mines Metallurgy Division reports that experience with the Hygas pilot plant gasifier reactor shows "no satisfactory material now exists to make pressure vessels for the gasification of coal." It also contends that "the technology to make large pressure vessels of high temperature resistant materials does not exist."

Atlantic Richfield Reviewing Plans as North Slope Development Expenditures Mount

Unseasonably heavy ice north of Point Barrow, Alaska, apparently is having repercussions in Atlantic Richfield Company's energy development efforts far distant from the North Slope, including oil shale in Colorado.

The ice delayed 25 barges and forced rerouting of supplies on 22 others. "The delay will cost Atlantic Richfield some money," ARCO chairman and chief executive officer Robert O. Anderson told a security analysts meeting in Houston Oct. 28. "Probably \$25 million to \$30 million. While that is a great deal of capital, it will add only three to four percent to our total projected investment at Prudhoe Bay now estimated at about \$2.5 billion through 1990."

HIGHLIGHTS

Prudhoe production is scheduled to begin in July 1977. Meanwhile, the huge field only represents current expense. Regulatory restrictions on the company's capital-generating ability and inflationary escalation of its capital program are causing the company to review its overall plan for the 1975 to 1980 period, Anderson said.

"As far as we are concerned, several projects have highest priority--the North Slope of Alaska, our chemical complex in Houston and our U.S. exploratory programs. We will spend what we must to bring these projects on stream as quickly as possible. At the moment, all other projects are of lower priority.

"Elsewhere we are upgrading existing operations, deferring expenditures where we can and feel we should, reviewing things that begin to look uneconomic, and selling off marginal properties and assets in cases where we believe the capital can be better put to some other purpose."

While not specifically mentioned, oilsands and oil shale clearly had to be re-examined and deferred because ARCO does not believe that synthetic crude can be produced competitively near term from these sources.

ARCO is a partner in federal prototype oil shale lease C-b and is operator of the Colony consortium on the Dow property north of Grand Valley, Colorado. Commercial development plans for the latter were postponed in October, 1974 (*see page 2-46 in December 1974 issue*) and the draft detailed development plan for C-b, indicates a decision on commercial plant construction is still years away (*see page 2-46*). ARCO turned C-b management over to Shell Oil in June.

NOTICE

Extra copies of the cumulative annual index to Synthetic Fuels will be available if we are notified by January 10, 1976.

H I G H L I G H T S

Canadian Coal Interest Increasing as Doubts Grow Over Amount and Availability of North Slope Gas Reserves

Canadians are taking a fresh look at their western coal resources because of doubts about the amount of natural gas in the Arctic and when it might reach the market. A recent Canadian government announcement indicates there might be only a tenth of the natural gas in the Mackenzie Delta as first supposed. Availability of coal from U.S. suppliers is uncertain.

Alberta coal is getting renewed attention with the apparent blessing of the provincial government. The Alberta Energy Resources Conservation Board may be in the process of coining a new term, "synfeed." Coal is widely seen as feedstock for synthetic fuel chemical and fertilizer plants. ERCB member G.J. DeSorcy told the Western Canada Fertilizer Association the board thinks eight new ammonia plants will be built in the province by the end of the century. Two will be designed exclusively for coal. The plants will not come on stream until the 1990's. Revised estimates of Alberta recoverable coal deposits are 1.2 billion tons, 370 million tons of it recoverable by surface mining. Mountain coal beds, while subject to strip mining, are only about 4 feet thick. New technology is probably necessary.

U.S. Geological Survey Updates "Coal Resources of The United States" to January 1, 1974; A 23 Per Cent Increase Cited Since 1969

Increased geologic mapping, exploration and study by the U.S. Geological Survey has revised estimated coal reserves to 3,968 billion short tons. The work by Paul Averitt cites 1,731 billion tons identified and 2,237 billion tons as hypothetical to depth of 6,000 feet. The coals are classified by rank, thickness of overburden, degree of reliability of estimates and thickness of beds in 21 states (about 60 per cent of the total identified tonnage).

The classic work, the first edition of which was published in 1965, is taken from approximately 1,500 detailed USGS reports. It notes coal resources "...do have limits. In the extensively mined eastern coal fields, new areas containing thick beds of high-rank and high-quality are becoming increasingly difficult to locate."

The report includes the usual maps, charts and tables and an expanded bibliography.

HIGHLIGHTS

Colorado School of Mines Schedules Special Engineering Programs on Shale Oil Production, Properties and Utilization

A one-week short course on "Shale Oil: Its Production, Properties and Utilization," has been scheduled at Colorado School of Mines, Golden, the week of January 5, 1976.

The up-to-date introduction to oil shale and shale oil is for managers, engineers, economists, and scientists in industry, academia, government. Lecturers are Dr. Phil Dickson, head of the Department of Chemical and Petroleum-Refining Engineering; Dr. Vic Yesavage, assistant professor of chemical and petroleum-refining engineering and Dr. Mark Atwood, manager of laboratories for The Oil Shale Corporation. Nineteen persons attended a similar course in August, 1975. Tuition is \$350.

Colorado Releases Proposed Surface Mine Land Reclamation Rules and Regulations Affecting Coal and Other Minerals

Stringent surface mine land reclamation rules and regulations affecting extraction of coal, sand, gravel, quarry aggregate and limestone were published in November by the Colorado Department of Natural Resources. Applicable to all lands, they specify revegetation density, filing of reclamation plan with mine permit application, newspaper publication, public hearings, annual reports, maps reclamation performance standards on water pollution, drainage, topsoiling, fencing and performance bonds sufficient to finance reclamation in case of default. Additional regulations pertaining to oil shale and other minerals are being drafted.

Shell Halts Work on In Situ Process; More Conventional Approach is More Economic Now

Shell Oil Co. has halted work on in situ recovery of oil from shale after patenting (*see page 2-34 September 1975 issue*) its process for using hot fluids to retort the shale in place.

Shell believes the process is technically operable but "we don't believe the time has arrived when that's the thing to do...a more conventional approach is more economic," a Shell official reports. Shell anticipates the time is coming when it will not be economic to mine and process shale above ground. In situ field tests which have been underway at various times for 10 years have been halted.

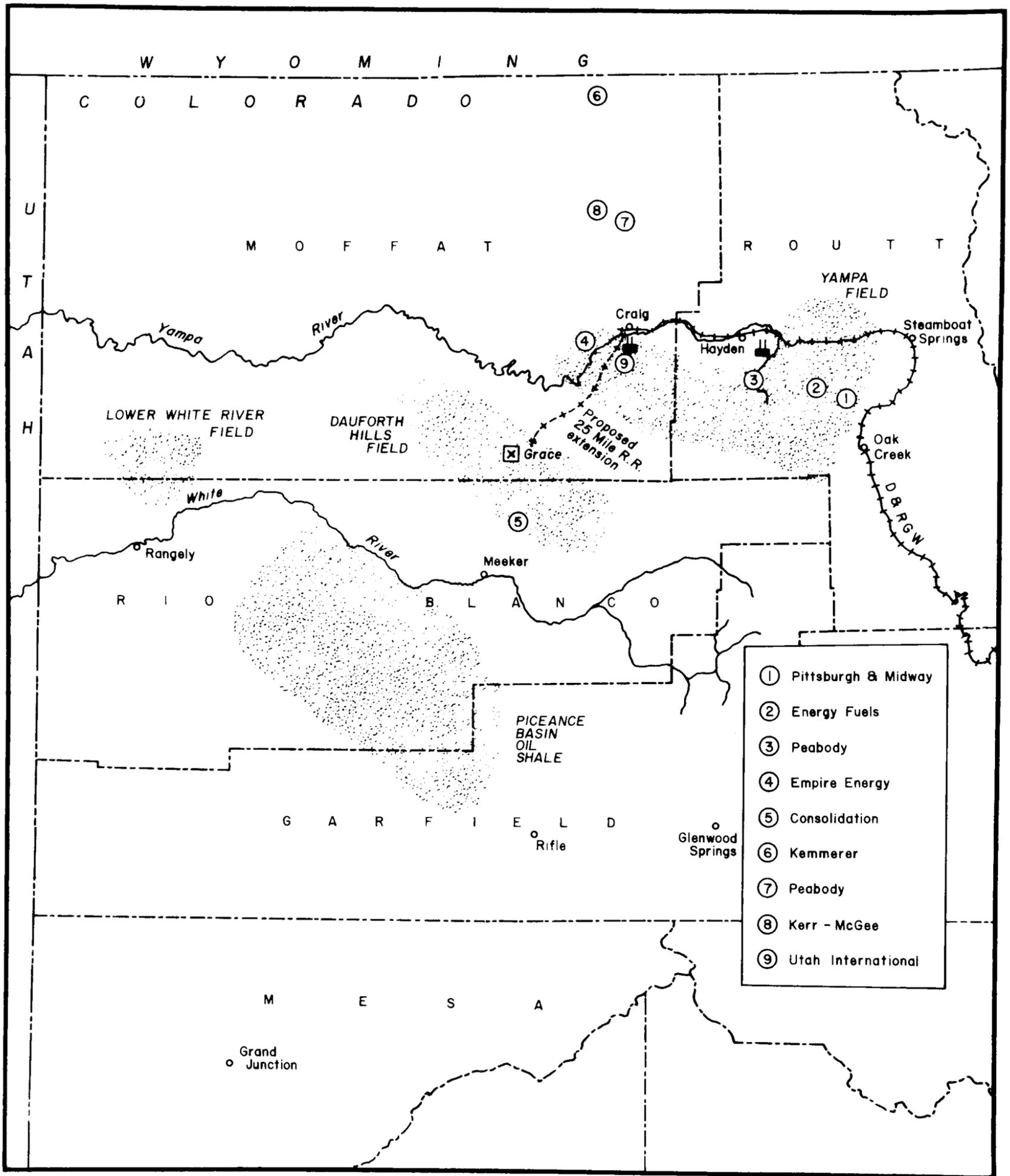


Figure 1. Northwest Coal Activity a Booming Reality Despite Federal Coal Leasing Moratorium; Not Affected by Northern Great Plains Injunction

SPECIAL FEATURE

NORTHWEST COLORADO COAL ACTIVITY APPEARS ONLY A PRELUDE TO EXPANSION

In 1974, a U.S. Bureau of Mines report (Speltz) estimated the strippable coal reserves in the Danforth Hills coal field along the Moffat and Rio Blanco county line in northwest Colorado at 163.8 million tons.

A 1975 draft environmental impact statement on five planned coal developments in the area notes "The W.R. Grace & Co. lease area itself, just a small part of the Danforth Hills coal field, has 165 million tons that the company plans to mine by surface methods."

That is one measure of the emerging coal activity and energy potential of northwest Colorado (see Figure 1), an area receiving increased attention in the wake of the Northern Great Plains dispute (see Synthetic Fuels, page 4-42, September 1975 issue).

The study region covers one of the widest variations in geography to be found in the Mountain West. It extends from Mancos shales exposed in the sheepherder's anticline at Rangely--Colorado's biggest oil field--on the west to the nearly two-mile high peaks of the Park Range, and from Dinosaur National Park to the escarpment of the proposed Flat Tops Wilderness. Between these landmarks lies a varied country of high desert, rolling pinion-juniper covered hills giving away to buckbrush, then to aspen and finally, spruce at higher elevations. Coal is exposed along nearly every highway cut.

Synthetic Fuels Implications

While all five actions covered by the EIS deal with conventional coal and no mention is made of synthetic fuel projects such as liquefaction or gasification, one seems to have direct implications for oil shale developments just south of the study region. Superior Oil Co. is known to be pleased with the southward movement of a railhead toward its multi-mineral property. (See the Oil Shale section of this issue.)

Eight Seams In One Strip

The most impressive of the five developments covered by the Bureau of Land Management Northwest Colorado Coal EIS is the stripping operation planned by W.R. Grace some 25 miles south of Craig, Colorado. It is on federal lease obtained in the December 1973 acquisition of Colowyo Coal Co. Starting in Streeter Canyon and working southwest, Grace plans to strip eight seams simultaneously in one pit (see Figure 2).

Original plans had been to mine only four seams. Exploration and core drilling of the tract after acquisition--Colowyo had operated the underground Red Wing Mine and had done little surface exploration--revealed a previously unidentified seam now known as the "X".

From the surface down, the target seams are the Y, X, A, B, C, D, E, and F. Total coal thickness averages 55 feet. With a pit depth averaging around 350 feet--maximum will be about 400--the ratio of overburden to coal is roughly six to one. The mineable seams are four to fourteen feet in thickness. When the pit is fully developed--it will be about three years after startup before the X and Y are developed, the distance between the high-wall above the Y seam and the top of the reclaimed spoil pile will be some 1,500 feet (see Figure 3).

The mine will be opened by stripping along the F seam near the canyon floor. The X and Y seams near the top of the canyon will not be exposed until about three years after start-up. The south boundary of the lease will be reached in the year 2005 or 30 years after mining starts. The mines will operate only in the east half of the total lease area, with some 1,500 acres disturbed to recover about 85 million tons of coal. The draft EIS notes that most of Grace's planned strip operation is not included on Speltz' maps of strippable reserves.

The west half of the lease is envisioned as the second phase of Grace's operation on the property. There could be a third although there are no plans in this

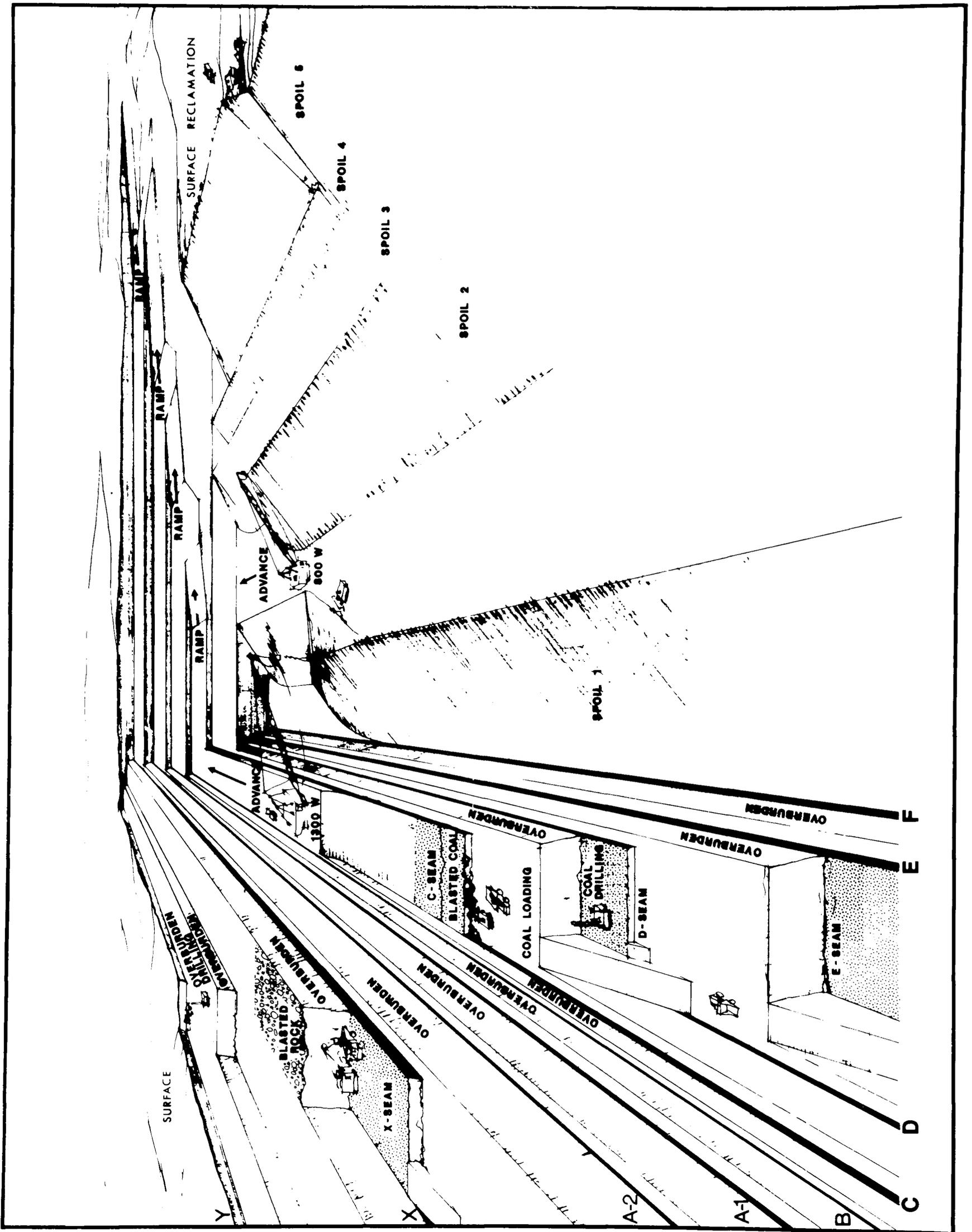


Figure 2. Perspective View Shows How W.R. Grace & Co. Plans to Strip Eight Coal Seams from One Pit on Its Colowyo Property 25 Miles South of Craig, Colorado

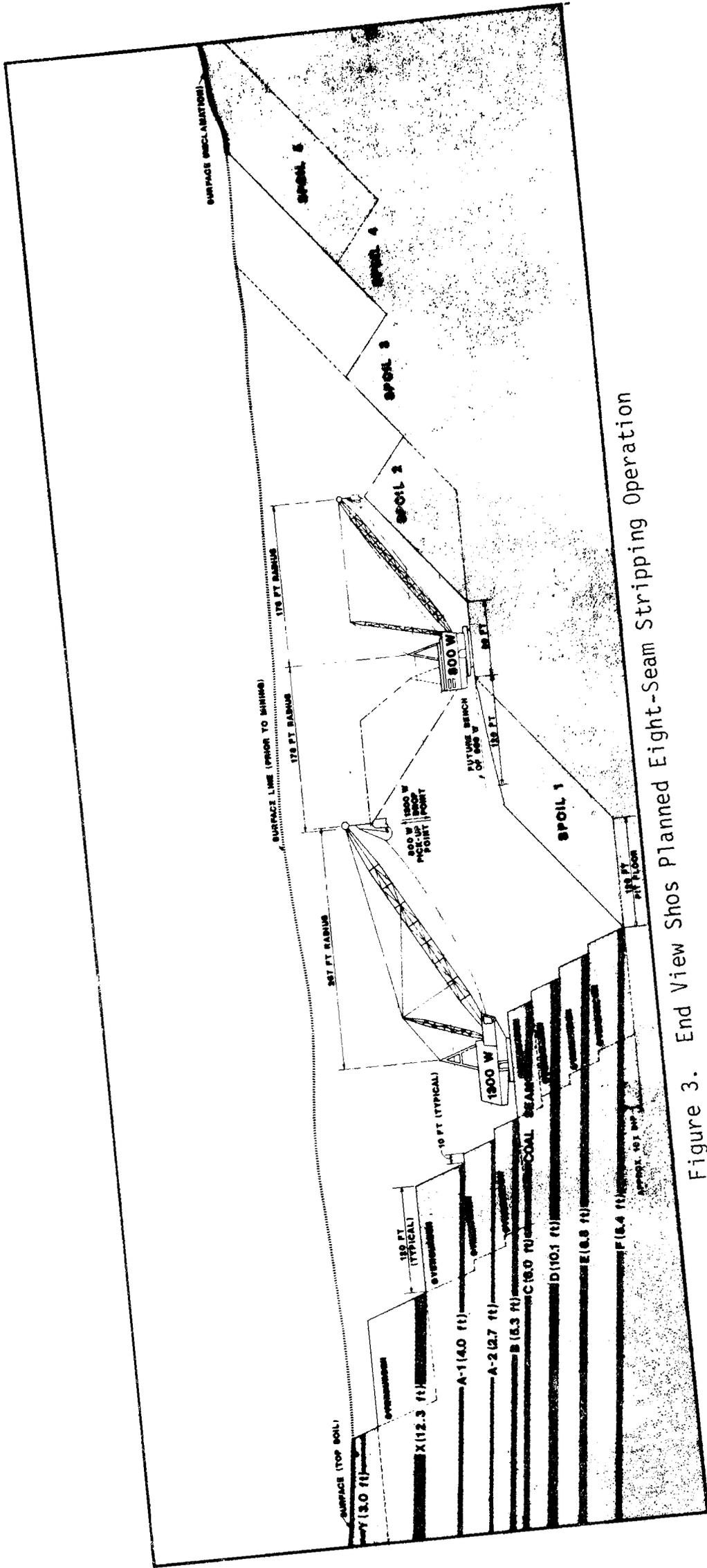


Figure 3. End View Shos Planned Eight-Seam Stripping Operation

direction at present.

Four other seams of interest, the G, H, I, and J, are mineable by underground methods. About 150 feet of overburden separate the F and G seams. Two underground mines, the Streeter and the Red Wing, previously operated from Streeter Canyon. The Red Wing was operated by Colowyo in the G seam. The Streeter also operated in the G and H seams north of Grace's lease. The Streeter caught fire some years ago and the Red Wing was subsequently closed because of noxious gases which appeared to originate from the Streeter.

Railroad Extension

A key feature of Grace's overall plan is a 25-mile extension of railroad tracks south from Craig. This is the second of the five projects awaiting completion of the regional EIS. Building of the line seems certain to speed planning and development of other operations in the area.

The railroad is now being extended four miles south from Craig to the site of the Craig coal fired electric generating plant being built by Colorado-Ute Electric Association in partnership with three other cooperatives. The Craig station and Utah International's strip mine just south of it are not covered in the EIS, having previously been approved under their own site specific statements.

The Grace extension will put the railroad roughly half the distance from Craig to Meeker and the White River Valley on the northern perimeter of the Piceance Basin.

Construction of the rail extension is expected to take about two years. Meanwhile, Grace expects to mine and truck some 600,000 tons of coal to Craig in the first six months of the mine operation; 900,000 tons in the following year, and increase output to 1.2 million tons with completion of the railroad. Five years after startup, the mine will produce about three million tons annually or about half of Colorado's total state coal production in 1974.

Grace officials said sales contracts have not been signed. They said this is a matter of price and "not a matter of finding a buyer." It is a seller's market.

Ruby Construction Mine

The third planned development in the region, that by Ruby Construction Co., is the only other entirely new one covered by the EIS. The other two site-specifics are extensions of existing mining operations.

Ruby has filed a mining plan for underground operations on 146-acre Federal Lease D-051698 some 12 miles southwest of Hayden. It plans to mine 200,000 to 300,000 tons of coal per year, all for the local and domestic markets. It is of some interest that a mine is being opened for this purpose. Much of the Routt County domestic is supplied by Pittsburgh & Midway from their Edna mine. P&M has been selling about 7,500 tons of coal locally since 1948 and plans to continue.

Pittsburgh & Midway

P&M's plans are uncertain or unknown. According to Bureau of Land Management officials, P&M asked to be included in the regional study on the theory that a supplemental statement could cover any P&M requests for additional federal coal leases and thus avoid the donnybrook encountered by Peabody a few miles to the west at the Seneca 2W seam.

P&M operates the Edna strip mine near Oak Creek, producing 1.2 million tons per year, the bulk of which is consumed in state by Public Service Company of Colorado and Colorado Fuel & Iron. The Edna is scheduled to close in 1991.

Peabody Coal's Seneca

Peabody has operated the Seneca strip east of Hayden to fuel the Hayden power plant of Colorado-Ute since the plant was built in the early 1960's. Colorado-Ute is nearing completion of a 257 megawatt second unit at the Hayden plant. It originally was scheduled to go on line in

the fall of 1975.

Peabody had contracted to supply the second Hayden unit and planned to mine the coal from its new Seneca 2W strip west of the present Seneca 2. Seneca 2W consists of a combination of state, private, and federal leases. Interior Department officials deemed that development of the federal leases, an integral part of 2W, was a major federal action which would have to await completion of the regional EIS.

A carpenter's strike honored by some other crafts caused a slippage in the schedule of Hayden No. 2. The plant is now expected to go on line in April 1976 and go commercial in June.

Peabody filed a revised mining plan in July 1975 in which both units of the Hayden plant will be fueled with coal from the Seneca 2. Production from the 2W strip will begin in 1980 at the rate of 900,000 tons per year.

Energy Fuels Corp.

Energy Fuels Corporation operates the Energy strip about 15 miles southwest of Steamboat Springs and its application for six competitive federal coal leases on 2,865 adjoining and nearby acres resulted in the fifth of the five site-specific statements included in the regional study. In the interim, it will mine mostly for Colorado markets about 22 million tons from 1,840 acres in the 1975 to 1979 period. The additional leases are sought for the post-1979 production.

Energy's reclamation efforts probably are among the most outstanding in the state. According to BLM officials, the reclamation has surprised a number of strip mining opponents. Topsoil is being stacked from current mining operations. Old mining operations are being rehabilitated by leveling to simulate the original contours. The surface is then covered with topsoil and reseeded with smooth brome, orchard grass, intermediate wheatgrass, and alfalfa. Two acres which were topsoiled and seeded two years ago already are being invaded by native successors such as mullen, yarrow, larkspur, big

sage, penstemon, dandelion, and wild onion.

Another eye-catcher in the Energy operation is a large mobile building erected on boxcars. The structure is designed to move back and forth, enclosing workers erecting the firm's new 55-cubic yard dragline. Because of heavy snow, winter cold and spring mud at the 7,000-foot elevation mine site, Energy officials reasoned that the \$100,000 cost of the pad and building would be repaid through earlier completion of the \$8 million machine. Most dragline erection projects have been open air operations.

Present Operations Only the Beginning

BLM officials said that the regional coal picture is rapidly changing. Marvin Pearson, district manager, noted that 15 letters of intent had been received from firms whose properties and current plans are not firm enough to be covered by the regional EIS.

The region covered by the study is all of Routt and Moffat counties and Rio Blanco County north of the White River. It does not cover the 760-megawatt net Craig power plant project and supporting mine and railroad extension. These, plus the still incomplete Hayden No. 2 station, are the source of most current socio-economic impacts. About 1,000 workers were employed at the two plants in mid-October. Craig's population before plant construction started was around 4,000.

Synthetic Fuels Not Envisioned

To date, none of the plans reveal any indication that coal liquefaction or gasification is being considered. BLM officials are of the opinion that the coal quality is too high. Grace officials say their coal averages 10,000 BTU and 0.3 to 0.4 percent sulfur. The draft statement says, "Mean values of over 1,600 samples from various Moffat and Routt coal beds as reported by Speltz (1974) were nearly 11,580 BTU's and 0.9 percent sulfur." This compares to BTU averages around 8,500 and sulfur averages of 0.5 to 0.6 percent for coal from Wyoming's Powder River Basin.

The northwest Colorado coal of economic interest is in the Iles and Williams Fork members of the Cretaceous Mesa Verde formation. The EIS identifies three different coal fields. The Yampa field in eastern Moffat and Routt counties includes coals in the Iles and Williams Fork of the Mesa Verde and the Lance and Fort Union formations. Approximately, 25,607 million tons are estimated to lie in this field, 76 percent of which is bituminous and 24 percent is sub-bituminous.

The Danforth Hills field, where Grace holds its lease, is all Mesa Verde. The field straddles the Moffat and Rio Blanco county lines. Some 7,854 million tons of "mainly high volatile C bituminous coal" are recoverable. The Lower White River field is estimated to contain 7,012 million tons of bituminous coal, all in the Williams Fork member of the Mesa Verde formation.

First among the potential developments is Colorado-Ute's plan for additional units at the power plant now under construction at Craig. The two 380-megawatt units under construction are scheduled to go commercial in 1978 and 1979. Colorado-Ute has had tentative plans from the start for third and fourth units although possibly at another location.

Norman R. Cates, construction coordinator for Colorado-Ute, said the decision on the third and fourth units will be made by the end of January. "In all probability, three and four will go here (Craig)," Cates said. He noted that Colorado-Ute and its partners have options on most of the major equipment that would go with the third and fourth units. Load growth projections show the power will be needed, Cates said.

Social Consequences

The boom town experience suffered by Rock Springs, Wyoming, has been widely publicized. Craig is the first major town the crow flies southeast of Rock Springs. There appear to be few similarities between coal and power plant development near the two towns. No provision was made at Rock Springs for a heavy influx of construction labor. The results have added to energy

development problems across the west and are partially blamed for the increased cost of construction of the 2,000-megawatt Bridger Power Plant near Rock Springs.

The Wyoming city faced a land availability problem Craig is not faced with. Rock Springs is situated in a checkerboard of Union Pacific Railroad and Bureau of Land Management land. The railroad was reluctant to sell land, and BLM cannot provide land in time to solve any problems. Rock Springs and arriving construction workers were caught in a squeeze that saw garages and an assortment of buildings turned into living quarters.

Colorado-Ute is benefiting from some of the lessons learned by Pacific Power & Light on the Bridger plant. One of the results is Shadow Mountain Village just northwest of Craig. It is a permanent mobile home subdivision with curbs, gutters, and paved streets. It will contain spaces for 540 mobile homes plus ten 20-man bachelor buildings and a mess hall, recreation hall, swimming pool and "even a beauty parlor."

Colorado-Ute officials say they will sell Shadow Mountain an "get out of the housing business" when construction is complete.

Cates said Colorado-Ute attempted to promote housing construction in the Craig and Hayden area without too much success. This included guaranteeing the rent on 140 trailer spaces, but the private capital did not come forward. Employment at the plant construction site hit 840 in mid-October. Peak employment of 1,750 including non-construction workers, is expected in mid-1977. The completed plant will employ about 105.

Moon Lake Electric Association

For the past two years, another cooperative, Moon Lake Electric Association of Roosevelt, Utah, has been studying the oil shale rich Rangely, Colorado, area and the Lower White River coal field for a 500 to 1,000-megawatt generating station. The size of the demand appears to be the major question facing Moon Lake. Much depends on the pace of oil shale development.

Three of the federal prototype oil shale leases are in Moon Lake's territory and it has already filed the right-of-way application for a line to serve the Colorado C-a oil shale tract.

Moon Lake holds one coal lease and has preference right lease applications on two other tracts and has made one competitive lease application on coal northeast of Rangely.

Consolidation Coal Company

Consolidation Coal, a wholly-owned subsidiary of Continental Oil, is termed by BLM officials as "the big sleeping giant in this country." Consolidation owns seven federal leases totaling 10,000 acres and three preference right leases covering 9,600 acres. State and private leases push the firm's holdings, all in the Nine Mile Gap area northeast of Meeker, to about 50,000 acres. Consolidation's holdings are six to 12 miles south of Grace's Colowyo property. This is one of the reasons Pearson said he thinks the Grace railroad extension "will just be the first leg of it." Consolidation's letter of intent to BLM anticipated underground mining operations "no sooner than 1980."

Core drillers are busy all across the northwest region. Holes on Consolidation leases are among the 600 holes BLM officials expected to be completed by the end of 1975.

Empire Energy

In some respects, the Northwest EIS is a description of a point in time that passed even before completion of the statement. An example is Empire Energy, operator of a strip and underground mine at Wise Hill about five miles south of Craig. At the time data were gathered in mid-1975, Empire had been producing 300,000 tons per year. As of November 1, the firm was expecting to have mined a million tons in 1975.

BLM officials conducting the environmental analysis decided to leave original figures stand rather than revise the report with each new bit of information. Thus, the figures in Table 1 already are

at variance with actual production. An Empire official said the firm's plans are for two million tons a year by 1980 rather than the 300,000 tons shown in the table. Gary Carson, BLM team leader for the EIS, statistics were hiked by seven million tons per year in chapter 1 of the EIS to cover such changes. Thus, while Table 1 shows projected 1990 production from the region at 26.2 million tons per year, there is recognition it could be as high as 33 million tons. Carson said the 23.9 million tons projected for 1980 may be high because of equipment delays and the lead time required for environmental work. However, the figures for later years shown in the table probably are too low.

Empire holds 80 acres in federal coal leases plus state and private coal. The bulk of production comes from the state and private coal. It also has applied for three competitive leases covering 9,300 acres.

American Electric Power Service Corporation

American Electric is considering development of an underground mine on 640-acre federal lease in the Williams Fork Mountains on the west border of Routt County. The coal would be shipped to American Electric's coal-fired generating plants in the midwest. Their plans are dependent on obtaining additional coal leases.

Coal Fuels Corporation

Coal Fuels has a competitive coal lease application filed on 6,690 acres southeast of Hayden in Routt County and is core drilling on adjacent fee lands. According to the draft EIS, if Coal Fuels is successful in acquiring a lease, it would start underground development in 1977 with full-scale production of two million tons per year envisioned. "Additional development at some later date would bring production up to eight million tons per year." The coal would be shipped to out-of-state markets.

Midland Coal Company

Midland, a division of American Smelting

TABLE 1

TABLE FROM THE DRAFT ENVIRONMENTAL IMPACT STATEMENT NORTHWEST COLORADO COAL CONTAINING FIGURES BASED ON INDUSTRY PROJECTIONS AT MID-YEAR EMPIRE ENERGY HAS ALREADY TRIPLED PRODUCTION SINCE THE DATA WERE COMPILED

<u>Mine</u>	<u>Present</u>	<u>1980</u>	<u>1985</u>	<u>1990</u>	<u>Start Date</u>	<u>Present Employment</u>	<u>Employment</u>	<u>Underground or surface</u>	<u>Market</u>
American Fuels Consolidation Coal	11,500	300,000	300,000	400,000	Active	25	25	U	Local
Empire Energy	0	**	**	**	1981	0	500	U & S	Unknown
Energy Fuels Corp.	300,000	300,000	300,000	400,000	Active	72	150	U & S	Midwest
Moon Lake Electric	2,500,000	4,500,000	4,500,000	4,500,000	Active	175	593	S	In state
	0	1,500,000	2,300,000	3,700,000	1981	0	700	U & S	Local
Peabody (Seneca 2-W)	0	900,000	900,000	900,000	1980	0	44	S	Local
Peabody (Seneca 2)	600,000	600,000	600,000	600,000	Active	30	30	S	Local
Rouff Mining (Apex)	14,000	30,000	40,000	40,000	Active	10	10	U	Local
Ruby Construction (Sun)	0	200,000	200,000	200,000	1976	0	65	U	In state
Star International	0	2,880,000	2,880,000	2,880,000	1976	0	165	S	Local
W. R. Grace & Co.	0	3,000,000	3,000,000	3,000,000	1976	0	244	S	Unknown
Gulf Oil Corp. (Edna)	1,000,000	1,100,000	1,150,000	400,000	Active	75	75	S	In state
Coal Fuels	0	2,000,000	2,000,000	2,000,000	1977	0	290	U	Unknown
**Thomas Woodward	0	**	**	**	1980	0	40	S	Unknown
**Merchants Petroleum	0	**	**	**	1980	0	30	S	Unknown
Midland Coal	0	200,000	300,000	300,000	1981	0	46	S	Unknown
Paul Coupey	0	1,000,000	1,000,000	1,000,000	1980	0	75	S	Unknown
American Electric Power	0	500,000	750,000	750,000	1981	0	150	S	AEP System
American Electric Power	0	500,000	650,000	750,000	1981	0	125	U	AEP System
	4,425,000	19,510,000	20,870,000	21,820,000					
**Aggregate total for Woodward, Merchants and Consolidation Coal:		4,400,000	4,400,000	4,400,000					
TOTAL		23,910,000	25,270,000	26,220,000					

*Figures based on industry projections

and Refining, is reported to be negotiating with Paul Reibold for a federal lease and a preference right lease application, both northeast of Rangely. "If successful in these negotiations, the company intends to conduct a detailed exploration program," the draft EIS says.

Merchants Petroleum Company

Merchants holds 2,500 acres of leased fee land near Milner in Routt County. Their plans are indefinite until a joint venture partner can be found, the statement says.

Independent Coal Operators

At least two independent coal operators are cited in the draft EIS. They are Thomas C. Woodward who holds 920 acres in two state leases near Milner and is conducting an exploration program, the other is Paul S. Coupey, holder of two leases. One is a 280-acre parcel near Milner on which Coupey has applied to the Colorado Land Reclamation Board for a strip permit. This lease would deplete in three years. Coupey also holds a 640-acre state lease in Axial Basin south of Craig.

State and Private Lands

A considerable acreage of state and private coal land is under lease. The amounts and future plans cannot be determined. There has been extensive core drilling on much of it. Colorado law does not require recording or reporting of coring and exploration activities on private land. Data obtained would provide a basis for bidding on adjacent federal coal.

Peabody, Kemmerer Coal, and Kerr-McGee all have sizeable holdings north of Craig but their intentions have not been made public.

BLM officials also report considerable recent exploration activity in the Lay area west of Craig. State lands in this area are under lease to Ark Land Co. of Sherdian, Wyoming. Coal was mined in the area in the past and the deposits are near the site of the proposed 1,080,000 acre-foot Juniper Reservoir on the Yampa River.

EIS Timetable

The preliminary draft was scheduled to be completed by mid-November. Printing of the draft is expected about January 1 following an in depth review by the Interior Department and the Council on Environmental Quality. BLM officials hope to have the final statement out by July 1976.

Any operations other than the five covered by the EIS undoubtedly will have to repeat at least a portion of the process. BLM officials hope a supplementary statement will suffice when another coal development in the region is ready to move forward. They see a need for streamlining the present environmental analysis program. "Where you have identical situations, it's a waste of time to repeat the process," Pearson said.

Although the federal coal leasing moratorium is still on, extensive drilling operations on private land adjacent to federal minerals will enable some firms to bid on prospective future leases with significant data.

Much attention has focused on Northern Great Plains coal. A boom in the higher quality Colorado coal is virtually unrecognized.

#

STATUS OF SYN FUELS PROJECTS

Synthetic Fuels From Oil Shale

Underlining denotes changes since September 1975 issue.

PRINCIPALS	PROJECT DESCRIPTION	DETAILS COMMERCIAL PROJECTS	STATUS
Atlantic Richfield Co., The Oil Shale Corp., Ashland Oil. Shell Oil Co.	Proposed 50,000 BPD plant on 5,094 acre federal tract C-b; Piceance Basin Colo.	Rights acquired on bid of \$117.8 million at DOI lease sale 2/12/74. Lease issued 4/1/74. Proposed room and pillar mining of 75 foot, 35 GPT interval in Mahogany zone. TOSCO II retorting: possible eventual in situ recovery. Water requirement, 10,000 AFY. Recoverable reserves estimated at 723 million barrels. Shell is operator. <u>Lease operation to begin with four-year mine development phase after which decision will be made on commercial plant. First shale oil production in 1984.</u> Project cost <u>estimated at \$923 million.</u>	A \$6 million environmental/exploration analysis underway. DDP expected Jan. '76. No decision on full development. (See page 2-46.)
Colony Development Operation (ARCO, TOSCO, Ashland, Shell)	Proposed 50,000 BPD plant on 44,000 acres of Dow West fee land near Grand Junction, Colo.	Room and pillar mining of a 60-foot horizon to put 66,000 tons of 35 GPT shale daily into TOSCO II retort system. Mining of about 4,100 underground acres anticipated. Water requirement; 10,000 AFY. BLM preparing draft EIS for 92 mile, 50,000 BPD pipeline to LaSal, Utah. Peak plant/mine construction employment, 1,200; operation force, 900. <u>Draft environmental impact statement on pipeline to be published by 12/1/75.</u> Project cost <u>estimated at \$1.132 billion including \$20 million for community development.</u>	No announced change since development suspended 10/4/74. TOSCO offered FEA a draft cooperative development plan, June 1975. (See June 1975 issue, page 2-1.)
Rio Blanco Oil Shale Project (Standard Oil of Indiana, Gulf Oil Corp.)	Proposed 50,000 BPD plant on 5,090 acre federal tract C-a Piceance Basin, Colo.	Rights acquired on \$210.3 million bid at DOI lease sale 1/8/74. Lease let 3/1/74. Proposed open pit mine for 25-30 GPT shale in 1,100-1,200 foot interval with 60 to 70 percent recovery compared to 10 to 25 percent recovery from contemplated underground mine. TOSCO II and other retorts. Operational in 1980. Morrison-Knudsen retained in 1975 for \$5 million mining-environmental study, reported most labor for 50,000 BP plant could come from population already in NW Colorado. Water requirement for 50,000 BD plant, 11,200 AFY; 60,000 AFY sought for potential 300,000 BD. Colorado River Water Conservation Board voted 10/21/75 to drop opposition to change in point of diversion of 53,000 AFY from White River which partners propose to purchase from Rocky Mountain Power Co. Recoverable reserves 4 billion BBL open pit; 1.3 billion BBL underground. Application for 4,950 acre off-tract land (surface only) for spent shale disposal pending; Congressional authority needed. Project cost <u>expected to exceed \$600 million.</u>	A \$6 million environmental/exploration analysis underway. DDP in March 1976; no decision on full development (See Sept. 1975 issue, page 2-48.)
Sun Oil Co. and Phillips Petroleum Corp.	Proposed 50,000 BPD plant on 5,120 federal tract U-a near Vernal, Utah.	Acquired rights on \$75.6 million bid 3/12/74. Lease let 6/1/74. Room and pillar mining of 30 GPT shales at rate of 80,000 TPCD from 50-60 foot horizon about 1,300 feet underground. Both TOSCO II and Paraho retorting anticipated with Paraho processing 80 percent of input. Water requirement 8,250 AFY. Water development contract in negotiation state. Construction labor, 1,350; permanent force of 850. Shale oil, develop jointly with adjacent U-b tract under advisement by Interior. Reserve estimated is 244 million BBL. <u>Modular development planned.</u> Project cost <u>in excess of \$600 million.</u>	Environmental and exploratory work proceeding. DDP <u>to be filed by 4/1/75.</u> Water assurances imminent with state backing. (See Sept. 1975 issue, page 2-48.)
Superior Oil Co.	Proposed 50,000 BPD shale & multi-mineral development on 7,000 acres private land near Meeker, Colo.	Production of 80,000 TPD 25 GPT shale to yield 50,000 BBL shale oil; 5,000 to 15,000 TPD nahcolite; 3,000 TPD aluminum tri-hydrate (or 2,300 TPD alumina); and 3,000 TPD soda ash from underground mine. Underground ore processing for surface pyrolyzation in continual feed, circular, traveling grate retort. Application to Interior for exchange of 2,571 acres Superior land for 1,769 adjacent BLM acres to block up economical unit filed 12/3/73. Spent shale backfilled in mine. Employment, 1,000. Recovery of multiple products offers economic advantages. <u>Completion of pilot plant work anticipated mid-1976 (see page 2-52).</u> Project cost <u>estimated to exceed \$600 million.</u>	Interior analyzing comparative land values prior to decision on exchange. (See March, 1974 issue, page 2-53)
The Oil Shale Corp. (TOSCO)	Proposed 35,000 BPD plant on 14,688 acres of state leases in Sand Wash area near Vernal, Utah.	Utah State Land Division asked to unitize 29 state oil shale leases totaling 14,688 acres in Sand Wash area. Leases are under option from Shell Oil. TOSCO proposes 8-year, \$8 million tract evaluation. Room and pillar mine extraction of 75,000 TPD of 30 GPT shales from 30 to 40 foot interval 2,000 feet underground. TOSCO II retort and pipeline for upgraded shale oil. Water requirement estimated 1,500 AFY. Eventual in situ contemplated for secondary recovery. Investigations could lead to commercial operations by 1981-83. Project cost - undetermined.	Utah State Land Board evaluating unitization proposal. (See June 1975 issue, page 2-5.)

STATUS OF SYNFUELS PROJECTS

Underlining denotes changes since September 1975 issue.

PRINCIPALS	PROJECT DESCRIPTION	DETAILS	STATUS
Union Oil Co., California	Proposed 7,000 BPD plant on 22,000 acres private land near Grand Valley, Colo.	Union proposes its 'B' retort for a 10,000 TPD feed of 30-35 GPT shale from room and pillar mine on east fork of Parachute Creek. Scale up to 1,200 TPD steam gas recirculating process deferred. Processing water requirement 1,500 AFY using Colorado River intake structure. Possible site preparation 1976; construction 1977. Operational in 1979 with 100-150 workers. Eventual site scaleup to 150,000 BPD possible. High grade reserves hold 2 billion barrels: low grade, 2 billion barrels. Union, a pioneer oil shale firm, has land, reserves, technology and water. Needs favorable political/economic climate to proceed. Project cost undetermined.	Environmental work continuing (see page 2-29); go ahead awaiting Congressional action on energy legislation (See page 2-52 in Sept issue).
White River Shale Oil Corp. (Sun, Phillips and Sohio)	Proposed 50,000 BPCD on 5,120 federal tract U-b near Vernal, Utah	Rights on 5,120 federal oil shale prototype program tract U-b acquired with \$45.1 million bid 4/9/74. Lease issued 6/1/74. Recoverable reserves 266 million barrels. Room and pillar mining of shales probably for Paraho retort. By-product of shale crushing briquetted for Paraho or used for TOSCO II retort. Water requirement 8,250 AFY. White River water development shared with U-a, Ute Indians, Uinta and Central Utah water districts, Bureau of Reclamation. Employment 1,375 for construction; 895 for operations. Joint development with tract U-a sought. <u>Modular development planned. Solicitation of participation by federal government being evaluated.</u> Project cost probably in the \$600 million plus range.	Environmental, exploratory work underway. DDP expected, 4/1/75. Water development with state help imminent. (See page 2-9 and 2-48) in Sept. 1975 issue.)
<u>DEMONSTRATION PILOT AND RESEARCH PROJECTS</u>			
Dow Chemical Co.	Proposed in situ oil and gas recovery near Midland, Michigan	Dow asked ERDA for \$42 million for seven year field evaluation on extracting low BTU gas and liquid products from 200 foot horizon of Antrim shales 3,000 feet underground. Fracturing needed prior to using forward combustion process on 10 GPT shales. Reserves extensive as 2/3rds of state underlain with shale. Project cost \$42 million.	ERDA evaluating proposal. No recent agency action (see page 2-1 in Sept. issue)
<u>Geokinetics, Inc.</u>	<u>In situ test in Uintah County, Utah</u>	<u>Proposed tests is in NE 1/4 of Section 2, T14S, R22E. Approved by Utah Board of Oil, Gas and Mining on 9/17/75. Test will involve explosive fracturing of shallow oil shale deposits followed by in situ retorting by means of horizontal fire front.</u> Project cost undetermined	<u>In progress (see page 2-49).</u>
Institute of Gas Technology, American Gas Assn.	One ton per hour oil shale gasification plant in Chicago	Pilot plant being built to use 25 GPT shale from Anvil Points in one ton per hour non-continuous feed test. Tests of 8 and ten hour duration to verify bench scale yields of up to 80 percent conversion of organic carbon to gaseous products. <u>Dec. '75 startup anticipated.</u> Project cost \$330,000	<u>Construction virtually completed.</u>
National Science Foundation, Denver Research Institute	Environmental effects of spent shales at DRI	<u>Second phase of study of carbonaceous solid waste from commercial oil shale operations nearing completion with analysis of auto-oxidation of spent shale. First annual report of 2-year study 1/75 cited properties of polynuclear/polycondensed aromatics and other constituents, including carcinogenic potential.</u> Study cost \$120,000 NSF grant.	Research continuing. (See June 1974 issue, page 2-70.)
National Science Foundation, University of Southern California	Use of bacteria to release kerogen from shale at USC	Investigation of sulfur-oxidizing bacteria for releasing kerogen from in situ shale bodies. Study cost \$120,000 NSF grant.	Active
Occidental Oil Shale, Inc.	Modified in situ shale oil recovery near Grand Junction, Colo.	Modified in situ with upper and lower level adit. 120' x 120' x 310' column of 15 GPT fractured shale <u>ready for ignition.</u> Top of column to be ignited and oil recovered from lower level adit with gas recycle for sustained combustion and temperature control. Work is based on 30' x 30' x 70' results. <u>Permit sought for increase in mine waste disposal from 500,000 to 8.8 million yards.</u> Project cost \$25 million expended to date.	Active (see page 2-48).

STATUS OF SYN FUELS PROJECTS

Underlining denotes changes since September 1975 issue.

PRINCIPALS	PROJECT DESCRIPTION	DETAILS	STATUS
Paraho Development Corp. (Development Engineering, Inc.) & A.G. McKee, ARCO, Carter Oil, Chevron, Cleveland Cliffs, Gulf, Kerr-McGee, Marathon, Mobil, Phillips, Shell, Sohio, So. Calif. Edison AMOCO, Sun, Texaco, Webb Resources	Development of direct/indirect retorting processes at BuMines facility, Rifle, Colo.	Government tested seven fuels from 10,000 BBL refinery runs of Paraho retorted shale oil. Direct combustion of 30GPT shale attained up to 95 percent recovery; 8,420 SCF of low BTU gas per ton. Operating factor 88 percent. Low organic content in spent shale in 56 day test run. <u>Concluding direct fired mode of operation. Indirect mode of operation to begin Dec. '75. Combination mode operation planned in late spring of 1976 in conjunction with commercial evaluation studies. Conclusion of 30-month demonstration project scheduled for late May 1976.</u> Project cost \$9 million.	Testing of refinery products; indirect combustion operations readied. (See page 2-14 in Sept. 1975 issue.)
Paraho Development Corp.	Scale-up of retort to 7,300 BPD at BuMines facility, Rifle, Colo.	Proposal to build 42 foot diameter retort capable of processing 11,500 TPD of 30 GPT shales to yield 7,300 BBL/D liquids at Anvil Points. A scale-up and refinement of 8 1/2' diameter retort. <u>ERDA officials revealed that full-blown EIS would have to be prepared for scale-up. Awaiting guidelines on scope of EIS.</u> Project cost \$76.2 million.	Participants sought. (See June 1975 issue, page 2-43.)
Petrobras (Petroleo Brasileiro, S.A.)	Demonstration plant near Sao Mateus do sul, Parana, Brazil	Petro Six 2,200 TPD shale retort operating near design capacity to yield 1,000 BBL/D oil, 12 MMCFD gas and 14 TPD sulfur in series of demonstration tests. A 50,000 BPD facility contemplated by Mines & Energy Ministry. Cost of production about \$9 per barrel. <u>U.S. patent obtained on the process.</u>	Demonstration runs being made
The Oil Shale Corp. (TOSCO)	Direct gasification of oil shale at Research Center near Denver, Colo.	Series of tests with 5 TPD retort using 36 GPT shales and oxygen-steam gasification in fluidized bed. Preliminary results warrant continued work. Report scheduled early 1976. Project cost undetermined.	In progress.
U.S. Bureau of Mines, Cameron Engineers, Inc.	Underground mining Research studies	Technical phase of 18 month study complete; economic analysis of technology in progress for deep, thick bedded shale deposits in Piceance Basin, Colo. Study cost \$293,224 contract.	First phase completed July 1975; second phase due January 1976. (See page 2-12 this issue.)
U.S. Bureau of Mines Fenix & Scisson, Inc.	Modified in situ oil shale study of Piceance Basin	Study of modified in situ shale oil recovery from deep, thick bedded shales of Piceance Basin, Colo. Features conventional mining, rubbilization of shales and in situ retorting. An 18 month study from July 1, 1974. Project Cost \$220,696	Technical phase completed economic analysis due January 1976.
U.S. Bureau of Mines, Sun Oil Co.	Open pit mining analysis of Piceance Basin	Technical and economic analysis of open pit shale mines, Piceance Basin, Colo. Two year study due June 1976. Concept is for one large mine to supply several retorts. Project cost \$395,309	First phase done April 1975; second phase underway.
Western Oil Shale Corp., Ashland, Chevron, Cities Service, Getty, Gulf, AMOCO, Shell, Sun, A.G. McKee	Experimental in situ project	Planning and costing of three small in situ chimneys in 30 GPT and 15 GPT shales fractured by Dupont designed explosives begun July '75; due 2/1/76. Second phase field testing scheduled in 1976. Project cost First phase \$400,000	First phase due 2/1/76. (See Sept. 1975 issue, page 2-53.)

Synthetic Fuels From Oil Sands

Underlining denotes changes since September 1975 issue.

COMMERCIAL PROJECTS

AOP Group, owned jointly by Petrofina Canada (35%), Pacific Petroleum (35%), Hudson's Bay Oil and Gas Co., Ltd. (19%), and Murphy Oil Co., Ltd. (11%)	Commercial plant in Athabasca deposit, Alberta, Canada	Proposed plant to be located on Lease Nos. 12 and 34. Allowable production will be 122,500 BPCD. Mining bucketwheel excavators; extraction -hot water process; upgrading fluid coking. On-site power plant will use byproduct coke. Initial production scheduled for 1982. Project cost -estimated at \$1.7 billion.	ERCB approval granted, awaiting provincial approval
-------------------------------------------------------------------------------------------------------------------------------------------------------	--------------------------------------------------------	-----------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------	-----------------------------------------------------

STATUS OF SYNFUELS PROJECTS

Underlining denotes changes since September 1975 issue.

PRINCIPALS	PROJECT DESCRIPTION	DETAILS	STATUS
Great Canadian Oil Sands, Ltd., owned 97% by Sun Oil Co., 3% publicly owned	Commercial plant in Athabasca deposit, Alberta, Canada	Plant has been in operation since 1967 on Lease No. 86. Authorized annual production is 65,000 BPCD equivalent. Mining - bucketwheel excavators; extraction hot water process; upgrading - delayed coking. Coker bottoms are used for power plant fuel. 100,000 TPY of sulfur is being exported and sold in Italy. <u>\$7 million loss reported for first three quarters of 1975.</u>	Operating
Home Oil, Ltd. and Alminex Corporation	Commercial plant in Athabasca deposit Alberta, Canada	Proposed plant to be located on Lease No. 30. Allowable production is 103,000 BPCD. Mining bucketwheel excavators; extraction hot water process; upgrading fluid coking. Initial production scheduled for 1982. Project cost estimated at \$2.4 billion	Approved by ERCB, awaiting provincial approval
Shell Canada, Ltd.	Commercial plant in Athabasca deposit Alberta, Canada	Proposed plant to be located on Lease No. 13. Allowable production is 100,000 BPCD. Mining electric draglines; extraction hot water process; upgrading - vacuum flash deasphalting. Initial production scheduled for 1980. Project cost now estimated at \$2 billion	ERCB approval granted. Ratification by provincial government awaited
Syncrude Canada, Ltd. (a joint venture consisting Imperial Oil Ltd., (44.64%), Canada Cities Service Ltd., (31.43%) and Gulf Oil Canada Ltd. (23.93%), Province of Alberta (10%), Province of Ontario (5%) and the Canadian Federal Government (15%))	Commercial plant in Athabasca deposit, Alberta, Canada	Plant located on Lease No. 17. Allowable production is 125,000 BPCD. Mining electric draglines; extraction hot water process; upgrading fluid coking. Canadian Bechtel, Ltd. is managing contractor. Startup scheduled for 1978 with initial production of 104,500 BPCD. Project cost now estimated at over \$2 billion.	Construction continuing
<u>DEMONSTRATION, PILOT OR RESEARCH PROJECTS</u>			
Arizona Fuels, Inc. and Burmah Oil	Pilot plant on Asphalt Ridge, near Vernal, Utah	Plant will be located on Sohio property about seven miles south of Vernal. Extraction unit will be 51 feet high and six feet in diameter. Feed will be loaded in the top, heated by a gas-fired furnace, and bitumen will be separated in a water-filled chamber. The product will be processed at Major Oil's Roosevelt refinery. Initial production expected to be 1,000 BPD. <u>Roosevelt refinery sold at tax sale (see page 3-15 this issue); project continuing with crude destined for processing at A-Z's Fredonia, Ariz. refinery.</u> Project cost \$3.0 million	Start-up scheduled for <u>Dec. 1975 or Jan. 1976</u>
AMOCO Canada Petroleum Ltd.	Experimental in situ recovery project in Athabasca deposit, Alberta, Canada	Location is section 27-85-8 W4M. Application submitted in October 1968 seeking provincial authority to produce 15 million barrels of crude bitumen at rates up to 8000 BPD. This planned sub-commercial in situ project was to fracture the formation by the patented Hydra-Frac technique and follow up with a combination forward combustion-water flood procedure known as the COFCAW process. AMOCO owns patent rights to both processes. Project cost -estimated at <u>\$9 million to date.</u>	Expansion operations suspended. Older phases of project continuing
Bingham Mechanical & Metal Products, Inc.	<u>Pilot plant operation at Idaho Falls, Ida.</u>	<u>Pilot plant under consideration after three years of bench-scale tests on oil sands from Asphalt Ridge, Utah. Proposed plant would be 2,500 BPD using cold and solvent processes. Residual sand fines in primary oil claimed at 0.1 to 0.2 of one percent. Pilot plant operations to be complete by spring 1976.</u> <u>Project cost - estimated \$1.5 million.</u>	<u>Process patent application being prepared</u>
Bureau of Mines Laramie Energy Research Center	In situ field experiment on northwest Asphalt Ridge, near Vernal, Utah.	The site of the reverse combustion test is five miles west of Vernal. The line drive pattern will consist of two rows of injection wells with a row of producing wells between. Each row will contain three wells, the rows will be 60 feet apart and the wells in each row will be 20 feet apart. The pattern should be burned out in 30-90 days after ignition. Project cost \$1 million	

STATUS OF SYN FUELS PROJECTS

Underlining denotes changes since September 1975 issue.

PRINCIPALS	PROJECT DESCRIPTION	DETAILS	STATUS
Canadian Industrial Gas and Oil, Ltd. (CIGOL), Fuyo-Marubeni Oil and Gas of Alberta, Ltd.	Experimental in situ project in Cold Lake deposit, Alberta, Canada	CIGOL will be operator of a \$20 million program funded mostly by the Japanese firm. A delineation drilling program is in progress. Location will be on Lease No. 60. Successful completion of first phase will entitle Fuyo-Marubeni to 50% interest in CIGOL holdings. CIGOL to merge with Northern & Central Gas Corp. Ltd. Project cost Initial phase \$16.5 million Total project \$20 million	Project approval granted by ERCB. Japanese participation. Drilling is underway
Chevron Standard Ltd.	Experimental in situ project in Cold Lake deposit, Alberta, Canada	Project will be located at 36-61-2 W4 north of Imperial Oil's Lease No. 39. The one-well huff-and-puff test began in July 1975.	Active
Canadian Javelin Ltd.	Pilot plant in Montreal, Canada	Small scale pilot plant studies being conducted on Javelin Environmental Protection Oil Sands System (JEPOSS). Process involves solvent extraction after pretreatment with infrared radiation. Patent rights obtained through Calgary subsidiary, Bison Petroleum & Minerals Ltd.	Active
Fairbrim Company	Pilot plant near Bowling Green, Kentucky	A chemical extraction process is to be used, however the exact nature of the chemical solvent has not been disclosed. Ore will be obtained from local deposits and Ashland Oil has been contacted about the use of their facilities for upgrading.	Kentucky project active
Guardian Chemical Corporation	Pilot plant in Hauppauge, New York	The project investigates the feasibility of using a low-concentrate solution of Polycomplex to extract bitumen from oil sands. The chemical was originally designed to break up oil slicks. Pilot plant operates on 400#/hr of feed. Claim made that process uses only 1/2 the energy of conventional hot water process and requires only 1/3 the construction costs. Tests being made for interested companies. New Western Oil Sands, Ltd. a subsidiary of Rainbow Resources, Ltd. has provided the oil sands feed for the tests as well as financial backing.	Pilot plant operations underway
Gulf Oil Canada Ltd.	Experimental in situ project in Wabasca deposit, Alberta, Canada	Project will be located at 6-83-22 W4. Recovery scheme will involve the injection of steam through 11 wells arranged in three five-spot patterns. Nine observation wells will also be drilled. The producing formation lies at a depth of 800 ft. A 50,000 lb/hr steam generator will be installed. The 7°API crude product will be processed at Gulf's Calgary asphalt plant.	Active
Imperial Oil, Ltd.	Experimental in situ recovery project in Cold Lake deposit, Alberta, Canada	Imperial has been conducting steam stimulation tests in the Ethel Lake area of the Cold Lake deposit since 1971. The exact location is 27-64-3 W4 on Imperial's Lease No. 40. In December 1973 Imperial received ERCB approval for production from the current project from 1500 to 4000 BPCD. Imperial has sold data and ongoing program monitoring rights to five companies. New project (Leming) uses a 7-spot drilling pattern, whereas the previous project used a 5-spot pattern. Leming pilot began production in April 1975. 14-well expansion underway. Project cost \$5.25 million expected to be spent over next 10 years.	Active
Marconaflo, Inc. a subsidiary of Marcona Corp.	Slurry mining project in Southern California	Underground mining system uses high pressure water jets to remove ore and produce slurry which can be pumped to the surface. Process has been successfully used in mining uranium ores.	Active
Murphy Oil Co. Ltd.	Experimental in situ recovery project in Cold Lake deposit, Alberta, Canada	The project is located in Section 13-58-5 W4. Approval was granted for production of 600 BPCD. Inverted 7-spot pattern being drilled. After each hole is stimulated by huff-and-puff, steam flood will follow.	All wells to be stimulated by 1976
Numac Oil and Gas, Limited	Experimental in situ recovery project in Athabasca deposit, Alberta, Canada	Location is 30-83-6 W4 on Lease No. 72. The project will use a steam injection technique on a five-spot pattern. If the pilot plant is successful, plans are to begin a commercial operation producing 100,000 BPCD.	Active
Payette River Mines	Experimental in situ project in Duchesne County, Utah	Corehole data indicates a 500-foot thick zone of oil saturated dolomite in Sec 12, T3S, R2W SLM. Depth is between 5000 and 6000 feet. Approval has been granted to begin hot water injection tests. The casing will be perforated with four perforations per foot from 5792 to 5800 feet and with two perforations per foot from 5760 to 5770 feet. A packer will be located between these intervals. Hot water will be pumped from the lower section in the saturation zone, and up through the upper section. A ten-foot penetration is anticipated. Success on this test could lead to huff-and-puff in situ techniques.	Project approval granted by Utah O & G Conservation Board
Shell Canada, Ltd.	Experimental in situ project in Peace River deposit, Alberta, Canada	Project located at 21-85-18 W5 on Shell's Lease No. 1. Program will involve 24 production wells, 7 steam injection wells, 12 observation wells, and 2 fuel gas wells, arranged in 7-spot patterns. A two-cycle steam drive process designed especially for the Peace River site will be used. A four-year steam injection phase will be followed by a 1-1/2 year production period. <u>Possible large commercial scheme is being considered.</u> Project cost installation \$33 million. total program (9-year) \$85 million.	<u>Experimental work terminated</u>

STATUS OF SYN FUELS PROJECTS

Underlining denotes changes since September 1975 issue.

PRINCIPALS	PROJECT DESCRIPTION	DETAILS	STATUS
El Paso Natural Gas Co.	Commercial plant SNG from coal "North Dakota Project"	El Paso has announced intentions of building four plants in North Dakota. Reserves of two billion tons are under lease in Bowman, Stark and Dunn Counties. First plant scheduled on stream by 1981. El Paso recently withdrew an application for 71,800 AFY from Lake Sakakawea filed with the N.D. state water commission.	Planning
Exxon Corporation (Carter Oil)	Commercial plant SNG from coal	Carter Oil, a subsidiary of Exxon Corp., is studying the possibility of constructing a coal gasification plant in northern Wyoming. Carter has State and Federal leases in both Sheridan and Campbell counties; however, the probable location of the plant will be near Gillette, Wyo., in Campbell County. Also, Carter has an industrial water contract for 50,000 AFY from the Yellowtail Unit on the Big Horn River. Project cost \$400-\$500 million for commercial plant.	Planning
Illinois Coal Gasification Group 8 companies	Commercial plant SNG from coal	Nothing definite on plans for a commercial scale gasification plant. The group consists of Central Illinois Light Co., Central Illinois Public Service, Commonwealth Edison Co., Illinois Power Co., Iowa-Illinois Gas and Electric Co., Northern Illinois Gas Co., Peoples Gas Light and Coke Co., and North Shore Gas Co.	Investigating feasibility
Natural Gas Pipeline Company of America a wholly-owned subsidiary of the Peoples Gas Company	Commercial plants SNG from coal "Dunn Center Coal Gasification Project"	NGPL has received rights to 2.1 billion tons of lignite from the Nckota Company under a 20-year lease agreement, Jan. '73, covering 110,000 acres in central Dunn County, North Dakota. NGPL has applied to the North Dakota Water Commission for eventual use of 70,000 AFY of water for both mining and gasification. First of four planned 250 MMCFD Lurgi plants is currently envisioned to be operating by 1982 with successive plants following at three-year intervals. Fluor will be the engineering contractor for the project. The University of North Dakota and North Dakota State University are currently studying the environmental, social, and economic impact of the project. Dames and Moore will be conducting environmental work also. FPC filing is planned for early 1976.	Planning studies underway
Panhandle Eastern Pipeline Co. and Peabody Coal Co.	Commercial plant SNG from coal	Capacity is 270 MMCFD. Lurgi gasification methanation processes will be used. The plant will be located about 15 miles northeast of Douglas, Wyoming. Peabody has dedicated over 500 MM tons of coal to the project, from a reserve located in Campbell County. Coal will be delivered to the plant site by railroad. Plant start-up is now predicted for the 1980-81 period, at the earliest. Bechtel and SERNCO are the general and environmental contractors, respectively. SASOL has been retained as a consultant. The state has issued a 1974 appropriation to take water from the North Platte and permit to construct a 26,000 acre-foot surface reservoir. Up to 5,000 AFY is approved from the existing LaPrele Reservoir which is to be rehabilitated by Panhandle. Project cost now estimated at \$1 billion.	Design and development is proceeding
Texaco, Inc.	Commercial plant SNG or liquid products from coal	Texaco acquired, Oct. '73, rights to coal reserves estimated at 2 billion tons and certain water rights from Reynolds Metals Co. These reserves are located near Lake DeSmet in Wyoming on some 37,000 acres held by Reynolds. Commercial plant employing either a gasification or liquefaction process could result. Green Construction Co. of Des Moines, Iowa has started on a multi-million-dollar water development system which will include a 5,100 AF impounding basin, a 7-mile 66-inch pipeline from Clear Creek to Lake DeSmet and a pumping plant. Completion is expected by late 1975. Morrison-Knudsen Co. will do an engineering study of Texaco's coal, land, and water holdings near Lake DeSmet. Texaco announced, June 1975, that it has contracted with Genge Resources, Inc. for collection of baseline environmental data (15 month study) and the preparation of an Environmental Impact Assessment regarding development at Lake DeSmet.	Planning studies & water development work underway
Texas Eastern Transmission Corp. & Pacific Lighting Corp. Western Gasification Co. (WESCO) will own and operate plant	Commercial plants SNG from coal "WESCO Coal Gasification Project"	Lurgi gasifiers will produce 250 MMCFD of pipeline quality gas; possible expansion to 1,000 MMCFD. Plant will be located adjacent to coal reserves held by Utah International Inc., on the Navajo Indian Reservation in Northwestern, N.M. Fluor Corp. did feasibility study and Battelle prepared the environmental impact statement. Approximately 9.6 million tons of coal per year, along with sufficient water rights to operate the plant will be purchased from Utah International under terms of a 25-year contract. Gas will be sold to the Pacific Lighting Service Corp. (75%) and Cities Service Gas Co. (25%). Construction and mining permits granted by the New Mexico Air Quality Division on September 27, 1974, and the New Mexico Surface Mining Commission on July 25, 1974, respectively. A re-hearing for further consideration of the final FPC decision, rendered 4/21/75, has been granted. Project cost \$852.9 million.	Pending FPC certification

STATUS OF SYN FUELS PROJECTS

Underlining denotes changes since September 1975 issue.

PRINCIPALS	PROJECT DESCRIPTION	DETAILS	STATUS
Texas Gas Transmission Corp.	Commercial plant SNG from coal	Texas Gas has acquired from Consolidation Coal Co. a half interest in an extensive block of coal reserves in the Illinois Basin area. The reserves are in two parcels. Approximately 3.5 trillion SCF of SNG are recoverable from these reserves. Texas Gas has signed a formal agreement with the state of Kentucky to establish a two phase program to develop gasification technology. Under phase one a 80 MMCFD pilot plant will be built with an expansion to 250 MMCFD under phase two. Pilot plant could be operational by 1980 followed by the commercial plant by 1983. The plant will be located on the Ohio River in Western Kentucky. Project cost pilot plant is estimated at \$200 million.	Planning studies underway.
TransCanada Pipelines, Ltd.	Commercial plant SNG from coal	TransCanada has initiated a study to determine the feasibility of constructing a 250-MMCFD coal gasification plant in western Canada using Lurgi technology. Plant location is to be based on evaluation by Lurgi of representative samples from as many as four west Canadian coal fields. TransCanada has been unsuccessful in obtaining NEB approval for inclusion of \$8 million in rate base resubmission of application is expected. Project cost \$8 million for feasibility study and down payment of critical capital equipment.	Proposed
<u>DEMONSTRATION, PILOT AND RESEARCH PROJECTS</u>			
COGAS Development Company (CDC), joint venture of Consolidated Natural Gas, FMC Corp., Panhandle Eastern Pipeline, and Tennessee Gas Gas Pipeline	Pilot plant SNG and synthetic crude oil from coal	Pilot plant facility in Leatherhead has achieved several successful test runs and is in the final stages of feasibility testing. The plant has a feed capacity equivalent to 100 tons of coal per day, and is operated under contract with the British Coal Utilization Research Association. Future runs are anticipated to be of longer duration and intended to optimize process variables. CDC is also continuing with the assistance of Bechtel, Inc. to evaluate comparative process alternatives and conduct preliminary economic and technical evaluations for a larger scale operation. Project cost Initial development program, including pilot plants, estimated at \$8.5 million.	Operational
Commonwealth Edison Co., EPRI, and Fluor Corp. sponsors	Demonstration plant gasification turbine test facility	Commonwealth is helping to finance, with assistance from Electric Power Research Institute, build, and operate a plant near Pekin, Illinois close to its existing power plant. Lurgi gasifier will be used to process 60 T/hr of coal and produce 120 BTU/CF gas for a 25,000 KW generation unit. A test facility with commercial size equipment will allow Edison to scale-up the process to a 500 NW unit. Fluor Corp. was recently named contractor for the operation. Details of the proposed project not available. Project cost undetermined.	Active
Conoco Methanation Co., (subsidiary of Continental Oil Co.)	Demonstration plant methanation of coal gas	Plant was adjacent to and methanated purified gas from the Scottish Gas Board's Lurgi gasifiers at Westfield, Scotland. Conoco designed the facilities; Woodall-Duckham constructed the plant. British Gas Council acted as consultant. 13 companies participated with Conoco. Plant operated successfully producing high methane gas (95%) at rates of 2.5 MMCFD. Project cost estimated at \$6 million.	Methanation tests completed
Continental Oil Co. and 13 other U.S. companies	Demonstration plant coal gasification	The three-year test program will involve the modification of a Lurgi gasifier at the Westfield, Scotland gas plant for operation under slagging conditions. Conoco will coordinate project and British Gas Corp. will be project operator. This slagging process was tested on a pilot plant scale during the 1962-64 period by BGC. Advantages claimed for this modification are lower steam consumption, higher throughput and higher thermal efficiency. Project cost estimated at \$10 million.	Operational
Electric Power Research Institute and the Southern Services Co. sponsor, catalytic, Inc. contractor	Pilot plant solvent refining of coal	Plant is on the site of Southern Electric Generating Company's E.C. Gaston Steam Plant near Wilsonville, Alabama. It was designed, built and is operated by Catalytic, Inc. The process dissolves coal under pressure in the presence of a small quantity of hydrogen. Through the use of filters and other separation processes, ash content is reduced to about 0.1 percent; sulfur content can be reduced to as low as 0.3 percent. Plant capacity is 6 TPD. The product is a clean fuel containing approximately 90 percent of the carbon in the original coal. A 75 day continuous run has been completed. Project cost The project is currently funded to operate through calendar year 1975. Total cost to construct and operate the plant through the current year is \$11.3 million with EPRI contributing \$7.8 million, Southern Services \$3.5 million.	Operational

STATUS OF SYNFUELS PROJECTS

Underlining denotes changes since September 1975 issue.

PRINCIPALS	PROJECT DESCRIPTION	DETAILS	STATUS
EPRI - sponsor, B & W - contractor	Design study - Entrained bed coal gasification	EPRI is funding detailed design studies for a 20 tons/hour unit by Babcock & Wilcox to operate at 50 psig. Project cost - undetermined.	B & W submitting proposal to ERDA for additional funding.
EPRI - sponsor, Combustion Engineering - contractor	Design study - coal gasification	EPRI is funding detailed design studies for a 5 tons/hour atmospheric pressure unit by Combustion Engineering. Project cost - undetermined.	Combustion Engineering recently obtained partial funding for this project from ERDA. Additional funding from ERDA will be sought.
El Paso Natural Gas Co.	Pilot plant - SNG from coal development coal gasifier project	One Lurgi module located at Burnham, New Mexico for process development to test: capacity, low-BTU production, gasification of coal fines, various coals and environmental aspects. Land reclamation will proceed concurrently. FPC has granted intermediate approval for inclusion of development costs in rate base.	Pending final FPC decision in commercial project rate case
ERDA/Fossil Energy and American Gas Association	Pilot plant SNG from coal, Lurgi process development	Modification of the Lurgi reactor to permit handling of coking and swelling American coals. Tests were made in Scottish Gas Board's Lurgi plant at Westfield, Scotland. Lurgi was responsible for internal reactor modification while Woodhall-Duckham made necessary ancillary system modification to isolate the single gasifier unit. Technological guidance was provided by the British Gas Corp. and Lurgi throughout the program. Some 20,000 tons of the following U.S. coals were tested: Illinois No.5, Illinois No.6, Pittsburgh No.8, and Montana Rosebud.	Tests completed Final report has been published
ERDA/Fossil Energy and American Gas Association Sponsor Battelle Columbus Contractor	Pilot plant SNG from coal, Agglomerating Burner Project	A 25-TPD pilot plant is being built by Chemico at Battelle's West Jefferson, Ohio, Laboratories to investigate the Agglomerating Burner Process proposed and developed by Battelle under sponsorship of Union Carbide Corporation Project cost \$8.85 million.	Construction in progress
ERDA/Fossil Energy and American Gas Association Sponsors, Bituminous Coal Research, Inc. -Contractor Phillips Petroleum Operator	Pilot plant - SNG from coal, BI-GAS project	The entrained bed process, developed by Bituminous Coal Research, Inc., pulverized coal in a stream of oxygen and steam at high temperature and pressure to produce SNG. Stearns-Roger Corp. to design and build the pilot plant to process five TPH to produce 100 MCFH of pipeline gas. Plant site is Homer City, Pennsylvania. Project cost plant cost estimated at \$18 million total cost estimated at \$24 million	Testing to begin in early 1976
ERDA/Fossil Energy, American Gas Association Sponsors, Chem Systems Contractor	Process development unit liquid phase methanation (LPM)	A skid mounted LPM development unit is being constructed by Davy Powergas for evaluation in a coal gasification pilot plant in late 1975. The HYGAS and CO ₂ Acceptor pilot plants are being considered as test sites. Project cost current funding is \$1.9 million	Development unit in construction phase
ERDA/Fossil Energy, American Gas Association Sponsors, Consolidation Coal Co. Contractor	Pilot plant SNG from coal, CO ₂ Acceptor project	Plant located at Rapid City South Dakota is designed to produce 2 MMCFD of 375 BTU/SCF gas from 40 tons of lignite and 3 tons of dolomite per day. In the CO ₂ Acceptor process developed by Consol, ground lignite is fed into the gasifier under pressure of 150 to 300 psi and heated to 1560°F by steam. Dolomite, preheated to 1900°F is introduced into the gasifier to chemically remove free CO ₂ from the produced gas stream by the exothermic CO ₂ Acceptor reaction. Gas purification and packed tube methanation units to start-up soon. Project cost \$9.3 million for construction and an estimated \$5 million annually for operation.	Operational
ERDA/Fossil Energy, American Gas Association Sponsors, Institute of Gas Technology Contractor	Pilot plant SNG from coal, HYGAS project	Pilot plant capacity is 1.5 MMSCFD of SNG. The Process involves the simultaneous reaction of coal with process derived hydrogen and steam. Alternative processes under development for hydrogen production are: electrothermal, steam-oxygen and steam-iron. ERDA reported that in a test run in July '75, steady state conditions were achieved for 160 hours. The plant is now in operation with Illinois No. 6 bituminous coal. Project cost total ERDA/AGA commitment since 1964 has been \$55.1 million steam-oxygen development program, \$16.5 million steam-iron development program, \$18.2 million	Operational
ERDA/Fossil Energy Sponsor, Bituminous Coal Research Contractor	Process development unit low-BTU gas	PDU to develop fluid bed low-BTU coal gasification. Project cost \$2.5 million	Unit shakedown underway

STATUS OF SYNFUELS PROJECTS

Underlining denotes changes since September 1975 issue.

PRINCIPALS	PROJECT DESCRIPTION	DETAILS	STATUS
ERDA/Fossil Energy Sun, ARCO, Ashland, Mobil, Dupont, Reynolds, Martin Marietta, Con- solidated Gas, Y and O Coal, and EPRI Sponsors. Coalcon Contractor	Demonstration plant- coal to clean boiler fuel	Coalcon will design, construct and operate a 2,600 TPD demonstration plant using a hydrocarbonization process for producing 3,900 barrels/day of 17°API liquid product and 22 MMCFD of SNG. The project is framed in four phases over eight years. Coalcon is a joint venture of Union Carbide and Chemical Construction Corporation. Project cost estimated at \$256 million.	Plant design and pro- curement underway
ERDA/Fossil Energy Sponsor, Combustion Engineering Contractor	Process development unit low-BTU gas from coal	Four-year, three-phase program to demonstrate the C-E atmospheric entrainment gasification system to produce low-BTU gas. A 5 TPH PDU will be designed, constructed and operated by C-E at C-E's Windsor, Connecticut site. Investment and operating costs for a commercial scale plant will follow under the final project phase. Project cost \$20.6 million.	Pilot plant under way
ERDA/Fossil Energy Consolidation Coal Co. and Continental Oil Co. Sponsors Morgantown Energy & Research Center Contractor	Underground coal gasification project	The project is designed to assess the potential value of coal gasification in thin eastern coal beds. Project site will be Grants District of Wetzel County, West Virginia. The process will use directional drilling techniques to place parallel, horizontal, holes through the coal bed. Air will be injected to sustain gasification and partial combustion. The process will rely on natural porosity of the bed for product gas accumulation. The 5-phase project will cover preparation, field testing, and technical, environmental and social evaluation. Project cost \$10 million for the five-year project	Active with field preparations underway
ERDA/Fossil Energy - Sponsor, Continental Oil Co. Contractor	Bench scale liquid products	Conoco Coal Development Division at Library, Pennsylvania is to test the potential application of a zinc-halide hydrocracking process to produce distillate fuel from coal. Four barrels per ton is expected. A 100 pound per hour test unit is under development. Shell Development Corp. is also participating. Project cost \$6.5 million.	Testing is under way
ERDA/Fossil Energy Sponsor, Eyring Research Institute Contractor	Bench scale low-BTU gas from coal	Research is aimed at development of a high specific rate gasifier to produce gas of about 300 BTU/SCF at a 70% or greater thermal efficiency. A bench scale gasifier operating at 50-100 lbs of coal/hr has shown consistent results and reasonably high efficiency.	Studies in progress
ERDA/Fossil Energy -Sponsor, Fluor Corp. Contractor	Pilot plant liquid products from coal	Fluor Engineers and Constructors has a contract to convert the former coal-to-gasoline pilot plant in Cresap, West Virginia to a multiprocess test facility for coal liquefaction processes. The former program was terminated in 1970. In addition to procurement and construction services, Fluor will manage the overall program. Project cost - \$13 million for 3-year contract.	Construction underway
ERDA/Fossil Energy Sponsor, FMC Corp. Contractor	Pilot plant liquid products from coal, COED project	Pilot plant at Princeton, N.J. had a capacity of 36 TPD yielding 30 BPD of refinery feedstock plus char and fuel gas. Plant has operated on seven coals from West, Midwest & Eastern fields. Char to be tested in July 1975 in a commercial Koppers-Totzek gasifier in Spain with report to be issued in late 1975. Pilot plant data deemed to be complete and operations have been discontinued. Project cost Over \$20 million.	Completed final report to be issued in late 1975
ERDA/Fossil Energy Sponsor, Foster-Wheeler Contractor	Pilot plant low-BTU gas from coal	Foster-Wheeler is to design and prepare construction bids for a low-BTU coal gasification pilot plant under phase two of the four phase program. Phases three and four will include construction and operation. Details of process are not available. Project cost ERDA \$5.8 million Foster-Wheeler \$2.9 million	Pilot plant design has begun
ERDA/Fossil Energy - Sponsor, Foster- Wheeler and Bethle- hem Steel Co. Contractors	Process Development Unit liquid products from coal, Synthoil project	Foster Wheeler is to design a 10 TPD coal liquefaction PDU using the Bureau's Synthoil process. The coal is converted catalytically slurried with process derived oil, to produce synthetic crude. The scaled-up plant will be located at Bruceton, Pennsylvania and will be constructed and operated by Bethlehem Steel Co. Start-up is expected in 1976. A 500 TPD pilot plant is proposed. Project cost \$6.9 million (present contract value).	Design of PDU underway

STATUS OF SYNFUELS PROJECTS

Underlining denotes changes since September 1975 issue.

PRINCIPALS	PROJECT DESCRIPTION	DETAILS	STATUS
ERDA/Fossil Energy Sun, Ashland, ARCO, Standard of Indiana, Commonwealth of Kentucky, and EPRI Sponsors, Hydrocarbon Research, Inc. Contractor	Pilot plant low-sulfur fuel oil and other liquid products from coal, H-coal Project	600 TPD pilot plant to test the commercial potential of H-coal liquefaction process is to be built at Catlettsburg, Kentucky. The plant design calls for the production of 0.7 percent fuel oil from 3.0 percent coal. The three-phase project will cover plant design, construction, and operation, respectively. Under phase one HRI is completing testing at Trenton, New Jersey and gathering data for environmental, technical, and economic assessment. Fluor Engineers and constructors has been selected as design contractor. Project cost \$8.1 million for phase one	Pilot plant in design stage
ERDA/Fossil Energy Sponsor, Laramie Energy Research Center Contractor	Hanna underground coal gasification Project	The linked vertical well process being developed at Hanna, Wyo. is in the second phase of experimentation (air blown) and is directed at the gasification of coal seams between 15 and 50 feet thick. This involves the linkage of well bores by reverse combustion followed by gasification by forward combustion. <u>A seam sweep test is planned for early 1976.</u>	Field Experiments underway
ERDA/Fossil Energy - Sponsor, Lawrence Livermore Laboratory Contractor	Underground coal gasification project	The LLL packed bed process is being developed for the gasification of coal seams greater than 50 ft. thick and at depths greater than 500 ft. Chemical explosives are used to fracture the reaction zone. Gas collection is from the bottom of the reaction zone with oxygen/steam injected towards the top to sustain combustion and gasification. Field work for the first experiment has begun at a site on Hoe Creek, 25 miles southwest of Gillette, Wyoming. <u>Preliminary gasification run set for Dec. '75.</u> Project cost ERDA funding at \$3.3 million for FY'75.	Field work underway
ERDA/Fossil Energy - Sponsor, A.D.Little, Inc. Contractor	Bench scale - liquid products from coal	Project consists of an exploratory experimental program at the bench scale with a 20 to 40 lb extractive coker at Foster-Wheeler. Data will be provided for design of a pilot plant. Work is to be conducted in conjunction with an experimental laboratory investigation at the Pittsburgh Energy Research Center at Bruceton, Pennsylvania. Project cost \$0.57 million.	Study in progress
ERDA/Fossil Energy - Sponsor, University of North Dakota Engineering Ex- periment Station Contractor	Process Development Unit SNG and liquid products from lignite	A process development unit of approximately 50 lb/hr capacity will be used for the solvent refining of lignite. Data generated in autoclave experiments and bench-scale tests are being used to design the PDU. Project cost a five-year, \$3.4 million contract.	PDU tests underway
ERDA/Fossil Energy Sponsor, Oak Ridge National Laboratory - contractor	Bench scale - SNG from coal	ORNL is conducting hydrogasification bench scale studies with a continuous 10 lb/hr fluid bed reactor to determine optimum reactor design and reaction conditions. Other projects include: catalyst development, petrographic studies, and laboratory support to Lawrence Livermore Laboratory's underground coal gasification project.	Active
ERDA/Fossil Energy - Sponsor, Pittsburgh & Midway Coal Mining Co. Contractor	Pilot plant - liquid products from coal, solvent refined coal (SRC) project	The 50 TPD SRC pilot plant is located at Ft. Lewis, Washington. The plant produces 30 TPD of solvent refined coal (demineralized/low sulfur extract). The process has been developed by P&M from bench scale. The pilot plant was designed and constructed by Stearns-Roger and Rust Engineering, respectively. Project cost \$28 million contract to continue until 1976.	Operational
ERDA/Fossil Energy Sponsor Ralph M. Parsons Contractor	Process design and evaluation	Parsons is to complete conceptual design for a commercial scale COED plant; evaluate the demonstration plant design for the solvent refined coal process; prepare preliminary commercial design for a Fischer-Tropsch conversion plant; prepare preliminary design for a complex to demonstrate various coal conversion processes beyond the pilot stage and preliminary design for a commercial SRC plant. Project cost \$3 million.	Studies in progress
ERDA/Fossil Energy Sponsor, Pittsburgh Energy Research Center contractor	Pilot plant SNG from coal Synthane project	This process, developed by the Bureau of Mines uses a steam-oxygen, fluid-bed gasifier to produce a pipeline-quality gas from coal. Pilot plant (72 T/D) is being started up, at Bruceton, Pennsylvania. Plant includes gas purification and methanation units.	Active

STATUS OF SYNFUELS PROJECTS

Underlining denotes changes since September 1975 issue.

PRINCIPALS	PROJECT DESCRIPTION	DETAILS	STATUS
ERDA/Fossil Energy sponsor, Rockwell International Corp., Northeast Utilities Service Co. Contractor	Pilot plant low-BTU gas from coal	Rockwell to design, build and operate a 5 TPH plant to test molten sodium carbonate process for low-BTU gas production for power generation. The system will operate at 1800°F and 10 atm. and will include salt regeneration and sulfur recovery units. The pilot plant will be located at Connecticut Light and Power Company's Norwalk Harbor Generating Station. Forty-month program to obtain scale-up data and investigate air pollution emission control characteristics. Project cost - \$6.9 million	Plant design underway
ERDA/Fossil Energy - Sponsor, Rockwell Inter- national Corp. Rocketdyne Division - Contractor	Design and evaluation Study - Liquid products from coal	Rockwell International Corp. to develop coal liquefaction process by direct hydrogenation using the Rocketdyne process. Technique involves mixing and conditioning of two streams, coal and hydrogen, almost instantaneously. Conversion process forms light hydrocarbon liquids and gases and prevents breakdown of larger, complex molecules. Project to consist of low flow testing followed by design and fabrication of large-scale reactor for demonstration purposes. Rocketdyne process originally developed for propellant injection in liquid fuel rocket engines. Project Cost - \$1 million.	Studies in progress
ERDA/Fossil Energy Sponsor, University of Utah Contractor	Bench scale process evaluation, SNG and liquid products from coal	The University of Utah under a four-year contract will conduct process evaluations, catalytic liquefaction studies, and evaluation of coal conversion products. Project cost \$2.6 million	Active
ERDA/Fossil Energy Public Service Indiana, Bechtel Corp., AMAX Coal Co. and Peabody Coal Co. Sponsors, Westinghouse Electric Corp. Contractor	Process development plant low-BTU gas from coal	The project will involve a six-phase development. First is a 1200 lb/hr process development plant supported by laboratory investigations to confirm operational data received from the PDU. This will be followed by building and operating a five-ton/hr pilot plant. A 50 ton/hr power plant will then be built and operated by Public Service Indiana at their Dresser facility. The process will provide a clean burning gas with a heating value of 120 to 160 BTU/SCF. Project cost total program cost estimated at \$80 million; Westinghouse has an \$8.2 million contract from ERDA for 70% of the initial R&D cost.	PDU tests active
Exxon Corporation	Pilot plant liquid products from coal	A two-phase research program is underway to develop a coal liquefaction process with the first phase being design and the second being construction and operation of a 300 TPD pilot plant. A companion project by Exxon to develop a coal gasification process was postponed in November 1974. Project cost Phase one \$10 million Phase two \$145 million	Active
General Electric Company Sponsor and Investigator (Gasifier), Electric Power Research Inst. Sponsor (Operation and Extrusion R&D)	Pilot Plant Low-BTU gas from coal GEGAS-D Project	The construction and erection of a one TPH, 23 atmosphere fixed bed gas producer is underway in Schenectady. Checkout runs are to begin Feb. '76. The unit is equipped to study gasification of highly caking fuels at reduced steam/air ratios under clinkering conditions. Test results on a wide range of coals in a 50 pound per hour atmospheric gasifier provided many of the design bases. Coal extrusion feeding and tar balances are to be developed on GEGAS-D. Plans are underway to ultimately have this facility supply gas to gas cleaning, combustion and combustion gas apparatus. The goal is to provide design bases for an integrated coal-fired gas turbine combined cycle. Project cost undetermined.	Operational
Gulf Research and Development	Pilot plant liquid products from coal, catalytic coal liquefaction	In the CCL Process slurried coal plus hydrogen at 2,000-4,000 psi passes over a catalyst to yield two to four barrels of low sulfur liquid fuel per ton, depending on type of coal charged. The process is capable of converting lignite, subbituminous or bituminous coal. Three pilot project plants are currently in operation, the largest of which has a capacity of 1 TPD of coal. Project cost undetermined.	Operational
Institute of Gas Tech- nology and Ralph M. Parsons Co.	Pilot plant - low-BTU gas from coal, U-Gas project	Parsons will engineer and design a demonstration gasifier to fuel a 50-100 MW power generation plant. Industry and government financing is being sought. Process reacts crushed coal with air and steam in a single-stage fluidized-bed gasifier at pressure of about 300 psig. Produced gas has a heating value of 140 BTU/SCF. Sulfur and particulates are removed from the raw gas in a high temperature cleanup system. Plant site not yet selected. Project cost undetermined.	Active

STATUS OF SYNFUELS PROJECTS

Underlining denotes changes since September 1975 issue.

PRINCIPALS	PROJECT DESCRIPTION	DETAILS	STATUS
Island Creek Coal Co. and Garrett Laboratories (both subsidiaries of Occidental Petroleum)	Pilot plant liquid products from coal	Planning is underway for a 200 TPD pilot plant to convert coal to fuel oil using Garrett's pyrolysis process developed to produce fuel oil from municipal solid waste. Sponsors are being sought for a four year program. Project Cost \$6 million.	Active
Stone & Webster Engineering Corp. and General Atomic Co.	Process evaluation	Joint program to use Gulf's HTGC nuclear reactor to provide heat for S&W's solution-hydrogasification coal conversion process. Two-year R&D program to be managed by S&W. Industry support being sought. Project cost first phase estimated at \$650,000 (San Diego Gas & Electric has committed \$100,000.)	Active
<u>Swindell-Dressler Co. - Sponsor, Technology Application Service Corp. - Contractor</u>	<u>Process Development Unit - Medium BTU gas from coal</u>	<u>Swindell-Dressler Co., with Technology Application Service Corp., is working on a program to develop the Plasma Arc Torch Process on a subcommercial scale. Process would involve passing coal in a gas such as argon or hydrogen, in an anerobic environment, through an electric arc, which would generate a plasma flame 15,000°F-100,00°F, instantaneously gasifying the coal. High quality product gas would be methanated to achieve pipeline quality. Swindell-Dressier Co. is contacting several electric and gas utility companies about development of the project.</u> <u>Project cost - undetermined.</u>	<u>Under Development</u>
Texas Utilities Services, Inc.	Underground gasification of Texas lignite	Texas Utilities Services Inc., an affiliate of Dallas Power and Light Company, Texas Electric Service Company and Texas Power and Light Company, has purchased (through the Resource Sciences Corp., Tulsa, Okla.) underground gasification technology developed in the Soviet Union to determine the feasibility of gasifying deep lignite deposits in east Texas. A pilot plant is scheduled for operation in 1976 for gasification of lignite below 150 feet. <u>Project cost - \$2 million (process licensing).</u>	Active
Universal Oil Products	Pilot plant liquid products from coal	High temperature and pressure hydrosolvation process producing four barrels of low-ash/low-sulfur syncrude per ton. Des Plaines, Illinois pilot plant to be enlarged.	Active
University of Texas at Austin, National Science Foundation, Texas Utilities Service Co., Continental Oil Co. and Mobil Oil Corp.	Underground gasification of Texas lignite	In situ gasification to recover energy content of Texas lignite, which has now been estimated to be 100 billion tons below stripping depth. Development of physical properties for lignite and overburden, and analysis of economics, environmental effects, subsidence, reaction kinetics, heat-transfer, low-BTU gas utilization, lignite geology are underway. Physical models will be developed from laboratory data and scaled-up for application to field test. High lignite permeability and reactivity favor economics. Two candidate field test sites will be selected in 1975.	Preliminary studies underway
Wheelabrator-Frye Inc.	Demonstration plant solvent refined coal	Wheelabrator-Frye is studying the feasibility of a 1000 TPD plant to produce low sulfur/low ash coal using Gulf Oil's SRC process. The plant will provide fuel for power generation in Southern Company's system. The plant may be scaled to commercial capacity. Project cost estimated between \$70-100 million.	Plant design has begun

COMING EVENTS

NOVEMBER 30 - DECEMBER 5, 1975, MEXICO CITY -- The First Chemical Congress of the North American Continent. For more information write Chemical Congress-Mexico, c/o American Chemical Society, 1155 16th Street, N.W., Washington, D. C. 20036.

DECEMBER 1-4, 1975, NEW YORK CITY -- Exposition of the Chemical Industries at the Coliseum. For additional information, write the AIChE, 345 East 47th Street, New York, New York 10017.

JANUARY 12-16, 1976, DUSSELDORF, GERMANY -- Symposium on Gasification and Liquefaction of Coal. For more information, write Mr. H. Giesel, Gesamtverband des Deutschen Steinkohlen-Bergbaus, Friedrichstrasse 1, D-4300 Essen, Federal Republic of Germany.

FEBRUARY 22-26, 1976, LAS VEGAS, NEVADA -- 105th Annual A.I.M.E. Meeting. For additional information, contact the A.I.M.E., 345 East 47th Street, New York, New York 10017.

MARCH 25-27, 1976, SANTA MARIA, CALIFORNIA -- A Symposium on Alternate Fuel Resources will be sponsored by the American Institute of Aeronautics and Astronautics. One of the sessions will be devoted to R & D in synthetic fuels. For more information, write Dr. F. J. Hendel, Professor (Propulsion and Fuels), School of Engineering and Technology, California Polytechnic State University, San Luis Obispo, California 93407.

APRIL 13-14, 1976, CHICAGO -- The fifth Mineral Waste Symposium will be cosponsored by the U.S. Bureau of Mines and the IIT Research Institute. For additional information, write S. A. Bortz, IITRI, 10 West 35th Street, Chicago, Illinois 60616.

APRIL 21-24, 1976, SAN FRANCISCO -- Fifty-First Annual Meeting of the Pacific Sections of the American Association of Petroleum Geologists, the Society of Economic Paleontologists and Mineralogists, and the Society of Exploration Geophysicists. For additional information, write Bob Blaisdell, Standard Oil of California, Box 3862, San Francisco, California 94119.

MAY 17-21, 1976, TULSA, OKLAHOMA -- International Petroleum Exposition and Congress. For additional information write the IPE&C, Inc., Box 4804, Tulsa, Oklahoma 74104. The following are among the papers to be presented:

- . "Processing Problems of Synthetic Oil Derived from Shale," Art Corrigan, Great Western Refinery.
- . "Coal Gasification," Dr. Henry R. Linden, President, Institute of Gas Technology.
- . "Oil Shale" Henry Pforzheimer, Program Director, Paraho Oil Shale Demonstration, Inc.
- . "Coals to Liquid Fuels," Erich H. Reichl, President, Conoco Coal Development Company.

RECENT PUBLICATIONS

GENERAL INTEREST

"A Listing of Prepared, Planned or Under-Construction Energy Projects in Federal Region VII," a report to the USBM Committee on Energy and Environment of the Denver Federal Executive Board by the Subcommittee to Expedite Energy Development, 1975.

*Anderson, J. J., et al, "A Summary of Reserve and Resource Data on Coal, Uranium, and Oil Shale in the States of Michigan, Ohio, Kentucky, Tennessee, West Virginia, North Dakota, South Dakota, Montana, Wyoming, Colorado, and Utah," 12 May 1975. Prepared for the American Petroleum Institute. For more information, write the author at 7578 Skyview Drive, Kent, Ohio 44240.

Beychok, M. R., "Process and Environmental Technology for Producing SNG and Liquid Fuels," May 1975, EPA-660/2-75-011. For more information, write F. M. Pfeffer, Robert S. Kerr Environmental Research Laboratory, National Environmental Research Center, Ada, Oklahoma 74820. Copies are available from the Superintendent of Documents, Government Printing Office, Washington, D. C. 20402.

Burke, D. P., "Methanol," Chemical Week, Volume 117, No. 13, September 25, 1975, pages 33-42.

Carlson, J., "Energy Minerals: An Assessment of the Current Situation," presented at the Rocky Mountain Energy Minerals Conference of the U.S. Bureau of Land Management, Billings, October 1975.

Continental Oil Company, "Outlook: 1975 and Beyond," a presentation to security analysts, May 13, 1975.

Doig, K., "Energy Independence: Will We Get There From Here?" presented at the Rocky Mountain Energy Minerals Conference of the U.S. Bureau of Land Management, Billings, October 1975.

Elliott, T., "Canada's Mineral Industry: Will it be Destroyed by Socialist Economic Ideology?", presented at the Rocky Mountain Energy Minerals Conference of the USBLM, Billings, October 1975.

Federation of Rocky Mountain States, "Energy Development in the Rocky Mountain Region: Goals and Concerns," 1975. Copies are available at \$2.50 from the FRMS, Inc., 2480 West 26th Avenue, Suite 300-B, Denver, Colorado 80211.

"Fossil Fuel and Advanced Systems Division," report FF-3 by the Electric Power Research Institute, 1975. Contains brief reports on stacks vs. scrubbers, fossil fuel gasification, liquefaction, and environmental control.

Hansen, D. C., "Water Resources Planning Related to New Energy Development in the Upper Colorado River Basin," presented at the ASCE Annual Meeting, Denver, Colorado, November 1975.

Horton, J., "Energy and the Environment," presented at the Rocky Mountain Energy Minerals Conference of the U.S. Bureau of Land Management, Billings, October 1975.

Judge, T. L., "Producing Energy Minerals in Montana," presented at the Rocky Mountain Energy Minerals Conference of the U.S. Bureau of Land Management, Billings, October 1975.

*Reviewed in this issue.

Klein, M., "What Are the Prospects for Breakthroughs in Fossil Fuels," 1975. Paper presented at the Fourth Annual International Pollution Engineering Congress, October 1975. For more information, write Milton Klein, The Mitre Corporation, 1820 Dolly Madison Boulevard, McLean, Virginia 22101.

*Montana Geological Society, "Energy Resources of Montana," June 1975. Copies are available from the Montana Geological Society, Billings, Montana 59103, at \$19 each.

Mungen, R., "Present Technology for Shale Oil and Tar Sands Recovery," November 1975. Paper presented in Easton, Maryland, at the Engineering Foundation Conference on the Role of Microorganisms in the Recovery of Oil. For additional information, write Engineering Foundation, United Engineering Center, 345 East 47th Street, New York, New York 10017.

Radosevich, Dr. G., et al, "Colorado Water Laws: A Compilation of Statutes, Regulations, Compacts, and Selected Cases," 1975. Copies are available at \$20 from the Center for Economic Education, Department of Economics, Colorado State University, Fort Collins, Colorado 80523.

Resource Planning Associates, "Energy Supply/Demand Alternatives for the Appalachian Region, Executive Summary," EQ 4AC-022, March 1975, prepared for the National Science Foundation. Copies are available at \$4.75 from the National Technical Information Service, Springfield, Virginia 22151.

Rope, R., et al, "Energy Conservation Waste Utilization Research and Development Plan," report number MTR-3063 by the Mitre Corporation for the Energy Research and Development Administration, 1975, 189 pages.

Roth, P. M., et al, "An Examination of the Accuracy and Adequacy of Air Quality Models and Monitoring Data for Use in Assessing the Impact of EPA Significant Deterioration Regulations on Energy Developments," 8 August 1975. Report prepared by Systems Applications, Inc., and Rockwell International for Greenfield, Attaway, and Tyler, Inc., as EF75-58R under contract to the American Petroleum Institute. For more information, write the API, 1801 K Street, N.W., Washington, D. C. 20006.

Schultz, H., and Walker, F. E., "Characterizing Combustible Portions of Urban Refuse for Potential Use as Fuel," USBM Report of Investigations No. 8044, 1975. Copies are available from the Superintendent of Documents, Government Printing Office, Washington, D. C. 20402.

"Solid Fuel Chemistry," Journal published by the Academy of Sciences of the USSR. For information on English translations from the Alberton Press, Inc., 150 Fifth Avenue, New York, 10011. The annual subscription is \$145.00 for six issues.

"The Petroleum Industry: A Report on Corporate and Industry Structure and Ownership," report prepared for the Federal Energy Administration by R. Shriver Associates. Copies are available at \$10.50 each for Part 1 and Part 2 from FEA, Washington, D. C.

"Transactions of the 9th World Energy Conference" held in Detroit in September 1974. Contact the National Committee of the World Energy Conference, 345 East 47th Street, New York.

U.S. Forest Service, "Anatomy of a Mine -- From Prospect to Production," 1975. Prepared under the SEAM Program. For more information, write the USFS Intermountain Region, 324 25th Street, Ogden, Utah 84401.

*Reviewed in this issue.

*Vaughan, B. E., et al, "Review of Potential Impact on Health and Environmental Quality from Metals Entering the Environment as the Result of Coal Utilization," August 1975, a Battelle Energy Program Report. Copies are available from the Director, Battelle Energy Program, 505 King Avenue, Columbus, Ohio 43201.

"World Directory of National Earth-Science Agencies," USGS Circular 716, 1975. Compiled by A. L. Falk and R. L. Miller. Free copies are available from the USGS, National Center, Reston, Virginia 22092.

GENERAL - PATENTS

Chevron Research Company, U.S. Patent 3,874,116, "Synthesis Gas Manufacture." This is a process for producing synthesis gas from solid waste materials, most preferably solid municipal waste. The synthesis gas is produced under substantially endothermic gasification conditions, which comprise (a) feeding an organic material, containing hydrogen and at least 10 weight percent oxygen and containing less than 5 weight percent sulfur, to a reaction zone; (b) feeding steam to the reaction zone; and (c) contacting the steam with the organic feed material in the reaction zone at a temperature between about 500° and 1,600°F.

OIL SHALE

Appledorn, C. R. (CER Geonuclear Corp.), "Rio Blanco Massive Hydraulic Fracture Project," presented at the ERDA Symposium on Enhanced Oil & Gas Recovery, Tulsa, Oklahoma, September 1975.

Beard, T. N., and Smith, J. W., "In-Place Recovery of Multiple Products from Colorado's Saline Mineral-Bearing Piceance Basin," presented at the 68th Annual Meeting of AIChE, Los Angeles, November 1975.

Blum, J. R., "Oil Shale/Wildlife -- What's It All About?," presented at the Environmental Oil Shale Symposium, Colorado School of Mines, Golden, 1975.

Carpenter, H. C., "Fracturing Oil Shale for In Situ Retorting Experiments," presented at the 68th Annual Meeting in AIChE, Los Angeles, November 1975.

Cresswell, G., "Quality Assurance for Meteorological and Air Quality Studies in Support of the Rio Blanco Oil Shale Project," presented at the Environmental Oil Shale Symposium, Colorado School of Mines, Golden, 1975.

Danielson, J. A., "Colorado Water Resources and Colorado Law: Constraints to Oil Shale Development?" Presented at the ASCE Annual Meeting, Denver, Colorado, November 1975.

Doctor, L., "Combustion of Oil Shale Carbon Residue," presented at the 68th Annual Meeting of AIChE, Los Angeles, November 1975.

French, G. B., "The Meeting Between Man & Nature - Oxy's Way," presented at the Fall Meeting of the SME of AIME, Salt Lake City, September 1975.

Gash, R., "Gathering Terrestrial Baseline Data in a Prepared Oil Shale Development Area," presented at the Environmental Oil Shale Symposium, Colorado School of Mines, Golden, 1975.

*Reviewed in this issue.

- *Gash, R., et al, "Environmental Evaluations of Proposed Disposal Sites, Tract C-a, Rio Blanco Oil Shale Project," a report by Gulf Oil Corporation and Standard Oil Company (Indiana).
- *Golder Associates, "A Study of Costs of Producing In Situ Retorts in Oil Shale by Conventional Mining Methods," October 1975. For additional information, write Laurich Kennedy Associates, Inc., 577 Industry Drive, Seattle, Washington 98188. Copies are available at \$5.75 from the National Technical Information Service, Springfield, Virginia 22151.
- *Harmston, G., "Utah Policy in Oil Shale Development," presented at the Environmental Oil Shale Symposium, Colorado School of Mines, Golden, 1975.
- Hart, D., "Majors Support Utah Modified In Situ Planning," in Western Oil Reporter, August 1975, page 59.
- Ivory, T. M., "Some Autecological Relationships of Algae in the Piceance Creek Basin," presented at the Environmental Oil Shale Symposium, Colorado School of Mines, Golden, 1975.
- *Jackson, L. P., "Characteristics and Possible Roles of Various Waters Significant to In-Situ Oil Shale Processing," presented at the Environmental Oil Shale Symposium, Colorado School of Mines, Golden, October 1975.
- Kissell, F. N., "The Potential Hazards of Methane Gas in Oil Shale Mines," presented at the Environmental Oil Shale Symposium, Colorado School of Mines, Golden, 1975.
- Kross, B. C., "A Review of Announced Oil Shale Developments in Colorado and Utah," presented at the 68th Annual Meeting of AIChE, Los Angeles, November 1975.
- Legatski, M. W., "Prediction of Air Quality Impacts for a Commercial Shale Oil Complex," presented at the 68th Annual Meeting of AIChE, Los Angeles, November 1975.
- *Lipman, S., "Union Oil Company Revegetation Studies," presented at the Environmental Oil Shale Symposium, Colorado School of Mines, Golden, 1975.
- Mannion, L. E., "Wyoming Trona-Greatest Source of Natural Soda Ash," presented at the Fall Meeting of the SME of AIME, Salt Lake City, September 1975. Discusses origin of trona within the Green River oil shale formation.
- Martin, S. G., and McGuire, R. J., "Environmental Assessment Studies for Oil Shale Development in Western Colorado," presented at the 68th Annual Meeting of AIChE, Los Angeles, November 1975.
- McCarthy, H. E., "Development of the Modified In Situ Oil Shale Process," presented at the 68th Annual Meeting of AIChE, Los Angeles, November 1975.
- Meyers, L., "Adequacy of Regional Atmospheric Data for Specific Predictive Purposes in the Piceance Creek Basin," presented at the Environmental Oil Shale Symposium, Colorado School of Mines, Golden, 1975.
- Milam, C. J., "The Art of Drilling Oil Shale," presented at the Fall Meeting of the SME of AIME, Salt Lake City, September 1975.
- Musgrove, C., "Considerations in Monitoring Low Level Air Quality Parameters," presented at the Environmental Oil Shale Symposium, Colorado School of Mines, Golden, 1975.
- *Reviewed in this issue.

Neal, L. G., et al, "An Evaluation of Wastewater Control Technologies Available for Processing of Oil Shale," presented at the 68th Annual Meeting of AIChE, Los Angeles, November 1975.

Nelson, R., "Meteorological Dispersion Potential in the Piceance Creek Basin," presented at the Environmental Oil Shale Symposium, Colorado School of Mines, Golden, 1975.

Novak, Alys, "Coming To Terms With Net Energy," Shale Country, August 1975, page 4-6.

Olson, A. P., "Archaeological Investigation and Mitigation in the Three Corners Region," presented at the Oil Shale Environmental Symposium, Colorado School of Mines, Golden, 1975.

Perrini, E. M., "Oil From Shale and Tar Sands, 1975," Chemical Technology Review No. 51. Copies are available at \$36 from Noyes Data Corporation, Mill Road at Grand Avenue, Park Ridge, New Jersey 07656.

Pforzheimer, H., "The Paraho Oil Shale Demonstration," presented at the 68th Annual Meeting of AIChE, Los Angeles, November 1975.

Philip, R. P., "Early Stage Formation and Structure of Kerogenlike Material in Recent Sediments," presented at the ACS/Society for Applied Spectroscopy 1975 Pacific Conference on Chemistry and Spectroscopy, Los Angeles, October, 1975.

*Robinson, W. F., and Cummins, J. J., "An Oil Shale Conversion Process Using Carbon Monoxide and Water," ERDA Technical Progress Report 75/1, 1975, 14 pages.

Ruskin, A. M., and Phillips, J. R., "Environmental Studies as a Project Planning Tool," presented at the 68th Annual Meeting of the AIChE, Los Angeles, November 1975. Examples are presented of studies being conducted for Occidental Petroleum Corporation in situ oil shale process.

Schmidt-Collerus, J., "Problems of Carcinogenicity in By-Products of Shale in Synthetic Fuels Production," presented at the Environmental Oil Shale Symposium, Colorado School of Mines, Golden, Colorado, October 1975.

Schulman, B. L., "Shale Matrix Plays Important Role in Energy From Oil Shale," presented at the 68th Annual Meeting of AIChE, Los Angeles, November 1975.

*Sherman, H., "Colorado's Policy in Oil Shale Development," presented at the Environmental Oil Shale Symposium, Colorado School of Mines, Golden, October 1975.

Spence, H. M., "Shale Oil: The Economics of Environmental Protection," presented at the 21st Annual Rocky Mountain Mineral Law Institute, Rapid City, South Dakota, July 1975.

States, J. B., "Quantitative Baseline Definition for Terrestrial Ecosystems at Oil Shale Tract C-a," presented at the Environmental Oil Shale Symposium, Colorado School of Mines, Golden, October 1975.

Trepp, D. W., "Mining of Oil Shale Commercially by Room and Pillar Method," presented at the Fall Meeting of the SME of AIME, Salt Lake City, September 1975.

*"Will Shale Yield Chemicals Before Oil," Chemical Week, August 20, 1975, page 37.

*Reviewed in this issue.

Winsor, D., "Endangered Species -- Their Importance to Oil Shale Development," presented at the Environmental Oil Shale Symposium, Golden, Colorado, 1975.

Yen, T. F., "Current Status of Microbial Shale Oil Recovery," November 1975. Paper presented in Easton, Maryland, at the Engineering Foundation Conference on the Role of Microorganisms in the Recovery of Oil. For additional information, write Engineering Foundation, United Engineering Center, 345 East 47th Street, New York, New York 10017.

OIL SHALE - PATENTS

*Atlantic Richfield Company, U.S. Patent 3,876,533, "Guard Bed System for Removing Contaminants From Synthetic Oil."

Shell Oil Company, U.S. Patent 3,894,769, "Recovering Oil From a Subterranean Carbonaceous Formation." Described is a process for recovering oil from oil shale which comprises injecting a fluid such as steam into contact with finely-divided, unconsolidated, solid particles in a rubble oil shale chimney; withdrawing fluids from the chimney from a point above the injection point of the fluid and adjusting the rate of fluid injection and withdrawal so that a circulation current is established within the chimney sufficient to suspend at least a portion of the particles in the fluids in the chimney. Preferably the current upflow is extended radially by increasing the permeability at the base of the chimney over a wide area.

OIL SANDS

"Alberta Oil and Gas Industry Annual and Cumulative Statistics-1974," Report No. ERCB 75-17 by the Alberta Energy Resources Conservation Board, 603-6th Avenue, S.W., Calgary, Alberta T2P 0T4 Canada.

Ali, L. H., "Studies on the Ageing Phenomenon of Tar Sand," Fuel, Vol. 54, Number 3, July 1975, page 223.

Berkowitz, N., and Speight, J. G., "The Oil Sands of Alberta," Fuel, Vol. 54, Number 3, July 1975, page 138-149.

Cupps, C. Q., "Field Experiment of In Situ Oil Recovery From a Utah Tar Sand by Reverse Combustion," presented at the 68th Annual Meeting of AIChE, Los Angeles, November 1975.

George, A. E., et al, "The Effect of Thermal Hydrocracking on Hydrocarbon-Type and Sulphur Compound Distribution in Athabasca Bitumen." Paper to be presented at the First Chemical Congress of the North American Continent in Mexico City, November 30 through December 5, 1975. For more information, write Chemical Congress-Mexico, c/o American Chemical Society, 1155 16th Street, N.W., Washington, D. C. 20036.

Giel, D., "Asphalt Ridge Oil Sand Projects Moving Slowly," Western Oil Reporter, August 1975, page 54-55.

Humphreys, R. D., "Oil Recovery From Alberta Oil Sands," presented at the 68th Annual Meeting of AIChE, Los Angeles, November 1975.

Johnson, L. A., et al, "Properties of Utah Tar Sands -- Asphalt Wash Area, P. R. Spring Deposit," USBM Report of Investigations 8030, 1975.

Lowe, R. M., "The Asphalt Ridge Tar Sands Deposits," presented at the 68th Annual Meeting of AIChE, Los Angeles, November 1975.

*Reviewed in this issue.

Moschopedis, S. E., and Speight, J. G., "Air Blowing of Athabasca Bitumen." Paper to be presented at the First Chemical Congress of the North American Continent in Mexico City, November 30 through December 5, 1975. For more information, write Chemical Congress-Mexico, c/o American Chemical Society, 1155 16th Street, N.W., Washington, D. C. 20036.

Moschopedis, S. E., and Speight, J. G., "Oxidation of (Athabasca) Bitumen," Fuel, Vol. 54, Number 3, July 1975, pages 210-212.

Nandi, B. N., and others, "Coke Formation During Simultaneous Hydrocracking of Bitumen and Hydrogenation of Coal," Fuel, Vol. 54, Number 3, July 1975, pages 197-200.

Oblad, A. G., "Recovery of Bitumen From Oil Impregnated Sandstone Deposits of Utah," presented at the 68th Annual Meeting of AIChE, Los Angeles, November 1975.

*Peterson, P. R., "Lithologic Logs and Correlation of Coreholes -- P. R. Spring and Hill Creek Oil - Impregnated Sandstone Deposits, Uintah County, Utah." Utah Geological and Mineral Survey Report of Investigations No. 100, 1975.

* "Reserves of Crude Oil, Gas, Natural Gas Liquids and Sulfur -- Province of Alberta," report number ERCB 75-18 of the Alberta Energy Resources Conservation Board, 1975.

*Ritzma, H., "Oil-Impregnated Rock Deposits of Utah," Utah Geological and Mineral Survey Map No. 33, Scale 1:1,000,000. This map updates Map No. 25 of 1968 and includes accompanying information on estimated reserves, extracted oil analyses, origin, bibliography, and geology of 51 deposits and potential development conflicts. Copies are available at a cost of \$1.50 from the Utah Geological & Mineral Survey, University of Utah, 103 U.S. & M.S. Building, Salt Lake City, Utah 84112.

Ritzma, H. R., "Utah's Tar Sand Resource: Geology, Politics and Economics," presented at the 68th Annual Meeting of AIChE, Los Angeles, November 1975.

Speight, J. G., "The Distribution of Nitrogen, Oxygen, and Sulfur in Athabasca Asphaltenes." Paper to be presented at the First Chemical Congress of the North American Continent in Mexico City, November 30 through December 5, 1975. For more information, write Chemical Congress-Mexico, c/o American Chemical Society, 1155 16th Street, N.W., Washington, D. C. 20036.

*"Syn crude: Mining the Athabasca Tar Sands," The Orange Disc, September-October 1975, pages 1-7.

Terwilliger, P. L., "Fireflooding Shallow Tar Sands," presented as SPE 5568 at the 50th Annual Fall Meeting of the SPE of AIME, Dallas, 1975.

OIL SANDS - PATENTS

*Exxon Research and Engineering Company, U.S. Patent No. 3,893,907, "Method and Apparatus for the Treatment of Tar Sand Froth." The advantages of using a disc-type centrifuge to improve froth quality are disclosed.

*Great Canadian Oil Sands Ltd., Canadian Patent 973,500, "Freeze-Thaw Separation of Solids From Tar Sands Extraction Effluents." It has been found that agglomeration followed by freezing and thawing can be applied to clay and silt containing water discharges to provide a suitably-clarified water.

Jeremic, M. L., "Tar Sand," Western Miner, Volume 48, No. 9, September 1975, pages 25-31.

*Reviewed in this issue.

*Rosenbloom, W. J., U.S. Patent 3,875,046, "Recovery of Oil From Tar Sand by an Improved Extraction Process." Oil sands are mixed with hot water then screened to remove oversize. Fine sand drops into a fluidized bed extraction vessel. Sands flow downward through a rising stream of hot water, solvent, and steam. Oil forms as a layer at the surface of the vessel. Sand and water are removed from the bottom of the vessel.

*Texaco, Inc., U.S. Patent 3,874,452, "Recovery of Viscous Petroleum From Asphaltic - Petroleum - Containing Formations Such as Tar Sands Deposits." This concerns a method for recovering hydrocarbon materials from tar sand deposits utilizing a combined in situ deasphalting process with in situ combustion.

COAL

Abrams, R. N., "Balance of Plant Engineering for Coal Gasification Systems," AIChE Paper No. 23e presented at the 68th Annual AIChE meeting in Los Angeles, California in November 1975. Copies are available from the American Institute of Chemical Engineers, 345 East 47th Street, New York, New York 10017.

Anderson, L. L., et al, "Clean Liquid Energy From Coal," presented at the Fall Meeting of the SME of AIME, Salt Lake City, September 1975.

Atlantic Richfield Company, "Mine Storage and Handling of Western Coal -- Black Thunder Mine," presented at the Fall Meeting of the SME of AIME, Salt Lake City, September 1975.

Bagge, C., "Coal and the Public Lands," presented at the Rocky Mountain Energy Minerals Conference of the U.S. Bureau of Land Management, Billings, October 1975.

Bagge, C. E., "Economic Viability of Synthetic Fuels From Coal," presented at the Financial Times' World Coal Conference, London, September 1975.

*Baria, D. N., "Evaluation of Gasification and Liquefaction Processes Using North Dakota Lignite," a report by The Engineering Experiment Station, University of North Dakota, Grand Forks, North Dakota, 1975.

Batchelor, J. D., and Shih, C., "Solid-Liquid Separation in Coal-Liquefaction Processes," AIChE Paper No. 41d presented at the 68th Annual AIChE meeting in Los Angeles, California in November 1975. Copies are available from the American Institute of Chemical Engineers, 345 East 47th Street, New York, New York 10017.

Bauer, A., "Reclamation of Surface-Mined Lands on the Northern Great Plains," presented at the Fall Meeting of the SME of AIME, Salt Lake City, September 1975.

Brandenburg, C. F., "Interpretation of Chemical and Physical Measurements From an In Situ Coal Gasification Experiment," presented as SPE 5654 at the 50th Annual Fall Meeting of SPE of AIME, Dallas, September 1975.

Busch, R. A., et al, "Physical Property Data on Fine Coal Refuse," USBM Report of Investigations 8062/1975, prepared at the Spokane Mining Research Center. Copies are available from the USBM, 4800 Forbes Avenue, Pittsburgh, Pennsylvania 15213.

Canadian Conference on Coal, sponsored by the Coal Association of Canada and the Department of Energy, Mines, and Resources, was held in Vancouver, B.C. on September 21-23, 1975. The program consisted of the following two panel discussions:

- . The Energy Crisis, What Role Will Coal Play?
- . Constraints on Coal Production, Delivery and Utilization, and Possible Solutions.

*Reviewed in this issue.

Clyde, E. W., "Coal Mining, Development and Processing - The Associated Water Problems," presented at the 21st Annual Rocky Mountain Mineral Law Institute, Rapid City, South Dakota, July 1975.

*"Coal Development Information Packet -- Supplement I," prepared by the Montana Energy Advisory Council, Lt. Governor Bill Christiansen, Chairman, 1975.

Coates, R. L., "Gasification of Pulverized Coal and Char with Oxygen and Steam in a pressurized Suspension Combustor," presented at the 68th Annual AIChE meeting in Los Angeles, California in November 1975. Copies are available from the American Institute of Chemical Engineers, 345 East 47th Street, New York, New York 10017.

Codney, L. E., et al, "Experiences in Transportation of Dried Low-Rank Western Coal presented at the Fall Meeting of SME of AIME, Salt Lake City, September 1975.

College of Engineering, Washington State University, "Development of a Process for Producing an Ashless, Low-Sulfur Fuel From Coal," OCR R & D Report No. 53, Interim Report No. 10, Vol. IV, Part 2, An Annotated Bibliography on Mineral Fiber Production From Coal Mineral.

College of Engineering, Washington State University, "Development of a Process for Producing an Ashless, Low-Sulfur Fuel From Coal," OCR R & D Report No. 53, Interim Report No. 11, Vol. VI, Part 3, Products From Coal Minerals.

College of Engineering, Washington State University, "Development of a Process for Producing an Ashless, Low-Sulfur Fuel From Coal," OCR R & D Report No. 53, Interim Report No. 12, Volume IV, Part 4, Sulfur Removal From Coal Minerals.

College of Engineering, Washington State University, "Development of a Process for Producing an Ashless, Low-Sulfur Fuel From Coal," OCR R & D Report No. 53, Interim Report No. 13, Volume IV, Part 5, Developmental and Rate Studies in Processing of Coal Minerals.

Currie, J. W., and Braun, D. J., "The Potential for Producing and Marketing Portable Fuels from Coal for the Transportation Sector," June 1975. Prepared as a Battelle Energy Program Technical Note. For more information, write Battelle Pacific Northwest Laboratories, Richland, Washington 99352.

Damen, E. L., et al, "Engineering Aspects of Using Coal for Combustion Gasification, and Liquefaction," AIChE Paper No. 23d presented at the 68th Annual AIChE meeting in Los Angeles, California in November 1975. Copies are available from the American Institute of Chemical Engineers, 345 East 47th Street, New York, New York 10017.

*Denver Research Institute, "The Social, Economic and Land-Use Impacts of a Fort Union Coal Processing Complex," ERDA R & D Report No. 103, Interim Report No. 1. Copies are available at \$5.45 as NTIS No. FE-1526-T1 from National Technical Information Service, Springfield, Virginia 22161.

*"Development of a Process for Producing an Ashless, Low-Sulfur Fuel from Coal," ERDA R & D Report #53, Interim Report No. 8, Volume II - Laboratory Studies, Part 2, Continuous Reactor Experiments Using Petroleum - Derived Solvent, 1975. Copies of this report, prepared by The Pittsburgh and Midway Coal Mining Company are available at \$7.60 as item FE-496-T1 from the National Technical Information Service, Springfield, Virginia 22151.

*Reviewed in this issue.

*"Development of a Process for Producing an Ashless Low-Sulfur Fuel From Coal," ERDA R & D Report No. 53, Interim Report No. 9, Volume III - Pilot Plant Development Work, Part 2 Construction of Pilot Plant, 1975. Copies of this report, prepared by The Pittsburgh & Midway Coal Mining Company, are available at \$7.60 through NTIS, Springfield, Virginia, 22151, as Item FE-496-T2.

Dollar, K., "Coal Conversion Technology," presented at the University of Missouri/Missouri Energy Council Conference on Energy, Rolla, October 1975.

*"Draft Environmental Impact Statement for the Proposed Kaiparowits Project," prepared by an Inter-agency Team for the Bureau of Land Management, U.S. Department of the Interior, 1975, 5 volumes.

Eddinger, T. R., "Pyrolysis Route to Coal Conversion," presented at the World Coal Conference, sponsored by the Financial Times, London, September 1975.

Edgar, T. F., "Modeling of In Situ Coal Gasification Systems," presented at the 68th Annual AIChE meeting in Los Angeles, California in November 1975. Copies are available from the American Institute of Chemical Engineers, 345 East 47th Street, New York, New York 10017.

Edwards, R. G., "Environmental Considerations for Coal Conversion," presented at the NCA/BCR Coal Conference and Expo II, Louisville, 1975.

English, J. M., and Smith, J. L., "Portfolio Approach for Selection of Coal Demonstration Plants," AIChE Paper No. 59b presented at the 68th Annual AIChE meeting in Los Angeles, California in November 1975. Copies are available from the American Institute of Chemical Engineers, 345 East 47th Street, New York, New York 10017.

*"Energy Resources of Montana," the 22nd annual publication of the Montana Geological Society 1975. Copies are available from the Society, P.O. Box 844, Billings, Montana, 80210. The following papers which concern coal are contained in this publication:

- . Gwynn, T. A., "Coal and the Environment in the Western United States."
- . Matson, R. E., "Strippable Coal Deposits, Eastern Montana."
- . Carmichael, V. W., "The Sentinel Butte Member of the Fort Union Formation, Powder River County, Montana."
- . Cooley, S. A., "Analyses of Coal and Ash From Lignites and Subbituminous Coals of Eastern Montana."
- . Tudor, M. S., "Geological Exploration and Development of Coal in the Sarpy Creek Area, Big Horn County, Montana."
- . Rose, J. L., "Sarpy Creek Mine, Methods of Operation."
- . Chadwick, R. A., et al, "Sulfur and Trace Elements in the Rosebud and McKay Coal Seams, Colstrip Field, Montana."
- . Burlington Northern, Inc., Energy & Minerals Department, "The Fort Kipp Lignite Deposit, Northeastern Montana."
- . Glass, G. B., "Using Published Wyoming Coal Analyses."
- . Gibbs, P. Q., "Industrial Water Availability Eastern Montana."

Ennis, C. E., "Coal Solvent Refining at the Wilsonville Pilot Plant," presented at the NCA/BCR Coal Conference and Expo II, Louisville, 1975.

Evans, J. M., "Recent Advances in Coal Conversion Technology," presented at the NCA/BCR Coal Conference and Expo II, Louisville, 1975.

Farouq Ali, S. M., "A Two-Dimensional Mathematic Model of the Underground Coal Gasification Process," presented as SPE 5653 at the 50th Annual Fall Meeting of SPE of AIME, Dallas, September 1975.

*Reviewed in this issue

Ferretti, E. J., "Coal Hydrocarbonization - A Commercial Plant Design Concept," AIChE Paper No. 59e presented at the 68th Annual AIChE meeting in Los Angeles, California in November 1975. Copies are available from the American Institute of Chemical Engineers, 345 East 47th Street, New York, New York 10017.

*"Final Environmental Impact Statement - Proposed Federal Coal Leasing Program," prepared by the U.S. Department of the Interior. Copies available at \$5.20 from the Superintendent of Documents, Government Printing Office. Stock Number 024-011-0006203.

Furlong, L. E., et al, "Coal Liquefaction by the Exxon Donor Solvent Process," AIChE Paper No. 41a presented at the 68th Annual AIChE meeting in Los Angeles, California in November 1975. Copies are available from the American Institute of Chemical Engineers, 345 East 47th Street, New York, New York 10017.

Gahr, W. N., "Environmental Constraints Related to Coal Extraction in Colorado." Presented at the ASCE Annual Meeting, Denver, Colorado, November 1975.

Gavalas, G. R., et al, "Experimental and Modeling Studies of Coal Pyrolysis," presented at the 68th Annual AIChE meeting in Los Angeles, California in November 1975. Copies are available from the American Institute of Chemical Engineers, 345 East 47th Street, New York, New York 10017.

Given, P. H., and others, "Dependence of Coal Liquefaction Behavior on Coal Characteristics," OCR R & D Report No. 61, Interim Report No. 9. Copies are available from the Superintendent of Documents, Government Printing Office, Washington, D. C. An article having the same title and by the same author appeared in Fuel magazine, Vol. 54, January 1975, and was reviewed in the September 1975 issue of Synthetic Fuels.

Gray, J. A., "New Technical Trends in the Production of Gas From Coal," presented at the Financial Times' World Coal Conference, London, September 1975.

Guin, J. A., and Tarrer, A. R., "Photomicrographic Studies of Coal Particle Dissolution," presented at the 68th Annual AIChE meeting in Los Angeles, California in November 1975. Copies are available from the American Institute of Chemical Engineers, 345 East 47th Street, New York, New York 10017.

*Hand, J. W., "Drying of Western Coal," presented at the AMC 1975 Mining Convention, San Francisco, September 1975.

Hess, M., "Fuel Grade Methanol From Coal," presented at the NCA/BCR Coal Conference and Expo II, Louisville, 1975.

Hittman Associates, Inc., "Environmental Effects, Impacts and Issues Related to Large Scale Coal Mining Complexes." ERDA R & D Report No. 101, Interim Report No. 2. Copies are available at \$7.60 as No. FE-1508-T2 from National Technical Information Service, Springfield, Virginia 22151.

Holmes, J. M., "An Evaluation of Current Process Technology in Coal Carbonization and Hydrocarbonization," AIChE Paper No. 7a presented at the 68th Annual AIChE meeting in Los Angeles, California, November 1975. Copies are available from the American Institute of Chemical Engineers, 345 East 47th Street, New York, New York 10017.

*Holmes, J. M., et al, "Hydrocarbonization Research Phase I Report: Review and Evaluation of Hydrocarbonization Data," report number ORNL-TM-4835 prepared by Oak Ridge National Laboratory for the Energy Research and Development Administration. Despite its non-specific title, the report deals specifically with coal hydrocarbonization. Copies may be obtained at \$7.60 from the National Technical Information Service, Springfield, Virginia 22161.

*Reviewed in this issue.

- Howard, J. B., and Sarofim, A. F., "Coal Behavior Under Rapid Heating Conditions," AIChE Paper No. 8f presented at the 68th Annual AIChE meeting in Los Angeles, California, in November 1975. Copies are available from the American Institute of Chemical Engineers, 345 East 47th Street, New York, New York 10017.
- Huebler, J., "Gasification and Liquefaction of Coal," presented at the AMC 1975 Mining Convention, San Francisco, September 1975.
- * Hydrocarbon Research Inc., "Solvent Refining of Illinois No. 6 and Pittsburgh No. 8 Coals," Final Report, Volume 1, EPRI 389. June 1975. Prepared for the Electric Power Research Institute. For additional information, write the EPRI, 3412 Hillview Avenue, Palo Alto, California 94302.
- Johnson, C. A., et al, "H-Coal Process Development," AIChE Paper No. 41c presented at the 68th Annual AIChE meeting in Los Angeles, California in November, 1975. Copies are available from the American Institute of Chemical Engineers, 345 East 47th Street, New York, New York 10017.
- Jones, J. R., "The Dichotomies of Coal Supply and SO₂ Control," AIChE Paper No. 26e presented at the 68th Annual AIChE meeting in Los Angeles, California in November 1975. Copies are available from the American Institute of Chemical Engineers, 345 East 47th Street, New York, New York 10017.
- Kowalski, J. J., "Coal Analysis From Well Logs," presented as SPE 5503 at the 50th Annual Fall Meeting of the SPE of AIME, Dallas, September 1975.
- Larsen, L. W., "Alkylation Reactions of Coal and Their Structural Implications," October 1975, paper presented at the 11th Annual Midwest Regional Meeting of the American Society. For additional information, write the ACS, 1155 16th Street, N.W., Washington, D. C. 20036.
- Le Fleur, P. P., "Trace Element Standard Reference Materials for Coal, Fly Ash, and Fuel Oil," presented at the Fall Meeting of the SME of AIME, Salt Lake City, September, 1975.
- Lewis, R. A., "Predicting the Biological Effects of Air Pollution from Fossil Fuel Conversion Facilities in the Northcentral Great Plains," presented at the ASCE Annual Meeting, Denver, Colorado, November 1975.
- Lloyd, W. G., "Fate of Minor and Trace Elements in Alternate Gasification Schemes," presented at the NCA/BCR Coal Conference Expo II, Louisville, 1975.
- Luckie, P. T., "Thermal Drying of Western Coals," Presented at the Fall Meeting of the SME of AIME, Salt Lake City, September 1975.
- Maimoni, A., "In Situ Coal Gasification," presented at the NCA/BCR Coal Conference and Expo II, Louisville, 1975.
- Martin, J. R., et al, "Coalcon's Clean Fuels from Coal Demonstration Plant," AIChE Paper No. 59c presented at the 68th Annual AIChE meeting in Los Angeles, California in November 1975. Copies are available from the American Institute of Chemical Engineers, 345 East 47th Street, New York, New York 10017.
- Mayo, F. R., "Some Problems in the Oxidative Degradation of Coal," October 1975, paper presented at the 11th Annual Midwest Regional Meeting of the American Chemical Society. For additional information write the ACS, 1155 16th Street, N.W., Washington, D. C. 20036.

McPhail, R., "Availability of Water for Energy Development in the Upper Missouri Basin," presented at the ASCE Annual Meeting, Denver, Colorado, November 1975.

Montana Academy of Sciences, "Proceedings for the Fort Union Coal Field Symposium," April 1975. Copies are available at \$8.75 from Coal Symposium, c/o Bookstore, Eastern Montana College, Billings, Montana, 59101.

Naill, R. F., et al, "The Transition to Coal," Technology Review, Volume 78, No. 1, October/September 1975, pages 18-29.

National Coal Association, "Bituminous Coal Data," 25th edition, 1974. Copies are available at \$15 from the NCA, 1130 17th Street, N.W., Washington, D. C. 20036.

National Coal Association, "Coal Traffic Annual," July 1975. Copies are available at \$10 from the NCA, Coal Building, 1130 17th Street, N.W., Washington, D. C. 20036.

Nolden, C. C., "Rotary Tray Dryer Fills the Bill for HRI," Coal Mining and Processing, Volume 12, No. 9, September 1975, pages 66 and 67.

Noss, S., "Coal Conversion - A Viable Industry," presented at the NCA/BCR Coal Conference and Expo II, Louisville, 1975.

O'Hara, J. B., et al, "Fischer-Tropsch Plant Design Criteria," AIChE Paper No. 59d presented at the 68th Annual AIChE meeting in Los Angeles, California in November 1975. Copies are available from the American Institute of Chemical Engineers, 345 East 47th Street, New York, New York 10017.

Pastor, G. R., "Operation of the SRC Pilot Plant," AIChE Paper No. 41b presented at the 68th Annual AIChE meeting in Los Angeles, California in November 1975. Copies are available from the American Institute of Chemical Engineers, 345 East 47th Street, New York, New York 10017.

Peterson, M. W., and James, D. E., "Entrained or Suspension Bed Gasification," AIChE Paper No. 23c presented at the 68th Annual AIChE meeting in Los Angeles, California in November 1975. Copies are available from the American Institute of Chemical Engineers, 345 East 47th Street, New York, New York 10017.

Plass, H. J., Jr., "How Might Synthetic Fuels From Coal Effect the Environment?" Presented at the University of Missouri/Missouri Energy Council Conference on Energy, Rolla, October 1975.

Powe, G. R., "Overall Economics of the Unit Train for Western Coal," presented at the Fall Meeting of the SME of AIME, Salt Lake City, September 1975.

"Proceedings of the Second Annual Symposium on Coal Gasification, Liquefaction and Utilization" Best Prospects for Commercialization." Copies are available at \$50 from the Office of Continuing Education, School of Engineering, 231 Benedum Engineering Hall, University of Pittsburgh, Pittsburgh, Pennsylvania 15261.

"Proceedings of the Sixth Synthetic Pipeline Gas Symposium," held in Chicago in 1974. Copies are now available at \$40 from A.G.A.

"Proceedings of the W. S. Tyler (Subsidiary of Combustion Engineering, Inc.) Coal Technology Conferences," held in Pittsburgh, Charleston, St. Louis, and Denver, 1975. Papers consist of:

- . Akhtar, S., "The Synthoil Process"
- . David H., "The Coal Market - 1975"
- . Drake, R. M., Jr., "Coal: Technology for Clean Fuel Applications"
- . Fink, J., "Status of SO₂ Regulations Affecting Coal Users"
- . Forney, A. J., "The Synthane Process: Coal to Clean Gas"
- . Lovell, H., "Coal Preparation"
- . Meyers, R. A., "Chemical Desulfurization of Coal"
- . Nelson, L. C., "Water Quality Management"
- . Saltsman, R. D., "Results of EPA-Sponsored Programs in Sulfur Removal"

Scott, P., "Research in Coal Chemistry," October 1975, paper presented at the 11th Annual Midwest Regional Meeting of the American Chemical Society. For additional information, write the ACS, 1155 16th Street, N.W., Washington, D. C. 20036.

Simnick, J. J., et al, "Solubility of Hydrogen in Hydrocarbon Solvents at Coal Liquefaction Conditions," AIChE Paper No. 20a presented at the 68th Annual AIChE meeting in Los Angeles, California in November 1975. Copies are available from the American Institute of Chemical Engineers, 345 East 47th Street, New York, New York 10017.

Skaperdas, G. T., "Fluidization - Reactor Design for Coal Gasification," AIChE Paper No. 23b presented at the 68th Annual AIChE meeting in Los Angeles, California in November, 1975. Copies are available from the American Institute of Chemical Engineers, 345 East 47th Street, New York, New York 10017.

Solomon, P. R., "The Evolution of Pollutants During Rapid Devolatilization of Coal," presented at the 69th Annual AIChE meeting in Los Angeles, California in November 1975. Copies are available from the American Institute of Chemical Engineers, 345 East 47th Street, New York, New York 10017.

*Southern Services, Inc., "Status Report of Wilsonville Solvent Refined Coal Pilot Plant," Interim Report, May 1975. Prepared for the Electric Power Research Institute. For more information write the EPRI, 3412 Hillview Avenue, Palo Alto, California 94304.

Stanbaugh, E. P., et al, "Environmentally - Acceptable Solid Fuels by Battelle Hydro-thermal Coal Process," Skilling's Mining Review, July 1975 issue, pages 4-6.

Stander, A. H., "Gasoline From Coal - A Reality," presented at the Financial Times' World Coal Conference, London, September 1975.

Steinberg, M., and Fallon, P., "Coal Liquefaction by Rapid Gas Phase Hydrogenation," presented at the 68th Annual AIChE meeting in Los Angeles, California in November 1975. Copies are available from the American Institute of Chemical Engineers, 345 East 47th Street, New York, New York 10017.

Sternberg, H. W., "Asphaltenes and Coal Liquefaction," October 1975, paper presented at the 11th Annual Midwest Regional Meeting of the American Chemical Society. For additional information, write the ACS, 1155 16th Street, N.W., Washington, D. C. 20036.

Stoller, H. M., "In Situ Instrumentation Applied to Underground Coal Gasification," Sandia Laboratories Report No. SAND-75-0459. Copies are available at \$4 from the National Technical Information Service, Springfield, Virginia 22151.

Thames, J. L., et al, "Hydrology of Black Mesa Reclaimed Land," presented at the AMC 1975 Coal Convention September 1975.

"The Expanding Soviet Coal Industry," World Coal, Volume 1, No. 7, September 1975, pages 28-34.

*University of North Dakota Engineering Experiment Station, "Project Lignite: Premium Fuels from Northern Great Plains Lignite," R & D Report No. 106, Interim Report No. 1, March 1972 to September 1974. This report was prepared for the Office of Coal Research to describe process development for solvent refined lignite design of a continuous 50 pound per hour PDU. Copies are available at \$4 from the National Technical Information Service, Springfield, Virginia 22161.

*U.S. Department of the Interior, "Draft Environmental Statement, Proposed Inclusion of the Missouri River Into the National Wild and Scenic Rivers Systems," July 1975. Prepared by the U.S. Bureau of Outdoor Recreation as DES 75-45.

U.S. Geological Survey, "Final Environmental Impact Statement on the Proposed Expansion of the Belle Ayr South Strip Coal Mine, Campbell County, Wyoming," 1975. For more information, write the USGS, Public Inquiries Office, Room 1012, Federal Building, Denver, Colorado 80202.

Utter, D., "Oil Shale R & D - A Bureau of Mines Program," presented at the University of Missouri/Missouri Energy Council Conference on Energy, Rolla, October 1975.

Vasan, S., "Alternate Desulfurization Techniques for Coal-Gasification Projects," presented at the NCA/BCR Coal Conference Expo II, Louisville, 1975.

Weinrich, G. N., et al, "Socioeconomic Significance of Western Coal Mining," presented at the Fall Meeting of the SME of AIME, Salt Lake City, September 1975.

Williams, T. T., "Water, Limiting Factor in Northern Great Plains Coal Development." Presented at the ASCE Annual Meeting, Denver, Colorado, November 1975.

Winger, J. G., "Financing New Coal Developments," presented at the Financial Times' World Coal Conference, London, September 1975.

Van Derwalker, J. G., "Water Requirements for Energy Development in the Upper Missouri Basin," presented at the ASCE Annual Meeting, Denver, Colorado, 1975.

Zahradnik, R. L., "Coal Conversion and Utilization R & D in ERDA," presented at the Fall Meeting of the SME of AIME, Salt Lake City, 1975.

Zahradnik, R. L., "Overview of the Government Program in Coal Conversion Research and Development," AIChE Paper No. 23a presented at the 68th Annual AIChE meeting in Los Angeles, California in November 1975. Copies are available from the American Institute of Chemical Engineers, 345 East 47th Street, New York, New York 10017.

COAL - PATENTS

Coal Industry Patents Ltd., Canadian Patent 973,826, "Extraction of Dissolution of Soluble Materials from Coal." The patent claims to describe improvements in "the dissolution of coal using organic solvents to provide an extract or digest of the coal...(and) is based on the realization that the solvent power of a solvent for carbonaceous material may be enhanced if a cyclic activator is added to the solvent."

Colorado School of Mines Research Institute, U.S. Patent 3,891,744, "Process for Producing Carbon Monoxide and Hydrogen." By this novel process, hydrogen is produced by oxidation of phosphorus with steam in the first step of the process. The resulting phosphorus oxides are reduced with carbon in the second step of the process to produce carbon monoxide and elemental phosphorus which latter is recycled to the first step. Essentially no phosphorus is consumed.

*Reviewed in this issue.

Exxon Research and Engineering Company, U.S. Patent No. 3,870,480, "Process and Apparatus for the Production of Combustible Gases." Described is a fluidized bed process for making substantially sulfur-free fuel gas from coal by gasifying the coal particles with a steam-oxygen mixture and providing an alkaline earth metal oxide (such as CaO) to react with SO₂.

Hinderliter, C. R., and Perrussel, R. E., U.S. Patent 3,884,796, "Solvent Refined Coal Process with Retention of Coal Minerals." The patent describes a "solvation process for producing deashed solid and liquid hydrocarbonaceous fuel from coal. Raw coal is slurred with a solvent comprising hydroaromatic compounds in contact with hydrogen in a first zone to dissolve hydrocarbonaceous fuel from coal minerals by transfer of hydrogen from hydroaromatic solvent compounds to hydrocarbonaceous material in the coal. The slurry is then treated with hydrogen in a second zone to replenish the solvent with hydrogen. The process is improved by retention of coal minerals in the second zone."

Lummus Company, U.S. Patent 3,852,182, "Coal Liquefaction." A method is described in this patent in which "Insoluble material is separated from a coal liquefaction product by use of a promoter liquid prepared from a fraction of the coal liquefaction product. The promoter liquid is prepared from a fraction having a 5 volume percent distillation temperature of at least 250°F, preferably at least 400°F and a 95 volume percent distillation temperature of at least 350°F, and no greater than 750°F, by hydrogenating the fraction to raise the characterization factor thereof to at least 9.75."

Steag, AG, U.S. Patent No. 3,892,542, "Reactor for Pressure Type Gasification of Coal." The invention concerns "a reactor for the pressure type gasification of coal, comprising a reactor chamber between whose wall and shell enclosing the latter, a space for cooling water flow is formed, to which space a collector mounted on the reactor is connected, from which collector the evaporated cooling water in the form of saturated steam flows through a steam pipe and into the reactor; a compensating tank connected to the steam pipe, including a fall tube discharging into the cooling water jacket, and equipped with a sensing element for the measurement of the cooling water level."

Torrax Systems Inc., Canadian Patent 966,075, "Production of Usable Products from Waste Material." This patent claims that "incineration as a method of disposal of refuse has been found highly desirable as opposed to landfills which contaminate the land and water and open burning which pollutes the air. High temperature incineration immediately disposes of refuse which might provide a breeding ground for rodents and insects, produces a residue which is inert and readily acceptable as landfill, and discharges nonpollutant gaseous products to the atmosphere."

Universal Oil Products Company, U.S. Patent 3,867,275, "Coal Liquefaction Process." A process is described "for producing liquid hydrocarbonaceous products from coal utilizing two steps of solvent extraction with different solvents. In the first stage, coal is contacted, at relatively high temperature and pressure, with a heavy hydrocarbon solvent containing a mixture of hydroaromatic hydrocarbons and saturated aliphatic hydrocarbons in a hydroaromatics/aliphatics weight ratio between about 1:2 and about 2:1. The solid materials remaining after the first liquefaction step are subsequently separated from the liquefied coal and the heavy solvent and the liquefied coal from the first extraction step is recovered as a product. The solid materials recovered from the first extraction step are solvent extracted, at relatively low temperature and pressure, with a monocyclic aromatic hydrocarbon solvent, and the resulting liquids are also recovered as a product."

USS Engineers and Consultants, Inc., Canadian Patent 971,897, "Coal Conversion Process." This is a process for producing coal liquids and metallurgical grade coke from non-coking, high-sulfur coal. Utilizing a fluid-bed vessel, coal is carbonized to produce gases, liquids, and coal char. Metallurgical coke is produced by blending char with certain coal liquids then carbonizing the mixture.

ECONOMICS

CONFERENCE FOCUSES ON FINANCING WESTERN ENERGY DEVELOPMENT

One of the better efforts so far to deal with energy finance problems was the recent conference on "Financial Requirements for Energy Development in the Western States Region" held in Albuquerque on October 29-31. Among the most prevalent themes were:

- . Given realistic government policies, the private sector can supply the capital needed for energy development. Direct government financing is not the answer since it must go to the same capital markets as industry.
- . Government policies should be aimed at providing a reasonably secure financial environment for industry to do its job.
- . Front-end financing for community development is more a problem of timing than capital availability. Various federal and state policies could be implemented to provide a solution.

Sponsored by the Western Regional Governors' Energy Policy Office and the State of New Mexico, the meeting drew a relatively high-level group of speakers representing the energy industry, the financial community, state and local government, and the federal energy bureaucracy.

FEA Administrator Frank Zarb offered little basis for complacency about the energy situation. He noted that two years after the oil embargo:

- . U.S. dependence on imported oil has risen by three percent despite curtailed consumption due to the recession and conservation efforts.
- . Dependence on OPEC oil has increased from 49 to 60 percent total imports.
- . Cost to the U.S. of imported oil has more than tripled to \$27 billion per year.

Financing Energy Development

One of the most stimulating papers of the conference was "Capital Requirements for Energy Development in the Western States Region" by Dr. Irwin M. Stelzer,

President of National Economic Research Associates, Inc. In his view, capital in the needed amounts will be forthcoming from the private sector *if* rational government policies are pursued at the national, state, and local levels.

Stelzer noted that we face a new kind of capital requirement, "one distinguished from the past not so much by its magnitude but by the size of the incremental investment unit required." In the past, a single incremental investment unit was an oil well; its capital could be raised at a Petroleum Club luncheon. Today, a single coal gasification project or a single 1000 MW nuclear power plant requires an investment of nearly \$1 billion.

He emphasized, however, that these huge increments do not mean we must subsidize energy growth, as proposed by the Ford Administration. The private sector can perform its role, provided two basic conditions prevail to attract the necessary capital.

The first condition is a reasonable degree of security of earnings. This does not mean a guaranteed return, but rather some reasonable protection against capricious changes in government policies. Secondly, there must be the prospect of adequate prices. Some form of government intervention is needed to prevent continued monopolistic manipulation of energy prices by OPEC and to insulate domestic energy prices from foreign predation.

While this protected price might be somewhat higher, "domestic consumers would be far better served by paying that price to domestic producers." He emphasized that if some alternative to price protection could provide the desired security at a lower cost, such a method should be pursued.

Stelzer noted that not all environmental costs are worth avoiding. If the costs of environmental protection exceed the benefits to be obtained, those costs should not be incurred. Precision of measurement is, of course, unattainable.

Uncertainties may well be decided in

favor of environmental enhancement. "But the notion that unlimited sums should be expended to avoid killing a few fish is silly," Stelzer said.

Stelzer cautioned Western States not to strive for selective independence. The notion that this region should not export its resources to other states would be valid only if its residents were willing to do without a host of products other states produce. The average Coloradoan consumes 50 percent more gasoline annually than any other average American. Only one-fourth of that gasoline is refined in Colorado. "Other states suffer the environmental impact of refineries which provide gasoline for the Colorado citizen to drive to the polls to vote against oil shale development, and jet fuel for its senators to whiz back and forth between their hometowns and Washington for roll call votes against strip mining," he said in response to Colorado's apprehension over impending energy development.

A Banker's Views

Walter Hoadley, Executive Vice President, Bank of America, spoke on "Financing Energy Development in the U.S." He listed five essential elements necessary to finance massive energy development:

- . A clearly defined high priority goal
- . Broad-based public and private support
- . Technological feasibility
- . Economic and financial feasibility
- . Practical and convincing means to demonstrate program progress

Hoadley noted serious shortcomings to the view that government should step in and take over energy development "in the public interest." First, government has to raise funds principally out of the same private capital markets as does the private sector. Second, the U.S. voting public has far less confidence in the ability of government to manage and operate a project than they have for the private sector. Finally, in practical terms, no major national project can be pursued successfully either by the public or private sector alone because of the inevitable blend of economic, social, and political influences acting upon it.

While government and the private sector obviously must cooperate in energy development, America has no definitive public policy designed to resolve the public-private joint venture issue. What is needed is a public policy which: (1) encourages the private sector to underwrite economic risks with open expectation of a reasonable return on the private money invested, and (2) encourages the government to underwrite the non-economic, especially the social and political, risks of a project while allowing no private profit on public funds involved. Without such a policy, Americans can expect endless confusion and controversy as to the proper role of the public and private sectors.

Formidable Roadblocks

Hoadley said one of the most formidable roadblocks to energy development is the unwillingness of U.S. and foreign investors to provide the necessary financial assistance. They are reluctant because "(1) they expect government fiscal and monetary irresponsibility in the election era ahead to generate another period of extreme inflation followed by a severe downturn worldwide--all before 1980, and (2) they fear greater government intervention by tax and regulatory means into the management of their business."

Reassurances on both of these points are needed before massive financial support will be provided.

Public Utility Financing Problems Noted

Ralph DeNunzio, Chairman of Kidder Peabody & Co., expressed confidence that large scale energy development is possible within the framework of our capital markets and regulatory systems as we know them today. But such financing can only come about if federal and state regulatory agencies establish the rate of return necessary to attract the required capital.

He was critical of proposals to finance energy needs by direct governmental assistance in the form of grants and/or guarantees. In his view, President Ford's proposed Energy Independence Agency would involve all the drawbacks and inefficiencies associated with massive federal planning

and expenditures.

Before any project can go forward, it must meet the test of the market place. The proper role of government bodies is to remove many of the impediments which stand in the way of energy resource development. At present, a morass of bureaucratic hurdles in such areas as environmental, safety, and plant siting regulations stymie energy projects and impede financing. State and federal governments should seek to simplify these procedures to eliminate as much uncertainty as possible. This would build investor confidence and permit investors to assess the risks associated with energy projects. These actions must be accompanied by enlightened regulation that permits recovery of the full cost of service, including an adequate rate of return on investment.

Regional Bank Consortium Suggested

Rawles Fulgam, President of the First National Bank in Dallas, noted that the energy industry has successfully introduced a number of innovative financing techniques. The consortium bank has been one of the most successful banking innovations in the international markets during the past ten years. Usually a separate legal entity is formed with its capital stock owned by founding banks. But there have been problems with such arrangements. Fulgam concluded that correspondent banks and loan syndication networks would be equally effective for financing Western energy development.

Community Development Costs of Energy Development

Edward H. Allen of the Rocky Mountain Institute for Policy Research, summarized the results of a recent workshop on "Financing Infrastructure in Energy Development Areas in the West." His first conclusion was simple: capital is not getting into public investment programs at the times and in the amounts needed. What is surprising, Allen noted, is that it should be such a difficult problem--because so little money would be required to overcome it. Little, that is, compared to capital requirements for the energy projects themselves. He stated that less than \$5 billion

will be required for community development of infrastructure in Western rural areas between now and 1985. Some feel only \$2 billion may be needed.

Participants in the workshop agreed that it is the consumer who should bear a substantial portion of these financing costs. However, coordinated efforts of industry and federal, state, and local government are needed to transfer those costs back to the consumer in an equitable manner.

Community development needs were also addressed by Jack Campbell, president of the Federation of Rocky Mountain States, and Camilla Auger of TOSCO. Campbell noted that providing basic personal services for 450,000 to 600,000 new residents in the Rocky Mountain area would require a one-time investment of \$1.8 to \$2.4 million based on an estimate of about \$4,000 per capita. In addition, communities will be faced with annual recurring operating costs of between \$400 and \$800 per capita. Auger's estimate for front-end costs is \$4,500 per capita or \$27 million (\$40 million including highways) total one-time cost for a population of 6,000 resulting from a 50,000 BPD facility. Annual maintenance costs would be \$600 per capita or about 3.6 million dollars for the new population.

Both Campbell and Auger identified various alternatives for financing these costs:

- . Increasing the state's share of mineral leasing act royalties with increases being used for public services.
- . Restructuring a federal grant in aid programs for local and state planning.
- . New federal-state matching programs for both planning and implementation.
- . A federal loan guarantee fund to support loans by consortium of private lending institutions.
- . Outright federal loans to state and local governments, long-term and low interest.
- . Creation of state bonding authorities pledging present and future energy related revenues (as in Wyoming).
- . Improved state severance tax structures (as in Montana) pledged to providing needed public services.
- . Rearrangement of tax distribution mechanisms to provide that "dollars

follow impact".

- . Prepayment of taxes by energy developers.
- . "Social investment" tax credit to energy developers.

Auger feels there are several advantages of direct industry participation in the provision of housing and services. First, in contrast to new forms of taxation, which in many cases require new legislation and are often slow to return revenues to the area of impact, direct industry participation can provide front-end funds quickly and directly to the communities and with maximum flexibility and responsiveness to changing needs. Second, this approach links socio-economic costs directly and clearly to the overall project costs, so that the full cost and benefits of energy development can be more clearly assessed and forthrightly handled. Third, the operator derives obvious practical benefits by collaborating with local and state governments to assure orderly development. Direct industry involvement is only part of the solution, of course. The most practical overall solution might be to provide a range of legislative options at the state level involving a balanced system of both taxation and credits against special impact taxes for those companies wishing to participate directly.

#

ENVIRONMENT

API ASSESSES IMPACT OF EPA AIR QUALITY REGULATIONS ON ENERGY DEVELOPMENT

The American Petroleum Institute, Office of the General Counsel, released a study in August 1975 entitled, "An Examination of the Accuracy and Adequacy of Air Quality Models and Monitoring Data for Use In Assessing the Impact of EPA Significant Deterioration Regulations on Energy Developments". The prime contractor for the study, Greenfield, Attaway, and Tyler, Inc., of San Rafael, California, sub-contracted to Systems Applications, Inc., and Rockwell International/Air Monitoring Center for an analysis of available air quality models and monitoring systems. The study prepared for the API is a comprehensive review of models and monitoring systems for predicting and measuring SO₂ and TSP (total suspended particulates) from point source emitters for purposes of air quality maintenance. The study presents inherent errors and imprecisions in existing models and monitoring instruments. Data generated by a common algebraic model are presented for several proposed "first-new" energy development projects to ascertain their compliance with EPA significant deterioration criteria. See page 1-26 of the September 1975 issue of Synthetic Fuels for the status of the Clean Air Act amendments.

The study first (chapters II and III) presents a comprehensive review and examination of seventeen currently used (or being validated) mathematical models for the simulation of air quality. And appraisal of the current state of the art in monitoring ambient concentrations of sulfur dioxide and TSP. Secondly, (chapters IV and V) the report discusses the precision, accuracy, and adequacy of emissions and meteorological data and the input requirements of mathematical models followed by an appraisal of the impact of combined model and data inadequacies on air quality predictions. The final chapter of the report (chapter VI) applies the results of the foregoing analysis to a site-specific examination of impact of the implementation of the significant deterioration regulations on the feasibility and permissibility of new energy development projects. Three areas of the the United

States are taken as subjects of this examination: The Piceance Basin of western Colorado - Oil Shale; Campbell County, Wyoming, - coal gasification and Harlan County, Kentucky, - coal gasification. A discussion and presentation of the data and conclusions obtained in the site-specific examination are presented below following a brief discussion of the models and monitoring systems studied.

Evaluation Conclusions Presented

A number of significant conclusions concerning models, monitoring, and site-specific evaluation emerged from this study:

Mathematical models are an important tool in assessing, forecasting, and predicting air quality. While considerable time and funding has been devoted to the adaptation of known theories and development of new models that are suitable for such applications, it is generally accepted that existing models do not possess sufficient accuracy to be judged "reliable". This lack of confidence in the predictive capability of models clearly calls into question the use of model predictions as the key component of the total information that forms the basis for crucial decisions. Unfortunately, but for good reason, measures of the expected inaccuracies of model predictions are rarely, if ever, available.

- Although algebraic formulations (such as the Gaussian) are the class of models in most common use today, this is not testimony to their inherent superiority. These models are readily available and easy to use and understand, but they are based on assumptions that severely limit the range of their applicability.
- The Gaussian formulation, the model most generally available and in use, has an uncertainty associated with its predictions conservatively estimated to be a factor of two. This factor can be substantially higher when the model is applied to irregular terrain situations or when complex meteorological

- conditions prevail. Moreover, in most cases, the model tends to overpredict at points distant from the source and to underpredict at points near the surface.
- . Numerical models are superior as a group to algebraic formulations, but have not yet reached a stage of development wherein they are both available and suitable for general use. Further development and evaluation are needed in most instances, as are streamlining and simplification, while keeping the user in mind.
 - . EPA has not yet specified that a particular model or models be used in a given situation, probably because of the less-than-adequate state of development of models. Consequently, the "user" must demonstrate that a model is suitable and adequate in a specific application.
 - . Errors incurred in ambient air monitoring of SO₂ and TSP using the best available instruments are substantial when compared with maximum allowable increments. Average concentration over the long time periods indicated in the regulations essentially does not reduce the errors. Errors introduced into model prediction as a consequence of the need to transform, interpolate, extrapolate, or otherwise manipulate "raw data" to create suitable inputs can be substantial.
 - . It may be concluded, based on a generalized application of the Gaussian model and the assumption of worst-case conditions, that a new emissions source of typical size (1/2 kg/sec SO₂ emissions rate) may be expected to violate the Class I regulations (see Table 1), even if it is the first new source in the area. A new emissions source of typical size, sited in a Class II area, may well violate the increment limit in an adjacent Class I area if the latter area is 50 to 80 kilometers (31 to 50 mi.) or less from the source and if trapping conditions may be expected to occur in the region. A new emissions source of typical size, one which is the first constructed in the area, may or may not violate Class II regulations. Under the conditions noted, however, the probability of a violation is not great, since the Gaussian tends to overpredict.
 - . Based on specific calculations for the proposed Colorado, Wyoming, and Kentucky development sites, Class I increments for SO₂ for a three-hour averaging period may be expected to be exceeded under worst-case conditions. The critical distances (the distance beyond which exceedance is not expected) range from 2.5 to 76 kilometers (1.6 to 47 mi.), depending upon the project and the type of meteorological conditions. However, Class II limits are not exceeded for any of the cases examined for the three-hour averaging period. (Note that in each case the impact of the first new development in the area is being assessed; the entire allowable increment is considered to be available.) In the case of 24-hour averages, the results were somewhat different. The Class I allowable increment may be expected to be exceeded for both SO₂ and TSP for all worst-case conditions examined, the critical distances ranging from less than 1.5 to 70 kilometers (1 to 43 mi.) in the case of SO₂ and from 6.5 to 36 kilometers (4 to 22 mi.) in the case of TSP. Class II exceedance, however, involved only TSP. Predicted TSP concentrations exceeded the allowable increments for both Class II and Class I areas for most worst-case conditions, and some best-case conditions as well. The critical distances for exceeding Class II TSP limits in worst-case conditions ranged for 1.4 to 15 kilometers (1 to 10 mi.). Maps depicting the areas of expected exceedance for several cases are shown in Figure 1. Table 3 summarizes the full results.

Modeling of Air Quality Discussed

While both monitoring and modeling are essential to understanding and controlling air pollution, neither is a highly precise "tool" for establishing concentration levels. Monitoring procedures are considerably more reliable than modeling which is constrained, on the most part, by the knowledge of the dynamics of atmospheric processes. Primarily problems associated with monitoring systems are instrument

TABLE 1

ALLOWABLE INCREMENTAL TSP AND SO₂ CONCENTRATION INCREASES
FOR NEW OR MODIFIED SOURCES UNDER NONDEGRADATION REGULATIONS¹

	Class I		Class II	
	$\mu\text{g}/\text{m}^3$	ppm ²	$\mu\text{g}/\text{m}^3$	ppm
Particulate matter				
Annual geometric mean	5 (+ 2.9) ³		10 (+ 3.0)	
24-hour maximum	10 (+ 3.0)		30 (+ 3.4)	
Sulfur dioxide				
Annual arithmetic mean	2 (+ 42)	0.0008	15 (+ 39)	0.006
24-hour maximum	5 (+ 39)	0.002	100 (+ 40)	0.038
3-hour maximum	25 (+ 38)	0.010	700 (+ 63)	0.267

¹Federal Register, Vol. 39, No. 235, Part III, Thursday, 5 December 1974, pp. 42510-42517.

²1 ppm = 2620 $\mu\text{g SO}_2 \text{ m}^3$.

³Estimated errors in measurement (95% confidence level) associated with best available instruments.

NOTE: Under the proposed regulation, all areas of the country would be designated Class II initially, with provisions for allowing States to reclassify any area to accommodate the social, economic, and environmental needs and desires of the public. (39FR 42510)

Class I applied to areas in which practically any change in air quality would be considered significant; Class II applied to areas in which deterioration normally accompanying moderate well-controlled growth would be considered insignificant; and Class III applied to those areas in which deterioration up to the national standards would be considered insignificant. (39FR 42510)

drift, repeatability, and limits of detectability and serve to reduce the overall accuracy of the best available instruments.

A total of seventeen models are assessed and ordered in terms of desirability. Table 2 presents these models in order of decreasing comprehensiveness or superiority. The models ranked are of two basic types - algebraic and numeric according to the mathematical methods and assumptions employed in solving the full boundary layer equations or equations of continuity (the basic expression for stimulating air quality) -- the equations of conservation

of mass, momentum, energy and individual species (SO₂, TSP). While these equations, in principle, offer an accurate description of atmospheric transport, diffusions, and reaction phenomena, these equations have such large data and computing requirements that they are seldom seriously considered for use in prediction. Most commonly, models based on the conservation of mass equation, alone, are adopted with other pertinent factors supplied as input data.

It is convenient to classify models according to the type of solution used in

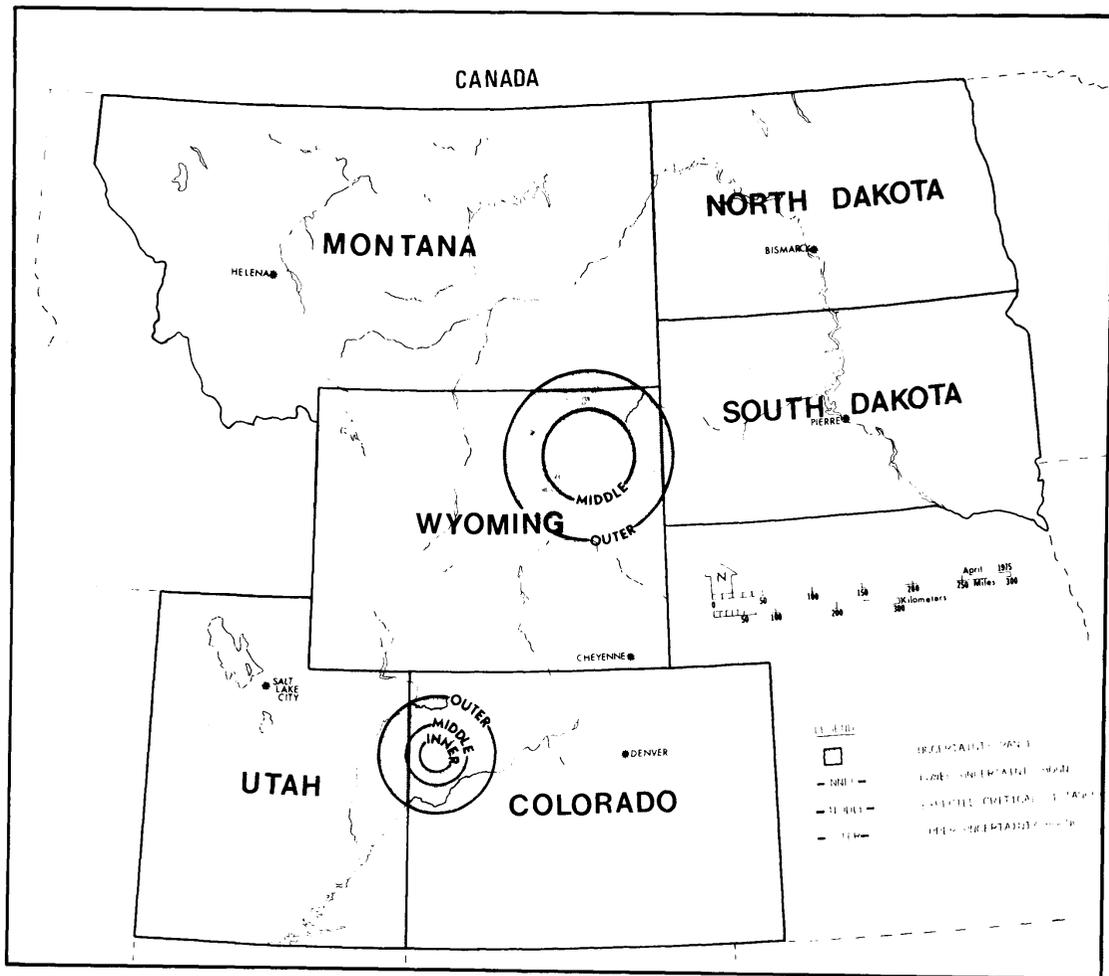


Figure 1. Critical Distance Circles for Campbell County, Wyoming -- 24--Hour SO₂, Class I Increments--And Piceance Basin (Project Independence Data)-- 24-Hour SO₂, Class I Increments

applying a simplified form of the continuity equation. The first approach, and the one most commonly used, is the development of an algebraic (Gaussian) solution. The second approach is to solve the governing equation through numerical integration. The second method allows the handling of non-steady-state or time-dependent situations as well as irregular terrain in a much more efficient manner than the first. In many instances, this is a highly desirable attribute and, in part, explains why the numeric models are generally ranked higher than the algebraic in Table 2. Numeric models are more complex and pose problems of execution and data acquisition.

The greater extent to which a model incorporates meteorological and transport considerations, the more complex it is with attendant greater data requirements and use costs. The algebraic models tend to be less complex and easier to use than the numeric and are more widely used. The less complex the model, the more assumptions are inherent in it. To apply any model, a complete understanding of these assumptions is necessary.

Virtually all models have been developed for computing short time averages - from one minute to many hours to, at most, a week. However, legislation is based on compliance with concentration maxima for averaging periods of one hour to one year.

Synfuels Assessed in Light of Significant Deterioration Regulations

The effect of regulations on new energy fuels facilities, as measured by the state-of-the art in air quality monitoring and modeling, needs to be evaluated. Consequently, this technical assessment of air quality monitoring and modeling performed. The limitations of the equipment, procedures, and methodologies to be used in evaluating proposed new facilities - synthetic fuels, thermal power generation, coal cleaning, and oil refineries - is applied to an examination of the impact of the implementation of significant deterioration regulations on the feasibility and permissibility of these facilities.

As was previously stated, three areas of the United States were examined -- the

Piceance Basin of western Colorado, Campbell County, Wyoming, and Harlan County, Kentucky. Each is typified by terrain features of substantially varying elevation, which are boundary conditions that are difficult for the present genre of models to treat. (The one exception is the topography near the proposed plant site in Wyoming. In the immediate vicinity of the site, the terrain is relatively flat.) These sites are typical, however, of future energy development locations. In each case, the Gaussian model (algebraic) was used for simulation purposes, despite the problems associated with its use in such situations. As the study points out, models based on the numerical solution of the species continuity equation are the most suitable class of models capable of adequately treating point sources in complex terrain situations. However, while there are several such models currently under development (and at least one, that is to the author's knowledge nearly developed but not validated, that is proprietary), none have been adequately evaluated or have been put into regular use. Thus, the Gaussian, while deficient in many respects, is the most suitable model available. It also has the distinction of being used in nearly all evaluative studies of this type that have been carried out to date. The Gaussian, then, as given by Turner (1969) (see Table 2) is used in all simulations applied to the examination of the oil shale and coal gasification projects studied. The Turner model requires three types of data inputs: emission factors (emission rate), meteorological conditions, and topographic information.

Data for the simulation exercise were acquired from several sources. The oil shale project, Piceance Basin, emissions data were acquired in part through the Colony Development Operation (compiled by Battelle Pacific Northwest Laboratories, and Dames and Moore) and from Project Independence reports. The coal gasification project, Wyoming, emissions data were acquired in part from the environmental assessment of the Proposed Panhandle Eastern/Peabody Coal Project (compiled by Sernco). The data for the hypothetical Kentucky site were extrapolated from existing data and in the end analysis, the

TABLE 2

AIR QUALITY SIMULATION MODELS AVAILABLE OR UNDER DEVELOPMENT - RANKED
IN DECREASING ORDER OF SUPERIORITY

(As Evaluating by API - 1975)

<u>Model Name</u>	<u>Model Designation</u>	<u>Degrees of Use</u>	<u>Primary Reference</u>
Hino	Numerical solution of the momentum boundary layer and species continuity equations.	Comparison of the computed pollutant distributions with some model results suggests that the results are as reliable, or more reliable, than the conventional wind tunnel experiments for the estimation of the distribution of wind velocity and smoke concentration over an area with complex topographical features.	Hino, M. (1968), "Computer Experiment on Smoke Diffusion Over a Complicated Topography," <u>Atmos. Environ.</u> , Vol. 2, pp. 541-558.
C.E.M.	Numerical solution of the momentum, energy, humidity, and species continuity equations.	This model has been validated using Los Angeles Basin data and has been shown to be somewhat less accurate than the SAI model but more accurate than the PIC model.	Pandolfo, J. P., and C. A. Jacobs (1973), "Tests of an Urban Meteorological-Pollutant Model Using CO Validation Data in the Los Angeles Metropolitan Area -- Volume I," The Center for Environment and Man Report 490a.
SAI	Numerical solution of the species continuity equation.	The SAI model has been validated by comparing predicted results with data taken in the Los Angeles Basin in September, 1969, and favorable agreement has been obtained.	Reynolds, S. D., P. M. Roth, and J. H. Seinfeld (1973), "Mathematical Modeling of Photochemical Air Pollution--I: Formulation of the Model," <u>Atmos. Environ.</u> , Vol. 7, pp. 1033-1061.

TABLE 2 (Cont.)

<u>Model Name</u>	<u>Model Designation</u>	<u>Degrees of Use</u>	<u>Primary Reference</u>
Shir	Numerical solution of the species continuity equation.	The model is currently at the theoretical stage and has only been compared with simpler algebraic formulations to ascertain the errors involved in the imposition of constraints in developing the latter solutions.	Shir, C. C., "Numerical Investigation of the Atmospheric Dispersion of Stacks Effluents," IBM. J of. Res and Sev. 16, 171-179, (1972)
PIC	Numerical solution using particle-in-cell technique for the species continuity equation.	Results of this analysis have been compared with data taken from the Los Angeles Basin. In general, unsatisfactory agreement occurs between the two sets of results, and the error has been attributed to the inadequate kinetic scheme used in the model.	Sklarew, R. C., A. J. Fabrick, and J. E. Prager (1971), "A Particle-In-Cell Method for the Numerical Solution of the Atmospheric Diffusion Equation, and Applications to Air Pollution Problems-- Final Report," EPA Contract No. 68-02-0006.
Lamb-Neiburger	Algebraic Formulation	Model has been validated for the Los Angeles Basin for carbon monoxide, and the results have compared favorably with observed values. Authors intimate that the model may be extended to handle more complex cases, but to date no work has appeared in the literature.	Lamb, R. G., and M. Neiburger (1971), "An Interim Version of a Generalized Urban Air Pollution Model," <u>Atmos. Environ.</u> , Vol. 5, pp. 239-264.
Shir and Shieh	Numerical solution of the species continuity equation.	The model was used to study SO ₂ distribution in the St. Louis metropolitan area during 25 consecutive days in February 1965. The computed results agreed favorably with the experimental measurements for both long-term and short-term averages.	Shir, C. C., and L. J. Shieh (1974), "A Generalized Urban Air Pollution Model and Its Application to the Study of SO ₂ Distribution in the St. Louis Metropolitan Area," <u>J. of Appl. Met.</u> , Vol. 13, pp. 185-204.

TABLE 2 (Cont.)

<u>Model Name</u>	<u>Model Designation</u>	<u>Degrees of Use</u>	<u>Primary Reference</u>
Shieh, et al	Algebraic Formulation (Gaussian)	Model has been validated for New York City. Comparison with observed data indicates that the standard error in the estimates is of the order of a factor of two.	Shieh, L. J., B. Davidson and J. P. Friend (1970), "A Model of Diffusion in Urban Atmospheres: SO ₂ in Greater New York," Proceeding of Symposium on Multiple Source Urban Diffusion, EPA AP-86
Argonne	Algebraic formulation (integrated Gaussian Puff)	Model has been validated for Chicago TAMS data. Greatest accuracy was achieved for long time averaging on the order of either a day or a month, with accuracy increasing with the magnitude of the observation. Short term averages (one to three hours) exhibit substantial error.	Croke, E. J., and J. J. Roberts (1971), "Chicago Air Pollution Systems Analysis Final Program Final Report," Argonne National Laboratory, Argonne, Illinois.
LLL Lawrence Livermore Laboratory	Numerical solution to the vertically integrated species continuity equation (box model)	The model has only recently been developed and remains unvalidated.	Knox, J. B., R. C. Maniger, M. C. McCracken, and C. F. Miller (1974), "Development of An Air Pollution Model for the San Francisco Bay Area," UCRL-51537.
Turner	Algebraic formulation (Gaussian)	Algorithm is the primary computational tool of EPA in estimation of atmospheric dispersion. Its basis for computational approaches are discussed in "Guidelines for Air Quality Planning and Analysis, Volume 10: New Stationary Sources."	Turner, D. B., (1967), "Workbook of Atmospheric Dispersion Estimates," Public Health Service Publication 999-AP-26, Robert A. Taft Sanitary Engineering Center, Cincinnati, Ohio.

TABLE 2 (Cont.)

<u>Model Name</u>	<u>Model Designation</u>	<u>Degrees of Use</u>	<u>Primary Reference</u>
ESL	Algebraic Formulation (Gaussian)	To date, model remains unverified.	Lamb, D. V., F. I. Badgley, and A. T. Rossano, Jr. (1973), "A Critical Review of Mathematical Diffusion Modeling Techniques for Predicting Air Quality with Relation to Motor Vehicle Transportation," University of Washington, June.
Aerovir- onment	Algebraic Formulation (Gaussian)	Laterally integrated form has been used for predicting the downwind concentration from ground level line sources, notably roadways, with some success. General applicability of the model remains unproven.	Lissanman, P.B.S. (1973), "A Simple Unsteady Model Explicitly Incorporating Ground Roughness and Heat Flux," APCA 66th Annual Meeting, June 24-28, Chicago, Illinois.
Lebedeff- Hameed	Algebraic formulation (solution of steady state two-dimensional diffusion equation.)	The model has only recently been postulated and remains unverified for any existing situation.	Lebedeff, S. A., and S. Hameed (1975), "Steady State Solution of the Semi-Empirical Diffusion Equation for Area Sources," to appear in <u>J. of Appl. Meteorology</u> .
Martin- Tikvart	Algebraic Formulation (Gaussian)	Algorithm constitutes the basis of EPA's Climatological Dispersion and Air Quality Display Models. It provides satisfactory estimates of air quality over long time intervals (seasonal or yearly) and reduces to the Gaussian formulation over short time intervals.	Martin, D. O. (1972), "An Urban Diffusion Model for Estimating Long Term Average Values of Air Quality," <u>Journ. of Air Poll. Control Assoc.</u> , Vol. 21, No. 1, pp. 16-19 (January 1972).

TABLE 2

<u>Model Names</u>	<u>Model Designation</u>	<u>Degrees of Use</u>	<u>Primary Reference</u>
Gifford-Hanna	Algebraic Formulation	A simplified steady state version of the Gifford-Hanna model which neglects kinetic effects has been compared with existing data and found to be in agreement to within a factor of two for SO ₂ and TSP. The simplified model is included within the EPA's Guideline for air quality. The more complex kinetic model has been shown to compare favorably with the predictions of the numerical PIC model developed by Sklarew, (1971) although neither model adequately predicts the observed conditions in the Los Angeles Basin.	Hanna, S. R. (1973), "A Simple Dispersion Model for the Analysis of Chemically Reactive Pollutants," <u>Atmos. Envir.</u> , Vol. 7, pp. 803-817.
APRAC	Algebraic Formulation (Gaussian)	Model has been applied to St. Louis area with limited success. Its main emphasis has been in highway design.	Johnson, W., F. L., Ludwig and A. Moon (1970), "Development of a Practical Multipurpose Urban Diffusion Model for Carbon Monoxide." Proceedings of Symposium on Multiple-Source Urban Diffusion Models, U.S. Environmental Protection Agency, No. AP-86.

conclusions drawn closely resemble those for the Wyoming site.

The study is particularly interested in worst-case conditions, those having the greatest potential for exceeding the allowable increments (see Table 1). As a consequence, meteorological conditions were selected which would be typical of those associated with the largest values of ground level concentrations - plume "fumigation" and "trapping". Plume trapping occurs when a stable layer persists above a neutrally stable or unstable layer. Fumigation is characterized by the dynamic evaluation of the vertical temperature profile across the pollutant cloud. Maximum fumigation occurs when the inversion base reaches the upper edge of the plume; at this point the entire pollutant cloud is homogeneously mixed between the ground and the stable layer aloft. Because fumigation is a transient phenomenon, it is difficult to treat with a steady-state model such as the Gaussian.

The results of the examination are presented as plots of concentration (microgram/m³) of SO₂ and TSP vs. distance (Km) from source. Plots are prepared for both trapping and fumigation conditions over 3 and 24-hour averaging periods for the three related sites. Table 3 summarizes the data presented in these plots.

The results of the simulations are examined in basically three ways:

- . Comparing the predicted 3-hour and 24-hour average SO₂ and TSP concentrations to the maximum allowable deterioration increments for Class I and Class II regions.
- . Determining, where maximum increments are violated, the downwind distance beyond which violations are not expected to occur (critical distance = R_{crit}).
- . Estimating the uncertainty in the expected critical distance.

The critical distance as predicted by the model is shown in Table 3 as the middle figure of the three figure array $y-R_{crit}-x$ where x and y represent the upper and lower limits, respectively, to these predictions and indicate the inherent error in the values presented as generated by the Turner model.

"Clearly, the uncertainty ranges associated with the critical downwind distances can be considerable. The ratio of the upper to the lower bound (again, conservatively estimated) is typically 3 to 5, but can be much greater. More importantly, an uncertainty range of 50 kilometers (31 mi.) or more is not uncommon, and some are of the order of one hundred kilometers. In our view, the magnitude of these uncertainties--and not the magnitude of the expected value of the critical downwind distances--is the most important information to emerge from this modeling exercise. These uncertainties overwhelmingly dominate the predicted results, thus undermining the value of the predictions."

Figure 1 represents the values of R_{crit} graphically for the Piceance and Wyoming studies as the "middle" radius. The outer and inner radii are the x-y bounds to the critical distance.

An analysis of the dependence of the critical distance on emission rate is presented in the study also.

#

ENERGY BOOM TOWN PROBLEMS TO BE STUDIED IN FOUR WESTERN STATES

The University of Denver Research Institute (DRI) has been awarded a \$74,500 contract by the Federal Energy Administration to study community problems and problem solving in financing growth due to energy development. Four typical coal or oil shale communities facing rapid growth rates have been selected for study: the Meeker area in north-west Colorado, the Sheridan area of northern Wyoming and southern Montana, Sweetwater County in southwestern Wyoming, and Emery County in northeastern Utah. Actual or prospective needs for public services, facilities and housing will be evaluated in light of estimated public revenues, public and private capital availability. Various state and federal policy options for solving potential financial problems will be analyzed. The project will be supervised by John S. Gilmore, senior research economist at DRI. The firm of Beckert, Brown, Coddington Associates Inc., of Denver, is the major subcontractor. The project is scheduled for completion in March 1976.

#

TABLE 3

SUMMARY OF INCREMENT EXCEEDANCES, TABULATION OF PREDICTED CRITICAL DISTANCES
AND UNCERTAINTIES IN CRITICAL DISTANCES

<u>Project and Pollutant</u>	<u>Operative Conditions</u>	<u>Critical Distance for 3-hour Averages (km)</u>	<u>Increment and Class Exceeded</u>	<u>Critical Distance for 24-hour Averages (km)</u>	<u>Increment and Class Exceeded</u>
Piceance Basin Project Independence SO ₂ Concentrations	(B	20 - 40 - 67 ¹	(25 µg - I)	32 - 56 - 95	(5 µg - I)
	F (
	(W	19 - 35 - 60	(25 µg - I)	28 - 50 - 85	(5 µg - I)
	(B	NV - 4.5 - 10	(25 µg - I)	3.5 - 7.5 - 18	(5 µg - I)
Piceance Basin Project Independence TSP Concentrations	T (15 - 35 - 80	(5 µg - I)
	(W	9 - 20 - 45	(25 µg - I)		
	(B			9 - 16 - 27	(10 µg - I)
	F (3.4 - 6.4 - 11.5	(30 µg - II)
	(W			21 - 36 - 60	(10 µg - I)
				7.5 - 15 - 26	(30 µg - II)
		NO 3-HOUR REGULATORY INCREMENTS FOR TSP		NOT EXCEEDED	
Piceance Basin Colony Data SO ₂ Concentrations	(B			2.8 - 11 - 25	(10 µg - I)
	F (1.9 - 2.6 - 7	(30 µg - II)
	(W				
	(B	NV - NV - 19	(25 µg - I)	NV - 15 - 31	(5 µg - I)
	F (
	(W	NV - 2.5 - 20	(25 µg - I)	NV - 14 - 26	(5 µg - I)
T	(B		NOT EXCEEDED ²	NV - 2.2 - 2.4	(5 µg - I)
	(W		NOT EXCEEDED	NV - 1.2 - 3.6	(5 µg - I)

TABLE 3 (Concluded)

SUMMARY OF INCREMENT EXCEEDANCES, TABULATION OF PREDICTED CRITICAL DISTANCES
AND UNCERTAINTIES IN CRITICAL DISTANCES

<u>Project and Pollutant</u>	<u>Operative Conditions</u>	<u>Critical Distance for 3-hour Averages (km)</u>	<u>Increment and Class Exceeded</u>	<u>Critical Distance for 24-hour Averages (km)</u>	<u>Increment and Class Exceeded</u>	
Piceance Basin Colony Data TSP Concentrations	(B			NV - 8.9 - 21	(10 µg - I)	
	F {			NOT EXCEEDED	(30 µg - II)	
	(W			2.1 - 29 - 55	(10 µg - I)	
	T {		NO 3-HOUR REGULATORY INCREMENTS FOR TSP	NV - 1.4 - 2.6	(30 µg - II)	
	(B				NV - 2.3 - 7	(10 µg - I)
	F {				NOT EXCEEDED	(30 µg - II)
(W				NV - 6.5 - 15	(10 µg - I)	
T {				NV - NV - 4.2	(30 µg - II)	
(W						
Kentucky/Wyoming SO ₂ Concentrations	(B	NV - NV - 120	(25 µg - I)	NV - NV - 130	(5 µg - I)	
	F {					
	(W	NV - 76 - 140	(25 µg - I)	NV - 70 - 140	(5 µg - I)	
	T {					
	(B	10.5 - 24 - 52	(25 µg - I)	11.5 - 25, 58	(5 µg - I)	
	F {					
(W	23 - 50 - 110	(25 µg - I)	25 - 56 - 130	(5 µg - I)		

Key: F = fumigation conditions
T = trapping conditions
B = "best-case" conditions
W = "worst-case" conditions
NV = no predicted violations

¹ Critical distance is middle figure, left and right figures are lower and upper bounds, respectively.

² Due to the inapplicability of the model for "near source" prediction, critical distances less than 1.5 kilometers are neglected when the upper bound is also less than 1.5 kilometers.

WATER

INTERIOR SETS GUIDELINES ON WATER FACTS NEEDED TO GET PERMITS, LICENSES, LEASES, AND CONTRACTS

The Department of the Interior announced late in August it will require basic water information associated with new leases, contracts, licenses, and permits issued by the agency, even if the water involved is not within Interior's marketing authority. The rule applies to arrangements involving the use of 5,000 or more acre feet per year of municipal and industrial water and 20,000 acre feet per year of agricultural water. Interior also published guidelines for compliance. Coal and lignite gasification, oil shale processing, and associated land reclamation efforts of commercial scale ventures are affected by the ruling.

The purpose of the rules and guidelines according to Jack Horton, Assistant Secretary of the Interior for Land and Water Resources, is to conserve water, assure water quality, and inform states, Indians and others affected by the water use. In the case of mining objectives related to leases or permits, the information can be provided at the time plans are filed or at other appropriate intervals when water impacts can be more readily ascertained. In situations regarding water from Bureau of Reclamation Projects, anticipated water uses should be revealed as soon as possible, preferably in the project planning stage.

Interior will seek advice from states, Indians, and others on the suitability of the intended water use and effects. In cases where non-federal water is involved, it will require the permit applicant to demonstrate that all applicable state laws and regulations have been met. Guidelines suggested include showing:

- . The quantity and quality of water required and the justification for its use.
- . The expected "significant" changes in water quality and quantity.
- . The method of use, amount diverted, amount consumed, return flows, legal requirements, and any required treatment prior to disposal or return.

- . The methods of conservation.
- . The alternatives considered to reduce consumption or minimize fresh water demand such as use of poor quality water, recycling, air cooling.
- . The compatibility of the proposed conservation methods with the National Environmental Policy Act.
- . The compatibility of the uses with state and federal pollution control regulations.
- . The compatibility with the state, regional, and other water management procedures including fish and wildlife coordination and endangered species laws.

The water information is now required in relation to projects having environmental impact statements. It would be provided at the time of making application for a lease or permit under the new rules. While not retroactive, Horton indicated it might expedite processing of an existing permit, lease or other application if the information were available.

#

WATER RESOURCES COUNCIL HIKES PERCENT LEVEL

The National Water Resources Council hiked the interest rate used in computing cost benefit ratios of 1/4 of one percent, to 6-1/8 percent for FY 1976. The hike is the maximum permitted by law for any one increase. The figure is used in computing discount rates in water project planning. The former rate was 5-5/8 percent.

The cost benefit ratio has been a determining factor in Army Corps of Engineers, U.S. Bureau of Reclamation, and other federally funded water development projects. Since the interest rate is below that available in commercial channels, it is often attacked by opponents to projects as being a taxpayer subsidy since if prevailing interest rates were used, the cost benefit ratio would be substantially altered and in many cases would render a project unjustifiable economically.

The 6-1/8 percent can be compared with nine and ten percent and even higher interest rates now prevailing in commercial channels for financing development programs.

#

GOVERNMENT

PROPOSED COLORADO SEVERANCE TAX CONSIDERED BY LEGISLATIVE COMMITTEE

The interim committee on mineral taxation of the Colorado General Assembly is conducting hearings on proposed severance tax legislation for consideration during the 1976 session. A copy of the proposed bill is included in the Appendix of this issue. (For a review of severance taxes on coal and oil shale in other Western states, see the September issue of Synthetic Fuels.)

The proposed bill prepared and sponsored by Rep. Morgan Smith, is significantly milder than the one rejected by the Colorado legislature during the last session. Basically, the bill would impose a five percent severance tax on the gross proceeds from coal, oil shale, oil and gas, and metals. The definition of gross proceeds generally corresponds to mineral value at the point of severance. The previous bill, by comparison, was based on "gross income" (that used for calculating depletion), which included significant value added by processing.

Oil Shale

Under the proposed bill, oil shale production would be taxed in the same manner as metals. The gross proceeds base is that defined for ad valorem tax purposes (Section 39-6-106 (1), C.R.S. 1973). This value is determined by subtracting from the gross value "costs of treatment, reduction, transportation, and sale of such ore or any products derived therefrom."

The first \$10 million of gross proceeds would be exempt from the tax. In addition, oil shale producers would choose one of the following exemption options:

- (1) Oil shale operations would be exempt from the tax until they reached 60 percent of design capacity, with a phased-in tax thereafter amounting to 25 percent of the tax in the first year, 50 percent in the second year, 75 percent in the third, and 100 percent in the fourth and succeeding years.

- (2) In lieu of the \$10 million exemption, the entire gross proceeds from an oil shale plant that produces an average of less than 10,000 barrels per calendar day would be exempt from the tax. After shale oil production reaches an average of more than 10,000 barrels per calendar day, the tax would be phased in at the same rate as that in option 1.

Coal

Gross proceeds for coal would be the value of the coal immediately after extraction, which is determined by subtracting from the value at the first point of sale all costs of cleaning, washing, breaking, crushing, screening, sizing, dust allaying, treatment to prevent freezing, oiling, loading for shipment, and shipment incurred after severance and before sale. The first 5,000 tons produced each quarter would be exempt from the tax. In addition, coal produced from underground mines would receive a tax credit of 20 percent. The present coal inspection fee (0.7 cents per ton) would be repealed.

Oil and Gas

The present production tax on oil and gas would be replaced by the proposed five percent severance tax on gross proceeds, which would allow a credit equal to lesser of: (1) 50 percent of the severance tax liability, or (2) 50 percent of all ad valorem taxes paid. Stripper wells producing less than an average 10 BPD would be exempt from the tax.

Revenue Use to be Controversial

Projected revenues from the proposed tax, based on estimated 1975 production, would be approximately \$15 million. One of the major political controversies when the bill reaches the floor will be distribution of these revenues. Western slope representatives want a portion of the revenues returned to communities impacted by mineral development, while other legislators are more concerned with augmenting the state general fund. The

administration of Governor Richard Lamm has taken no position. It is expected to favor some kind of revenue distribution to impacted areas.

In view of the potential alternatives, it appears that most coal and oil shale concerns are supporting the approach taken in the proposed bill. If the legislature fails to pass some kind of mineral severance tax this session, there is certain to be an initiated severance tax measure on the ballot in November 1976. Such a measure undoubtedly would be more severe than anything likely to result in the legislature. For example, one initiative petition purportedly under consideration would impose a ten percent tax on gross proceeds from oil, oil shale, and coal produced by underground methods; or a 50 percent tax on surface-mined coal and oil shale, 80 percent of which would be refunded after satisfactory reclamation.

#

SYNTHETIC FUELS TASK FORCE RECOMMENDS INFORMATIONAL PROGRAM

Recommendations by the Synfuels Inter-agency Task Force to President Ford's Energy Resources Council recognizes significant synthetic fuels production is too risky to be undertaken by the private sector alone. The recommendations envision sufficient risks to a government funding role to provide ammunition for opponents of the program.

A two-phase program is recommended. First is a 350,000 barrel informational program of no specific mix to begin in Fiscal 1976. Phase II, starting about 1978, would use information gained on processes and environmental problems to establish second generation technology for a 1,000,000 BPD industry by 1985.

Cartel Is Big Question

Just as with a private firm pondering a heavy capital outlay, the dominant question in the task force's consideration and recommendations is the strength of the world oil cartel and the resulting world oil price when such plants would come on the line. This is a huge and unpredictable variable.

The committee assumed two possibilities in a difficult-to-follow quantitative analysis: one assumes a strong cartel and the other assumes a 50-50 chance of a strong cartel. The task force recommended a program be undertaken with a budgetary authority to install immediately a synthetic fuels capability of approximately 350,000 BPD. This option does not preclude achieving a goal of 1,000,000 BPD by 1985, but defers the scale-up decision.

Incentive Currently Lacking

The task force concluded that "in the absence of federal incentives and changes in regulatory policy with regard to synthetic gas or other policies creating a stable and favorable synthetic fuels investment environment, significant amounts of synthetic fuels are not likely to be produced in the U.S. by 1985.

"This conclusion stems primarily from the present cost of synthetics and from the risk associated with large synthetic fuel plant investments in light of the uncertainty of future world oil prices," the report said.

A 50-50 Chance

Based on anticipated future U.S. demand and production, the expected cost of synthetic fuels commercialization and assuming the cartel has a 50-50 chance of remaining strong, the task force saw in quantitative analysis a better than even chance for red ink in a federal program.

On those assumptions, "the 350,000 BPD program could be expected to cost the nation on the order of \$1.6 billion in discounted (constant) 1975 dollars. However, there is a ten percent chance the 350,000 BPD program could result in a net benefit to the nation of more than \$7 billion (net present value cost discounted at ten percent while there is a ten percent chance it could result in more than a \$9 billion cost."

A million BPD program would cost the nation \$5.4 billion. The task force saw ten percent chances each for a net benefit of more than \$15 billion, or a net cost of \$26 billion.

A third and highly unlikely case of a 1.7 million BPD program was considered. This figure represents a "maximum" program, the largest that could be anticipated by 1985 with an intense national effort in the absence of "major dislocations in the economy." Its cost on the above assumptions was figured at \$11 billion in discounted 1975 dollars.

Strong Cartel Assumed

If a strong world oil cartel and a high world oil price is assumed, the task force's quantitative analysis found all three programs would be expected to result in net benefits to the nation. These were calculated at \$1.5 billion for the 350,000 BPD program, \$3.5 billion for the million BPD program and \$3.1 billion for the 1.7 million BPD program.

Sensitive Factors

In the first case, the task force found at least three factors which could heavily affect the cost/benefit ratio besides the cartel strength and world oil price question. These were the difference between domestic demand and production, the future costs of synthetic fuels, and the effectiveness of the program in reducing those costs.

Obviously reflecting on the Arab oil embargo of 1973, the task force saw high desirability in a large synthetic fuels program in the event imports are restricted. This desirability was not reduced by the existence of a fuel storage program.

Assuming a six million BPD import restriction by price or quota, the 350,000 BPD program would have an expected positive net benefit of \$12 billion and the million BPD program, \$27 billion. "However, in this case, the nation would incur a cost (decrease in social surplus) due to such import restrictions on the order of \$120 billion." The import restrictions mentioned above was assumed to be an action brought by the federal government. It would seem logical that some portion of the "decrease in social surplus" cost would have to be assigned to the cost of no synthetic fuels program in the event of a future embargo.

A storage program would not affect the desirability of a synthetic fuels program, but would justify itself. A storage program of between 0.6 and 1.0 billion barrels would have a net benefit to the nation of about \$7 billion, according to the report.

The Qualitative Variables

At least four factors were not included in the quantitative analysis. All are potential benefits that could accrue to the U.S. as a result of undertaking a program. The are:

- . "International leverage (improved bargaining position) associated with positive U.S. leadership in developing alternative fuel sources.
- . "Resolution of industry uncertainty with regard to government support for synthetic fuel development which may speed private sector investment.
- . "The value of potential decrease in world oil prices paid by importing nations.
- . "Possible weakening of the cartel strength (this was assessed as negligible)."

Quantitative Benefits

Evaluation of the alternative-size programs was on the basis of the following costs and benefits to the nation:

- . "Economic benefits (or costs) associated with having less expensive (or more expensive) synthetics as compared with alternatives such as imports, including the value of insurance, information, and decreased foreign oil prices.
- . "Environmental and socio-economic costs associated with accelerated development of shale and coal resources.
- . "Economic benefits associated with embargo protection."

Environmental Impacts

The task force found difficulty in assessing environmental impacts because of the considerable uncertainty regarding processes, effluents and plant locations. Nevertheless, it found "the environmental impacts currently estimated to result from the

350,000 BPD, or from the first phase of a two-phase 1 million BPD option, appear acceptable when considered in light of the environment and economic information likely to be gained from the program."

The task force noted that the impacts likely to result from current technologies and pollution abatement methods on a large-scale synthetic fuels commercialization program "would be regional in scope and could be severe." The report sees the 350,000 BPD program as a laboratory for rapid treatment of such problems in the second phase.

Recommended Incentives

A wide range of incentives was examined. These included loans and loan guarantees, purchase agreements and price supports, tax changes, accelerated depreciation, and government financed and owned facilities.

The recommendation was a combination of a federally-guaranteed non-recourse loan for up to 50 percent of the construction cost plus a competitively bid price support for shale oil and unregulated utility or industrial fuels.

Anticipated benefits of such an incentive program were threefold: encouragement of competition, reduction or elimination of government costs as market prices approach syncrude production prices, and minimal federal administrative involvement.

Coal Incentives

For high BTU gas from coal, the recommended incentive was a competitively awarded non-recourse loan guarantee for up to 75 percent of the project cost. "This incentive is suggested as a temporary measure pending either recommended changes to the Natural Gas Act to bring synthetic gas under FPC jurisdiction or complete deregulation of gas."

Among the strengths the task force saw in this incentive was that it facilitates acquisition of debt financing to the regulated industry and "entails no government liability in full life operation."

For regulated utility and industrial fuels such as low BTU gas, the recommended incentive was a competitively bid construction grant, overcoming "loan financing restrictions on electric utilities by providing up-front capital to the participating regulated utility..."

For production of liquids and gases from biomass, the recommended incentive was a competitively bid non-recourse loan guarantee for up to 75 percent of the project cost.

Cost/Price Ratio

Under the recommended incentives, the cost of the program to the federal government would depend on the future world price of oil.

If the world price fell from the present \$11 a barrel to about \$7 and remain low for the rest of the century and domestic coal increases to \$17 a ton, the 350,000 BPD program would require direct government expenditures of about \$3 billion in net present values or about \$13 billion in undiscounted dollars, about \$1.30 per barrel in net present value.

If world prices and domestic coal prices hold at current levels, the 350,000 BPD program would cost about \$2 billion (NPV) or \$7 billion in undiscounted dollars or 70 cents per barrel (NPV basis).

If world energy prices increase at an average of six percent a year, or if world oil rises to \$15 a barrel and holds, the program would cost the government virtually nothing since initial subsidy payments would be offset in later years by revenue to the government, the report says.

Socio-Economic Impacts

"It is likely that problems in financing public infrastructure in remote areas will slow the rate at which a synthetic fuels commercialization program can be implemented. Therefore, it is recommended that additional authorization for loans be made available for this purpose. Depending on the timing of project start-up, required outlays are estimated to be \$20 million to \$30 million

annually for three years," the report recommends.

The task force urged use of environmental protection criteria in evaluation of project proposals, federal approval of detailed site development plans, and extensive efforts to develop an environmental data base.

Changes In Law Needed

Along with the obvious changes needed in the Energy Research and Development Administration Act, the task force also suggested changes in statutes to allow the Department of the Interior to grant federal oil shale lease holders approval for off-site spent shale disposal, and changes in the Natural Gas Act to provide the FPC with clear regulatory jurisdiction over synthetic gas plants.

#

FEDERAL FUNDING, INCENTIVES OUTLOOK GOOD -- AT THE MOMENT

Forecasting what Congress will do and when is only a slightly imprecise science. It is somewhat akin to predicting the fate of specific legislation, the genesis of which is known, but the content isn't.

Despite the headlines, opposition and confusion, it appears there will be a loan guarantee program for synthetic fuels from oil shale and coal. The program is the controversial Section 103 provision of the ERDA Authorization Bill, S. 598.

Three versions of Section 103 were generated, one each by the Senate, House and Administration. These are outlined in a subsequent article. Several western governors asserted they wanted a voice in the legislation because federally funded projects might be in their resource rich states. So a House-Senate Conference Committee measure featuring 26 points taken from the three earlier versions and including some of the states rights concepts of the governors was being prepared as this issue of Synthetic Fuels went to press.

It appeared the \$6 billion Senate proposal would be cut back, perhaps in half. Social impact funds, a state "veto" of a specific

facility being funded, seemed likely to be included along with fixing the amount of social impact funding at a percent of each loan guarantee.

Dropping oil shale from the \$6 billion Section 103 synthetic fuels amendment to the ERDA authorization bill (S. 598) was a possibility if agreement cannot be reached

Congress is not going to delay the ERDA bill long because the Colorado Congressional Delegation and Colorado state officials are against a portion of it and rallying support for their position. Colorado has the richest oil shales and would receive the heaviest impacts if an oil shale price and plant results from Section 103 being passed and implemented. While politically Colorado is virtually impotent on Capitol Hill, Congressional leaders are faced with passing a measure a state doesn't want and four of the five Colorado Congressmen and one of the two Senators are against. One Senator is lukewarm; the fifth Colorado Congressman has taken no public position.

At least two concepts threaten the whole measure for eventual industry acceptance. They are the patent and default recourse provisions.

Private industry will not likely share patents necessary to erect synthetic fuels facilities with third parties, as required in the House version of Section 103. Much of the technology has existed for years. The investment has been made and the patent holders are entitled to a return on it. This is a major issue.

On the second concept, if a firm with assets of \$500 million seeks a loan for a \$1 billion facility, it seems unlikely it will risk all its assets as collateral in case the venture flops. Limiting default collection to the specific synthetic fuels facility subject to the loan guarantee, and not including the non-project assets of the sponsoring firm is essential to the workability of the program.

Assuming a loan program is passed, it would be signed by President Ford -- barring any unexpected additions. It would take more than a year for ERDA to prepare guidelines, seek specific project applications, evaluate them, hold public hearings, study environ-

mental impacts and get to a point of awarding a loan or seeking competitive bids. Hearings on the guidelines or rules alone could run into months despite the urgency provisions of some of the Section 103 versions.

In brief, despite the controversy, a tangible loan guarantee program is not imminent. Even if one were, it alone would not be sufficient incentive to get a commercial synthetic fuels industry established.

Almost forgotten in the politics surrounding Section 103 is the Nonnuclear Energy Research and Development Act of 1974 -- the major legislation of which synthetic fuels loan guarantees are only a portion.

Congress has approved more than \$4 billion in R & D and related projects. The current appropriation--still to be enacted and signed into law--calls for the following sums for program operating expenses:

- (1) Fossil Energy
 - . Coal, \$274,973,000
 - . Petroleum and Natural Gas, \$48,647,000.
 - . Oil Shale, \$25,113,000.
- (2) Solar Energy \$96,200,000.
- (3) Geothermal Energy \$33,870,000.
- (4) Advanced Energy Systems Research \$68,900,000.
- (5) Conservation Research and Development.
 - . Electric Power Transmission, \$11,830,000.
 - . Advanced Automotive Power Systems, \$18,000,000.
 - . Energy Storage System, \$23,100,000.
 - . End-use Conservation, \$31,000,000.
 - . Improved Conversion Efficiency, \$5,000,000.
 - . Urban Waste Conversion, \$30,000,000.
- (6) Other Programs, \$3,107,107,000.
 - . \$31,500,000 for general new programs in Environmental and Safety Research and Scientific and Technical Education in support of Non-nuclear Energy Technologies;
 - . \$18,000,000 for new programs of Physical Research in Molecular and Materials Sciences in support of Nonnuclear Energy Technologies;

- . \$1,700,000 for the National Bureau of Standards;
- . \$500,000 for the Council on Environmental Quality; and
- . \$1,000,000 for the Water Resources Council.

Nonnuclear Energy Development

- . Clean boiler fuel demonstration plant \$20,000,000.
- . High Btu synthetic pipeline gas demonstration plant \$20,000,000.
- . Low Btu fuel gas demonstration plant, \$15,000,000.
- . Low Btu combined cycle demonstration plant, \$5,000,000.
- . Fluidized bed direct combustion demonstration plant, \$13,000,000.
- . Five megawatt solar thermal test facility, \$5,000,000.
- . Ten megawatt central receiver solar thermal powerplant, \$5,000,000
- . Geothermal powerplant (steam), Raft River, Idaho, \$5,000,000.
- . Geothermal powerplant, Buffalo Valley, Nevada, \$5,000,000.

The thrust is clearly at finding energy generators, not producing energy in a volume adequate to begin to offset petroleum imports or bolster domestic supplies. It is argued that the implementation of the R & D program will create enormous energy demands...further aggravating the supply situation in the short term.

In contrast, a commercialization program as envisioned by Ford would supply not only modest amounts of energy, it would advance existing technology to provide increasing amounts of energy for domestic use.

Apparently it has not yet dawned on Congress the fantastic amounts of capital needed for both programs may not be available. Eventually significant cutbacks in the number of projects is inevitable.

#

OUTLINE OF FORD ADMINISTRATION SECTION 103 PROPOSAL ON SYNTHETIC FUELS

- . Eliminates solar and geothermal resources; keeping coal and oil shale as in H.R. 9723.

- . Loans are for construction (not operation of) "commercial demonstration facilities."
- . Loan guarantee program expires in 1982.
- . Loan guarantees provide complete amortization in no more than 25 years, or 90 percent of the useful economic life of the facility.
- . ERDA Administrator shall collect fees to cover program administrative costs and probable leases; fees not to exceed one percent per annum of the outstanding indebtedness. (This could make a revolving fund).
- . Income from a guaranteed loan is not tax exempt.
- . Guarantees are not extendable to third parties for guaranteeing tax sheltered leverage lease income.
- . Approval of ERDA Administrator and Secretary of Treasury is required on long term leases. The arrangement would have to benefit the government and would take potential tax revenues into consideration.
- . ERDA Administrator's report to Congress with a program would be 90 days after enactment (compared with 180 days in the House version).
- . Congressional review of individual guarantees is 30 days (instead of 90).
- . A revolving fund is created under the Secretary of the Treasury, with the Secretary able to replenish the fund by borrowing.
- . Authority to grant greater than 75 percent of project construction costs is specifically deleted.
- . Recourse provisions are essentially the same as in H.R. 9723.

Outline of H.R. 9723 (House Version of Section 103 of ERDA Authorization Bill)

- . Limited to coal and oil shale.
- . No mention of goals.
- . Guarantee criteria:
 - a. commercial size facilities employing a unique technological approach.
 - b. clear and distinguishable demonstration of commercial facility different from any plant on which a loan guarantee has been provided.
- . Amortization within 25 years.

- . No loans higher than 75 percent guarantee; including initial operation and construction stages.
- . No guarantee if "the income from such loan is excluded from gross income for the purposes of Chapter 1, Internal Revenue Service Code of 1954, or if the guarantee provides significant collateral or security, as determined by the Administrator, for other obligations, the income from which is so excluded." (Unclear, even after study).
- . No limit on fees charged by ERDA Administrator to cover administrative costs and probable losses.
- . No provision for ERDA Administrator to make progress reports to Congress. The loss suffered by any lender is not fully guaranteed. The government pays only "a reasonable percent of loss" as specified in the individual guarantee contract.
- . The government can sue the borrower for all payments made under the guarantee.
- . Fiscal year guarantee loan dollar limits set annually.
- . Consultation with states where facilities would be located.
- . Review and approval of construction and operating plans by the U.S. (presumably ERDA).
- . Patent limitation provisions.
- . No limits on competition.
- . Price floors and markets of synthetic fuels plants output allowable.

Outline Of Senate Version of Section 103 Of ERDA Authorization Bill

- . Goal of 1 MM BPD oil equivalent by 1985.
- . Loan guarantees for construction and operation of commercial coal-land oil shale facilities.
- . ERDA Administrator consult with Secretary of Treasury on loans, interest rates, repayment procedures for high BTU pipeline quality gas from coal and low BTU boiler gas.
- . \$6 billion limit.
- . ERDA Administration can require supporting documentation from loan applicants.
- . ERDA Administrator has discretionary power in writing loan provisions.
- . Private competition encouraged.
- . Secretary of the Treasury ascertains financial need of loan applicant.
- . Loan guarantee limit of 75 percent of

project cost with 75 percent limit not applicable during construction phases.

- . Determination of a "reasonable assurance of full repayment."
- . 60 days provided to cover payments in default with ERDA; payment within 45 days of claims being filed.
- . Administrator can seize, sell, operate, lease or otherwise dispose of property upon which loan guarantee default provisions are invoked.
- . Attorney General empowered to "protect U.S. interest" by suing obligor.
- . Administrator shall report to Congress within 90 days of passage with recommendations on implementing the program.
- . Each loan commitment shall be submitted to Congress for approval; approval or detail to be made within 30 days.

#

COMMENTARY ON SYNTHETIC FUELS LOAN GUARANTEE PROGRAM

None of the Section 103 versions prior to the Conference Committee measure provided the incentive for industry to raise the capital for a synthetic fuels plant. Incentives necessary but absent from the 103 legislation are:

- . Limit the collateral for the loans under guarantee to the project assets.
- . Provide for more than a 75 percent guarantee through plant completion.
- . Include cost over-runs and unanticipated expenses in the definition of total project costs covered by the guarantee.
- . Preserve the sanctity of prior patent rights.

Statement of Purpose

Both the Senate-passed bill and the Administration amendments spoke of providing adequate federal support to foster a joint government and industry commercial demonstration program capable of producing one million barrels equivalent of synthetic fuels from domestic sources by 1985. This is in line with the President's goals as set forth in his State of the Union message last January and more recently in his San Francisco address to the construction trade workers on September 22. The House

bill is silent on the enunciation of any such goals.

Percent of Project Guaranteed

The Administration amendments call for guarantees not to exceed 75 percent of total project costs. In addition, the Administration, in its testimony, indicated that the 75 percent level of guarantee would not be mandatory. Further, the Administration proposed to negotiate competitively between prospective applicants the percentage of project costs to be guaranteed.

Similarly, H.R. 9723 provides that the guarantee shall not exceed 75 percent of the cost of construction and initial operation. What was meant by "initial operation" is not clear.

The Senate-passed bill provides for guarantees not in excess of 75 percent of the total project costs, provided that this level may be exceeded during the period of construction of the project. The Senate version is essential if certain kinds of projects are to secure financing.

Projects of concern here are principally the high-BTU gas projects sponsored by the natural gas pipeline companies such as El Paso Natural Gas Company, Texas Eastern Transmission Company and others.

The gas pipeline companies are independent, publicly owned, regulated utilities with relatively small assets. The cost of a single \$1 billion coal gasification plant is greater than the net assets of all but the largest of these companies. Twenty-five percent of a \$1.0 to \$1.3 billion investment is too much for a \$1 million company to put at risk in a synthetic gas project. Coal gasification plants cannot be financed without at least a 90 percent loan guarantee through completion. After that time, guarantees may be necessary.

Projects should be selected from those meeting criteria determined by the Administrator that would include economic feasibility, availability of alternative gas sources, alternative fuels to gas, location with respect to water and coal

resources, existing transportation facilities and readiness to proceed. The percentage of the loan guaranteed by the government should be the same for all.

For similar reasons no arbitrary limitations below the 75 percent level should be placed on loan guarantees for oil shale and coal syncrude projects. A principal benefit of a loan guarantee is to make possible a relatively high component of low-cost debt capital in the financial structure of the project, thus making the syncrude more competitive. The cost of capital is the largest single item in the production of syncrude from either coal or oil shale.

Recourse Provisions

The Administration's amendments and its testimony in support of the loan guarantee program make it clear that any recourse by the government against a defaulting borrower should be limited to the assets of the project itself.

By contrast both Section 103 of the Senate bill and H.R. 9723 would permit total recourse against all of the assets of the borrower or project sponsors, thereby rendering the guarantee essentially meaningless from the point of view of borrowers who cannot afford to place their basic company assets at such risk. The provisions of the Administration amendments which limit the government's recourse to the project assets should be accepted by both the Senate and the House.

U.S. Obligations to the Lender

Under H.R. 9723 any loss suffered by any lender is not fully guaranteed. After a determination that a loss has occurred, the Administrator is required to pay to lenders only a "a reasonable percentage of such loss" as specified in the guarantee contract. This provision negates the purpose of the loan guarantee program; it should be rejected.

Funding Mechanisms for Honoring U.S. Obligations to the Lender

Both the Senate-passed bill and the Administration amendments put a \$6 billion

ceiling on the guarantee program and provide for adequate mechanisms to ensure that funds are available for the purpose of honoring the government's obligations under the guarantee.

By contrast, H.R. 9723 places no dollar limitation on the program but provides that the Congress is to authorize amounts to be guaranteed on a year by year basis. This lack of certainty and continuity which is the inevitable result of annual authorizations, would make it impossible to develop an effective program with credibility for potential lenders.

Project Review and Approval

H.R. 9723 provides that the Administrator shall review and approve the proposed plan of a borrower for the construction and operation of all projects. In addition, projects are to be monitored by the Environmental Protection Agency. This provision is redundant of existing law and regulatory requirements which provide the government, both state and federal, with ample mechanisms, such as the Environmental Impact Statement process, for project review and approval. In addition, the Administrator of the Environmental Protection Agency already possesses sufficient authority to enforce specific pollution control standards against any such project. This provision should be stricken from the trial loan guarantee program.

Over-runs and Contingencies

One of the major uncertainties of a synfuels project is its ultimate cost. Inflation over the four to five year period of construction, delays for various reasons including environmental lawsuits, regulatory lag, and material shortages, and fluctuation in interest rates make any long-term capital-intensive projects almost impossible to budget with reliability these days. It is essential that loan guarantees be applicable to cost-over-runs and unanticipated expenses, including the capitalization of extended start-up costs and interest during construction and start-up. In neither of the versions of Section 103 or in H.R. 9723 is this subject clearly treated.

Sanctity of Prior Patent Rights

Since projects utilizing this proposed loan guarantee program will use existing technology or that in an advanced stage of development, much of the technology will be covered by existing patents and licenses. For the most part, this technology is privately owned and has been developed through private initiative. For government to attempt to gain control of technology or require royalty free usage would be counter-productive. It should be sufficient as an obligation under a loan guarantee to require that the technology so demonstrated be available at reasonable terms and conditions to others. The intent of Congress to this extent should be made clear. As originally written, the patent provision dooms the whole program.

Loan Guarantee Fees

Both H.R. 9723 and the Administrator's proposed changes to Section 103 call for fees to be paid by the project sponsor for loan guarantees. This is appropriate. Other federal loan guarantee programs such as those of FHA, the Export-Import Bank and the Maritime Administration require fees of up to one percentage point annually on the outstanding indebtedness covered by the guarantee. Synfuel loan guarantees should be no problem.

In each case, government covers a financial risk not acceptable to private sources of capital to encourage activities considered to be in the public interest. However, the borrower (and his customers) pay for that service a fee commensurate with the risk to government.

If a reasonable and equitable loan guarantee fee is charged by government there is no need for arbitrary limitations on the percentage of the project to be covered by a guarantee.

Other Considerations

One commonly held misconception concerning the effect and impact of the loan guarantee program should be dispelled. The loan guarantee program is only one of several incentives which must be provided

if we are to realize a competitive synthetic fuels industry which will utilize, by 1985, the full range of technical processes and institutions presently available. The loan guarantee mechanism will not be of any practical benefit to large national and multi-national corporations, including our own major oil companies, with large financial reserves and ready access to supplemental capital. As a practical political matter, those companies with large assets arising from other operations could not afford to default on loan obligations whether or not their obligations had been guaranteed by the federal government.

What is necessary is not a loan guarantee program, but an adjustment in tax treatment which would make synthetic fuels projects competitive with conventional oil and gas operations with respect to the attraction of long-term, high risk capital. Either tax credits applied to other income or accelerated depreciation or amortization commencing at an early date in the life of the project under development are feasible.

The loan guarantee mechanism will have its most direct application to small companies which desire to compete in synthetic fuels production but which would have difficulty otherwise in raising the necessary capital.

They need to provide assurance to lenders beyond their own financial capabilities, and to those utilities which propose to develop synthetic fuel products for a regulated market, namely, the natural gas industry.

Loan guarantees covering 50 percent and 80 percent of project cost for an oil shale plant based on representative data are shown in Table 1.

ERDA is the appropriate agency to administer the program. While other agencies may be proposed in the energy field in the future, ERDA is presently in existence and has the necessary management structure and expertise.

Congress has provided itself with sufficient review mechanisms to insure that ERDA, in the administration of the loan guarantee program, does not go beyond

TABLE 1

COST DATA ON \$1.1 BILLION, 50,000 BPD SYNTHETIC FUELS FACILITY
BASED ON 1980 DOLLARS DERIVED BY USING A 9 PERCENT INFLATION RATE

Loan, Percent of Project Cost	50	80
Debt	\$550 Million	\$880 Million
Equity	\$550 Million	\$220 Million
Interest Rate (percent)	8.5	8.5
Return on Equity (percent)	15	15
Syncrude Selling Price	\$16.50/BBL	\$12.70/BBL

Congressional intent. The House Committee on Science and Technology can review the ninety-day report required to be submitted by the Administrator of ERDA to ensure that the program in its general concepts is tailored to the objectives as set forth by the Congress. The \$6 billion limitation keeps the program at extremely modest size. Specific Congressional action is needed to increase it.

The 75 percent loan guarantee limitation is marginal but hopefully will be adequate for most companies and most projects. It is absolutely essential that a higher guarantee be allowable through completion of the project as is provided. Loan guarantees must depend solely on the project as collateral and not on other assets of the sponsors. The \$6 billion ceiling on the total loan guarantees outstanding will not build \$20 billion worth of synthetic plants. It will, however, get the program under way, which is of prime importance.

#

FEWER FEDERAL PROCUREMENT NOTICES AND CONTRACTS AWARDS PUBLISHED

As may be seen in Tables 1 and 2, the list of published federal procurement notices and announced contract awards is much shorter than the list published in the last issue of Synthetic Fuels. While there is always a fluctuation in the number of notices and awards from quarter to quarter, the marked decrease in volume for this quarter may be another indicator of the failure of the Congress and the federal

government to establish a firm, viable national energy policy.

Although President Ford and other federal officials have stated the need for activities related to developing an oil shale industry, it is interesting to note that all of the procurement notices listed in Table 1 and 2 of the three contract awards in Table 2 are related to coal. There is no mention of oil shale.

#

TABLE 1

U.S GOVERNMENT PROCUREMENT NOTICES

(Note: This tabulation contains procurement notices listed in the Commerce Business Daily which are primarily related to synthetic fuels. In certain instances, procurement notices will also be included which relate to the more broad field of energy sources and similar subjects. Depending on the information available, each listing will include a title or description, the RFP or synopsis reference number, the requesting agency, and the date and page number of the issue in which the notice appeared.)

Control Technology Development for the Utilization and Disposal of Fuel Conversion System Wastes, Coal Storage, Preparation and Feeding, and Wastewater Treatment, RFP DU-75-A275, EPA Contracts and Management Division, Office of Administration, Research Triangle Park, N.C., 20 August 1975, page 1.

R & D Effort Related to the Investigation of Desulfurization and Denitrogenation of Coal and for Development of Mild Hydrogenation Process to Produce Clean Liquid and Solid Fuels from Coal, ERDA is negotiating with the Colorado School of Mines on the basis of an unsolicited proposal, 3 September 1975, page 2.

Pipeline Gas Demonstration Plant capable of converting coal (including lignite) to a pipeline quality gas, RFP E (49-18)-2012, ERDA Procurement Operations, Washington, D. C. 20545, 18 September 1975, page 1.

Coal Conversion System Transient Pollutant Evaluation, EPA is negotiating with Exxon Research and Engineering Co. for additional work under Contract 68-02-0629, 24 September 1975, page 1.

Study on Environmental R & D Needs Relative to Coal Using Technologies, President's Council on Environmental Quality, 722 Jackson Place, N.W., Washington, D. C. 20006, 30 September 1975, page 2.

Engineering Support in the Evaluation of Certain Coal Gasification Processes, ERDA is negotiating with C. F. Braun and Co., Alhambra, California for a modification to contract E (49-18)-1235, 7 October 1975, page 2.

Studies on the Economic Impact of Environmental Regulations on the Coal and Oil Producing Industries and on the Petroleum Refining Industry, RFP WA 76-X046, EPA Headquarters Contract Operations, Crystal Mall No. 2, Room 724, Washington, D.C., 8 October 1975, page 2.

Investigation of the Use of Shock Tube Technology to Study Coal Pyrolysis and Gasification at Heat-Up Rates at the Threshold of Conventional Gasifiers (10^4 °C/sec) and Above, ERDA is negotiating with Avco Everett Research Laboratories, Inc., on the basis of an unsolicited proposal, 14 October 1975, page 1.

TABLE 2

U.S. GOVERNMENT CONTRACT AWARDS

(Note: This tabulation contains those awards listed in the Commerce Business Daily and other similar publications and news releases which are related to synthetic fuels. In certain instances other awards will be included which relate to the general field of energy sources and related subjects. Depending on the information available, each listing will include a description or title followed by the contract number, the awarding agency, contract value, the contractor's name, and the date of the contract or date the notice was released.)

R & D Investigation of Desulfurization and Denitrogenation of Coal and the Mild Hydrogenation Processes to Produce Clean Liquid and Solid Fuels from Coal, contract E (49-18)-2047 for \$634,407 awarded to Colorado School of Mines, 8 September 1975, page 7.

Evaluation and Engineering Services in Support of a Coal Conversion Demonstration Plant, contract for \$2.9 million let by ERDA in August 1975 to Dravo Corporation, Pittsburgh, Pennsylvania.

Evaluate the Performance of a Liquid Synthetic Fuel in the Sector of a Full-Size FT-9 Annular Burner of a Navy Gas-Turbine Engine Combustion Chamber, Contract N00024-76-C5313 for \$62,274, awarded by Navy Department to United Technologies Corporation, West Palm Beach, Florida, 14 October 1975, page 13.

II

oil shale

TECHNOLOGY

UNION OIL PROPOSES TO DEMONSTRATE ITS "RETORT B" PROCESS AT 7,000 BARREL/DAY RATE

Union Oil Company's announcement that it planned to skip its 1500 TPD demonstration of its SGR process in favor of building a 7,000 BPD "Retort B" facility was noted in the September 1975 issue of Synthetic Fuels.

For those who are unfamiliar with the terms SGR and "Retort B", we present a review of Union Oil Company's oil shale program which explains these terms and which brings into focus the comprehensive shale investigation program which Union has conducted over many years.

Union Controls Prime Oil Shale Reserves

Union Oil Company's oil shale activities span more than 50 years, commencing with its acquisition of oil shale resources in Colorado in the 1920's. Today, Union owns more than 33,000 acres of land in Colorado on which Green River formation oil shale occurs. Some 28,000 acres border Parachute Creek and its upper tributaries in Townships 5 and 6 South, Ranges 96 and 97 West. On this block of privately-owned property, some 20,000 acres can be considered "shale-bearing". The property is estimated to contain in-place reserves equivalent to about 4.5 billion barrels of oil.

A second fee property owned by Union consists of 5,200 acres, of which perhaps 3,200 acres are shale-bearing, and contain in-place reserves equivalent to about 200 million barrels of oil. This smaller property, located in Townships 6 and 7, Range 100 West, is probably of minor importance in Union Oil Company's plans for commercial development. Also of minor importance is a large block of unpatented mining claims covering some 18,240 acres in Township 4 South, Ranges 95 and 96 West. Title to these claims is clouded, and private commercial development of these claims is not to be expected in the foreseeable future. It is the 28,000-acre fee property along Parachute Creek on which developments are expected to occur.

For details concerning the ownership of oil shale reserves in the Piceance Creek

Basin, please refer to the Oil Shale Mineral Right Ownership Map included in the December 1973 issue of Synthetic Fuels.

Union's Retorting Technology is Well-Developed

Union has a solid position in oil shale technology. Oil shale retorting processes have been studied extensively for over 30 years and three variations of a vertical kiln retorting process have been developed. These variations are known as the Retort A, the Retort B, and the SGR (Steam Gas Recycle) processes, and all three feature the use of a novel "rock-pump" which feeds oil shale upward through a retort which has the shape of an inverted cone. The upward flow of shale is countercurrent to the downward flow of gases and liquids. It is the "Retort B" variation which Union Oil now proposes to construct and demonstrate at the 7,000 BPD rate (10,000 tons oil shale feed per day) on the Parachute Creek property in Garfield County, Colorado.

Retort A, Retort B, and SGR Processes Compared

The Retort A oil shale retorting process was developed through 2 TPD, 50 TPD, and 350 TPD (nominal size) pilot plants which were built and operated prior to 1960. The 350 TPD plant actually processed 1,200 tons of shale per day during one demonstration. As shown in Figure 1, Retort A is an inverted cone fitted with the rock-pump shale feeder which pushes oil shale upward through the retort vessel. The retort is open to the air at the top. Shale solids, after having been retorted, overflow the vessel walls at the top. Air enters the bed of shale at the top and supports combustion within the bed of shale. The downward flow of air, combustion product gases, and pyrolysis product vapors is countercurrent to the upward flow of shale solids.

Hot gases, generated in the combustion zone where residual organic carbon remaining on shale fragments burn in air, flow downward and cause pyrolysis to occur in the zone below the combustion zone. The pyrolysis product vapors flow downward and are cooled on the incoming cold raw shale which is being fed into the kiln at

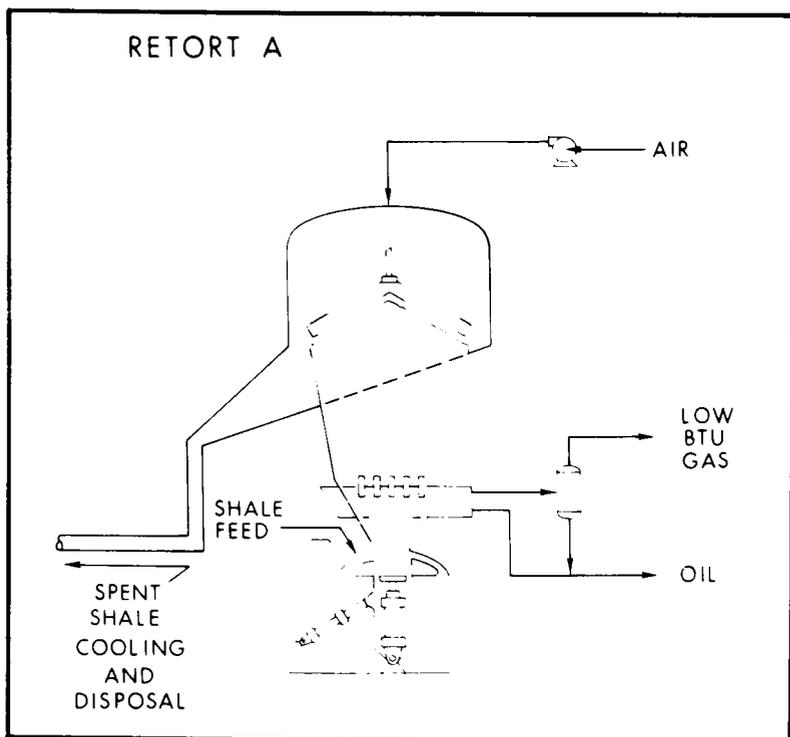


Figure 1. Retort A System

the bottom by the rock pump feeding device. All heat exchange is accomplished by direct solids-to-gas contacting.

Conversely, cold incoming shale is heated as it flows upward through the kiln. Pyrolysis occurs in the pyrolysis zone and combustion of residual carbon occurs in the uppermost zone near the surface of the retort, where spent shale solids overflow the retort rim.

As all three retorting process variations use many of the Retort A process concepts, these concepts will be described in more detail. Figure 2 is a more-detailed sketch of the Retort A process. It may be useful in visualizing the concepts described. Figure 3 depicts the principle of operation of the rock-pump feeder which operates in a manner which will be described.

Shale from feed hopper enters an oscillating piston feeder which forces the shale through the disengaging section located just below the vertical kiln and thence into the kiln proper. As the shale moves upward through the lower portion of the kiln it comes into direct contact with the downward flowing products of retorting. In this portion of the kiln, the products of retorting are condensed and cooled on the raw shale. The raw shale moving

upward from the condensation section next enters the retorting zone where the shale comes into direct countercurrent contact with hot flue gases. The hot gases transfer heat to the shale causing the kerogen to be converted to shale-oil vapors, shale gas, and organic residue. The flue gas sweeps the shale-oil vapors and the shale gas into the condensation zone and the organic residue remains on the retorted shale. The retorted shale continues its upward movement and enters the combustion zone. In this zone the retorted shale contacts a stream of preheated air, and organic residue on the retorted shale is burned; the hot flue gas generated flows into the retorting zone. Temperatures in the combustion zone are high enough (about 2000°F.) to fuse a portion of the shale. Rotating spiral plows were once used to break up the clinkers that are formed and also maintain uniform air distribution as well as a uniform combustion zone. The spiral plow system was ultimately abandoned. The ash from the combustion zone passes through a preheating zone where it preheats the incoming air drawn into the top of the kiln by a suction blower located in the product outlet line. The ash then discharges from the top of the kiln and falls into the ash disposal chute. The shale ash is discharged while hot.

The walls of the retort below the condensation section are slotted to allow separation of the oil and gas from the incoming shale. A bustle surrounds this section and the gas and oil pass through this bustle to the product-recovery system. Note that the shale feeder is constructed so that any fines which pass through the slots return to the feeding piston and are re-introduced into the kiln. Thus, the gas and oil collector does not become plugged with an accumulation of fines. The feeding mechanism is filled with oil to a level just below that of the slot edges, providing a liquid seal which prevents air being drawn into the kiln through the shale feeder. The liquid oil level in the retort is established by the location of the retort exit line through which the oil product drains from the retort to the bottom of a Roto-Clone collector. The gaseous products of retorting also pass through the Roto-Clone collector where large droplets of entrained

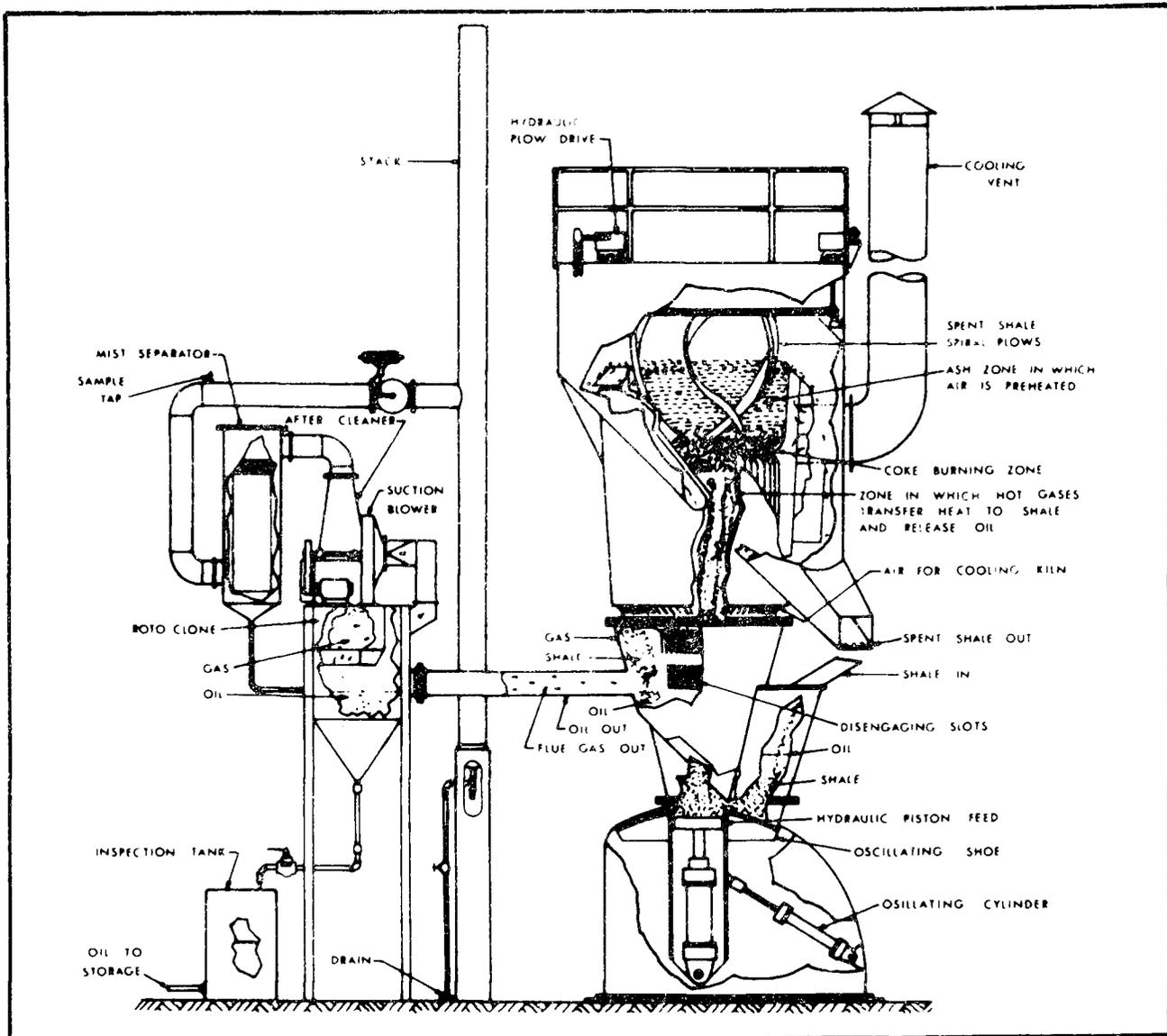


Figure 2. Detailed View of the Retort A System

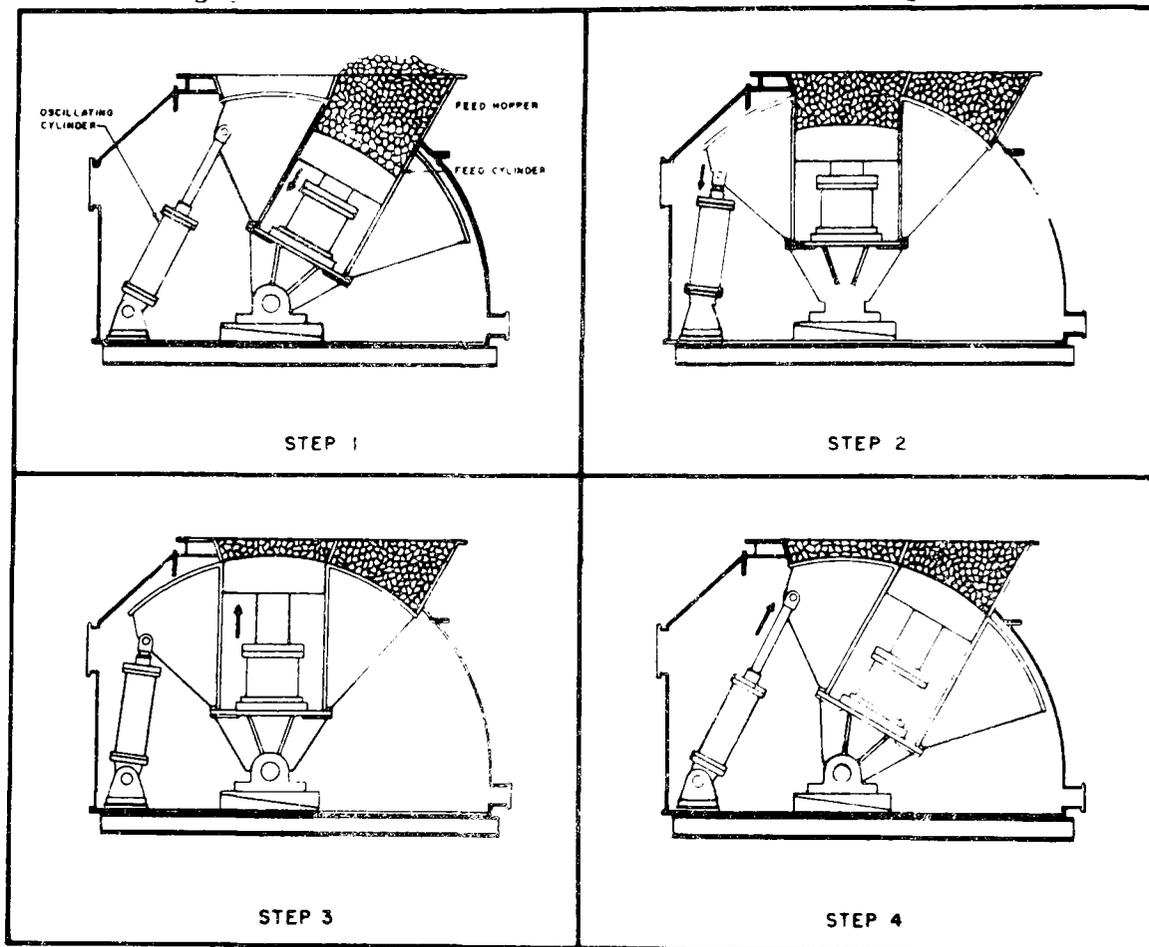


Figure 3. The Rock-Pump Shale Feeder

oil are separated from the gas stream. From this collector, the product gases flow through an ultrasonic chamber wherein oil mist particles are agglomerated. The gas stream next passes through a Roto-Clone blower which separates the agglomerated mist particles from the product gases. The gases then flow through an after cleaner, thence to a second blower which discharges into the stack. Entrained oil and oil mist recovered drain to the Roto-Clone basin where they mix with the liquid oil draining from the retort. The basin is equipped with a standard sludge ejector to remove shale fines and sediment which settle from the product oil. The oil product drains from the collection basin to inspection tanks from whence it is pumped to storage.

The demonstration of the Retort A process was extensive. Union built and operated the retort at the Parachute Creek location during the 1950's. An underground room-and-pillar mine was opened to provide the oil shale required.

An analysis of the crude shale oil from the Retort A process is presented in Table 1. For comparison purposes, Table 1 also contains analyses of the oil produced by the Retort B and the SGR processes.

The Retort B oil shale retorting process, which will be used in the proposed 7,000 BPD prototype plant, is shown in Figure 4.

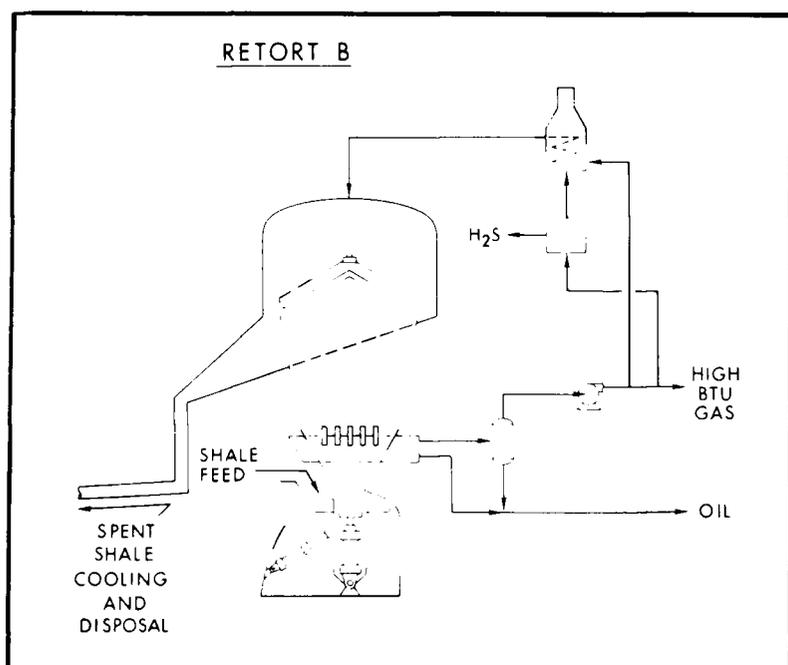


Figure 4. Retort B System

It uses much of the same equipment required in the Retort A process. The main difference between the "A" and "B" processes is that a portion of the retort off-gas stream is heated in an external furnace and the hot gas is reintroduced into the retort to provide all necessary heat for retorting the shale. A minor difference is that the rock-pump shale feeder has been redesigned to be capable of feeding 10,000 TPD of oil shale to the retort. Figure 5 shows the "Retort B" kiln design and the redesigned rock-pump feeder in more detail than is presented in Figure 4.

Sized and screened oil shale is continuously drawn through a shale oil seal in the feed chute and pumped into the bottom of the cone. The oil shale moves uniformly up through the cone to form a free-standing pile on top of the retort bed. Retorted shale falls by gravity from the top surface and may be assisted by a light-weight rake which is rotated above the top surface of the bed. The retorted shale is then discharged into a collection and cooling system not shown on the figure. Quenched and saturated retorted shale is removed from a water seal by a drag-chain conveyor and carried to a discharge point for solids disposal. The top of the retort cone is enclosed by a pressure dome which permits system operation at a nominal 15 psig. A series of vertical slots cut around the perimeter of the lower cone wall provides the openings for disengaging the condensed shale oil and retort vapors from the solids beds. The oil and gases then separate and leave through different nozzles.

Oil is liberated from oil shale by pyrolysis by heating the shale to about 900°F. As shale passes through the retort in the manner just described, a stream of hot recycle gas from the recycle gas heater flows into the retort dome and passes down through the upflowing bed of solids. The oil shale is heated by counter-current direct contact with the hot gas and the shale oil is educted as a vapor. The mixture of oil vapor and recycle gas is cooled by contact with the cold incoming shale in the slower portion of the retort cone. About 75 percent of the oil vapors condense in this zone and run out of the bottom of the bed to collect in the disengaging section which surrounds the lower cone.

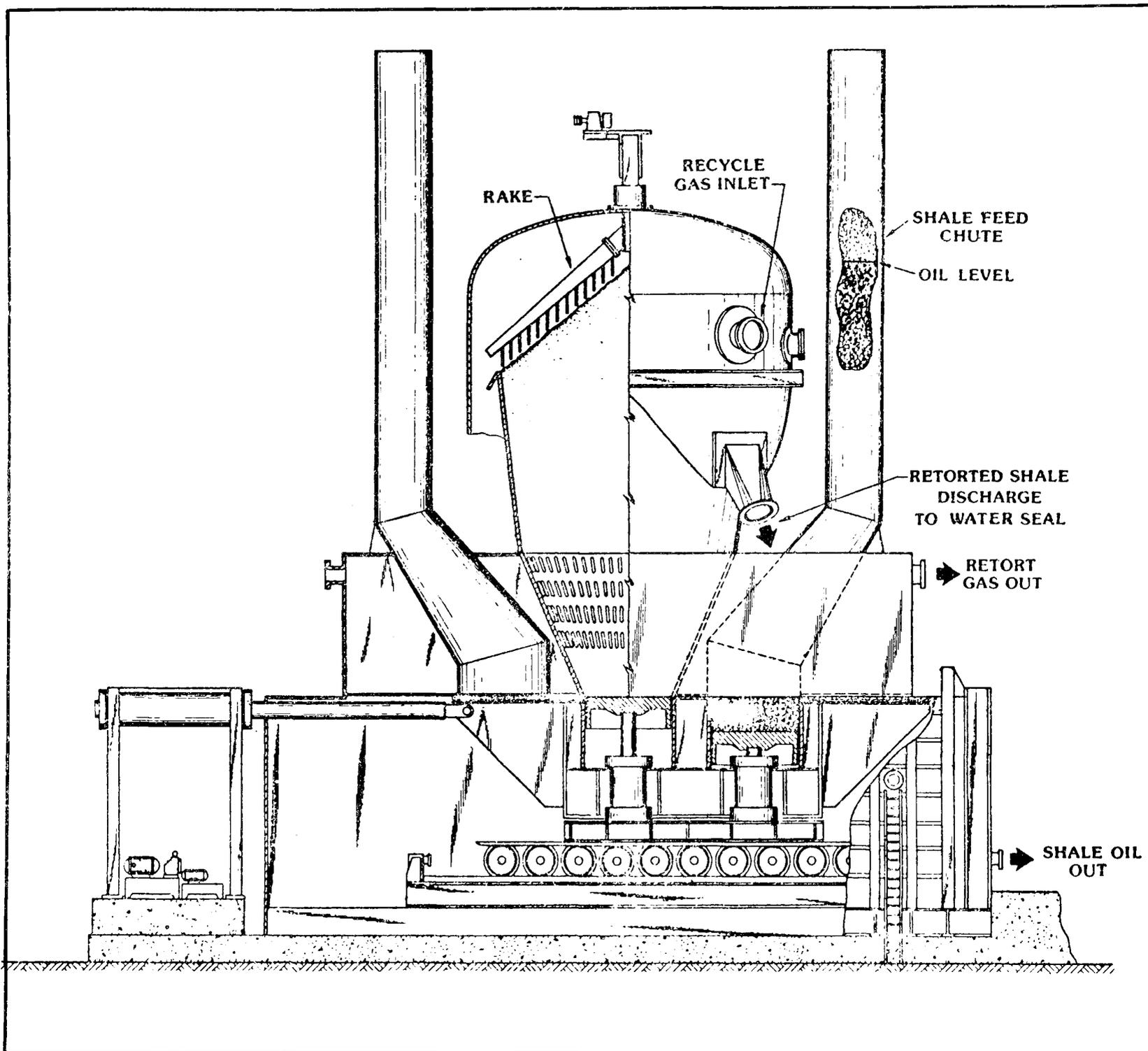


Figure 5. The Proposed 7,000 BPD Prototype Retort B Facility

Rundown oil is produced from the disengaging section on level control. Non-condensables, such as light ends oil vapors and mist, flow from the disengaging section to a Venturi scrubber for cooling and oil removal. A portion of the scrubbed high BTU gas is sent to a conventional gas treating system for sulfur removal prior to use as plant flue gas. The remaining gas is recycled to the retort through the recycle gas heater by the recycle gas centrifugal compressor and provides the heat for retorting the shale.

Union claims that the Retort B process produces as much as 103 percent of the Fischer assay oil content of shale feed, providing that butanes and heavier products are recovered from the off-gas stream. The Retort B process is said to produce enough gas to make the proposed prototype plant self-sufficient in fuel requirements. The percentage of energy in the oil shale feed that ends up as useful products, after deducting energy requirements for self-sufficiency, is said to be about 78 percent.

Table 1 gives the properties of Retort B process shale oil.

The SGR (Steam Gas Recycle) process was first described by Union's Chairman and President, Fred L. Hartley, before the Oil Daily's Third Annual Synthetic Energy Forum in June of 1974 and before the Colorado Interim Legislative Oil Shale Committee later in 1974. The process, shown in Figure 6, is taken from Hartley's presentation. The SGR process was intended to provide a higher thermal efficiency than either the Retort A or Retort B processes, being 82 percent compared with 73 percent for the Retort B process.

The SGR variation uses the same retort design as does the original Retort A process. The process changes consist of enclosing the top surface of the retort vessel to exclude air, sending the spent shale to a separate gasifier vessel where oxygen and steam react with (gasify) the residual carbon to produce hot recycle synthesis gas which then is injected into the retort to provide heat to retort the incoming oil shale.

No process data are available for the SGR process except that the gasifier operates at 1600°F and the retort operates at 970°F.

TABLE 1

PROPERTIES OF CRUDE SHALE OIL FROM RETORTING PROCESSES
DEVELOPED BY THE UNION OIL COMPANY

	Processes			Fischer Assay Oil
	Retort A	Retort B	SGR	
Gravity, °API	18.6	22.7	21.5	24.2
Carbon, wt. %	84.0	84.8		84.7
Hydrogen, wt. %	12.0	11.61		11.7
Nitrogen, wt. %	2.0	1.74	1.8	1.6
Sulfur, wt. %	0.9	0.81	0.7	0.7
Oxygen, wt. %	0.9	0.90		
Ash, ppm		50		
Conradson carbon, wt. %	5.6		1.8	2.5
Flash Point, °f	192 (COC)	79 (PMCC)		
BTU/lb		18,437		18,680
Pour Point, °F	80	60	70	70
Viscosity, SUS @ 100°F	210	98.2		
Distillation, mod. Engler, °F				
1BP		139		
10	465	400		
50	775	731		
90		960		
EP		1077		

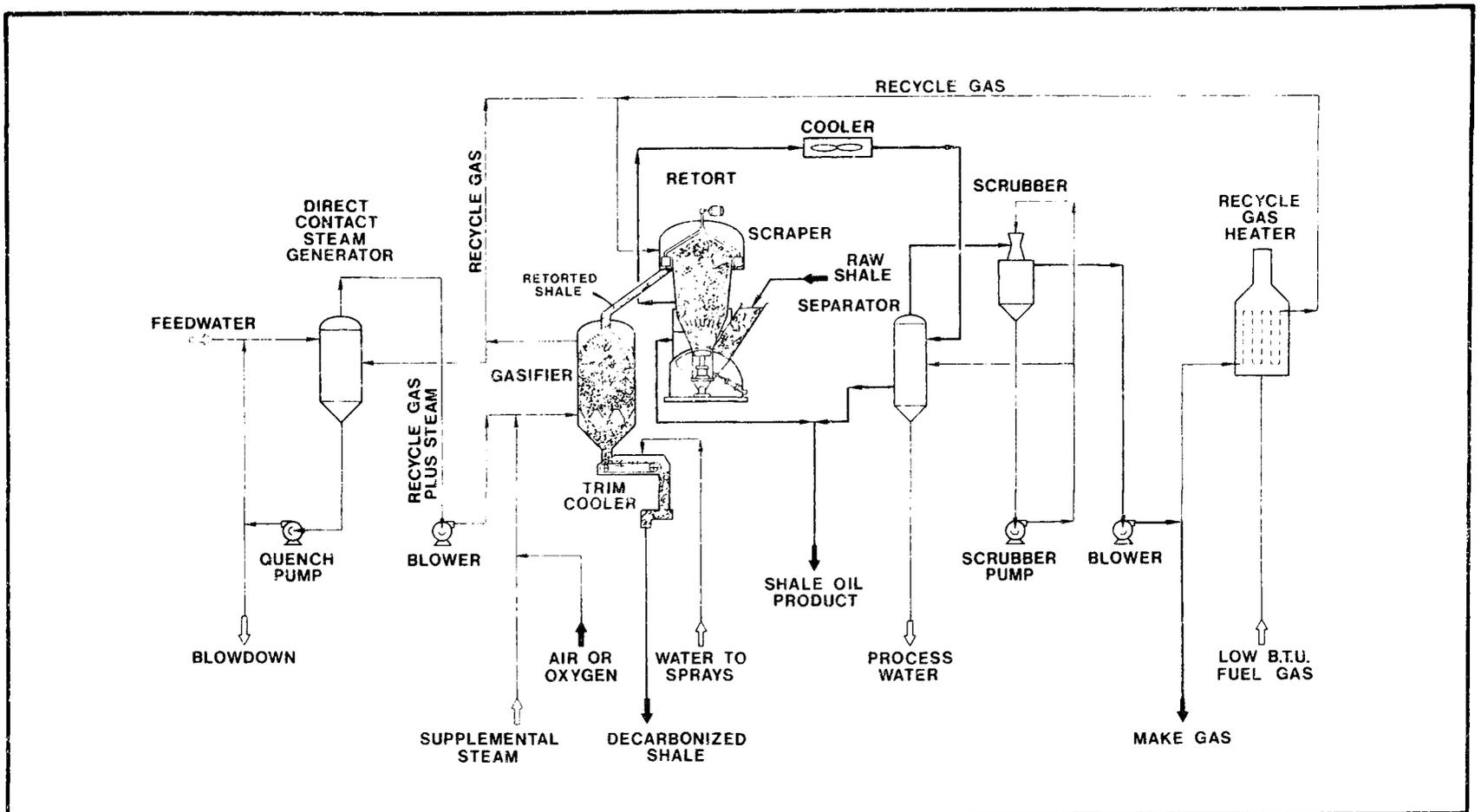


Figure 6. SRG Retorting Plant

Comparison of Properties of Crude Shale Oil From Retort A, Retort B, and SGR Processes

Table 1 presents the properties of the crude shale oil produced by the three retorting processes developed by Union Oil Company. For comparison, the properties of oil from the Fischer assay are also shown.

#

ARCO PATENTS METHOD OF REMOVING CATALYST-POISONING IMPURITIES FROM SYNTHETIC CRUDE OIL

Atlantic Richfield Company has acquired U.S. Patent 3,876,533 entitled, "Guard Bed System for Removing Contaminant From Synthetic Oil". This invention relates to a method of removing catalyst-poisoning impurities, such as arsenic and selenium, from synthetic crude oil or synthetic oil fractions obtained from shale oil.

The process involves several steps.

First, a guard bed is prepared consisting of particles of material that is either iron, cobalt, nickel, oxides or sulfides of these metals, or a mixture thereof. Next, the raw shale oil is admixed with hydrogen and flowed past the particles of material at a temperature and pressure great enough and with a residence time sufficient to allow the contaminant to be removed from the synthetic crude oil and be deposited on at least the surface layer of the particles of material. As the surface layer of the particles becomes substantially saturated with the contaminant, they are removed from the surface of the particles as small fines, entrained in the fluid stream and flowed from the guard bed. The small fines which hold the contaminant are separated from the hydrocarbonaceous fluid from which the contaminant has been removed. Thereafter, the hydrocarbonaceous fluid is treated as desired.

An interesting facet of this process is that as the surface layer of material becomes saturated with the contaminant,

for example, at a concentration in the range of 15 to 20 percent by weight of active material, the surface layer begins to flake off in small fines to expose new active material. The reason for this automatic flaking off of the surface layers to afford a pseudo automatic regulation of the activity in the system is not understood. The following theory was given by way of explanation. It is theorized that the arsenic is large enough that when it is substituted into the matrix of the material for the sulfur or oxygen, the matrix is disrupted. Once the disruption becomes severe enough, the macroscopic particles, or fines, flake off. The fines are entrained in the fluid stream and carried out through the effluent conduit. Initially, of course, there will be no flaking off of the fines as long as there is sufficient activity in the system. Once the activity begins to be reduced, or diminished, however, the flaking will begin to expose new and more active material, and afford an automatic regulation of the activity.

The fines are carried with the liquid stream into the filter where the fines are removed from the fluid stream by filtration.

#

COSTS OF PRODUCING IN SITU RETORTS IN OIL SHALE BY MINING METHODS ARE STUDIED

A report to Lawrence Livermore Laboratories has been prepared by Laurich Kennedy Associates, under AEC sponsorship, entitled, "A Study of Costs of Producing In Situ Retorts in Oil Shale by Conventional Mining Methods." The objective of this conceptual study was to determine the mining costs of producing rubblized chimneys in oil shale deposits of varying thickness. The parameters which were assumed are set out in Table 1, reproduced from the report.

Various competing layouts and methods of mine operations were produced and studied in detail to gain an understanding of the problem areas and of the factors which will influence costs. As the sub level caving system which is described in this report took shape, it became evident that many of the assumptions that had to

be made were far outside the level of knowledge available and that any conclusions reached as to absolute levels of cost would have to be severely qualified as to their factual basis. On the other hand, the authors believed their study contributed to the understanding of the possibilities and problems of conducting such an operation and of the influence of several parameters on costs.

The principal conclusions drawn were:

- . The sub level caving method of mining offers a reliable and flexible method of producing the required rubble chimneys.
- . The basic cost of producing in situ retorts in 20 gallon per ton oil shale will be in excess of \$3.60 per barrel.
- . The cost of such an operation will rise significantly in shale of less than 600 feet thickness.
- . Any reduction in retort size from the 500 feet square basic case will lead to increased oil costs.
- . Reduction in retort voids ratio will probably reduce costs slightly.
- . Costs will vary extremely widely with the different conditions which exist in various parts of the Piceance Basin.
- . Further studies of this nature will have little value if they are not related to a specific location, and based on an adequate field program of data collection.

#

REPORT DESCRIBES AN OIL SHALE CONVERSION PROCESS WHICH USES CO AND H₂O

The Laramie Energy Research Center of the Energy Research and Development Administration has published Technical Progress Report No. LERC/TPR/75-1 entitled, "An Oil Shale Conversion Process Using Carbon Monoxide and Water". In this report, the authors propose a process by which the kerogen in oil shale is converted to a solvent-soluble product by the carbon monoxide-water reaction.

Because of the success of this method in liquefying coal, lignite, manure,

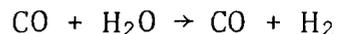
TABLE 1
LIST OF PARAMETERS

Production Rate	100,000 barrels per day
Shale Grade	20 gallons per ton
Shale Oil Recovery	
- surface retorting	95 percent
- in situ retorting	60 percent
Retort Voids Ratio	20 percent. One intermediate thickness to be costed at 15 percent also.
Retort Size - In Plan	500 feet square. One thinner section to be costed at 200 feet square also.
Overburden Thickness	800 feet
Specific Gravity of Oil Shale	2.25
Retort Front Rate of Advance	6 feet per day
Tons of Shale Extracted Per Day	62,500 (approx.)

municipal waste, and other carbonaceous materials at low conversion temperatures, this reaction and its application to oil shale kerogen solubilization is currently being investigated at the Laramie Energy Research Center. This report, LERC/TPR/75-1, is the first to present details of test results.

Process Scheme

The carbon monoxide-water reaction is the well known water-shift reaction which can be depicted by the chemical formula:



Tests at the Laramie Center are said to have shown that the shift reaction, when performed in a closed pressurized vessel in the presence of oil shale, gave significantly higher degradation of oil shale kerogen than did dry heating (pyrolysis) at comparable pressures and temperatures.

The flow diagram of the proposed process is shown in Figure 1, which is reproduced

from the Technical Progress Report.

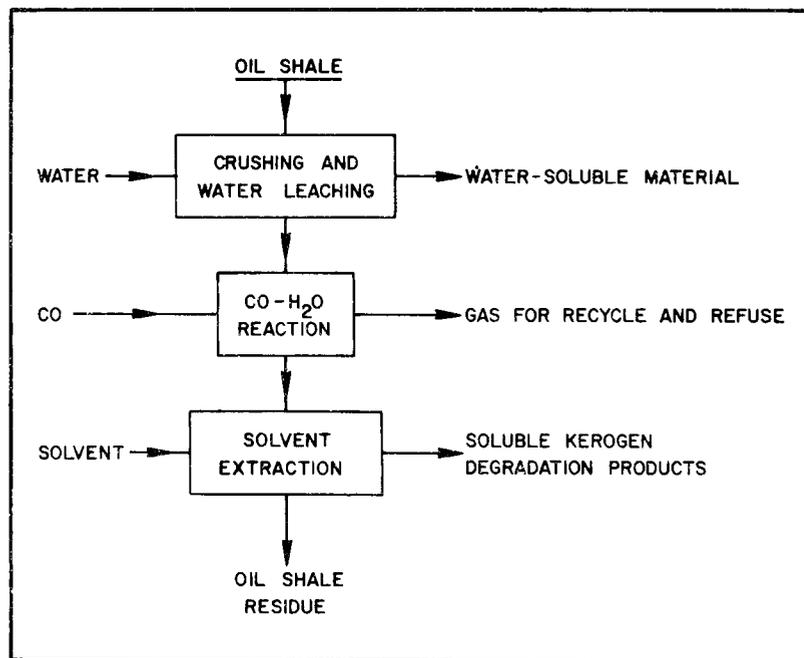


Figure 1. Reaction Process Flow Diagram

As water must be present, it is suggested that this proposed process would be particularly applicable to oil shales that contain water soluble salts, such as nahcolite, which could be recovered by water leaching. The leached oil shale would be charged to a pressure reaction vessel and would be heated to about 400°C (752°F) to 450°C (842°F) in the presence of water and carbon monoxide. Pressures would range from 2000 to a maximum of 4000 psig. About 0.4 pound water would be required per pound of oil shale processed. At 400°C, the amount of kerogen converted to solvent-soluble products equals the amount of oil obtained by the Fischer assay. This happens to average about 65 percent. At 450°C, the amount of kerogen converted to soluble products exceeds the Fischer assay.

The average composition of residual gases in weight percent from a run at 500 psig and 400°C was:

CO	10.3
CO ₂	50.8
H ₂	38.7
CH ₄	0.09

Table 1, reproduced from LERC/TPR/75-1, summarizes the results of eight tests.

The solvent used to extract the solubilized organic material is a mixture of methanol and benzene. Following filtration and drying, the final solid waste material is essentially free of any material that could be leached by atmospheric or underground waters.

#

LERC STUDIES THE ANOMALOUS HEATING BEHAVIOR OF LARGE SHALE BLOCKS

The Laramie Energy Research Center is studying the anomalous heating behavior of large oil shale blocks during retorting in the 150-ton retort. The abnormal behavior was observed during studies on the effects of: (1) oxygen content of retorting gas, and (2) the superficial gas velocity of the retorting gas on oil recovery by retorting mine-run oil shale in a 150-ton retort, as reported by A. E. Harak, L. Dockter, A. Long, and H. Sohns, in "Oil Shale Retorting in a 150-ton Batch-Type Pilot Plant,"

TABLE 1
PERCENT OF KEROGEN CONVERTED TO DEGRADATION PRODUCTS
USING THE CO-H₂O REACTION

Run	Temperature °C	Heating time, hrs.	Kerogen converted, wt pct ¹		
			Gas	Soluble product ²	Total
5	375	2	1.2	40.9	42.1
6	375	3	.8	52.2	53.0
7	400	.25	2.0	66.3	68.3
8	400	.50	3.0	65.8	68.8
9	400	.75	2.3	68.7	71.0
10	450	.25	9.4	87.8	97.2
11	450	.50	13.1	84.3	97.4
12	450	.75	16.1	79.7	95.8

¹ A rich oil-shale sample (66 gal/ton).

² Total kerogen converted minus the amount of gas formed.

BuMines Report of Investigations 7995, 1974. In a number of the previous tests, the interiors of large oil-shale blocks weighing as much as four, or more, tons were observed to heat up "as fast or perhaps even faster than the surrounding shale bed," according to A. E. Harak, L. Dockter, and H.C. Carpenter in "Some Results From The Operation of a 150-Ton Oil Shale Retort," BuMines TPR 20, 1971. These heating anomalies, while frequent, did not greatly diminish the ultimate recovery of oil.

In the current study of this peculiar heating behavior, two huge blocks of Mahogany-zone oil shale were mined during August 1975 at the USBM Anvil Points Oil Shale Facilities near Rifle, Colorado and are being used in retorting tests at Laramie, Wyoming. Block 1 measured about 4 by 6 by 4 feet, weighed 12,560 pounds, and had an average grade of 25 gallons of oil per ton. Block 3 had about the same dimensions as block 1 except it was only 40 inches high. It weighed 9,800 pounds, and had an average grade of 35 gallons of oil per ton.

In cooperation with Lawrence Livermore Laboratory, the blocks were instrumented to monitor internal temperatures and pressures. Thermocouples were inserted at the center of the top and near one corner of each block to depths that were one-third and two-thirds the thicknesses of the blocks. Other thermocouples were arranged adjacent to each fact of the blocks to measure gas temperatures surrounding the blocks. Four pressure taps were inserted in the blocks to measure internal rock pressure.

By packing with mine-run oil shale that assayed 24.4 gallons of oil per ton, the blocks were placed near the bottom and top of the 150-ton retort as shown in Figure 1. Retorting of the oil-shale charge was started on October 15 at the same conditions used in the previous run 5, namely, the circulation of air (containing 21 percent oxygen) at a superficial gas velocity of 1.25 scfm/ft² of bed. Under these conditions, the combustion front of the oil shale charge progressed slowly downward through the retort at a temperature of 800° to 1000°F. Two days later as the front approached block 3, the temperature within the block increased suddenly from an ambient

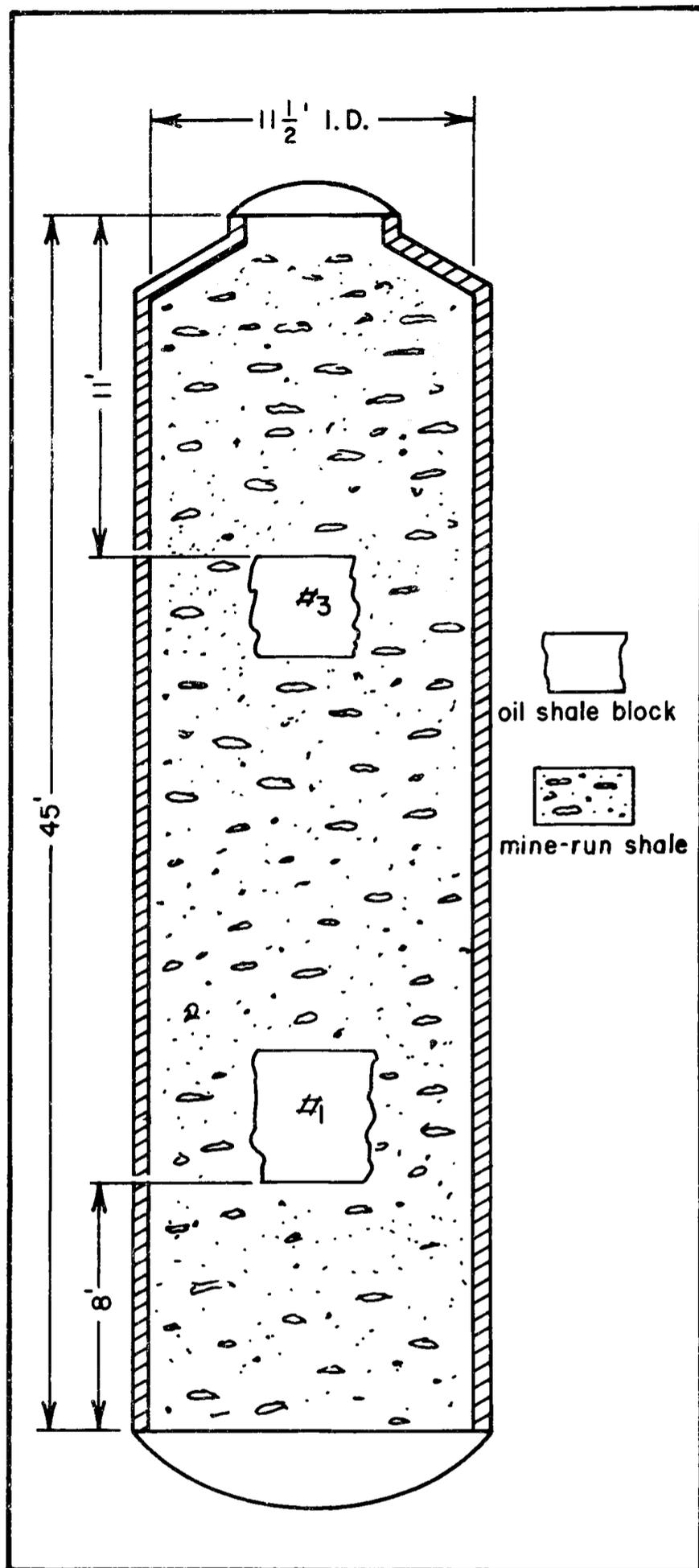


Figure 1. Positioning of Large Oil Shale Blocks in 150-Ton LERC Retort.

temperature of 150°F to a maximum temperature of 1400°F during a period of 2 1/2 hours. (The rock temperature increased at a rate of about 8°F per minute. At this time, the temperature of the block exceeded the surrounding temperatures in the retort. No pressure build-up in the block was observed and the oxygen content of gas surrounding the block was less than one percent. The temperature of the block remained constant at 1400°F for at least two days; the temperature then slowly declined as the combustion front progressed downward through the retort.

Six days later (eight days after starting the test) an even more spectacular surge in the rock temperature was observed. The temperature in block 1 jumped from an ambient temperature of 180°F to a maximum temperature of 1400°F in a period of only one hour (a temperature increase of 20°F/minute). At this time, the temperature of the gas surrounding the block was less than 1400°F and the gas contained less than one percent oxygen. As observed in block 3, which was a richer but smaller block of shale, the temperature of block 1 remained constant at 1400°F for two days or until the test was stopped after a run of ten days.

Preliminary Results Promising

It will be several weeks before the retort cools sufficiently to permit analyses of the spent shale residue and other products of the retorting test. However, in the previous published runs essentially all of the large blocks were completely retorted and their huge sizes did not greatly reduce the ultimate recovery of oil. For this reason, the abnormal heating behavior may have some application to the in situ retorting of oil shale. Publication by LERC of detailed results on the current retorting test, together with an explanation for the abnormal heating behavior is awaited with interest.

#

UNDERGROUND MINING OF OIL SHALE IN THE PICEANCE CREEK BASIN STUDY REPORT MADE TO BUREAU OF MINES

The technical phase of a report on "A Technical and Economic Study of Candidate Underground Mining Systems for Deep, Thick

Oil Shale Deposits" of the Piceance Creek Basin, Colorado, was completed in July for the U.S. Bureau of Mines. The study is based on parameters of 85,000 TPD operation expandable to 170,000 TPD. It will comply with federal mine health and safety standards, according to the authors, Cameron Engineers, Inc., of Denver, Colo. The Piceance Creek Basin requires mining systems capable of handling large quantities of water inflow. Underground disposal of spent shale was evaluated. High resource recovery, minimal environmental impact, and currently available or technically feasible equipment were also study factors.

The geology and hydrology of the Piceance Creek basin, resource evaluation, selection of a prototype mine site, compilation and interpretation of rock mechanics data, investigation of large underground mining systems, preliminary cost data, environmental assessment, ranking the respective systems are major features of the work.

Geology and Hydrology

The study notes the oil shale deposits of the Central Piceance Creek Basin are overlain by 600-1400 feet of overburden. The oil shale beds themselves are up to 2,000 feet thick in the Green River Formation, which is in turn composed of the Parachute Creek, Garden Gulch, and the Douglas Creek members. The Parachute Creek member is the thickest, varying from 500 feet along the periphery of the basin to more than 2000 feet thick in the north central portion.

Hydrologic studies revealed an upper and a lower aquifer. The net inflow into an underground mine project is 4,000 GPM.

Engineering Properties of Green River Oil Shale

The relative strength of the shales vary with oil content. As oil content increases the rock becomes more plastic and generally weaker. Published analyses of the engineering properties of oil shale have been on shales averaging 25 GPT from the Bureau of Mines Anvil Points mine several miles to the south where the shales outcrop. Since virtually no published data are available for deep oil shale deposits, design parameters

TABLE 1
SUMMARY OF MINING SYSTEM COSTS

Mining Method*	Net Capital Investment (\$)	Annual Costs					Total Annual Cost (\$/ton)	Preprod. Cost (\$)
		Labor & Supervision (\$/ton)	Operating (\$/ton)	Power (\$/ton)	Consolidated Miscellaneous per ton cost	Fixed (\$/ton)		
1	113,434,100	0.26	0.33	0.13	0.19	0.23	1.15	30,002,000
2	96,335,300	0.27	0.32	0.13	0.20	0.20	1.12	15,968,000
3	77,200,000	0.27	0.24	0.12	0.20	0.18	1.04	3,469,000
4	119,963,000	0.43	0.26	0.14	0.26	0.22	1.31	34,773,000

*1 Sublevel stoping with full subsidence.

*2 Sublevel stoping with spent shale backfill.

*3 Chamber and pillar.

*4 Block caving with slushers.

Compiled from "A Technical and Economic Study of Candidate Underground Mining Systems for Deep, Thick Oil Shale Deposits (Phase I) July, 1975.

were based on basin core sample data from the Anvil Points mine and outcrops around the perimeter of the basin.

Mining Systems

Eight mining methods were examined. Four were acceptable based on total evaluation of resource recovery, geologic, hydrologic, economic, environmental, health & safety and rock mechanics factors.

The report recommends chamber and pillar mining as most feasible. The second and third choices were sublevel stoping with spent shale backfill and sublevel stoping with full subsidence, respectively. The fourth method was block caving with slusher equipment. (See Table 1 for cost data.)

Mine Access and Underground Crushing

To obtain comparable data a theoretical mine was simulated with mine access via vertical shafts ranging from 12 to 28 feet inside diameters.

Since oil shale, when blasted, produces large fragments, secondary breaking is necessary. All the mining methods studied reduce shale to minus 10-inch size. The chamber and pillar method used portable crushers prior to conveyor belt hauling. The other methods employed gyratory crushers, railroad haulage and rotary car dumpers emptying into the crushers. The crushed shale goes to an ore pocket for hoisting to the surface.

Chamber and Pillar

Chamber and pillar mining as designed calls for sinking five shafts to the bottom of the ore zone. Five entries are driven North and South 60 feet from the top of the ore zone (Figure 1). A total of 12 chamber crosscuts are modeled. They are 100 feet wide by 60 feet high. A 100-foot pillar is left for support. A production rate of 85,000 TPD is accomplished by mining the 12 chambers simultaneously.

The preproduction development time for chamber and pillar is the lowest of any of the methods investigated -- 39-days. The \$77 million capital investment was the lowest of any method studied. The spent

shale is slurried and pumped back into the mined out chambers. The cost of \$1.04/ton was the lowest of any mining method studied. The major shortcoming of chamber and pillar mining is low percentage of reserve extraction (65 percent).

Sublevel Stoping With Spent Shale Backfill

The second method was sublevel stoping at the 1000-foot level with spent shale backfill (Figure 2). A block 480 by 640 feet is outlined by crosscuts and drifts. A network of 55 blocks each 960 feet by 480 feet is created. Each block is divided into eight parts.

While the 1000-foot level is being developed, a second level at a depth of 1320-feet also is being developed the same way. The ore in each stope is drilled out from the 1,140-foot sublevel. Access to the sublevel is by inclines at the ends of the outlined ore body. The ore from each stope is loaded into rail cars by front end loaders. The stope is backfilled with spent shale slurry. The capital investment was computed at \$96.3 million and the per ton cost at \$1.12 based on 90 percent reserve recovery.

Sublevel Stoping With Full Subsidence.

The sublevel stoping system with full subsidence is identical to sublevel stoping with backfill except for the undercut level. The undercut (1000-foot level) in the full subsidence system is a subsequent step of a room-and-pillar mining system. The pillars are blasted and allowed to cave into the stopes below (Figure 3). The capital required was calculated at \$113.4 million. Based on 95 percent reserve recovery, the per ton cost was \$1.15.

Block Caving With Slusher Equipment

In block caving mining which also uses the room and pillar approach on the undercut level, slushers load the shale into railroad cars for hauling to the crushing and hoisting facilities (Figure 4).

Production starts when the cones are completed and the pillars are blasted from the undercut and caving commences. A total of nine blocks with a draw rate of 18-inches per day are required to attain 85,000 TPD

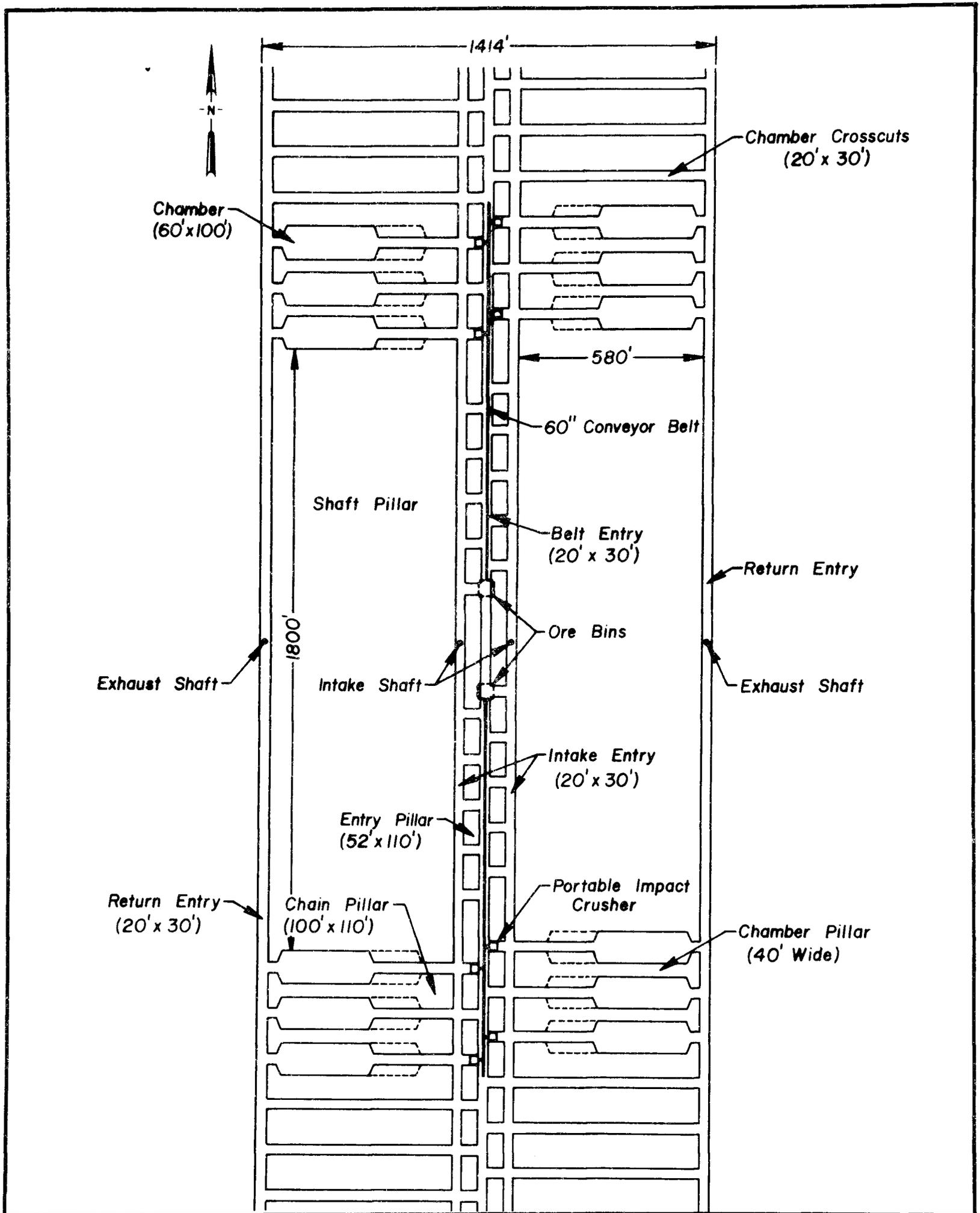


Figure 1. Plan View of Production Layout, Chamber and Pillar Mining

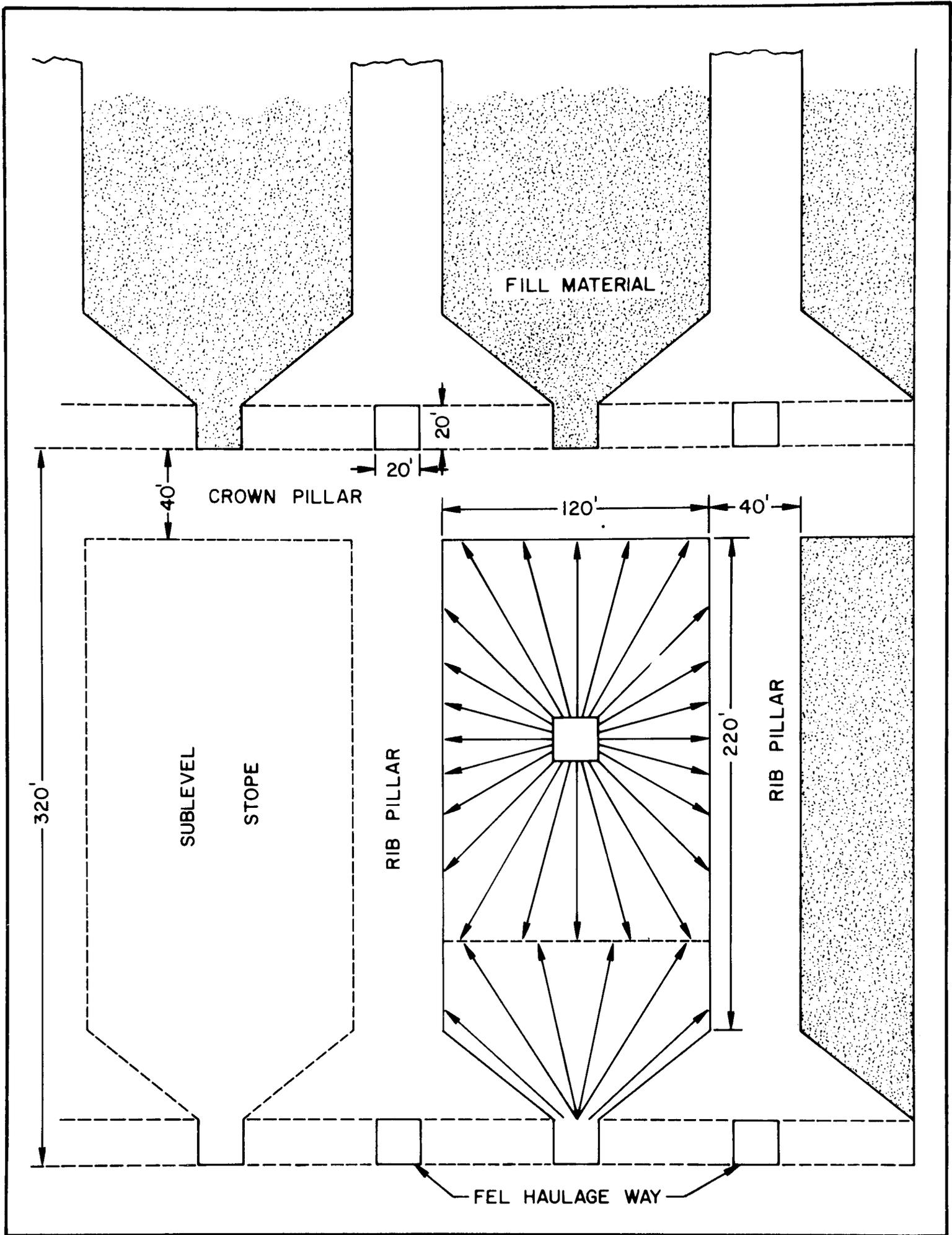


Figure 2. Vertical Section Through A-A', Sublevel Stoping with Spent Shale Backfill

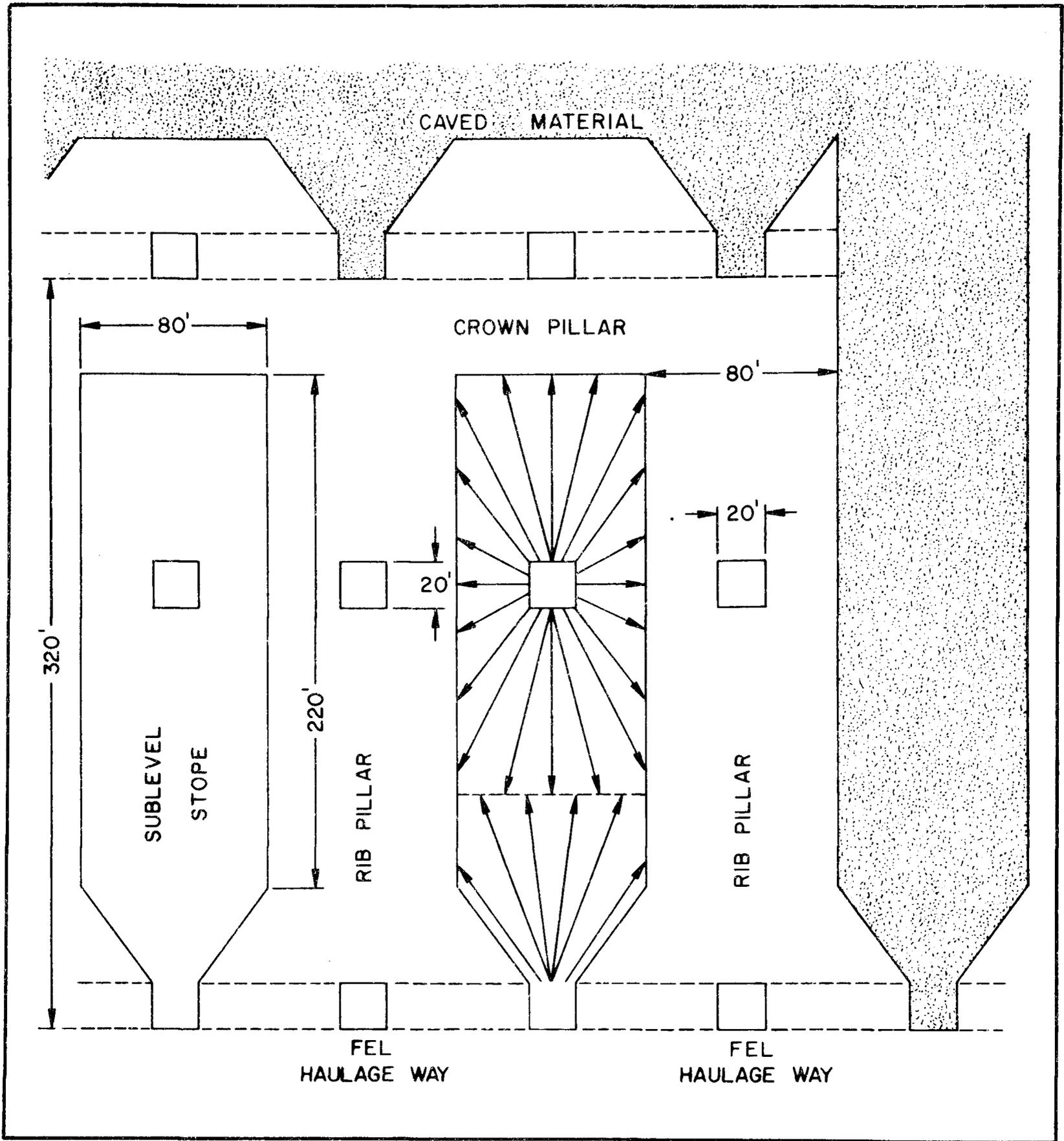


Figure 3. Vertical Section Through B-B', Sublevel Stoping with Full Subsidence

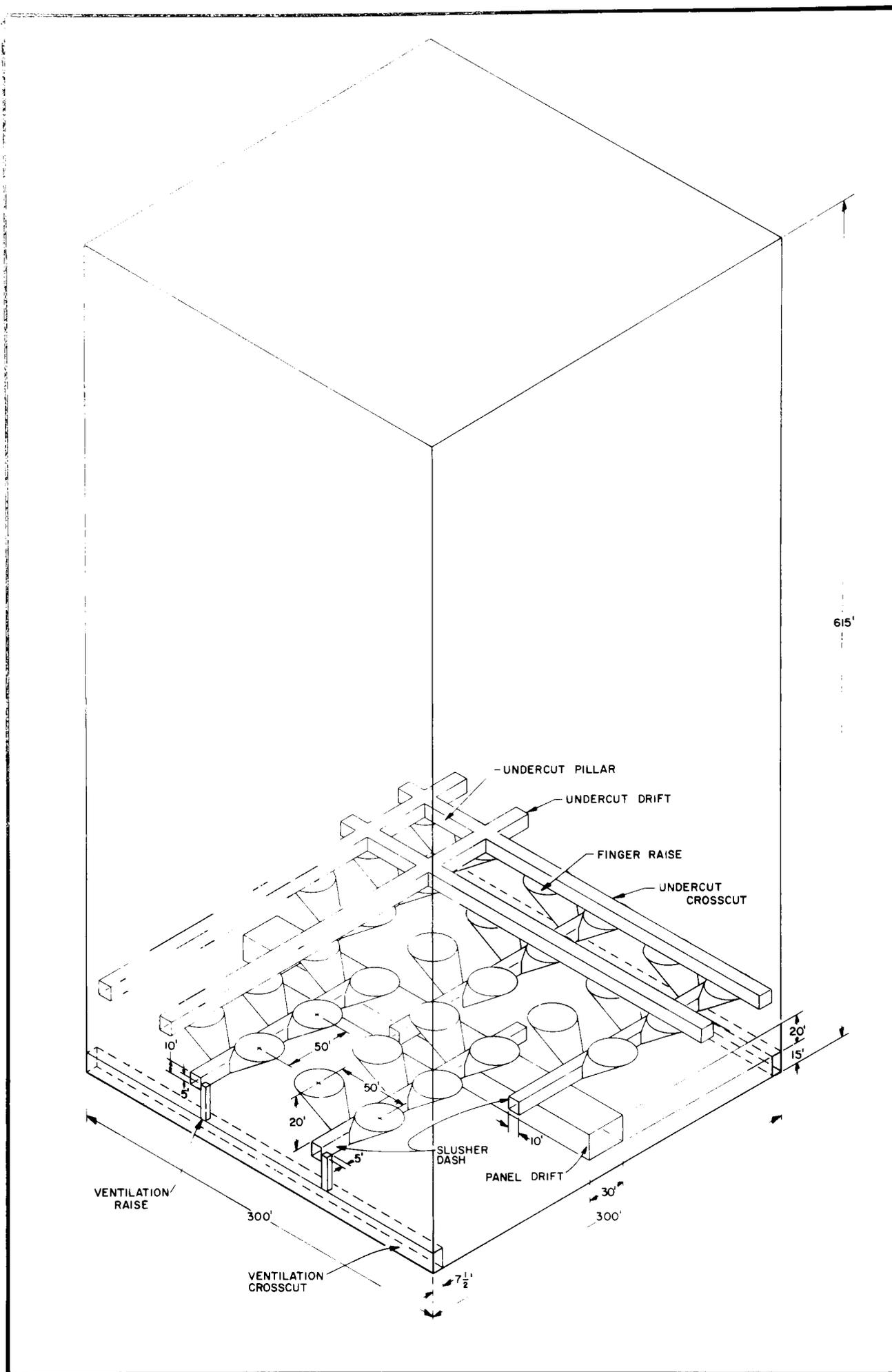


Figure 4. Isometric View of Block Layout Within a Panel, Block Caving With Slushers

production, according to the study.

This method would require \$119.9 capital expenditure and obtain 95 percent reserve recovery at a per ton expense of \$1.31.

Safety Included

One objective in studying each of the mining systems was to design a safe mining method applicable to gassy conditions.

Ranking of Mining Systems

The authors used "Dare" (Decision Alternative Ration Evaluation) System which was used to ascertain the most feasible mining method. It allows many factors such as resource recovery, health and safety, overall feasibility, and environmental impact to be evaluated.

Applying the "Dare" system gave the following ranking:

- . Chamber and pillar mining.
- . Sublevel stoping with spent shale backfill.
- . Sublevel stoping with full subsidence.
- . Block caving with slusher equipment.

Conclusions and Recommendations

The report concludes that large scale underground mining of oil shale in the Piceance Creek Basin is technically feasible.

Detailed mine designs and an economic analysis are in preparation as Phase II of the 2-part study.

#

COURT ORDERS FULL HEARINGS, BY INTERIOR, ON ALL OBSTACLES TO PATENTING OF OIL SHALE CLAIMS

In an effort to bring a host of oil shale civil action cases to a conclusion within a reasonable time frame, the Tenth Circuit U.S. Court of Appeals in Denver, on September 22nd, issued an "Order of Remand" which represents a major development in these protracted litigation proceedings.

Directly involved in the Order of Remand are the combined Civil Action Cases 8680, 8685, 8691, and 9202. Also involved are Civil Action Cases 9252, 9258, 9461, 9462 and 9425 which have been held in abeyance by the courts until the combined civil actions directly involved have been resolved.

The issues in all of these cases are similar and concern "satisfactory performance of assessment work" on unpatented oil shale mining claims.

In brief, the plaintiffs in these civil action cases are claimants to unpatented oil shale mining claims. They have been attempting, over a period of years, to obtain patents (titles) to their claims from the Department of the Interior. Interior had opposed issuing patents for several years, which was a change from earlier policy. Interior's opposition to issuing patents hardened when, in 1964, the Secretary of the Interior (Stewart L. Udall) acted on two matters relating to unpatented oil shale claims. These actions were, (1) the issuance of a legal opinion by Solicitor Frank Barry which rejected patent applications for 257 specific claims, and (2) the issuance of a directive to the Bureau of Land Management to identify and determine the status of all oil shale mining claims in Colorado, Wyoming and Utah and to begin contest proceedings against claimants to "clear title" to the lands.

In subsequent years, Interior has initiated contest proceedings against all claimants who could be identified. Many of the claimants have resisted rejection of their patent applications by exercising

all administrative remedies possible within Interior. When this failed, the claimants (represented in the court action cases previously cited) resorted to the courts.

The resulting litigations have been protracted. The cases have progressed through the U.S. District Court of Denver, the Appeals Court in Denver, the U.S. Supreme Court back to the Appeals Court which in turn remanded the matter back to the District Court with instructions to consider each mining claim on its own merits, but to do this in light of the Supreme Court decision.

Interior, in each of these cases, is contesting title to the mining claims only on one narrow issue, that being the satisfactory performance of annual assessment work. Many other possible issues, such as fraud, abandonment, lack of valid discovery, etc., have not yet been addressed. Hence, the probability exists that litigation could be continued indefinitely, with each separate issue slowly working its way up the court system to the U.S. Supreme Court, then back down the court system, as has been the case on the assessment issue.

Finally recognizing this, the U.S. Court of Appeals issued the Order of Remand dated September 22, which will be discussed here. For details on the prior events, however, Table 1 is presented as a guide to explanatory documents.

The Order of Remand is Examined

The September 22nd Order of Remand has a preamble that starts with the recognition that the first stage of this litigation focused on the narrow issue of assessment work, an issue that ultimately was decided adversely to the claimants by the U.S. Supreme Court. However, the assessment work contests are also recognized as being simply one ground for challenging claimants' right to patent. Other issues representing possible obstacles have not yet been the subject of any administrative hearing or court adjudication.

Recognized also is the fact that the litigation has been protracted. Some

claimants have sought patents since 1955.

Concluding that good judicial husbandry demands that litigation be brought to a conclusion within a reasonable time frame and recognizing that validity or invalidity of the claims cannot be determined by any decision the Appeals Court or Supreme Court could make with the case in its present posture, the Order of Remand was issued.

The cases are now before the U.S. District Court in Denver, with instructions to the Department of the Interior, to proceed "on an expedited basis" with examination of any and all bases for invalidity of the claims and to rule on these bases. Following the proceedings in Interior, the District Court is instructed to supplement its present findings as is needed to dispose of any new matters presented.

A copy of the Order of Remand is presented in the Appendix of this issue of Synthetic Fuels.

Comments

We estimate that 271 mining claims are directly involved in these civil action cases. Each claim covers about 160 acres, so some 43,300 acres are involved.

It is encouraging that the Courts have decided to act in a manner which will resolve the entire claim ownership matter "within a reasonable time frame."

Interior is facing, possibly, a mammoth task in examining and ruling upon all of the possible issues and doing this on an expedited basis. It is possible that a lot of evidence could be presented for consideration. In fact, in Bureau of Land Management Contest 359/360, a precursor of one of the civil actions here involved, several years time were consumed and a veritable warehouse full of evidence was accumulated on just one issue.

The effects of these civil action cases upon the Prototype Oil Shale Leasing Program should be minimal. Most leasing sites selected by Interior were clear of locations covered by claims involved in these Civil Actions. However, some of the contested claims are near Oil Shale Prototype Program

lease tracts and could have some side effects on tract developments related to off-site facilities such as roads, pipelines, rights-of-way, disposal sites, etc.

#

TABLE 1

DOCUMENTS WHICH DEFINE POLICIES RELATING TO
OWNERSHIP OF CONTESTED OIL SHALE MINING CLAIMS

<u>Document</u>	<u>Provisions</u>
The Mining Law dated 1872	These laws, as amended, provide for the location of unpatented mining claims on the public domain and for patenting the claims if certain requirements are met.
The Mineral Leasing Act dated 1920	This Act withdrew most mineral fuels from the provisions of the 1872 Mining Law and classified oil shale deposits as a leaseable material. Rights of owners to mining claims which were in good order were specifically protected.
Executive Order #5327 dated 1930	Withdrew oil shale temporarily * from leasing or other disposal and reserved oil shale deposits for investigation, examination and classification. *This "temporary" withdrawal of 45 years ago was tested in the courts in 1966/1967. The U.S. Court of Appeals (10th Circuit, Denver), ruling on an appeal by Alan Mecham of Salt Lake City in Civil Action C-22-65, ruled that, "We cannot say that from the government's viewpoint and considering its permanence compared to the life of man and the significance of oil shale as a natural resource, that this has not been temporary."
Executive Order #6016 dated 1930	Modified Executive Order #5327 to permit issuance of permits and leases for oil and gas on oil shale lands.
Executive Order #7038 dated 1935	Modified Executive Order #5327 to permit issuance of sodium permits and leases on oil shale lands.
Legal Opinion by Interior's Solicitor dated 1964	Opinion rejected applications for patents on selected oil shale mining claims.
Interior Secretary's Memorandum of Instructions to BLM dated 1964	Memorandum of Instructions order BLM to determine status of all identifiable oil shale mining claims and to initiate contests to clear title of the public lands.

TABLE 1 (Continued)

<u>Documents</u>	<u>Provisions</u>
Civil Action Cases	Claimants turned to the courts after exhausting all administrative relief available through Interior. Civil Actions of importance were initiated in the U.S. District Court in Denver and include 8680, 8685, 8691, 9202, 9252, 9458, 9461, 9462, 9464, & 9465. As all civil actions presented similar issues, essentially all are held in abeyance until the "Tosco Case" (8680) is decided.
U.S. Supreme Court Opinion dated 1970	Opinion No. 25 of the October Term, 1970 in the Tosco Case remanded the case to the U.S. Appeals Court in Denver, specifying that all issues relevant to the validity of earlier court proceedings be open and all issues relevant to the validity of the claims will be open.
U.S. Appeals Court Remand, dated 1975	The U.S. Appeals Court in Denver remanded the case to the lower courts and to the U.S. Department of the Interior for full hearings on all obstacles to patenting of the mining claims.

OIL SHALE IN SITU TESTS EFFECTS ON GROUND-WATER REPORTED

Water encountered in Wyoming oil shale during in situ retorting research conducted by the Laramie Energy Research Center and some indications of future research -- including horizontal modified in situ tests -- were described in a paper delivered at the Colorado School of Mines Oil Shale Environmental Symposium October 9 and 10. "Characteristics and Possible Roles of Various Waters Significant to In Situ Oil Shale Processing," was presented by Dr. L.P. Jackson (LERC chemist) for both himself and co-authors R. E. Poulson, (project leader), T. J. Spedding, T.E. Phillips, and H.B. Jensen. The experiments should be of considerable interest to potential in situ developers.

Water Types Identified

Five types of water are identified. The first is the obvious conventional supply, which is short in the test area. The other four are discussed in light of the shortage of the first.

The second and third types are those produced with shale oil. One is decantable and the other is adsorbed or emulsified with the oil. "The product water from in situ type combustion processes is often produced in quantities greater than ten times that in above ground processes," Jackson said.

A fourth type of water is that naturally occurring groundwater intercepted in underground development of an oil shale zone. Most of those in Sweetwater County, Wyoming, "are unusable for most purposes because of their high salt content."

The fifth type is backflood water resulting from natural water entering an in situ site after its development. It is a composite of retort water and natural water with the added effect of having contacted spent shale.

All Water Has Potential

"In the arid oil shale regions of the

Green River formation all available water, even that of low quality, must be evaluated for its dissolved mineral content and as a possible source of water for development. Environmental baseline establishment and water resource cataloging go hand-in-hand as do waste management and utilization," the authors said.

In practice, in most of the likely areas for in situ development in the Green River Basin, water would not be intercepted in competent oil shale zones. Large regions should be essentially dry except for water bearing strata above and below the shale. Most of the LERC field work to date has been in the shallow strata near Rock Springs, Wyoming, where groundwater intrudes through natural tension fracturing.

Retort Water Volume Significant

"The volume of retort water produced is significant with respect to in situ shale processing requirements. The consumptive requirement for a 50,000 barrel per day in situ development process is estimated as being between 2,200 and 2,800 acre-feet per year (USDI, 1973). Assuming one barrel of water produced for every barrel of oil (Harak, Long and Carpenter, 1970) the daily production of water would be 6.44 acre-feet per day which is 2,352 acre-feet per year...", Jackson said. This has important potential and "as the cost of energy increases, aqueous waste disposal methods may become more elaborate as water in the West becomes more valuable. Water handling and renovation processes previously too costly may come into consideration."

Rock Springs Experiments Described

Water data from two sites, 6 and 9, was provided. Site 6 was an unsuccessful experiment in that although in situ combustion was achieved, no oil was produced above ground. Site 9 is the next burn test and has not been ignited. Another experiment, Site 4, is being reopened after a successful burn in 1969. No data are available from it. All three are in the Tipton member of the Green River formation (see Figure 1).

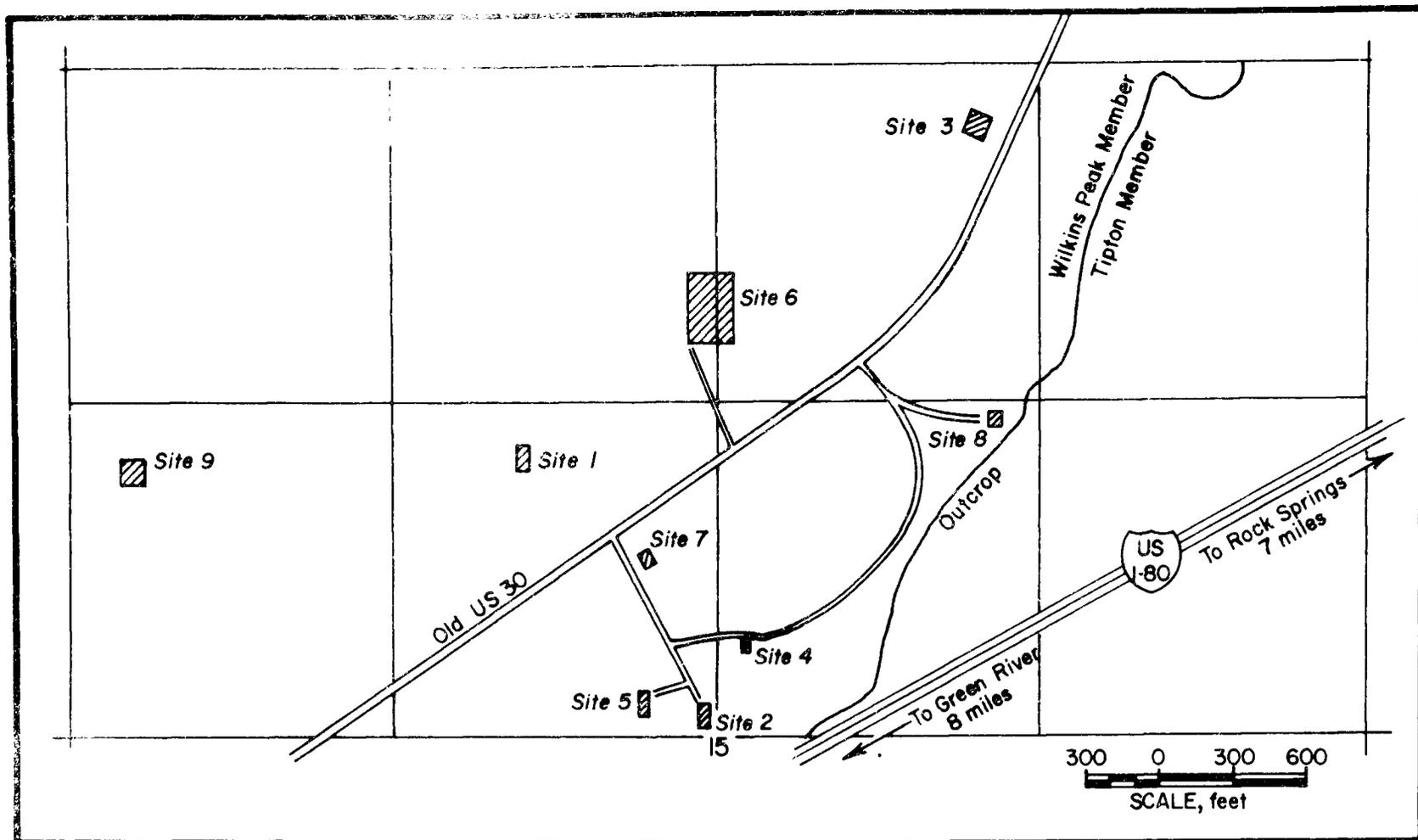


Figure 1. Sites of Laramie Energy Research Center In Situ Experiments.

Site 9

Chemical analyses of water from the nine production wells on Site 9 are given in Table 1 as reproduced from the report. Each value is the average of 15 or more samplings taken in 1974.

Analysis of water from the eight observation wells show significantly lower values -- about one-third average value shown by the production wells -- in all ionic material. "It may be that the proximity of the nine production wells (see Figure 2) has encouraged additional fracturing in the area..." Jackson noted.

In an experiment to enlarge the fracture system between Wells 9 and 1, the lowest of the three existing fractures was isolated with packers and heated air was forced between the two wells, a distance of 53 feet. At the conclusion of the experiment, water samples taken from the heated Well No. 9 showed as much as a 50-fold increase in

calcium content, a 98 percent increase in carbonate and a 33 percent drop in total dissolved solids.

Water in Well No. 1 was pumped during the experiment and showed an increase in almost all materials during the heating period, but returned to preheating values when heating was discontinued for several days. No large increases in values occurred in Well No. 1 at any time.

"Total dissolved solids showed about a 25 percent increase on the average during the heating period. This may indicate that only moderate increases in chemical content values will occur in groundwater at in situ sites during retorting and pre-retorting conditions will prevail after the burn is over. Future experiments in observation wells will be necessary to check this," Jackson said.

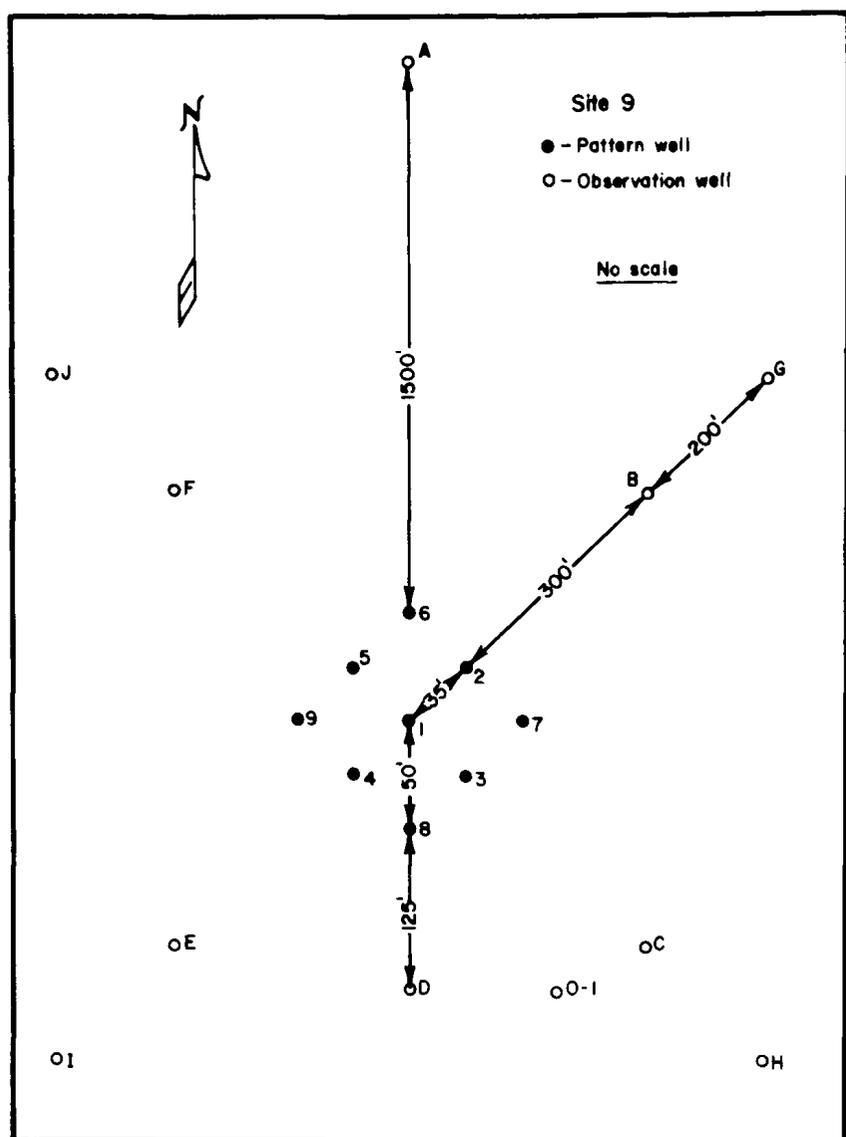


Figure 2. Well Pattern for LERC Site 9 In Situ Experiment

Site 6

Site 6 was the scene of an unsuccessful attempt at in situ production. Though re-torting conditions were maintained for an extended period, no oil was collected from the pattern wells. Chemical composition of water from the six pattern wells is shown in Table 2 reproduced from the report. The data were obtained from wells during combustion in the shale deposit. A series of monitor wells was drilled about six months later around the pattern area and the analyses on these waters are shown in Table 3 reproduced from the report. They show a much lower chemical content than do the reproduction wells during the burn.

Water samples taken from four production wells near the center of Site 6 and observation Well No. Q are shown in Table 4 reproduced from the report. They show that the water quality in the pattern well has

improved considerably from burn period values in the amounts of dissolved materials although they have not returned to the low values shown by the surrounding observation wells.

"The one observation well sampled this August (1975) shows more than twice the dissolved solids of the pattern wells and, in fact, tends to resemble the pattern wells during the burn. This may be due to water migration from the production well area," Jackson noted.

Site 4

Water data are not available for Site 4, Jackson said. A program is underway to drill into the six-year old site and sample any liquids found. He said this may some idea of what post burn shale oil is like as well as provide a first look at older back-flood water. The result "will allow a more complete evaluation of the impact of shale oil development on water quality of an area," he said.

Horizontal Modified In Situ

LERC researchers are now looking for a horizontal modified in situ experimental site on White Mountain near Rock Springs. Jackson said that a dry site probably will be selected so that the bulk of the waters will be retort generated.

Purpose of devising a horizontal mode of the modified in situ which marries some conventional mining and above ground re-torting technology for retorting the rock in-place is because the bulk of the Wyoming shale deposits are too thin for conventional vertical designs. Additionally, Wyoming shales, although extensive, are considered too low grade for mining and above ground retorting.

#

TABLE 1
WATER QUALITY ANALYSIS: ROCK SPRINGS, WYOMING/LERC SITE 9, PATTERN WELLS^a

	Well No.								
	<u>1</u>	<u>2</u>	<u>3</u>	<u>4</u>	<u>5</u>	<u>6</u>	<u>7</u>	<u>8</u>	<u>9</u>
Total depth, ft.	190	192	189	188	190	193	192	188	188
Cased to, ft.	138	138	136	135	137	319	137	134	136
Constituent									
Calcium	12.0	19.0	16.0	15.0	13.0	11.0	11.0	15.0	12.0
Magnesium	29.0	24.0	25.0	33.0	26.0	23.0	25.0	24.0	25.0
Sodium	4,520.0	7,270.0	5,490.0	5,090.0	5,550.0	7,100.0	7,040.0	5,450.0	6,020.0
Potassium	18.0	17.0	14.0	14.0	14.0	15.0	15.0	14.0	13.0
Carbonate	860.0	1,710.0	1,080.0	1,920.0	1,110.0	2,600.0	2,190.0	1,300.0	1,820.0
Bicarbonate	5,710.0	9,760.0	7,360.0	7,020.0	7,750.0	9,360.0	8,230.0	6,990.0	7,940.0
Total carbonate	3,650.0	6,490.0	4,680.0	4,740.0	4,920.0	6,670.0	6,220.0	4,720.0	5,710.0
Sulfate	1,280.0	2,210.0	890.0	1,700.0	1,250.0	1,620.0	780.0	1,060.0	1,160.0
Chloride	2,540.0	2,500.0	2,200.0	1,370.0	1,820.0	1,800.0	2,620.0	2,270.0	2,290.0
Nitrate	1.7	5.5	1.7	1.9	2.0	2.2	2.1	1.8	1.8
Fluoride	22.0	39.0	32.0	28.0	33.0	39.0	37.0	33.0	34.0
Dissolved Solids	11,900.0	19,600.0	14,140.0	12,980.0	14,940.0	18,730.0	18,080.0	14,090.0	15,750.0
pH	8.7	8.8	8.8	8.0	8.7	9.0	9.0	8.9	8.9
Boron	33.0	55.0	36.0	42.0	42.0	57.0	53.0	35.0	55.0
Silica	13.0	18.0	16.0	24.0	17.0	10.0	16.0	22.0	15.0
Total organic carbon	150.0	240.0	300.0	310.0	340.0	440.0	490.0	308.0	250.0

^aConcentrations in parts per million average of 15 samplings over 1 year, temperature 11° ± 2°C.

TABLE 2
WATER QUALITY ANALYSIS: ROCK SPRINGS, WYOMING/LERC, SITE 6, PATTERN WELLS^a

Constituent	Well No.							Ave.
	<u>107</u>	<u>207</u>	<u>307</u>	<u>407</u>	<u>507</u>	<u>607</u>		
Calcium	--	--	--	58	59	--	58	
Magnesium	--	--	--	223	238	--	230	
Sodium	6770	7370	7550	8170	11220	11740	8900	
Potassium	31	41	34	28	35	36	34	
Carbonate	2010	--	1900	1060	2800	1910	1940	
Bicarbonate	5430	--	7280	9860	14650	11550	9750	
Total carbonate	4647	--	5448	5891	9957	7557	6700	
Sulfate	5270	3440	3330	3620	3790	9410	4810	
Chloride	4763	4790	4620	3770	3880	3690	4250	
Nitrate	4.5	5.7	6.8	2.1	4.0	3.9	4.5	
Fluoride	--	--	--	39	67	--	53	
Dissolved solids	--	--	--	--	--	--	--	
pH	--	--	--	8.5	8.6	--	8.6	
Boron	--	--	--	--	--	--	--	
Silica	--	--	--	--	--	--	--	
Total organic carbon	--	--	--	--	--	--	--	
Sampling dates	12/70	12/70	12/70	12/70	12/70	12/70		
	to	to	to	to	to	to		
	7/71	1/71	5/71	7/71	8/71	7/71		
No. samples	23	3	14	15	19	17		

^aConcentrations in parts per million.

TABLE 3

WATER QUALITY ANALYSIS: ROCK SPRINGS, WYOMING/LERC, SITE 6, OBSERVATION WELLS^a

Constituent	Well No.					Ave.
	M	N	O	P	Q	
Calcium	13	7.0	15	12	8.1	11
Magnesium	6.8	5.3	0.2	6.2	4.9	4.7
Sodium	3510	749	1970	2220	723	1830
Potassium	7.3	2.5	9.7	11	4.8	6.9
Carbonate	855	91	423	1520	465	671
Bicarbonate	3980	254	624	1290	361	1300
Total carbonate	2798	214	723	2129	635	1300
Sulfate	747	104	153	145	119	254
Chloride	1240	820	1780	573	241	931
Nitrate	1.2	0.6	1.8	1.5	1.1	1.2
Fluoride	20	2.0	6.2	13	4.2	9.1
Dissolved solids	--	--	--	--	--	--
pH	9.2	9.0	10.1	10.4	9.6	9.7
Boron	21	2.3	8.2	20	5.5	11
Silica	--	--	--	--	--	--
Total organic carbon	--	--	--	--	--	--
Sampling dates	11/71 to 9/72	11/71 to 8/72	1/72 to 8/72	11/71 to 8/72	11/71 to 8/72	--
No. samples	8	8	5	8	7	

^aConcentrations in parts per million.

TABLE 4

WATER QUALITY ANALYSIS: ROCK SPRINGS, WYOMING/LERC, SITE 6, FROM YEARS AFTER^{a,b}

Constituent	Well No.					Observation well, Q
	0	104	Pattern Wells		503	
			203	304		
Calcium	1.5	0.6	0.7	6.5	4.1	3.7
Magnesium	1.3	1.5	1.6	14	12	5.0
Sodium	1500	4800	3700	2800	4500	8400
Potassium	300	14	22	130	37	30
Carbonate	840	1500	720	400	1700	5300
Bicarbonate	630	4600	3700	2600	3700	6000
Total carbonate	1136	3737	2527	1672	3491	8162
Sulfate	1400	2500	2800	2600	2700	25
Chloride	290	850	650	480	690	2700
Fluoride	10	37	27	20	29	50
Dissolved solid	4650	12000	9800	7580	11500	20000
pH	9.8	9.2	9.0	8.9	9.4	9.6
Boron	18	57	41	30	55	78
Silica	37	10	9.0	12	10	12
Total organic carbon	--	--	--	--	--	--

^aConcentrations in parts per million.^bSamples obtained August, 1975, 50 months after experiment completed.

ENVIRONMENT

UNION OIL COMPANY'S REVEGETATION STUDIES DESCRIBED

It has long been known that different retorting processes produce different kinds of spent shale requiring different revegetation processes and resulting in varying costs.

Union Oil Company of California, a firm with nearly a half century of involvement in oil shale work, tried one retorting process in 1958 which produced a five-acre pile of spent shale on Parachute Creek north of Grand Valley, Colorado. Since then, it has experimented in California with two modifications of the basic 1958 rock-pump retort. Each produced a different spent shale. (A description of three Union retorting processes is given in the Oil Shale Technology section of this issue of Synthetic Fuels.)

The quantified difference in the spent shales and the differing revegetation problems they present were detailed by Steve Lipman, Union's manager of environmental development, at the Colorado School of Mine's Oil Shale Environmental Symposium, October 9 and 10 at Golden, Colorado. The report revealed the higher the retorting temperature, the higher the alkalinity and the greater the difficulties in revegetating. The properties of a spent shale are not constant; they change with time and weathering. Particle size also affects the revegetation procedure.

The 1958 spent shale pile came out of what is now known as Retort A. It was a hot, clinkered ash, mostly lumps with few fines. Retorting temperatures, since it was a countercurrent flow combustion retort, were high enough to decompose the predominant carbonate material into oxides. For reclamation, this had the benefit of no black carbon residue or unstable, finegrained material...but problems did exist with a high pH and an easily cementable material.

Retort B spent shale is more similar to that produced by the Bureau of Mines and Paraho retorts at the Anvil Points, Colorado, facility. It is a coarse, gravel-sized material with some black carbon

residue remaining on the shale. Retorting temperatures remain below that for carbonate decomposition and the spent shale has a lower pH and little tendency of cementation. In the Retort B process, the heat is generated externally by heating and recycling part of the make gas. No air is introduced in the Retort B process.

The third Union retorting variation is the Steam Gas Recirculation (SGR) process in which steam, gas, and air are circulated through the retorted shale to strip it of its remaining heat and fuel value. Texture and size of the spent material is similar to that from Retort B, but most of the carbon has been burned off. "It's properties reflect the median temperatures reached in the process. Some carbonate decomposition has occurred causing a moderate tendency toward cementation and a relatively high pH," Lipman reported.

Retort B Shale Easiest

Lipman said the black spent shale from the Retort B "is the easiest to grow things on" and requires the least amount of soil treatment. The decarbonized shale from the SGR retort is more esthetically pleasing, but has more problems regarding alkalinity.

Cost figures are being revised, but Lipman indicated spent shale from the Retort B appears to be the least expensive to reclaim. It is the Retort B that Union intends to use in a 10,000 TPD plant it plans to build on Parachute Creek. The final decision on construction awaits action in Washington on such things as the loan guarantee or other incentives program for synthetic fuel development.

Lipman said he hopes cost will not get into the \$3,000 per acre range and noted that the per-acre cost could be misleading. Depth of the pile must be considered also and Union is now planning to use East Fork Canyon for disposal of spent shale. Some costs are difficult to compute, such as the cost for equipment borrowed from mining operations. Sulfur used to lower the alkalinity of the spent shale would come from the retorting and upgrading processes as a by-product. Some cost

would be fixed regardless of the acreage. Whether to use top soil cover prior to revegetation depends on tests now in progress.

Revegetation History

Retort A ash was not analyzed until 1974 and its 1958 pH could only be estimated at 12.5 to 13.0 (see Table 1 for chemical properties of the three spent shales). Some 100,000 tons of Retort A ash were dumped on a five-acre tract in 1958. The southern end of the pile was leveled and left to weather. Fifty pounds of range seed mixture consisting of orchard, brome, and English bluegrasses were sowed

into the one-acre southern plot in April 1966. The plot was sprinkler irrigated on 13 days spaced out over the months of May through August, using a total of one acre-foot of water.

Salts appeared on the surface when the irrigation was left on all day. When the irrigation cycle was reduced to two hours, the salt did not come back to the surface, Lipman said.

During the first year, the grass grew only to about three inches in height and appeared to have salinity damage on the leaf tips. Five tons of manure and 100 pounds of phosphate were applied in 1967

TABLE 1

CHEMICAL PROPERTIES OF UNION OIL SPENT SHALE

<u>Components, Wt. % *</u>	<u>Retort A Shale Ash</u>	<u>SGR Retort Decarbonized Shale</u>	<u>Retort B Retorted Shale</u>
SiO ₂	35.3	39.2	31.5
CaO	27.2	27.3	19.6
MgO	9.0	8.2	5.7
Al ₂ O ₃	8.5	8.9	6.9
Fe ₂ O ₃	7.3	3.8	2.8
Na ₂ O	5.5	3.7	2.2
K ₂ O	2.8	2.7	1.6
SO ₃	0.1	1.4	1.9
P ₂ O ₅	2.2	0.5	0.4
Mineral CO ₂	1.6	3.1	22.9
Organic C	0.5	0.3	4.3
Trace Elements	<0.5	0.9	<0.5
Nitrogen, Kjeldahl	<hr/>	<hr/>	<hr/>
	100.0	100.0	100.0
Ignition loss @ 950°C, Wt. %	2.1	3.4	26.9
Free Silica (quartz), Wt. %	<2	2 to 5	8.0
pH of Slurry	12.5-13 (est.)	12.5	8.7

*Analyses determined by heating sample to 950°C.
Analyses by Union Research Department.

and irrigation similar to the first year was repeated.

The rest of the pile was leveled in 1967 and in April 1968, 40 pounds each of alfalfa and tall wheatgrass were harrowed into a one and a half acre plot in the northern end of the pile. Both were irrigated for four to five days in June 1968. Both were irrigated one day every two weeks in May and June 1969. The southern plot was irrigated once in 1970. An attempt to flood irrigate the northern plot in 1973 failed because of the high permeability of the top surface. Neither has had irrigation or fertilization since 1970.

A 1974, field investigation of the pile revealed wide variation of the characteristics of the spent shale in the pile. Lipman said the top one to four feet had broken down into sandy loam, probably the result of freeze-thaw weathering over the past 16 years since it was dumped. The top surface still exhibits a thin layer of slightly weathered clinkers which appear to act as a mulching material over the finer-grained material below. Below the loose, sandy zone are layers of highly cemented ash, the result of percolation waters hydrating the calcium and magnesium oxides in the original ash. The greatest cementation is at a depth of four to eight feet. There is an accumulation of salts atop the cemented zone.

Results

Recent observations indicate the alfalfa in the northern plot and the grasses in the southern plot have matured and reseeded themselves naturally. The wheatgrass in the northern plot has not sustained itself as well as the grasses in the fertilized southern plot. "The lack of phosphate and/or the lower water application during establishment may account for the difference," Lipman said.

The existing grasses and alfalfa currently show no salt or pH damage, nor nutrient deficiency. No measurements have been made of the vegetation yield, but Lipman said qualitatively, the density appears similar to the surrounding native vegetation.

An unseeded and untreated third plot has a sparse growth of Russian thistle. Natural vegetation such as willow, box elder, and narrow leaved cottonwood trees have encroached in the edges of the pile where there is sufficient moisture.

Recent Work

Union's revegetation research received renewed emphasis in 1974. To test spent shale from the SGR and Retort B pilot plants, 22 revegetation plots were constructed in the Parachute Creek valley (elevation 5,800) in the summers of 1974 and 1975 and six were built on Long Ridge at a 7,800-foot elevation about a mile northeast of the 1958 mine bench.

Experiments are underway on a broad variety of treatments, including north-sloping and west-sloping exposures, top soil cover, and soil control (see Figure 1).

Summary of Findings

Alkalinity. Spent shale which has not been heated high enough for significant carbonate decomposition does not present a serious alkalinity problem. Materials which have had carbonate decomposition will require a reduction in alkalinity before a satisfactory plant growth can be established on it directly. Natural weathering and leaching will reduce alkalinity, but "it will take up to 8 years." Environmental requirements being what they are, the job probably cannot be left to nature. Granular sulfur can act as an effective neutralizing agent under appropriate temperature and water conditions. For example, sulfur applied at the rate of five tons per acre in the top few inches of decarbonized shale test plots lowered the pH in the top six inches from 11.2 to 8.5 in about nine months. The pH drop in an untreated storage pile was from 11.2 to 10.1 in the same period. Capillary rise is greatly reduced with coarse-grained material. "By the time particle breakdown occurs, the salts should have been already leached out."

Nutrients. Phosphorus and nitrogen are required during plant establishment. Sulfur used for alkalinity reduction

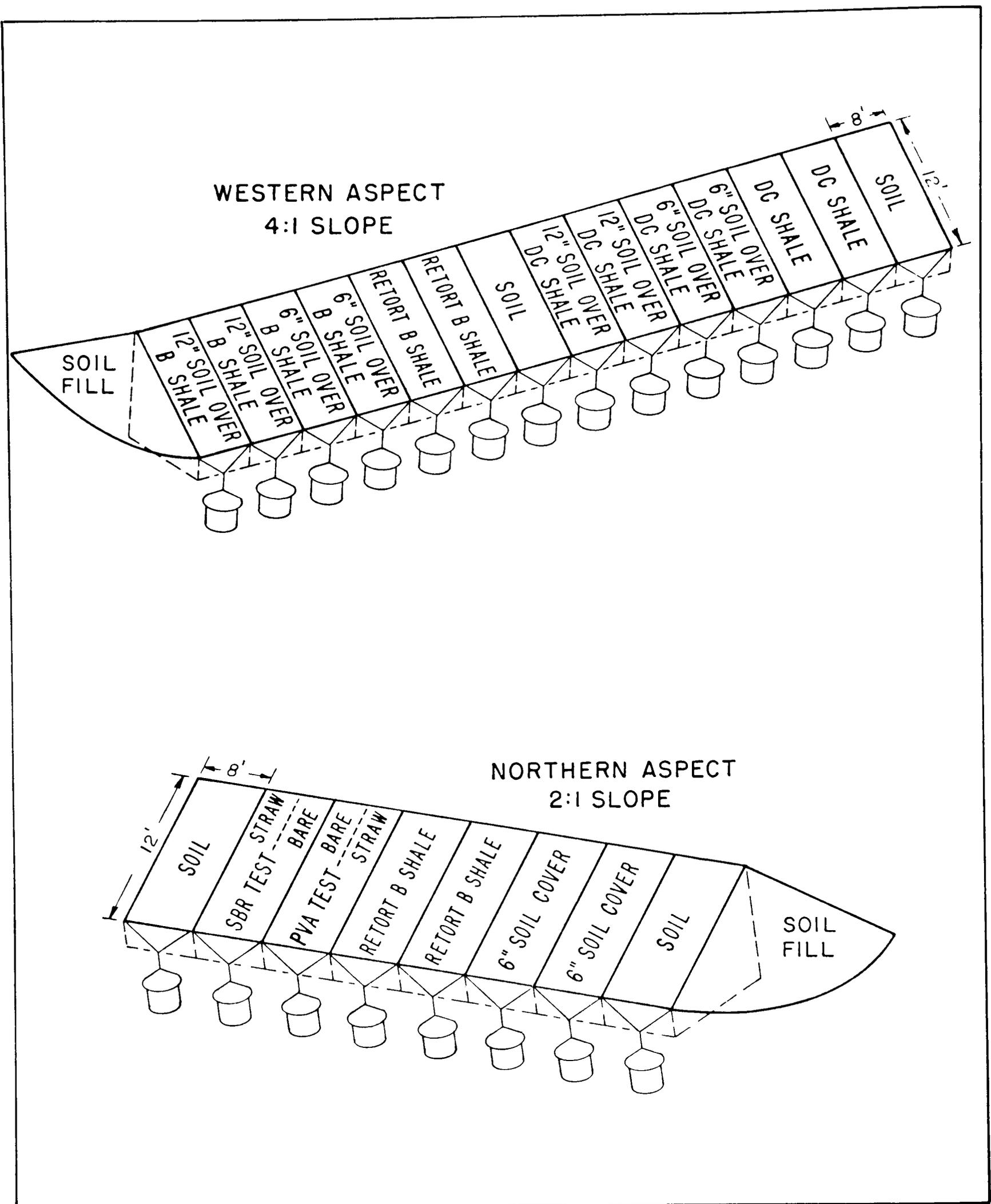


Figure 1. Union's Valley Revegetation Site

provides another source of this secondary nutrient.

Vegetation. Range grasses and alfalfa tests on Retort A shale have shown that they can mature and reseed themselves under natural conditions after initial irrigation and fertilization. Union is currently investigating more than 20 plant species at the newly established plots in the valley and plateau sites. Based on initial germination, the results appear favorable.

Erosion Control. A screening test was performed on two number of erosion control treatments using three different chemicals: polyvinyl acetate (Amsco Res. 3011), styrene-butadiene (Amsco Res. AB1881-C), and an asphalt emulsion (SS-1). The polymers were mixed with wood fibers and

applied at three different dilutions and two different solids concentrations. A wetting agent, X-77, was included in one test with each polymer to determine if deeper penetration was important. This did not increase effectiveness of the polymer.

Duplicate treatments were applied to Retort B shale in greenhouse flats and after curing for 48 hours, the flats were inclined at a 1:1 slope and exposed to simulated rain at a rate of two inches per hour (see Table 2 for application rates and results).

Conclusions

Pre-leaching of the Retort B spent shale does not appear to be needed. Lipman said greenhouse experiments revealed no difference

TABLE 2
EROSION CONTROL PERFORMANCE OF TREATMENTS ON RETORTED SHALE
(Rating: 10 = Excellent; 1 = None)

Chemical	Dilution Rate	Solids lbs/ac	Fiber lb/ac	Hours at 2" of Water Per Hour					
				1	2	3	4.5	8.5	13
PVA (3011)	6:1	500	200	10	10	9	8.5	8.5	7
PVA (3011)	12:1	500	400	10	10	10	10	8.5	8
PVA (3011)	24:1	500	400	10	10	9	8	6.5	
PVA (3011) X-77 @ 10 gpa	24:1	500	400	10	10	9	8	6	
PVA (3011)	6:1	1000	400	10	10	10	10	10	10
SBR (AB1881-C)	6:1	500	200	9	7	7	4	2	
SBR (AB1881-C)	12:1	500	400	10	10	10	8.5	5.5	
SBR (AB1881-C)	24:1	500	400	10	10	10	9	8.5	8.5
SBR (AB1881-C) X-77 @ 10 gpa	24:1	500	400	6.5	4.5	3	2	1	
SBR (AB1881-C)	6:1	1000	400	10	10	10	10	10	10
SS-1 33 gpa (2925 lb/ac)				9	8.5	7.5	4	1	
SS-1 742 gpa (7402 lb/ac)				10	10	10	9.5	9.5	9

Adapted from testing and rating conducted by Burgess L. Kay, Environmental Seeding Consultant, University of California at Davis.

in plant growth regardless of the amount of leaching. But as with all spent shale, water application during germination and establishment is critical.

Lipman's reported results on the 16-year old spent shale and experiments with more recent varieties indicate establishment of effective groundcover on spent shale piles will not in itself be a major economic handicap.

#

ENVIRONMENTAL OIL SHALE SYMPOSIUM AT CSM IS DISAPPOINTING

Colorado School of Mines hosted its first symposium on the environmental aspects of oil shale development at Golden, Colorado, on October 9 and 10. Although CSM has sponsored eight symposiums on the technical aspects of shale since 1964, the environmentally focused event was upstaged by congressional hearings on synthetic fuels legislation in Washington, D.C. (discussed elsewhere in this issue). Even though some excellent papers were presented, overall the symposium was disappointing. Much of the program was a reiteration of the obvious or too general to be of much value to the industry to which it was directed.

The directors of the Colorado and Utah Departments of Natural Resources were on the same day's program. The contrast in the outlook of the two states was unmistakable.

Gordon Harmston, executive director, Utah Department of Natural Resources, tried to show the similarities in Colorado and Utah policies toward energy development. A representative of one of the firms holding a federal oil shale lease said when Harmston finished--"They're just not there."

In short, Utah is many months--possibly several years--and many hard decisions ahead of Colorado, which has the bulk of the richest oil shale reserves. Utah wants oil shale development to provide jobs for its youth and boost its economy. What Colorado wants still was not clear when Harris Sherman, Colorado Director of

Natural Resources, finished speaking. He noted the program said he would speak on "Colorado Policy on Oil Shale Development," and commented "I wish I could deliver under that title." It was at least the second time since he took office early in 1975 that he left listeners wondering if Colorado wants an oil shale policy.

According to Sherman, the most important issue is "How does Colorado relate to the federal government on oil shale?" He added that "Colorado has taken the position that it can best manage its own future." He said Colorado seeks a "partnership...a general partnership where the state is not a junior partner to the federal government."

He noted that Colorado representatives sat with federal officials as equal counterparts on the committee to select tracts for the in situ phase of the prototype oil shale leasing program. The state involvement may have averted designation of one tract near the state line which could have resulted in the bulk of the employees living in Rangely, Colorado, and putting community development costs there, while the project taxes and royalty income went to Utah, he said.

Sherman offered no other insights to guide prospective developers. His talk dealt with the form rather than substance of oil shale development.

Utah Concerns

Harmston said air pollution control and river salinity management are the main oil shale concerns of the Utah government. He indicated Utah most desires the same thing that also would be most appreciated in western Colorado: a reliable timetable for oil shale development.

Harmston said Utah oil shale has largely escaped environmentalists' opposition because most of environmental activism is directed at the Kaiparowits steam generation plant in southern Utah. Utah has been pushing that project for 13 years. The water contract for it was signed by the Secretary of Interior ten years ago. The development is now snagged on a proposed transfer of the plant site to the state from the Bureau of Land Management.

Utah's new mined land reclamation act passed in the 1975 legislative session applies to both underground and surface mines. It becomes effective January 1, 1977, and applies to any disturbance of an acre or more. Colorado is still rewriting its state reclamation regulations.

The Utah energy legislative package included a tax revision act to allow for prepayment of taxes to offset the lag between tax revenues and community service needs. A \$2 million revolving state fund has been established for cities and towns affected by oil shale development to upgrade their water systems. The program allows the state to buy the municipal revenue bonds, Harmston explained.

Energy advisory commissions appointed by Gov. Calvin Rampton for both Kaiparowits and Uintah Basin oil shale country operate in conjunction with their respective regional councils of government to attain state recognition of local social, economic, and environmental concerns.

If anyone in Colorado state government appeared ready to solve oil shale related problems, it was Burman Lorenson, Gov. Richard Lamm's oil shale coordinator. He told the symposium that Colorado has "no clear policy other than the beneficiaries (the shale companies) shall pay the socio-economic costs of development," a multi-million dollar fact bonus-paying prototype tract developers are aware of, but which oil shale opponents continue to ignore.

Another symposium speaker, H. Michael Spence, vice president of The Oil Shale Corporation, observed that the last five years produced great strides in environmental protection legislation and regulation, yet a "major effort should be devoted in the next five years to the simplification and improvement of those regulations, both in substance and procedure."

Spence said that significant improvements in the regulatory scheme can and should be made without any weakening of the commitment to environmental protection. Environmental standards have been too-frequently set in a vacuum without adequate assessment of the secondary and tertiary effects.

"The irony of this situation is that perhaps the single most valuable contribution of the environmental age has been to bring about a real understanding of that first principle of ecology, that everything affects and is affected by everything else; and yet, that principle has been violated consistently in the establishment and application environmental rules," Spence said.

Spence also questioned whether litigation, "a most effective tool for environmental organizations in forcing agency compliance" with the National Environmental Protection Act "has been in the public interest." He said the public interest might be better served by alternative enforcement methods such as applicant (instead of federal) environmental impact statements and certainty of procedural compliance.

Industry is caught in the middle and significant risk has been added to business evaluation of a project. "(Final) determinations, if available at all, may entail litigation lasting years," he said. "The natural inclination of persons charged with responsibility for approvals is to require absolute proof of many matters which are not susceptible to such proof... Field personnel may prefer to make no decision or make decisions requiring impossible compliance." Spence said.

Recommendations

Spence urged a serious objective review of NEPA with an eye to improving the procedural aspects of the law. He said that the basic regulations for air and water pollution control have largely been completed. Many regulations were written without substantial reliable evidence and little thought given to marginal efficiencies of pollution control equipment. Nor was the inter-relationship of separate regulations adequately addressed.

"Field experience should now be considered in reviewing these regulations to make them economically, as well as environmentally sensible," Spence said.

Program Juggled

Some scheduled symposium speakers sent substitutes, the program was juggled to accommodate late arrivals and attendance was lighter than expected--fewer than 150 person registered. Most of the prominent oil shale industry leaders were absent. So were the environmental leaders. There was only one representative of the U.S. Environmental Protection Agency registered. No member of any citizen environmental organization identified himself by symposium registration.

CSM officials said a session of the Ninth Oil Shale Symposium scheduled for April 1976 would be reserved for environmental papers. No special environmental symposium is anticipated.

#

IN SITU OIL SHALE LEASE NOMINATIONS HIT SNAG

The process by which four potential prototype in situ oil shale lease tracts were selected and the resulting choice of tracts took a severe mauling at the Oil Shale Environmental Advisory Panel meeting in Grand Junction, Colorado on October 23.

It was apparent that the Interior Department would offend the fewest people by junking the Departmental In Situ Oil Shale Tract Selection Committee's recommendations for Tract 2 in Colorado and Tract 8 in Utah. There seemed considerable incentive for Jack Horton, Assistant Interior Secretary for Land and Water Resources, to put the two alternates, Tract 7 and 9, both in Utah, up for bid.

That would please industry-favoring Utah. It is doubtful it would displease environmentally-oriented Colorado officials. Five of the nominated tracts, 1, 3, 4, 5, and 6, are in the heart of Colorado's Piceance Basin. All five finished last in the section committee's consideration. That left one, Tract 2, in Colorado. It is in the south central part of the basin, and was attacked for a variety of reasons.

Panel's Concensus

After an almost day long debate, OSEAP chairman, Bill Rogers, won a concensus:

- I. The selection committee rejected all tracts nominated in the center of the Piceance Basin for what appears to be good and sufficient reasons. Had the nominators known these criteria would be applied in the selection process, others might have been nominated. Consideration should be given as to whether this warrants reopening of bids.
- II. If it is decided to proceed, serious consideration should be given to the following:
 - . Selecting the two sites put up for competitive bid from sites 2, 7, 8, and 9.
 - . Obtaining industrial input to ensure that the widest range of technologies available is used. This could lead to reopening of nominations.
 - . Reject any proposed site if its location prevents proper interpretation of existing prototype efforts. New sites should be of sufficient distance to allow each effort to be evaluated on its own merits.
 - . Consulting with state and local officials of the two states to minimize conflicts.
 - . Expanding efforts to arrive at estimates of socio-economic impacts before final selection is made.

Utah Is Piqued

Behind those recommendations are some ruffled feathers in Utah by what appears to be Colorado Gov. Richard Lamm's attempt to call the tune. The selection committee first met August 11 for what was to be a four-day meeting. Utah's representative was Howard Ritzma, state geologist. The meeting was called off at the request of Gov. Richard Lamm on the afternoon of the first day. When the meeting resumed August 25, Utah Gov. Calvin Rampton declined to send a representative because of the short notice.

Ritzma, in a telephone conversation on August 25, said Utah's preferences were Tracts 8, 7, and 9 in that order. However, after subsequent field investigation, Utah officials, in an October 21 letter from Gov. Rampton, gave equal recommendation to Tracts 7 and 9.

Adding to Utah's pique was the objection raised by Colorado officials to Utah Tract 7, northeast of Bonanza and a mile west of the state line. Colorado officials such as Burman Lorenson, the governor's oil shale coordinator, expressed concern that Utah would get the taxes and royalties while Rangely, Colorado, would get the socio-economic impacts.

The Utah Sites

As Gov. Rampton noted, "Tract 7 would afford an opportunity to test an in situ technology in an area of moderately rich, thick shale at modest depths that would increase from east to west across the tract. The tract is adjacent to power lines, an oil road and Bonanza, Utah, with some services available."

Tract 9, 11 miles west of the Colorado-Utah state line and about 20 miles south of Bonanza "is especially well suited to an in situ technology designed primarily for oil shale which is at or close to the surface... The small investment in capital, little lead time required, and low personnel needs makes this tract nomination very attractive," according to Gov. Rampton. One firm hoping to lease this tract is Geokinetics, Inc. Geokinetics vice president, John Downen, declined to give any information about his firm's process, but said it applies only to thinner shales with shallow overburden. All work is through bore holes from the surface, he said.

Downen said his firm's process is true in situ and is applicable only to Tract 9. Modified in situ, such as that developed by Occidental (see June 1975 issue of Synthetic Fuels, page 2-23) is applicable to all the other tracts.

Tract 8 is located 13 miles due west of federal tract U-a and dovetails in with a Utah state lease held by Western Oil Shale

Corp., the apparent nominator. The same firm holds four state leases adjoining Tract 7.

Rampton wrote that Tract 8 "contains richer and thicker shales that the two recommend, but the depth, ranging to 2,000 feet or more, is a serious negative factor."

Utah's View

The advisory panel was a bit sobered by the remarks of one of its members, Gordon Harmston, Utah director of natural resources. He said that out-of-state travel for Utah officials must be approved ten days in advance. We're just not going to run at every beck and call." He added, "if we get a feeling of cooperation here, we'll certainly cooperate."

He said Utah objects to complaints that development in the state would impact its neighbor. Noting that Bonanza had at times past served 200 gilsonite workers and could serve shale workers, he asked, "If Rangely doesn't want them (workers), why don't they just tear the road up?"

Harmston also quarreled with federal and Colorado--he mentioned Denver by name--concern over socio-economic impacts. "We think the job of state government and county and city government is to assess socio-economic cost and it's not to be imposed upon us by higher authority that's so much smarter than we are."

The Colorado Sites

All of the Colorado sites except Tract 2 are located in the heart of the Piceance Basin, mostly within the isopach delineating the deposits where 25 gallon per ton shale is 1,000 feet or more thick. All are in areas known or believed to contain significant quantities of dawsonite and nahcolite.

Colorado Tract 2, which was one of the top two recommended by the selection committee, has its northeast corner about two miles southwest of the southwest corner of tract C-b, a fact that disturbed some members of the advisory panel.

The five recommendations of the panel, should the Interior Department proceed with leasing, were authored by Dr. Thad Box of Utah State University. The third item aims directly at Tract 2 and concerns that dewatering of the orebody and any emissions from development which might affect operations and baselines on Tract C-b.

Conflicts With Other Leases

Tract 2 also was the target of strong criticism from Robert E. Chancellor of Rio Blanco Natural Gas Co. He displayed maps showing that the entire tract is within a federal oil and gas unit and that Tract 2 overlaps oil and gas leases held by Chancellor and by Rio Blanco Natural Gas. "The leases were simply not considered in the tract analysis," Chancellor said.

"The oil and gas leases I own in Tract 2... include rights to the natural oil and gas in the oil shales. An interesting practical question arises here. In the course of his work, how would an in situ extraction operator segregate and deliver to my company and myself the natural gas and oil in the oil shales which is ours?", Chancellor asked.

The Selection Process

The nine tracts were nominated by companies whose names were not revealed to the selection committee, but as in the case of Utah Tracts 7 and 8, ownership of adjoining state leases provided strong indication of the identity of the nominators.

Roy McBroom, chief, Branch of Energy and Minerals, of the Bureau of Land Management's Colorado State Office in Denver, was the chairman of the selection committee. McBroom attempted to explain the mathematical process by which the sites were recommended. They were ranked on their development potential, socio-economic impact, and environmental factors. He never was able to show the panel how Tract 2 became one of the top two. Tract 7 had better numbers. The selection committee was not told to pick a site in each state, he said.

According to McBroom, the selection process was made as objective as possible. He said, however, that when the committee ranked the tracts subjectively, the same two tracts topped the lists, although in reverse order. McBroom's numbers showed Tract 8 as the best.

Interior's Choice

The Oil Shale Panel ignored the fact that the tracts were nominated by industry and presumably are the ones the nominators think best fit their processes. At the same time, socio-economic impacts probably were overrated. Since in situ development does not feature the manpower requirements of underground or surface mine operations.

Downen indicated Geokinetics would employ about the same number as a normal oil field operation--"grossly smaller than a modified in situ" process. He said \$3 million to \$5 million would be spent and it would take three years to "develop or dry hole" the lease.

Even though the selection time was short in the view of some--nominations were cut off in early August--and the selection committee finished its work at the end of August, McBroom said the consensus of the committee was that additional study time would not have changed the recommendations.

There was sentiment among the environmentalist members of the panel for delaying the leasing. But Rogers noted there is a schedule and effort to "offer the tracts for leasing before the end of next summer." He said Horton had asked the panel's advice no later than November 1.

The panel's consensus recommendations will go to Horton, and so will the minutes and written views of individual panel members. It would not be surprising to see Utah get both tracts.

#

GOVERNMENT

CONGRESSIONAL HEARINGS IN COLORADO ON OIL SHALE

The Subcommittee on Energy, Research, Development, and Demonstration (Fossil Fuels) of the House Committee on Science and Technology held hearings on October 25 and 27 in Rifle and Boulder, Colorado, ostensibly on the effects of Section 103 (synthetic fuels economic incentives) of S. 598, the Senate passed version of the authorization bill for the Energy Research and Development Administration (ERDA).

The hearings were conducted by Rep. Timothy Wirth, D-Colo., whose essentially urban Fifth District stretches from Boulder south to Colorado Springs along the Front Range of the Rocky Mountains. Also sitting with Wirth were Rep. Ken Hechler, D-W. Va., and Rep. Phil Hayes, D-Ind. for the Rifle hearing. Hechler was not present at the Boulder hearings.

Hearings Raise Questions

The hearings were puzzling from several aspects. Congress was in recess. A third day of hearings scheduled in Denver was cancelled when Congress reconvened and two days of scheduled witnesses were heard at the Boulder hearing.

Hechler, a leading proponent of strip mining legislation, normally chairs the subcommittee. Rep. James P. Johnson, Fourth District Republican in whose district the first hearing was held and where the richest oil shale reserves are located, did not attend. Johnson, appointed to the House Select Committee on Intelligence, has been devoting the bulk of his time to that assignment. His interest in mining and Interior matters, never all consuming, has waned as a result.

Wirth's comments regarding the Administration were scornful. So were his words for fellow Democrat and Presidential Candidate Sen. Henry M. Jackson, sponsor of Section 103. His references to Johnson were courteous. All this was as expected. But it is unusual since most Congressmen have four subcommittee assignments, to see three members attending a subcommittee hearing.

It is especially rare to see three Congressmen present at a hearing outside their districts on a recess weekend. Especially since, as Rep. Hayes observed, "whatever we do only has moral authority." The hearings are not expected to affect Congressional action on Section 103.

Subcommittee Lacks Clout

Hayes comment was reference to the obvious fact that the subcommittee lacked the power to instruct House conferees on the bill, a point recognized before the hearings were called.

The ERDA authorization bill passed by the House originated in the House Science and Technology Committee. Rep. Olin Teague, D-Texas, is the chairman. In the Senate, it became S. 598 after the addition of some features such as Section 103. As Wirth said, no House hearings were held on that section. Since both houses passed the same basic bill, the amendments are destined for a Joint Conference Committee appointed by the leaders of the two houses of Congress. There the differences are to be resolved.

Significantly, Teague reaffirmed he planned no action to block Section 103 after the Wirth hearings.

One Scenario Fits

Wirth is known on Capitol Hill to be eyeing the Senate seat held by fellow Colorado Democrat Floyd Haskell whose first term expires in 1978. Haskell supported Jackson on Section 103. Curiously, Haskell's name was never mentioned in the criticism leveled by Wirth at what he termed "back door legislation." (Haskell's 1974 oil shale hearings in Grand Junction, Colorado, were a marked contrast in objectivity.)

There were strong indications that Wirth with only nine months in Congress, was building a platform for a statewide race and if so, he nailed firmly in place the fact that no committee hearings were held on Section 103 in the Senate where the provision originated.

The witness list was stacked both with

anti-development witnesses and with county Democratic Party officials with whom early acquaintance is valuable in future primary elections.

The presence of Hechler and Hayes, both from coal mining country where the United Mine Workers are dominant, is explained in remarks they made regarding the effect the westward movement of coal mining would have on the UMW Pension Fund. Western strip mining is now dominated by the Operating Engineers. Many underground coal mines in the west are not UMW controlled. An organized labor skirmish over unionizing Western oil shale and coal strip mine workers is looming with the powerful Oil, Chemical, and Atomic Workers, AFL-CIO, also a factor.

Predisposition Apparent

An overview of oil shale development never emerged at the Colorado hearings. Instead, the session focused on the worst possible theoretical cases of socio-economic impacts of development at a production schedule far beyond what knowledgeable shale people believe is possible in the near future.

The most pressing questions confronting oil shale country communities are whether development, imminent for half a century, will occur, when it will start and where. The lack of a timetable was noted by at least three witnesses but ignored by the Congressmen. Because of the geography involved, a shale development could affect one town severely and leave the others unaffected. There was no witness from De-Beque, Colorado, one town already feeling socio-economic impacts from oil shale from Occidental operations a few miles north.

The Congressmen showed no interest in the uses being made of the state's share of the \$131 million in bonuses already paid on the two Colorado federal prototype leases.

When Congress reconvened early, forcing cancellation of the planned Denver hearing and compressing it into the Boulder session, it was the industry witnesses such as Gary Operating Company, operator of the only oil refinery between Denver and Salt Lake, that were told their testimony was unneeded.

Political Legerdemain

Wirth's comments had little relationship to what actually is contained in Section 103 as passed by the Senate or two other versions of the measure. It speaks of a 350,000 BPD synthetic fuels goal, only 100,000 barrels of which would be shale oil. This was distorted at the Rifle hearing. A shale industry of 750,000 BPD capacity was projected at the end of 1985 as a result of Section 103. The latter figure was injected by Wirth during the testimony of R. C. Fischer, secretary-engineer of the Colorado River Water Conservation District, with whom all oil shale developers ultimately must deal for water rights. The source of the figure was not identified and it exceeds by 50 percent the most optimistic capacity by that date of all the shale developments now known to be on the drawing boards. It was repeated by State Rep. Nancy Dick (D. Aspen) at the Boulder hearings October 27. She is Gov. Richard Lamm's appointee to the Oil Shale Environmental Advisory Panel.

Water Needs

Fischer said an acre-foot of water would supply the domestic needs of 4 1/2 people. Wirth asserted a 750,000 BPD shale oil complex would mean a population increase of 85,000 people (apparently all in Colorado, since only Colorado's share of the Colorado River's water was under discussion). Fischer said the amount of water Colorado has available for oil shale development is uncertain because of a number of variables. It is thought to be between 200,000 and 400,000 acre-feet.

If the hearings were to determine the socio-economic impacts of shale oil development, there curiously were no witnesses from Utah and no hearings were scheduled in Utah from which about one-third of the potential 1985 shale oil production could come.

Fischer noted that the one benefit the River District would gain from Section 103 might be a timetable of shale water needs.

Associated Minerals

James Smith, of the Rock School Corporation, and Aspen, Colorado, has been a proponent of shale development. He quarreled with

Interior Department handling of the "associate minerals," dawsonite and nahcolite, in which Rock School and Smith are primarily interested. Rock School nominated an in situ tract under the prototype program.

Smith said he is opposed to guaranteed energy development loans which "tend to overlook the other minerals. We are going to need all the assets we have."

Hechler found Smith's testimony as "another argument for opposing the guaranteed loan program."

Boom Town Syndrome Fears

The Congressmen seized on the testimony of Rio Blanco County Commissioner Bill Brown who read the statement of the Colorado West Area Council of Governments representing four northwest Colorado counties.

"It is disappointing and frightening to discover that the bill before you subcommittee has no provision for dealing with the impact upon local government which a \$6 billion loan program will create. There are no provisions in this bill to deal with the financial strains upon local government which the bill will create. There are no provisions in the bill to prevent the boom town syndrome which the bill will create. This we think is unfair and unrealistic."

The statement echoed the position taken in part by Colorado Gov. Richard Lamm in many previous and subsequent speeches. Each succeeding witness was asked if they disagreed with Brown's testimony. None did although few appeared to agree with the grim, dark, scene painted later in the Brown's statement: "If facilities and men are not in place to meet this new influx then the situation will deteriorate immediately and the trend will be difficult if not impossible to reverse. Schools will be overcrowded immediately, taking years for the system to return to the quality education which existed prior to development. Water will have to be rationed and reduction in water pressure will inhibit the fighting of fires. Sewage treatment will be below par raising the possibility of sickness, epidemics, and environmental

degradation. Police protection will be below standard, endangering the lives of local residents. And the way of life of our people will be changed adversely overnight, with little anyone can do to reverse the tide. Alcoholism, suicide, alienation will result. The list is endless and depressing."

There Was Some Support

One who supported the loan program was Dan Giltz, Rangely Colorado, town manager. He viewed a synthetic fuels proposals as "a program that has considerable merit." Giltz noted that Rangely, like Rock Springs, Wyoming, is surrounded by Bureau of Land Management Lands and that the BLM controls two aspects of the town's future: a tract for town expansion, and an access road route from the town to Federal Lease C-a. Such a road would reduce by half the distance to the tract.

Former Colorado Gov. John Vanderhoof, now executive director of Club 20, a promotional organization of 20 western Colorado counties, said "the front end needs of our cities, towns, and counties must be a part of the nation's support program to develop these needed resources."

Speaking at the Boulder hearing October 27, Lamm, referring to state air and water quality laws, said, "We have very blunt instruments with which we could beat the oil shale industry about the head and shoulders for a long time and delay the program."

Governor's Recommendations

Gov. Lamm offered three recommendations in his Boulder testimony. They are:

"1. As a condition precedent to any loan guarantee under this program, the federal government shall make a full assessment of all direct and indirect costs to the affected municipalities, counties, and state that result from the development and shall affirmatively find that mechanisms and funds exist to fully ameliorate these costs. The affected state must concur in the assessment of costs and the mechanisms provided to meet said costs prior to the guarantee being finalized. In no event would the local residents be required to unfairly shoulder the burdens of such development.

"2. In the initial stage of synthetic fuels commercialization, oil shale development should proceed at the smallest possible size that is required to demonstrate the commercial feasibility and to test a variety of different technologies. The central focus of this initial stage is the development and testing of individual commercial-sized retorting plants -- this is referred to as the modular approach. A build-up to full-scale commercial development at a given site, which is in our understanding accomplished by placing a number of modules side-by-side, would be authorized only upon a showing by the applicant and ERDA that essential commercial and impact questions cannot be resolved through a modular approach.

"3. Colorado appears to have sufficient water resources to meet the demands of a demonstration oil shale program. However, the Committee and Congress should understand that Colorado does not have excess water to meet the requirements of a full-scale oil shale industry without major significant reallocation of the State's water resources. Therefore, full-scale development should not proceed until the water tradeoffs have been well identified and found acceptable by the State of Colorado."

There was no emphasis, if indeed any mention was made, that Congressional staffs already have drafted measures for insertion into the bill which would answer the very socio-economic questions the politicians were spotlighting.

Congress and the Ford Administration are aware of the socio-economic issues. Yet Western politicians continue to raise them, perhaps to later claim "look what I did."

The dominant feature of the hearings and discussion of Section 103 generally is the absence of objective, analytical perspective.

Observers of the oil shale scene in Colorado are confronted with the reality that the state doesn't want development of a shale oil industry, perhaps in part, because it views 30 or more years of development occurring overnight.

Also, the economic-employment woes which have beset the nation in recent months, are only now beginning to affect the state. The lag in such that as the rest of the nation hopefully is rebounding, Colorado will be enduring them at their peak. Before long the attitude may change to welcome the initial stages of a shale oil industry as a boost to the economy and employment.

#

NINE IN SITU OIL SHALE TRACTS NOMINATED UNDER INTERIOR PROTOTYPE LEASING PROGRAM: TWO SITES RECOMMENDED FOR LEASING; FINAL SELECTION UNCERTAIN

Two of nine in situ tracts nominated under the U.S. Department of the Interior Oil Shale Prototype Leasing Program were recommended in September for leasing.

The two tracts, one each in Colorado and Utah, promptly became objects of speculation and controversy. Utah gave equal endorsement to its two alternative tracts and expressed doubt about the wisdom of Interior's choice of a Utah tract. The top Colorado site came under fire for its proximity to an earlier shale lease tract and potential with existing oil and gas leases.

Interior did not reveal who nominated which tracts by the July 31 deadline. Moving with unusual swiftness, an Interior selection committee was formed with Governors Calvin Rampton, of Utah, and Richard Lamm, of Colorado, invited to send delegates.

Roy McBroom, of the Colorado State Office of the Bureau of Land Management, said six sites in Colorado were nominated. Three were in Utah. No tracts in Wyoming were named.

While Interior did reveal the identity of the nominees, companies known to have submitted nominations included Occidental Petroleum Company, Western Oil Shale Corporation, GeoKinetics, Inc., Equity Oil Company and Rock School Corporation. Some firms made more than one nomination.

(The Cameron Engineers' Utah and Colorado oil shale ownership maps from the June 1974 issue of Synthetic Fuels are helpful in plotting the tracts with the assistance of the maps and legal descriptions in the Appendix.)

Sites Nominated in Colorado

Tract 1 is a 4,954-acre parcel in the north central part of the Piceance Basin of Colorado straddling Piceance Creek and a strip of fee land owned 75 percent by Exxon and 12 1/2 percent each by Bell Petroleum and the Colorado Division of Wildlife.

Tract 2 is a 5,053-acre parcel between Willow and Hunter creeks and is bounded east and west by strips of fee land straddling the same creeks owned by Exxon. One small parcel on the northeast is owned 75 percent by Shell and 25 percent by Exxon. The northeast corner of Tract 1 is some two miles from the southwest corner of Colorado Federal Lease Tract C-b.

Tract 3 is a 1,303-acre tract on Yellow Creek two miles east by northeast of Federal Tract C-a and straddles fee land owned by Bell Petroleum and Cross V Cattle Company.

Tract 4 is some four miles southwest of the C-b lease. It is a 5,098-acre parcel between Black Sulphur Creek and Ryans Gulch. Roughly half of the parcel is covered by nomination 6. Flanking private parcels are owned by Colony on the northwest and on the southeast by Exxon, 50 percent; Atlantic Richfield, 40 percent, and Equity Oil, 10 percent.

Tract 5 begins five miles due east of the C-a lease. It is a 5,111-acre parcel straddling Ryans Gulch. The only adjoining private ground is a strip of fee land in Ryans Gulch owned by Bell Petroleum and Cross V Cattle Company.

Tract 6 borders on the south of Tract 5 and the above named fee land in Ryans Gulch. Covering 5,120-acres, it includes roughly the four-section acreage also nominated at Tract 4 and is bordered on the south by a strip of fee land along Black Sulphur Creek owned 50 percent by Exxon, 40 percent by Atlantic Richfield and ten percent by Equity.

Selection in Utah

Tract 7 begins about a mile west of the Utah state line. It covers 4,912-acres and

adjoins or devetails with four sections of Utah state lands leased to Western Oil Shale Corporation. It is about four miles north of Utah Federal Lease U-b.

Tract 8, a 5,120-acre parcel, begins 13 miles west of Utah Federal Lease U-a. It dovetails with ten sections of Utah state land leased by Western Oil Shale Corporation and adjoins three others under lease to The Oil Shale Corporation.

Tract 9 is a 4,429-acre parcel on McCook Ridge between Sweet Water Creek and Bitter Creek some 15 miles south of the two Utah prototype leases. It adjoins a large acreage owned by Texaco, a small acreage owned by Carter Oil, and Utah state leases owned by Atlantic Richfield, Cayman Corporation and three small parcels held by 3-D Investment.

Proposed Processes

The selection committee was advised of the proposed methods of in situ shale oil extracted and those knowledgeable in shale research probably accurately deduced the names of most of the nominators.

Company "A's" process involves injection of a heated fluid into the "leached" zone of shale at a temperature sufficient to retort the rock. This company has field tested the use of natural gas and steam as heat carriers through two different well configurations.

Company "B" proposed modified in situ involving experimental 50 x 50 x 100-foot chimneys to be retorted by combustion (two) and by a hot gas sweep. Three 50 x 50 x 300-foot chimneys also are being designed.

Company "C" also proposed a modified vertical in situ process by combustion, anticipating 70 percent recovery of the oil in-place.

Company "D", nominating a Colorado site, proposed modified in situ recovery from an oil shale section of 300 to 700 feet thick.

Company "E" proposed a true in situ on Utah Site 9 (see Appendix for map locating

the nominations). Blast holes would be drilled down from the surface through the overburden--a shallow deposit it required--and on through the shale. The shale would then be blasted, any fractures extending to the surface sealed, and the broken shale re-torted by a horizontally moving fire front. Large diameter drill holes would be used for air input, exhaust and product output.

Companies "F" and "G" both proposed the patented Shell process for extraction the shale oil and the dawsonite and nahcolite associated with it. See Synthetic Fuels, September 1974 issue, page 2-18. The minerals would be solution-mined with super-heated water injected under high pressure. Extraction of the soluble minerals would leave the shale sufficiently permeable for later retorting.

The selection committee was advised that Shell has reported the process is technologically, but not economically feasible.

Both "F" and "G" nominations were in the heart of the Piceance Basin, where nahcolite and dawsonite are deposited in significant quantities.

Selection Committee

Members of the Interior selection committee, in addition to McBroom, were Donald L. Pendleton, then Vernal, Utah District Manager of the Bureau of Land Management; John R. Donnell, Oil Shale Section Chief, U.S. Geological Survey; Eric G. Hoffman, Area Oil Shale Office environmental geologist; Jerald Stroebele, regional assistant, energy activities leader, U.S. Fish and Wildlife Service; Paul L. Russell, research director, U.S. Bureau of Mines; John Ward Smith, research supervisor, Laramie Energy Research Center; Lowell L. Madsen, Office of the Solicitor, Denver; Howard Ritzma, Utah state geologist; Burman H. Lorenson, Colorado oil shale coordinator, Denver; Gerald D. Sjaastad, deputy director, Colorado Department of Natural Resources, and D. Keith Murray, chief, Mineral Fuels Section, Colorado Geological Survey.

Committee Consideration

The selection committee first met August

11, 1975, at the BLM office in Denver. Lorenson represented the Governor of Colorado. Ritzma was present for the first and, as it turned out, the last time. The committee was briefed on the task and BLM management plans. The meeting then was recessed until further notice by the request of Colorado Gov. Richard Lamm.

The committee again met August 25 in Denver. Utah had taken exception to the postponement of the first meeting. Because of the short notice of the second session, Ritzma was not present. In a telephone conversation with McBroom, Ritzma gave an "off the top of the head" ranking of the Utah tracts--7,8, and 9.

Later, after onsite investigation of the tracts by Ritzma and other Utah officials, Utah Gov. Calvin L. Rampton announced on October 21 that Utah gives equal recommendation to Tracts 7 and 9. He expressed doubts about Tract 8 because of the 2,000-foot overburden.

Selection Criteria

The committee judged the nominated sites on three major criteria: development potential, environmental considerations, and socio-economic factors. Equal weight was given to each. An entire week was devoted to consideration of the sites, rating each on each criterion by a complicated number system designed for objectivity. Tract 2 in Colorado and Tract 8 in Utah got top recommendation with Tracts 7 and 9 in Utah as alternatives.

As a final step, committee members rated the tracts on a subjective basis and achieved "essentially the same recommendations and the same tract selections," according to McBroom.

OSEAP Criteria

The selection committee received from William L. Rogers, special assistant to the Secretary of the Interior, the Oil Shale Environmental Advisory Panel's recommended criteria for site selection. These were (1) Sites containing state-owned surface lands should not be selected, (2) Maximum use of existing service and access corridors should be made, and (3) No site

should be recommended if dewatering would affect existing Federal Prototype Oil Shale Leases.

The committee's recommendations were reviewed in the light of these criteria and, according to McBroom, "It was agreed that those major areas of concern to OSEAP have been considered in the rating system."

Major Factors In Recommendations

The committee observed, without elaborating, that the tracts nominated "may not necessarily have been situated at the best locations. OSEAP would later make the same point without suggesting better sites, overlooking the fact that the sites were nominated for their development potential.

In its report, Tract 2 in Colorado was found "moderately free of groundwater problems and suitable for development by modified in situ methods." "Tracts 7 and 8 in Utah are dry or free of groundwater problems and suitable for development by modified in situ methods." "Tract 9 is dry. It may offer the best opportunity for early production of shale oil in commercial quantities by a true in situ technique. Technology developed here may be applicable to a relatively large area adjacent to the tract and to oil shales in Wyoming."

Tracts 1, 3, 4, 5, and 6, in the Piceance Creek Basin, concerned the committee. These included abundant groundwater, thick overburden, potential air quality problems, wildlife concentrations, and "reservations concerning availability of present technology for full recovery of saline minerals."

The committee noted the presence of pre-1920 mining claims on Tract 7 and part of Tract 8, but "their existence was not considered to be a determining factor in deciding whether the tracts should be selected." However, if Tract 7 is selected, the claims will have to "be cleared through appropriate administrative proceedings by the Bureau of Land Management.

Tract 3 is covered by an existing sodium lease and Tract 1 is covered by an existing sodium preference right lease. Both were eliminated for those reasons.

Tract 7 in Utah was "considered unacceptable by some OSEAP members due to socio-economic impacts that would likely occur to Rangely, Colorado. Utah would get the monies from bonuses and royalties, and Colorado could get the people," the committee report said.

The next move is up to Jack Horton, Assistant Secretary of the Interior for Land and Water Resources. Norton's intention is to have two tracts under lease by late 1976.

#

CORPORATIONS

C-b LESSEES SUBMIT DRAFT OF DETAILED DEVELOPMENT PLAN.

The draft detailed development plan (DDP) for Colorado oil shale tract C-b under the Federal Prototype Oil Shale Leasing Program was filed with the Area Oil Shale Supervisor in October by Shell Oil Company and its partners in the venture. Examination of the 1,200-page document reveals it is not overly detailed despite its bulk, and that the C-b sponsors are pessimistic about the political and economic climate necessary to attain the prototype program's initial 50,000 BPD goal.

The four C-b partners: Shell, Ashland Oil, Atlantic Richfield, and The Oil Shale Corporation have paid the first two \$23.5 million installments on the \$117.7 million onus. The draft DDP contains a number of statements indicating that the bonus money and development costs will be written off with any worsening of conditions affecting the tremendous investment required. The estimated cost of a six TOSCO-II unit, 50,000 BPD plant is \$923 million. Costs can be expected to increase in the final plan. Charles H. Brown, senior vice president of TOSCO told a House Committee in Washington, D.C., on October 8, that the price tag for a 50,000 BPD plan proposed by the Colony Project partners for location at Parachute Creek, Colorado, would be \$1,132,600 including \$20 million for community development. Those costs closely parallel the C-b situation.

C-b Development Program Reviewed

Tract C-b development is envisioned in three phases: mine development, plant construction and operation, and decommissioning and clean-up (about year 2004). If the tentative schedule--it appears to be very tentative--outlined in the draft is followed, the first shale oil would be produced in 1984. The first four years would involve the sinking of two 30-foot diameter, 1,650-foot deep shafts to the orebody and development of a mine. It is noted that the lessees would not make the commitment to a commercial plant until completion of the mine development work.

The development mine would cover a 40-acre area or about 1,300 x 1,300 feet. Pillars are expected to range from 50 x 50 feet with room spans of from 40 to 60 feet. Room height is scheduled at about 60 feet with mining by top heading and bench similar to that in the Colony mine on Parachute Creek a few miles to the south.

The plan notes that mine development could span a two to three-year period and overlap into Phase II, the plant construction period. Up to 3 million tons of shale might be produced and stockpiled during this time. The maximum size of this ore pile is estimated as covering an area 1,200 x 1,200 feet, or about 35 acres.

Mine Development

The mining development program will include a number of comprehensive investigations into what is unexplored mining territory. No shale mine has ever operated in the heart of the Piceance Basin. Existing mines are adit operations on the south perimeter of the basin.

On tract C-b, the Mahogany Zone, the target deposit, is some 1,650 feet below the planned collar of the production shaft and does not outcrop anywhere on the tract. Information which must be obtained includes pillar strength, allowable roof spans, underground hydrology, equipment evaluation, and air quality in the mine. The Mahogany varies from 174 to 187 feet in thickness on the lease. No decision has been made on which interval may be mined although "one of several alternative intervals of interest is a section over 75 feet thick in the upper middle part of the Mahogany."

The plan discounts longwalling, long hole blasting, and block caving mining methods because of both equipment and subsidence problems. Continuous mining machines for shale have not been developed, but this is the "probable direction oil shale mining will take in the long term." The mine will be designed so no surface subsidence is anticipated.

The two main shafts will be sunk from the top of an as of yet unnamed ridge, roughly in the center of the tract. The two shafts will be 500 feet apart. The production shaft will be equipped with four 60-ton skips.

Surface Plans

The plan envisions a water storage reservoir in Scandard Gulch in the northwest corner of the tract and spent shale disposal in Sorghum Gulch in an area of about 1,200 acres some two miles long and over half a mile wide. Twenty years of production at 66,000 TPD would result in a spent shale pile 200 feet high, according to the report.

Better sites, because of esthetics and environmental factors, for both the reservoir and spent shale disposal, are located off the tract to the south. The plan notes no planning in this direction will be done without a change in the law permitting off-tract use for such purposes.

Oil would be moved via pipeline southward to the Parachute Creek area to link with the La Sal pipeline planned by TOSCO from the Colony site. The oil then would flow from the pipeline proposed from Grand Valley, Colorado to connect with the Pure Oil pipeline at Lisbon Station, Utah. Upgrading in the 66,000 TPD plant using 35 GPT shale would yield by-products of 150 tons a day of ammonia, 175 tons of sulfur, and 800 tons of coke, in addition to 45,000 BPD low sulfur oil and 4,200 BPD LPG.

Operating capital cost is estimated at \$77.35 million. A per barrel operating cost is tabbed at \$4.92.

Plant construction time is estimated to be 45 to 50 months. Employment on the tract would peak at 450 to 500 during shaft-sinking operations, then taper to 65 to 100 during development mining. Plant construction would push employment to 3,200 to 3,500 workers and this would taper to 900 to 1,200 men as the plant moved into production. The draft DDP has surprisingly detailed manpower projections.

Engineering Detail Lacking

Despite the thickness of the plan, technical detail is missing. There is little detailed engineering included and it is understood that the lessees intend to apply for bonus credit on it. Underground detail is understandably lacking because there are few data on the deep shales other than borehole information. Countering this, the construction phase is specific. It is one of several portions of the documents that have been taken from the Colony Operation's environmental and other oil shale studies. The corridor study for the pipeline is from the Colony work and is listed under an off-tract impact section.

The final DDP is expected to total about 2,000 pages. The draft urges approval as soon as possible in 1976. It states that Phase I development will begin as soon as the DDP is approved. That may be mid-1976 or later.

#

OIL SHALE ENVIRONMENTAL PANEL REVIEWS DRAFT OF C-b DEVELOPMENT PLAN

The Oil Shale Environmental Advisory Panel's (OSEAP) comments on the draft detailed development plan (DDP) for Federal Oil Shale Prototype Tract C-b ranged from the picky to the profound at its October 23-24 meeting in Grand Junction, Colorado. The draft was submitted as a learning experience for the lessees (Shell, Atlantic Richfield, Ashland, and The Oil Shale Corp.) for the panel, and for the Area Oil Shale Supervisor Pete Rutledge's office, and other prototype lease tract holders. Consequently, the final draft is expected to be substantially revised.

Uncertainties Applauded

An informal discussion prior to OSEAP's meeting was scheduled was attended by less than half the full panel which had a limited time to study the document. The uncertainties and probabilities throughout the 1,200-page document were quickly noted. Termed

"flexibilities" this aspect was applauded by some members and defended by Rutledge.

Bob Loucks, of Shell, project manager for the C-b partners, said the lessees "attempted to select the best scenario, the probable way we will go." He said it is "impossible and impractical to predict the actions and impacts" until the Phase I development is completed. Phase I is the mine development period, prior to the completion of which, the lessees say they will make no commitment to build a commercial plant.

Rutledge said "It's pretty obvious it's not going to be possible to trace an absolute path" in advance. A carte blanche path will not be approved. "What will be approved will be this 'most probable' path," Rutledge said.

Panelists Joe Blum, of the Western Energy and Land Use Team, Fort Collins, and Dr. Thad Box, Utah State University, applauded the draft DDP's "flexibility". Box called flexibility "the key to any development plan."

Doubts Expressed

Nevertheless, Box was skeptical that the lessees are gathering sufficient data to protect themselves from future attack regarding adequate evaluation of environmental effects. Loucks responded that the draft contained a limited summary of first-year-environmental studies and this section was to be bolstered considerably in the final plan. Box then contended that "you've measured the structure (of the C-b ecology), but there's little said about functions." He said the draft lacks a "good analysis of successional patterns."

It was apparent that the lessees had been in close contact with Rutledge's office in assembling the plan. To a criticism that worst possible cases of oil shale development impacts were not included, such as air pollution compounded by temperature inversions. Rutledge asked, "Is it better to cite the worst case and maybe mislead people...or emphasize the most probable?"

Socio-Economic Impacts

The draft does not address socio-economic

impacts. Lease terms do not require it. Nevertheless, Rutledge said all federal tract lessees have agreed to submit a separate statement on this aspect with their final draft DDP's.

Panel Comments

When the panel formally convened, commentary was most repetitious. There were two contradictory areas of criticisms. One complained of a lack of documentation-- "state why you are doing this based on what you've learned out on the tract." The other, voiced most noticeably by Dr. Box, urged a shortening rather than a lengthening of the report, "a tightening up on where we are and how we plan to get there."

Rutledge noted the difficulty of addressing three audiences: his office, OSEAP, and the public. He reiterated the need to pick the most probable path and noted "the process to date is preliminary." Something which looked fine at present may be quarreled with in the final. Review of the final draft will take six months, he said.

The panel made no formal recommendations and it is likely the draft will get more comment when members have had more than a couple of hours to scan the 1,200-page document.

#

OCCIDENTAL MOVES AHEAD ON MODIFIED IN SITU

Occidental Oil Shale Inc. planned to ignite its big No. 4 modified in situ retort on the D. A. Shale property north of DeBeque, Colorado, at the end of November or early December.

The No. 4 retort is a major scale-up measuring 120 x 120 x 300 feet. Previously tested retorts or chimneys measured 30 x 30 x about 70 feet (see June 1974 issue of Synthetic Fuels, page 2-30). Preparation of the No. 4 retort was delayed by delivery of some steel equipment and installation of such items as thermocouples which will provide data to the surface during the burn. Original plans had been to start the burn by mid-summer.

Meanwhile, Oxy has been mining out one of

the earlier retorted units to examine the spent shale, burn patterns, and especially the retort sidewalls. Burn effects on the latter will have much to do with spacing of future chimneys and ultimate recovery of the reserves. Oxy officials have maintained their traditional reluctance to discuss specific technical aspects of what they learned.

Mined Rock Disposal

Oxy made applications on August 29 for an enlarged disposal dump to receive up to 8.8 million cubic yards of mine waste. The procedure involves acquiring a special use permit required by Garfield County zoning regulations despite the fact the mine is a continuing operation on private land.

Oxy has had a permit for 500,000 cubic yards of disposal and used about 300,000 of it in work through preparation of retorts 1 to 4. Most of the rock is low grade shale mined from above and below--mainly below--the Mahogany Zone. The rock referred to in the permit would make a pile 30 feet high and half a mile on each side. Oxy has been dumping down the talus slope adjacent to the mine in Logan Wash.

Garfield County commissioners, who will decide whether to award the permit, referred the application to the Colorado Land Use Commission for review and recommendation. The latter in turn circulated it among 13 other agencies: the U.S. Bureau of Land Management and 12 state offices such as the Geological Survey, Division of Highways, Health Department, and Division of Wildlife. Any or all of the agencies could recommend stipulations or even denial of the permit.

Hearing Scheduled

Garfield commissioners, who make the final decision, scheduled a public hearing on the application for December 8 at Grand Junction, Colorado.

The permit is one of more than 30 that Occidental has had to secure for the Logan Wash operation (see September 1975 issue of Synthetic Fuels, page 2-55, for discussion of the variance on underground fires.)

An Occidental official said the permit is preparatory for work in 1976. He said Oxy also hopes to acquire a tract in richer--30 gallon per ton shale--and was a nominator of one of the sites proposed for federal leasing for in situ development. This apparently was Tract 2, discussed elsewhere in this issue. Occidental also has approached a number of shale land owners in attempts to extend their holdings.

The Oxy official said the disposal permit would allow expanded operations on the D.A. Shale tract where shale averages 15 to 25 GPT in the event the firm fails to acquire a tract with higher yield.

#

GEOKINETICS STILL SEEKING FEDERAL SHALE TRACT

Geokinetics Inc. of Concord, California, revealed at the October meeting of the Oil Shale Environmental Advisory Panel (OSEAP) in Grand Junction, Colorado that it was the nominator of proposed federal in situ oil shale lease Tract 9 on the southern rim of Utah's Uintah Basin. The nomination marks Geokinetics' second attempt to get into the oil shale business via a federal lease. They were the nominator of Tract U-b leased in the Prototype Oil Shale Leasing Program of 1974 and were an unsuccessful bidder on two leases. Tract 9, was one of two alternative sites recommended by the Department of the Interior's Site Selection Committee appointed to review the nominations and make recommendations. The 4,429-acre Tract 9 subsequently was given equal status by Utah officials with 4,912-acre Tract 7 who discounted the committee's top choice, Utah Tract 8 (5,120 acres). (See in situ tract discussion elsewhere in this issue). Of the nine nominated sites, only Tract 9 is of interest to Geokinetics, a relative corporate newcomer to the shale industry although its principals are not.

Geokinetics is mum about their in situ process. What is public is contained in the Site Selection Committee's report (see Appendix). The firm is conducting field tests in the area of Tract 9 some 15 miles south of the two federal prototype program leases U-a and U-b. The location of Geokinetics'

lease is confidential. It is a mining lease, which Utah law provides will be kept confidential at the operator's request.

The Process

John Downen, Geokinetics vice president, told OSEAP members, Geokinetics needs shale with thin overburden--Tract 9.

The Site Selection Committee report revealed the nominating company would use a true in situ process with no underground mine workings and no oil shale being brought to the surface: "The oil shale would be fractured and retorted in situ. The operation would be conducted in the following manner:

"A. Blast holes would be drilled down from the surface through the overburden and on through the oil shale.

"B. The blast holes would be spaced, loaded, and fired in such a manner that fragmentation would be maximized in the oil shale and be minimized in the overburden.

"C. Any fractures created by blasting, connecting the retort to the surface of the ground, would be sealed.

"D. After the shale in a retort is broken by blasting and the surface sealed, it would be processed by means of a horizontally moving fire front. Large diameter drill holes would be used for air input and output. Air blowers and mist extractors would be located directly adjacent to the operating retorts.

"E. Part of the oil would be produced as a mist with the retort off gases and part would be recovered as a liquid from producing wells located at the downstream end of the retort.

"F. The product would be crude shale oil that would initially be trucked out but later would be pumped via pipeline to an off-site plant for further treatment, or directly to a crude oil pipeline, depending upon its characteristics."

Production Plans

Downen told OSEAP at its October 22 meeting that Geokinetics would take about three years to "either develop the process or dry hole it." Once proved it can be rapidly expanded, he said. He estimated a reserve of 10 billion barrels available at Tract 9 suitable to the Geokinetics process. Downen placed the cost of proving the process at \$3 million to \$5 million.

Two to three years and another \$2 million to \$3 million would be required to move from field testing to production phase.

He said a modified in situ process can be used on all other nominated tracts but the true in situ process his firm proposes "is applicable only to Tract 9."

Geokinetics History

Downen and another geologist, Mike Lekas, formed Geokinetics in 1969. They organized a consortium to nominate and bid on leases in the Prototype Oil Shale Leasing Program.

Lekas, a former U.S. Atomic Energy Commission scientist, was among the early proponents of nuclear fracturing as a prelude to in situ retorting of oil shale (see the June 1966 issue of Synthetic Fuels). That led to the proposal for Project Bronco which was still born as more became known about the extensive aquifers in the heart of the Piceance Basin where the nuclear fracturing and in situ extraction experiment was planned.

#

AMERICAN LURGI SEEKS INDUSTRY SUPPORT FOR 4,000 T/D LURGI-RUHRGAS PROCESS DEMONSTRATION PLANT

American Lurgi has presented a proposal to 14 major owners or lessees of oil shale lands seeking industry support of a project for constructing and demonstrating the Lurgi-Ruhrigas oil shale retorting process. The proposal has been discussed with federal and state government officials so that they, too, would be aware of the proposed development.

American Lurgi is proposing that a plant "module" of 4,000 TPD capacity be demonstrated. A 4,000 TPD module, in Lurgi's view, is a fully commercial-scale unit. A module would consist of shale feed bin, a mixing screw (1), a gas-solids separation and surge bin (4) a lift pipe (2), a collecting bin at the upper end of the lift pipe, (6), and various accessory equipment necessary for handling the off-gas product (2 and 3), and flue gas and dust (7 and 8). The numbers refer to items shown in Figure 1, a simplified flow diagram for the Lurgi-Ruhrigas process.

A commercial plant would in all probability combine "modules" to form "trains". A train would consist of two 4,000 TPD mixing screws which would be arranged to operate with but one gas-solids separation and surge bin, one lift pipe, etc.

In its proposed plan, Lurgi estimated that the 4,000 TPD demonstration module could be operational 36 months after project approval.

Actually, Lurgi has presented two oil shale proposals recently. One is for the 4,000 TPD demonstration module, the subject of the proposal to the major companies. The other proposal concerns a 1,000 TPD module which is being offered to smaller companies.

From Figure 1, it may be seen that finely crushed oil shale is mixed with hot "heat carrier" spent shale solids in a mixing screw. The oil shale is pyrolyzed as it is heated to about 950°F. Pyrolysis gases separate from solids in the surge bin, and pyrolysis gases, shale oil, and water are separated from the off-gas. A portion of the spent shale is heated and lifted in the lift pipe, from whence it is fed back into the feed screw. Combustion of residual carbon, gas or even shale oil within the lift pipe provides the process heat. Combustion product gases leave the system. Feed shale must be crushed to approximately minus 1/4-inch size. Rather than crushing all mine-run oil shale to this fineness, a Lurgi-Ruhrigas unit might operate most profitably in conjunction with another retorting process which handles coarse shale, such as the vertical kiln processes (Gas Combustion,

Petrosix, or the Paraho version of these processes). Vertical kilns cannot handle the minus 1/4-inch shale very well, hence pairing the two types of retorts can offer some merit.

Lurgi Canada Ltd. has made similar proposal for industry support of a 4,000 TPD L-R plant to treat Alberta oil sands. This is discussed in the Oil Sands section of this issue of Synthetic Fuels. Also, Lurgi was recently commissioned to provide two 4,000 TPD L-R units for processing oil shale in Bulgaria. All of these various units are similar, except that minor adaptations are needed to accommodate specific shale grades, sources of fuel for burning in the lift pipe, etc.

#

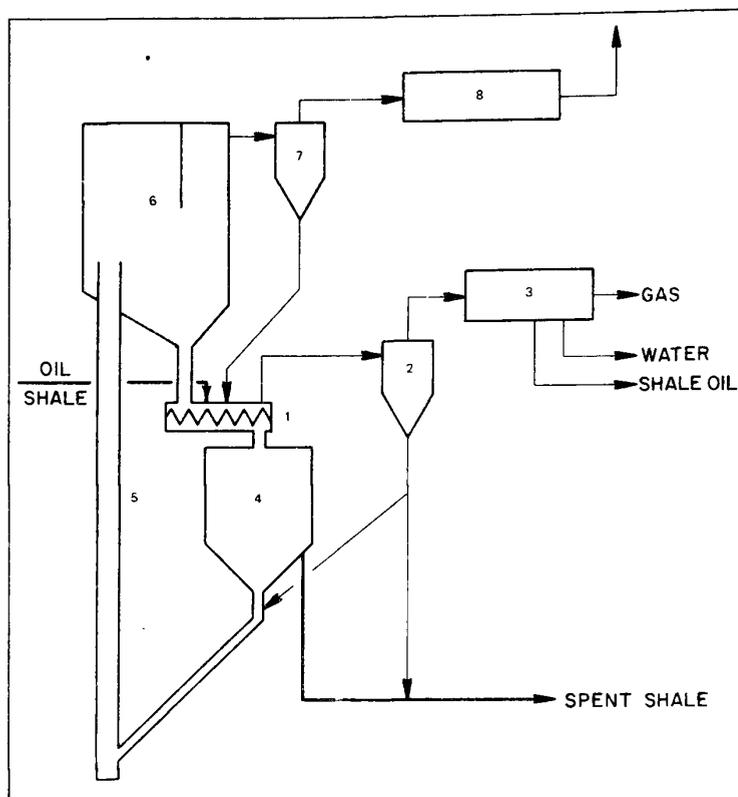


Figure 1. Simplified Flow Diagram For The Lurgi-Ruhrigas Process.

SUPERIOR OIL COMPANY'S MULTIPLE PRODUCT PROCESS REVIEWED

The October 1975 issue of Shale Country, a publication sponsored by Ashland Oil, Arco, Gulf, Shell, Standard Oil (Indiana), Standard Oil (Ohio), Sun Oil, and TOSCO, contains a general article on Superior Oil Company's oil shale process. Most public features of Superior's process have been reported previously in much greater detail than is presented in this article. Ben Weichmann, chief of Superior's oil shale operations, has authored several papers reviewed in previous issues of Synthetic Fuels (December 1972, page 2-6; September 1972, page 2-9; September 1973, page 2-19) and in the CSM Quarterly, Vol. 69, No. 2, pp. 25 through 43.

The distinctive thing about the Shale Country article is a drawing of Superior's circular traveling grate retort, a principle applied in several mineral extraction operations, but not previously linked with oil shale processing.

The article in Shale Country magazine does contain a picture of the circular traveling grate retort. This is the first public indication we have seen of the type of retort Superior plans to use. Traveling grate machines, in many variations, have been used for many years, but principally for sintering of iron ore fines or for oxidizing roasting of sulfide ores of lead and zinc. Their principle of operation is to place the rock to be retorted (or sintered, calcined, baked, etc.) on porous-bed carts which travel around a circular path within a sealed housing. The continuous train of carts is loaded, heated, retorted, cooled, dumped, etc. as it passes through specific sections of its route. Sealing of the different sections has been somewhat of a problem in the past, but evidently improvements have been made. Gases are capable of passing through the shale on each cart to accomplish the various functions such as heating, cooling, etc.

It is of interest that one function noted in the schematic drawing of the retort is labeled "residual carbon recovery." Evidently, Superior plans to recover fuel or energy from the residual carbon left on

the shale solids after retorting is completed.

This type of circular retort apparently allows accurate temperature control within each of the various processing zones, and maximizes recovery of both hydrocarbons and aluminum chemical products, either Al_2O_3 or $Al(OH)_3$.

If Superior obtains its proposed land exchange with Interior, the company estimates that its development project would start with the mine opening and production of nahcolite. The estimated time period is two years. Following this, construction of an initial 20,000 TPD complete modular unit for shale oil and mineral production would begin. It would require approximately three years to complete.

No cost estimates are available from Superior. Weichmann has consistently maintained that because of the multi-mineral product slate, the project would probably not require any type of subsidy and is economically viable.

Superior's pilot plant testing should be finished in mid-1976. If it proves successful, the main plant would be built in 20,000 TPD modules, with each module being a total retort system.

Superior's application to the Bureau of Land Management to exchange 2,500 acres of Superior fee land for about 1,700 acres of BLM land on north edge of Colorado's Piceance Basin is yet to be resolved. BLM asserts additional data from Superior and a report from the U.S. Geological Survey evaluating the tracts' respective resources are needed to ascertain the equitability of the proposal.

Superior has repeatedly indicated "blocking up" of oil shale deposits is necessary to make its venture feasible.

#

STATUS OF OIL SHALE LEGAL PROCEEDINGS NOTED

The status of various Bureau of Land Management administrative contests and of state and federal court cases which concern oil shale in the intermountain region of Colorado, Utah and Wyoming is summarized in Table 1.

TABLE 1

STATUS OF OIL SHALE LEGAL PROCEEDINGS

BUREAU OF LAND MANAGEMENT ADMINISTRATIVE CONTESTS:

Contest No. Colo. 359-360: USA vs. F.W. Winegar, et al

Contestant seeking to invalidate oil shale claims held by contestees on basis of no discovery. Recommended decision issued by BLM hearing examiner on 4/17/70 wherein three claims were declared invalid and six claims adjudged to be valid. BLM filed appeal brief on 6/12/70. Interior's Bureau of Land Appeals decision of 6/28/74 reversed 4/17/70 decision and all claims were ruled invalid. See September 1974 issue of Synthetic Fuels, p. 21, for discussion.

As a result of the adverse decision, the claimants have taken the matter to court. See discussion under Civil Action 74F-739 in the United States District Court in Denver.

Contest No. Colo. 193 & 260: USA vs. TOSCO

These contests will be decided by the courts in Civil Actions 8680, 8685, 8691, and 9202, all of which cases are before the U.S. District Court and the 10th U.S. Circuit Court of Appeals in Denver. See recent development in Action 74-13-44 before the U.S. Circuit Court of Appeals.

Contest No. Wyoming 27951, etc.:

By decision IBLA 74-113, dated March 20, 1974, the Board of Land Appeals affirmed the decision issued September 4, 1973, declaring the placer mining claims null and void in Contests W-28091, W-28124 and W-28126. The Plaintiffs filed on September 12, 1974, Petition and Complaint A.F. Anderson, et al vs. Rogers C.B. Morton, et al, Civil No. C-74-151, United States District Court, Wyoming. See discussion under U.S. District Court in Cheyenne.

By decision IBLA 74-155, dated June 26, 1974, the Board of Land Appeals affirmed the decision issued October 15, 1973, declaring the placer mining claims null and void in Wyoming Contests W-28032 and W-28429. The original contest proceeding involved 24 contests; however, appeals were taken on only the two contests. The Plaintiffs filed on September 12, 1974, Petition and Complaint Walter H. Burkhardt, et al, vs. Rogers C.B. Morton, et al, Civil No. C-74-152, United States District Court, Wyoming. See discussion under U.S. District Court in Cheyenne.

Contest No. Wyoming 30079, etc.:

These contests involve 21 complaints which were issued April 12, 1974. No further action has been taken.

controlled by Standard Oil Company of California. For discussion of issues, see Synthetic Fuels, September 1972, page 2-1. Motion for summary judgement denied. Pre-trial conference held 2/21/74. All actions since 2/21/74 concern interrogatories and responses. No trial date has been set.

Civil Action 4361: Amerada Hess vs. Secretary of the Interior

Complaint filed on September 26, 1972, wherein Plaintiff asks court to reverse decision of General Land Office Commissioner in BLM Contest 127900 (dated 1931) to reverse Interior Board of Appeals ruling of June 28, 1972 involving rejection of unpatented mining claim ownership, a pre-trial conference was vacated. On June 3, 1974, it was ordered that the matter be held in abeyance until 60 days after all appeals are completed in Civil Action 8680

Civil Action 74F-739: Shell Oil, et al vs. USA (R.C.B. Morton)

Complaint filed August 20, 1974. This is the continuation of BLM Colorado Contests 359 and 360. Having lost in the administrative contests, Shell Oil, et al, took the matter to the courts. The issues have been followed in numerous articles in Synthetic Fuels since 1964. The parties agreed that the case will be decided on the administrative record. The date April 15, 1975 was then set for filing motions for summary judgement. Forty-five days were allowed after April 15 for answers. Following this were various motions, extensions, and mailings. No trial date has yet been set.

Civil Actions 5276 and 5308: Merle I. Zweifel vs. USA

Zweifel sought to overturn portions of BLM's decision in Colorado Contest 441 which declared 2910 mining claims in Piceance Basin null and void, but the complaint was dismissed in December 1973 because of filing errors. Zweifel filed complaint again. On January 28, 1975, nullification of the claims was affirmed. Civil Action 5276 is now closed and Civil Action 5308 is still in appeal.

BEFORE U.S. DISTRICT COURT IN SALT LAKE CITY

Civil Action 74-64: State of Utah vs. USA

Complaint filed on 3/4/74 seeks to compel Interior Secretary Morton to approve Utah's school indemnity selection lists and thereafter to grant the State title to some 157 thousand acres of oil shale land in the Uinta Basin including federal lease tracts U-a and U-b. ON 4/22/74, court ordered that first year rentals and bonus installments for federal tracts be placed in escrow pending outcome of suit. See June 1974 Synthetic Fuels, page 2-2. No date set for pre-trial conference. No change since June of 1974.

BEFORE UTAH STATE DISTRICT COURT IN SALT LAKE CITY (Third Judicial District)

Civil Action 219340: Morgan & Justheim vs. State of Utah

Complaint filed in May 1974 alleges that State Land Board erroneously cancelled 25 state oil shale leases covering 13,829 acres in the Uinta Basin of eastern Utah. Leases were issued on old lease form which had a primary term of 10 years, unless the lessee was in commercial production (new lease form has a 20-year term). The case went to trial on January 21, 1975 and was decided in favor of the State of Utah. Morgan and Justheim have appealed the adverse decision before the Utah State Supreme Court and that appeal is still pending.

BEFORE U.S. DISTRICT COURT IN CHEYENNE

Civil Action C-74-151

A.F. Anderson vs. Rogers C.B. Morton

This court action is the continuation of Bureau of Land Management Wyoming Contest 27951 (IBLA Ruling 74-113). Hearing was held on 8/25/75. The matter is under advisement.

Civil Action C-74-152

W.H. Burkhardt vs. Rogers C.B. Morton

This court action is the continuation of Bureau of Land Management Wyoming Contest 27951 (IBLA Ruling 74-155). Hearing was held on 8/25/75. The matter is under advisement.

BEFORE THE 10TH U.S. CIRCUIT COURT OF APPEALS IN DENVER

Civil Action 74-13-44

Secretary of the Interior vs. TOSCO

This relates to Civil Action 8680 and its related and combined Civil Actions 8685, 8691, 9202, 9252, 9458, 9461, 9462, and 9465. On 9/22/75 the Appeals Court issued an Order of Remand which instructs the Department of the Interior to examine any and all bases for invalidating the oil shale mining claim patent applications involved. A detailed discussion of Order of Remand is presented in the text of this quarterly and a copy of the Order of Remand is presented in the Appendix section.

III

oil sands

TECHNOLOGY

A CLOSED CYCLE, SINGLE-STAGE SEPARATORY PROCESS ON ALBERTA OIL SANDS IS PATENTED

W.J. Rosenbloom recently obtained U.S. Patent 3,875,046 which describes a variation of the hot water separation process applicable to Alberta oil sands.

Figure 1 shows a process flowsheet reproduced from the patent in which oil sand is pretreated with hot water and steam so as to form a slurry which can be screened. Screen oversize is discarded and the screen undersize is charged into a covered extraction vessel. In the extraction vessel, a rising stream of treated water and steam fluidizes the oil sands solids. On the surface of the material in the extraction vessel, a layer on oil/solvent collects and is withdrawn. Barren sands collect, or "filter", the clay solids material and the sand and clay solids are removed from the bottom of the extraction vessel continuously by an auger-type of conveyor. Steam, pH additives, and an un-named solvent are added to the water which is used in this process. Most of the water is continuously recycled.

Advantages claimed for this process are that it requires less water, the clay and silt fines do not interfere with the separation process, heat requirements are minimal, and a single stage of separation is all that is required.

#

PATENT DESCRIBES USE OF DISC-TYPE CENTRIFUGE TO UPGRADE OIL SANDS FROTH PRODUCT

Exxon Research and Engineering Company recently obtained U.S. Patent 3,893,907 entitled, "Method and Apparatus for the Treatment of a Tar Sand Froth." It describes a scheme which involves treating a conventional hot water process oil sand froth product in a disc recycling type of centrifuge. The overflow effluent from the disc centrifuge is composed of an oil or bitumen phase which is relatively pure. The underflow effluent is composed of water and bitumen-wetted solids.

The underflow effluent is reintroduced into the disc centrifuge after a water-wetting "transfer agent" is added. The

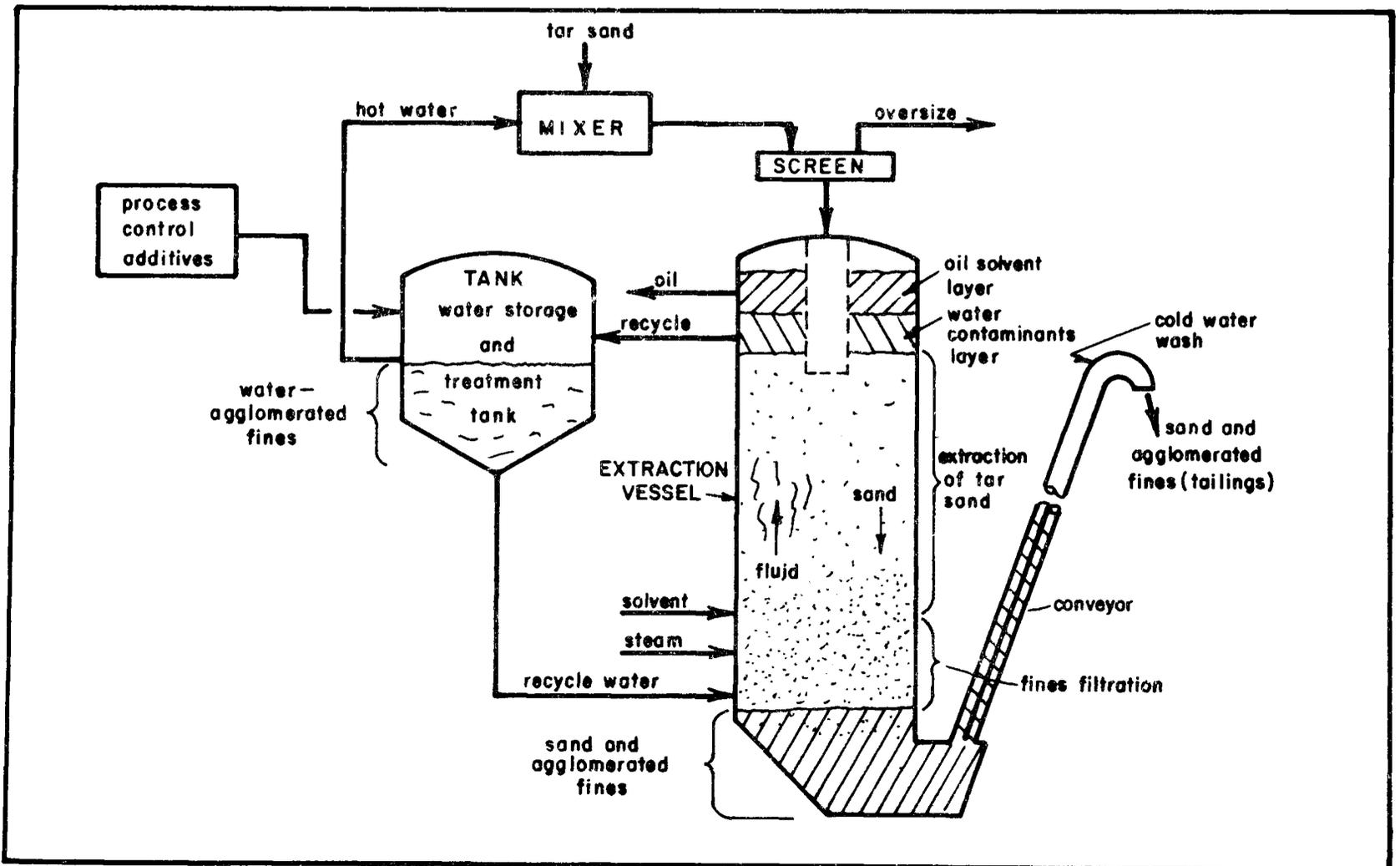


Figure 1. Process Flowsheet from U.S. Patent No. 3,875,046

transfer agent causes the sand solids to become water-wet, which allows solids to be rejected in a subsequent separation vessel.

The preferred transfer agent is tetrasodium syrophosphate, which is added at the rate of about 0.1 weight percent of the underflow stream which is recycled to the disc centrifuge.

#

TEXACO PATENTS PROCESS WHICH COMBINES IN SITU SOLVENT DEASPHALTING WITH SUBSEQUENT IN SITU COMBUSTION

Texaco obtained U.S. Patent 3,874,452 which claims that viscous petroleum may be recovered from viscous asphaltic petroleum-containing formations such as tar sand deposits by first injecting into the tar sand deposit a deasphalting solvent such as N-methyl-2-pyrrolidone, furfural, or a mixture thereof which solubilizes the non-asphaltic materials present in the tar sand, and causes precipitation of the asphaltic materials on and/or around the sand grains in the tar sand deposit. After the quantity of asphalt precipitating solvent is injected, air is injected in the tar sand deposit and the formation is ignited by conventional means to cause the initiation and propagation of an in situ combustion reaction front through the reservoir.

The precipitated asphaltic materials are used selectively as the fuel for the in situ combustion reaction, driving the more volatile materials ahead of the combustion front. The temperature of the combustion is higher than conventional in situ combustion reactions, and is sufficiently high to induce an appreciable degree of thermal cracking of heavy hydrocarbons. Air injection may be continued until the reservoir has been depleted, or it may be followed after a period of time by the injection of water into the burned out portion of the reservoir.

An attractive feature claimed for the process is that the asphaltic materials present in the formation hydrocarbon fluid are selectively used as the fuel for the in situ combustion reaction which accomplishes

the enhanced oil recovery. Since the asphaltic materials are the least desirable and least valuable of the hydrocarbon fluids, the economics of the oil recovery process are especially enhanced by the selective use of asphaltic materials as the fuel for in situ combustion. Furthermore, the precipitation of the asphaltic materials by the injected deasphalting solvent in the first step of the process ensures that a high fuel density will be available for the ensuing in situ combustion phase. The presence of a high fuel density will provide a high reaction temperature in the reservoir, which will result in a considerable amount of thermal cracking and in situ hydrogenation so that the viscosity of the produced fluid is reduced in situ in the reservoir. The thermal cracking and in situ hydrogenation operations aid in the improved oil recovery, and also increase the value of the crude produced on the surface.

According to the patent description, the use of deasphalting solvent in the first phase of the procedure represents a dramatic contrast to what would normally be good field procedure for miscible flooding operations in such reservoirs. Ordinarily, if were to operate a miscible flood recovery operation, the solvent would be carefully selected so as not to cause precipitation of asphaltic materials. Texaco claims, however, that the precipitation can be an advantage when used as the first phase of a multiple step operation wherein the solvent is followed by injection of air and ignition to achieve in situ combustion. Furthermore, it is not necessary to inject the same quantity of solvent as would be required for a conventional miscible placement procedure. Ordinarily, about 0.01 to 0.5 pore volumes of solvent will be adequate to effect the required degree of asphaltic material precipitation necessary to achieve the benefits of the invention.

After deasphalting solvent injection is completed, air is injected into the formation and sufficient heat is applied to the injection well bore to start a combustion reaction within the formation. The in situ combustion phase of the operation will be accomplished in essentially the same manner as any conventional in

situ combustion or fire flooding secondary recovery operation. Ordinarily, the preferred embodiment will involve the compression of air on the surface and injection of the compressed air into the formation, although any oxygen containing gas or pure oxygen may be used. The pressure will ordinarily be limited by the overburden thickness, since injection of high pressure air into a relatively shallow formation will cause fracturing of the formation, with channeling of the air through the formation without efficient displacement of oil. Since many of the tar sand deposits are relatively shallow, for example around 100 to 500 feet, the air pressure must be held below the 100 to 500 pound per square inch range.

#

GCOS PATENTS METHOD FOR CLARIFYING WATER DISCHARGED FROM HOT WATER SEPARATION PROCESS

Great Canadian Oil Sands Limited (GCOS) recently obtained Canadian patent number 973,500 entitled, "Freeze-Thaw Separation of Solids From Tar Sands Extraction Effluents".

In the description of the patented process it is pointed out that the water discharged from the hot water process must be stored, disposed of, or recycled back into the process. Because this water contains bitumen emulsions, finely dispersed clay with poor settling characteristics, and other contaminants, water pollution considerations prohibit discarding the water into rivers, lakes or other natural bodies of water. It has been proposed that the water be stored in evaporation ponds, but this proposal would involve large space requirements and the construction of expensive enclosure dikes. It has also been suggested that the water in the effluent discharge be recycled back into the process as an economic measure to conserve both heat and water. However, while some of this water can be so recycled, the amount of recycle is limited by the dispersed silt and clay content of the water which can reduce froth yield by increasing the viscosity of the middlings layer and retarding the upward settling of bitumen

flecks. A proportion of water in the diluted tar sands pulp fed into the separation cell must therefore be fresh water -- water which is substantially free of the clay and silt found in middlings water. In fact, with some high clay content tar sands feed, all of the water in the diluted pulp must be added as fresh water.

GCOS has found that water discharged from the process containing silt and clay can be made suitable for recycle as at least a portion of the hot water process water feed by treating the discharge according to a method of agglomeration, freezing, thawing, and filtration as described herein. Mere agglomeration, by means such as flocculation, even with extended settling, cannot be used to clarify water from a hot water process. Flocculation-settling produces sludges of less than ten weight percent solids from pondwater. It has been found by the present invention that agglomeration such as by flocculation, freezing, and thawing produces solids compaction of greater than ten weight percent solids up to about thirty weight percent. It has also been found that proper agglomeration of the pondwater must be combined with the freezing and thawing steps. Freezing and thawing alone will not produce a stable compacted sludge of more than ten weight percent solids.

Although the present invention is not bound by theoretical explanation, it is obvious that the freezing and thawing sequence causes solids compaction by concentration and compression of the clay agglomerates during the freezing step followed by settling of the larger and more dense agglomerates in the thawing step to a sludge displaying about thirty weight percent solids. The clarified water is suitable for recycling to the hot water process.

#

IMPERIAL RELEASES INFORMATION ON IN SITU PROJECT

Imperial Oil Ltd., a subsidiary of Exxon U.S.A., holds leases on more than one-fourth of the leased acreage in the Cold

Lake oil sands deposit of Alberta. The rest of the acreage is divided between twelve other companies or consortiums, with Mobil Oil Canada controlling roughly 36 percent of this remainder. Of all the companies conducting experimental in situ projects in the area, Imperial has no doubt been the most successful and is by far the closest to commercialization. At a recent "open house" at Imperial's newest in situ project, the firm released some technical information regarding their operations.

The "open house" was designed to acquaint members of the Alberta government, the Alberta Oil Sands Technology and Research Authority (AOSTRA), the press, the local Cold Lake community, and other interested persons in the actual operations of the company. Just as in the United States, the politicians of Canada make decisions which directly affect the future of industry, yet base their opinions only on what others have told them. While this information may be totally accurate, both opponents and proponents of development have been known to stretch a point at times. The Imperial open house at least provided an opportunity for these persons to see the plant and discuss the operation with the technical staff--not just the public relations department and upper level management. Furthermore, Imperial felt this would be an opportune time to put to rest the various rumors which have been discussed in the local community.

Ethel, May, and Leming Projects Described

The current in situ project, entitled the Leming pilot, involves the injection of 600°F, 1600 psi steam into the Clearwater oil sands zone through eight pads of injection and production wells arranged in a seven-spot pattern. The center injection well is drilled vertically and the surrounding six wells are drilled directionally on to yield 600-foot spacing in the producing formation. In addition to the steam, some quantity of natural gas is also injected. The concentration of this natural gas is still a proprietary bit of data. According to Imperial, the natural gas does enhance recovery, but at this time there is no well founded explanation for this behavior. The 80 percent quality injection

steam is produced in a 20,000 BPD gas-fired plant which is fed from a 26,000 BPD capacity water treatment plant, which in turn acquires feedwater directly from Ethel Lake.

The Leming project is actually the third in a series of demonstration projects in the Cold Lake area. The first such plant, the Ethel pilot, began in 1964 and operated for about six years. This project was subdivided into essentially three separate pilots, though all were in the same general location.

A second, larger pilot was then constructed. This project, entitled the May pilot, consisted of a 23-well array, part of which involved recompleted wells from the old Ethel pilot. The May pilot is still producing at various rates, with some wells yielding up to 400 BPD.

The new Leming project is authorized to produce up to 5,000 BPD and according to Imperial, oil is being produced at approximately that rate, though daily output is variable depending on the point in the injection/production cycle.

Comment

Perhaps no one will ever know the true lasting value of Imperial's information campaign, but it is obvious that such activities can certainly do no harm, as long as they function as an outlet for facts rather than propaganda. Industry has only to look at the events of the last year to see that it requires huge investments of time, energy, and money to offset the effects of a few erroneous statements by industry critics. Perhaps the aboveboard "fact-finding" open house held by Imperial will be a precedent which others may wish to emulate. If the politicians and writers came away from the Leming pilot with any significant thoughts, one can only hope that they include the fact that a \$100 million investment in oil sands technology is just a "drop in the bucket" and furthermore that the role of government should not be to give money to industry, but rather to provide a healthy economic climate in which industry money can circulate.

#

NDC PUBLISHES VOLUME OF OIL SANDS AND SHALE
PATENT REVIEWS

The Noyes Data Corporation recently published a book entitled, "Oil from Shale and Tar Sands" as number 51 in their Chemical Technology Review series. The hardbound volume was compiled by Edward M. Perrini and the foreword states that the... "detailed, descriptive information in this book is based on U.S. patents issued since 1960 that deal with obtaining oil from shale and tar sands. Where it was necessary to round out the complete technological picture, even earlier, but very relevant patents were included."

The book contains approximately 300 pages of patent reviews composed of what seems to be paraphrasing by the compiler of the actual patent wording. All of the illustrations appear to be direct reproductions from the patents.

The first paragraph of the introduction contains the statement, "As left by nature, oil shale is actually a substance called kerogen..." which is an unusual definition for a volume that goes to such lengths to tell the reader it contains "the complete technological picture." A subsequent section does note that, "Shale oil is not a naturally occurring product, but is formed by the pyrolysis or distillation of organic matter (commonly called kerogen) found in certain shale-like rock." There are other such contrasts in the book as well.

Copies available at \$36 each by writing the Noyes Data Corporation, Noyes Building, Park Ridge, New Jersey 07656.

#

STUDY DETAILS UTAH OIL SANDS

Another report on Utah oil sands has been published as Report of Investigation No. 100 of the Utah Geological and Mineral Survey. The report is entitled "Lithologic Logs and Correlation of Coreholes: P.R. Spring and Hill Creek Oil-Impregnated Sandstone Deposits, Uintah County, Utah." Data from 16 coreholes drilled in 1973 are presented by P.R. Peterson, consulting geologist. It is part of a long range, in-depth study by the survey, as outlined February 1974 in Investigations No. 88 (see Synthetic Fuels), March 1974, page 3-15.

The study is principally on the Mahogany oil shale bed and on oolitic and algal limestone beds in the Douglas Creek Member of the Green River Formation, which in the study area are 75 to 250 feet thick. In the Hill Creek portion of the study, significant oil impregnation occurs above the Mahogany zone as well as below it.

The report graphically illustrates the grade of sands and some of their properties. Besides the 30 page report, five cross-section plates are provided. They display a considerable variety of lithology in the P.R Spring deposit, a factor greatly influencing the economic potential of the sands. Concentration of oil in the Hill Creek deposit is primarily in the northwest and is revealed to be much leaner subsurface than outcrops indicate.

The report, along with three previously issued U.S. Bureau of Mines studies on Utah tar sands properties, broadens the publically available data on the resource and gives far better perspective on their development potential.

#

ALBERTA INDIANS THREATEN LAWSUIT OVER LAND CLAIMS

The Indian Association of Alberta (IAA), under the leadership of Harold Cardinal, again is threatening to go to court to receive direct benefits from massive development in the oil sands region. Although

no litigation has yet been filed, the initial indications are the Indians may have a case, just as they claimed in 1974 when the Cree Indians in the James Bay, Ontario, area were negotiating for a monetary settlement relative to the James Bay Hydroelectric Plant. The Ontario natives succeeded in obtaining \$150 million. It was discussed in the September 1974 issue of Synthetic Fuels page 3-9.

No one can deny that most of the Indians of Northern Alberta live under deplorable conditions, at least by the socio-economic yardsticks of today's culture. Furthermore, it is not just another case of the white man applying his "middle class" values to an entirely different type of society. Rather, the Indians themselves recognize their situation and want to improve their lot. The current lawsuit appears to be an attempt by them to pull themselves up by their bootstraps and thereby not be dependent on hand-outs and promises from the government.

Indians May Still Own the Land

The major issue essentially revolves around the real ownership of the oil sands region. When Great Canadian Oil Sands, Ltd. (GCOS), Syncrude, and the other oil sands developers leased their land from the Province of Alberta, they logically assumed that the province legally owned it. Likewise, when Alberta was granted ownership of the land by the Canadian federal government under the Natural Resource Transfers Act of 1930, they naturally assumed that the federal government actually had clear title to the land. The current claim of the IAA is that the federal government never really owned the land in the first place, or at least did not have the right to dispose of it.

While there are several ancillary complaints and claims the core of the Association's case is based upon the provisions of Treaty Number 8, signed in 1899. Harold Cardinal has been publicly quoted as saying that the Northwest Territories Supreme Court has ruled that the treaty is "one of friendship and peace, not a land surrender treaty." The basis for that decision is somewhat difficult to understand, in that

Treaty Number 8 specifically states:

"And whereas, the said Commissioners have proceeded to negotiate a treaty with the Cree, Beaver, Chipewyan and other Indians, inhabiting the district hereinafter defined and described, and the same has been agreed upon and concluded by the respective bands at the dates mentioned hereunder, the said Indians DO HEREBY CEDE, RELEASE, SURRENDER AND YIELD UP to the Government of the Dominion of Canada, for Her Majesty the Queen and Her successors forever, all their rights, titles and privileges whatsoever, to the lands included within the following limits..." (A map showing the area included in the treaty is provided in Figure 1).

"And Her Majesty the Queen HEREBY AGREES with the said Indians that they shall have right to pursue their usual vocations of hunting, trapping and fishing throughout the tract surrendered as heretofore described, subject to such regulations as may from time to time be made by the Government of the country, as may be required or taken up from time to time for settlement, mining, lumbering, trading or other purposes.

"And Her Majesty the Queen hereby agrees and undertakes to lay aside reserves for such bands as desire reserves, the same not to exceed in all one square mile for each family of five for such number of families as may elect to reside on reserves, or in that proportion for larger or smaller families; and for such families or individual Indians as may prefer to live apart from band reserves, Her Majesty undertakes to provide land in severalty to the extent of 160 acres to each Indian, the land to be conveyed with a proviso as to non-alienation without the consent of the Governor General in Council of Canada, the selection of such reserves, and lands in severalty, to be made in the manner following, namely, the Superintendent General of Indian Affairs shall depute and send a suitable person to determine and set apart such reserves and lands, after consulting with the Indians concerned as to the locality which may be found suitable and open for selection.

"Provided, however, that Her Majesty reserves the right to deal with any settlers within the bounds of any lands reserved for any band as She may see fit; and also that

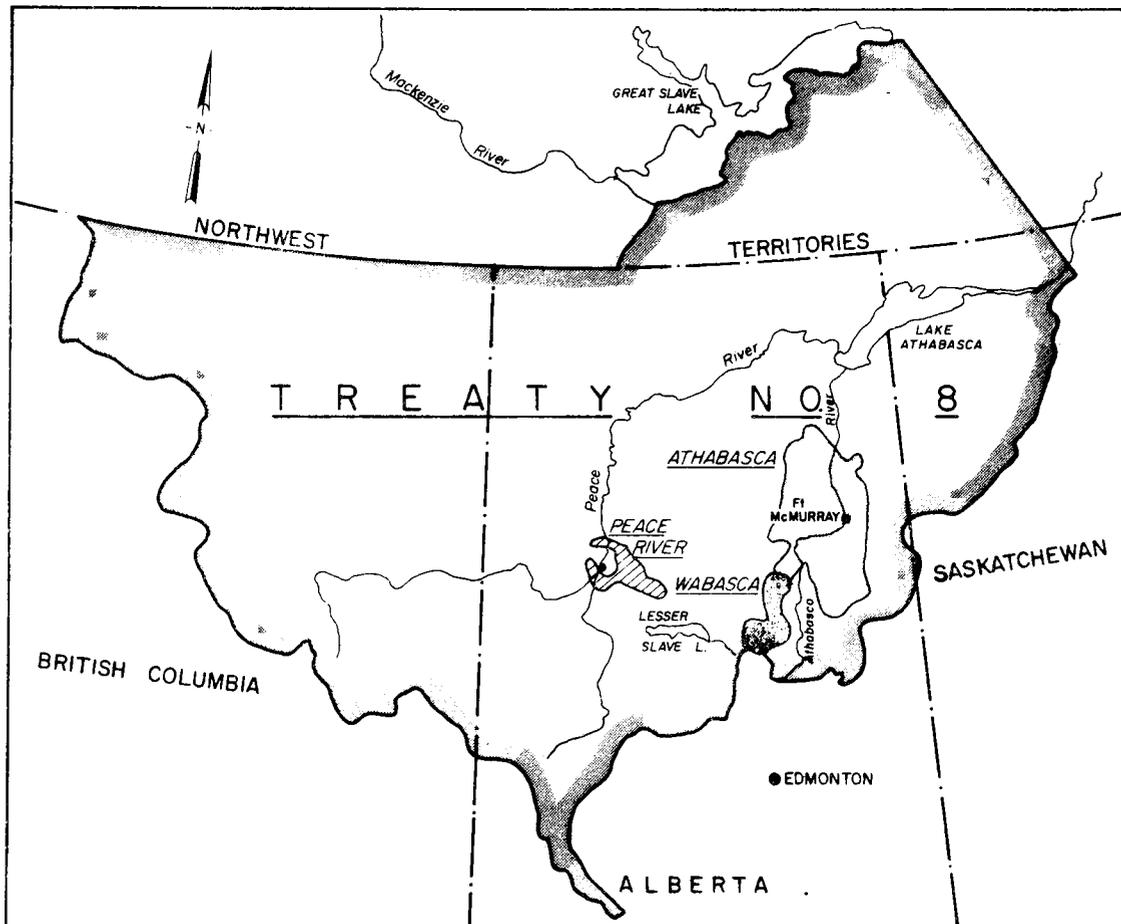


Figure 1. Area Covered by Treaty Number 8

the aforesaid reserves of land, or any interest therein, may be sold or otherwise disposed of by Her Majesty's Government for the use and benefit of the said Indians entitled thereto, with their consent first had and obtained.

"It is further agreed between Her Majesty and Her said Indian subjects that such portions of the reserves and lands above indicated as may at any time be required for public works, buildings, railways, or roads of whatsoever nature may be appropriated for that purpose by Her Majesty's Government of the Dominion of Canada, due compensation being made to the Indians for the value of any improvements thereon, and an equivalent in land, money or other consideration for the area of the reserve so appropriated."

Another factor being evaluated is the doctrine of discovery. That concept is based on Europeans "discovering" portions of the Western Hemisphere and laying claim to its land simply by setting foot on it, raising a flag and making a proclamation.

Leroy Little Bear, chairman of the Native American Studies Department, University of Lethbridge, asserts the doctrine does not apply to the Indians. Indians, he observes, all shared and share the land and had no individual ownership of specific property. It can be argued, then, that early treaties and grants of land to non-Indians are invalid because the grantors (Indians) had no land to cede away.

Future Claims May Be Based on Land Entitlements

Cameron Engineers in no way claims to have any expertise in the area of legal interpretation, especially of Canadian law. From a reading of the above statements, it can be agreed that future legal action can be founded on the clause which states that the Indians must grant their approval prior to any transfer of land ownership. Furthermore, the treaty grants a certain amount of land to each Indian wishing to claim such an entitlement. To date, many of the natives covered by the treaty have not made claims. It may be possible for them to claim entitlements in the oil sands deposits --possibly on the Syncrude plant site.

There is another approach which the IAA may follow. This would be to claim incompetence on the part of their ancestors who signed the original document. The claim could be made that the Indians were not fully aware of the consequences of their actions due to language or literary difficulties. We suggest this approach simply for completeness and offer no opinion regarding its legal applicability.

Latest word is that Mr. Cardinal has met with federal officials to discuss the situation, but no workable solutions have yet be offered by the government. Meanwhile, a recent survey showed that there is now a 78.8 percent unemployment rate among the Indians in the Fort McMurray area. Other similar studies have established that figure at 93 and 97 percent. The publicly stated goal of the IAA is to achieve a settlement somewhere between the \$150 million paid the James Bay Indians and the \$400 million awarded the Alaska natives. Mr. Cardinal proposes to use the money for the economic development of all the native people in the province of Alberta.

It should be observed that Indian rights issues pertaining to land, water, and resources are a North American issue, and are not limited to the western United States, central Alaska, or any other local region.

#

GOVERNMENT

ATHABASCA OIL SANDS INDEX SERVICE

The Athabasca Oil Sands Index, an idea conceived and begun by Syncrude of Canada and expanded by the Alberta Research Council, is a service which searches technical publications and makes available a keyworded index of pertinent articles therefrom. It can be obtained through a subscription which also provides, at cost, single copy reproductions of most of the articles and patents indexed. The Alberta Research Library makes this additional service possible.

Some years ago, Syncrude started an index of oil sands articles and soon found the proliferation of information so formidable that it recently asked the Alberta Research Council to adopt the project. The Council agreed. It published the first index in 1970. When it was revised in 1973, Carol Zawaski was hired as editor. For the current year, 3,500 articles have been recorded to constitute the original issue the subscriber receives. During each calendar year four supplements of about 250 articles each are to be published, listing approximately 900 additional articles annually. The cumulative edition is published in January and the quarterlies in April, July, and October.

Indexed material comes from more than 100 Canadian, United States, and foreign periodicals, patent agencies, government agencies, conferences, and other publications. Revision of oil sand literature is undertaken as new sources become available. The intention is to make the index as comprehensive as possible on a world wide scope.

Geologists, geochemists, chemists, and engineers, each with experience in oil sands technology aid in the selection and key-wording of index entries. Keywords are arranged alphabetically at the left hand side of each page, generally by subject or surname of the author. Titles are the original English language title or the English translation of a foreign language.

By January 1976, the index material will be recorded on a computer to effect cross-indexing and searching by reference

to authors, patents, publications or corporate names. Five consoles provide access to the data at any one time.

Subscription rates of \$1,000 (Canadian) for the first year and \$500 each succeeding year are under review and may be lowered. Additional copies are \$25 each to subscribers. Subscribers receive free abstracts of the Alberta Research Council's publications on oil sands. Inquiries may be directed to Carol D. Zawaski, Editor, Research Council of Alberta, 11315-87 Avenue, Edmonton, Canada T6G 2C2.

#

ALBERTA RESERVES DESCRIBED IN ERCB REPORT

The Alberta Energy Resources Conservation Board (ERCB) has released Report 75-18 entitled "Reserves of Crude Oil, Gas, Natural Gas Liquids, and Sulfur--Province of Alberta." This publication represents the fourteenth annual edition of the report. The reserve summaries contained in the report are as of year-end 1974.

The section of the report dealing with oil sands is brief and to-the-point, but does contain a considerable amount of good information. The official oil sands deposits designated by the ERCB are the Athabasca, Cold Lake, Peace River, Wabasca, and Buffalo Head Hills Deposit. Figure 1 shows the locations of the deposits as established by various Oil Sands Deposit (OSD) Orders.

The report discusses an considerable detail the ERCB's criteria for establishing economically recoverable reserves. These criteria are described in the March 1975 issue of Synthetic Fuels beginning on page 3-15. One of the most significant points of the oil sands section is the tabulation of reserves in each of the deposit areas. This compilation is reproduced in Table 1. It should be noted that prior to 1963, the evaluation of in place reserves was based on a minimum saturation of two weight percent bitumen. Since 1963, however, that cutoff value has been changed to three weight percent.

TABLE 1

THE PROVED RESERVES OF CRUDE BITUMEN AND SYNTHETIC CRUDE OIL
December 31, 1974

	1	2	3	4	5	6	7	8
<u>Deposit</u>	<u>Overburden Depth Interval</u>	<u>Areal Extent Thousand acres</u>	<u>Average Pay Thickness ft</u>	<u>Average Crude Bitumen Saturation Fraction by weight</u>	<u>Crude Bitumen Saturation Cut-Off Fraction by weight</u>	<u>Initial Crude Bitumen In Place Bstb</u>	<u>Crude Bitumen Recovery Fraction by volume</u>	<u>Initial Recoverable Crude Bitumen Bstb</u>
1 Athabasca	0-50	80	104	0.10	0.02	12	0.83	10
2	50-100	210	103	0.10	0.02	33	0.58	19
3	100-150	200	94	0.10	0.02	29	0.30	9
4	150-250	270	112	0.10	0.02	47	-	-
5	250-500	590	104	0.10	0.02	89	-	-
6	500-1,000	2,100	67	0.10	0.02	210	-	-
7	1,000-2,000	2,300	59	0.10	0.02	207	-	-
8								
9 Cold Lake A	1,000-2,000	1,800	53	0.08	0.03	118	-	-
10								
11 Cold Lake B	1,000-2,000	650	40	0.08	0.03	33	-	-
12								
13 Cold Lake C	1,000-2,000	710	16	0.08	0.03	14	-	-
14								
15 Buffalo								
16 Head Hills	500-1,000	22	6	0.05	0.02	-	-	-
17	1,000-2,000	131	7	0.05	0.02	1	-	-
18	2,000-2,500	6	21	0.05	0.02	-	-	-
19								
20								
21 Peace River	1,000-1,500	7	7	0.07	0.03	-	-	-
22	1,500-2,000	480	54	0.07	0.03	28	-	-
23	2,000-2,500	1,070	43	0.07	0.03	46	-	-
24	2,500+	49	18	0.07	0.03	1	-	-
25								
26								
27 Wabasca A	250-500	91	25	0.10	0.02	4	-	-
28	500-1,000	619	32	0.08	0.02	26	-	-
29	1,000-2,000	54	11	0.10	0.02	1	-	-
30								
31								
32 Wabasca B	1,000-2,500	1,000	26	0.06	0.03	23	-	-
33								
34 <u>TOTALS</u>		12,439				919 ^d		38 ^d
35						(146) ^d		(6) ^d

^a A Description and Reserves Estimate of the Oil Sands of Alberta, Oil and Gas Conservation Board, October 1963.

^b Geology and Proved In Place Reserves of the Cold Lake Oil Sands Deposits, ERCB Report 73-L-Geol, September 1973.

^c Geology and Proved in Place Reserves of the Peace River Oil Sands Deposits, ERCB Report 74-R, October 1974.

^d Metric equivalent in 10^9 m^3 .

^e Metric equivalent in 10^6 m^3 .

9 10 11 12 13 14 15

Synthetic Crude
Oil Recovery

<u>Cumulative Crude Bitumen Production</u> MMstb	<u>Remaining Recoverable Crude Bitumen</u> MMstb	<u>Of Crude Bitumen In Place Fraction by volume</u>	<u>Of Recoverable Crude Bitumen Fraction by volume</u>	<u>Initial Recoverable Synthetic Crude Oil</u> MMstb	<u>Cumulative Synthetic Crude Oil Production</u> MMstb	<u>Remaining Recoverable Synthetic Crude Oil</u> MMstb	<u>Remarks</u>	
138	10,200	0.58	0.70	7,200	97	7,100	Evaluated in 1963 ^a and 1972	1
-	18,900	0.40	0.70	13,200	-	13,200		2
-	8,800	0.21	0.70	6,200	-	6,200		3
-	-	-	-	-	-	-		4
-	-	-	-	-	-	-		5
-	-	-	-	-	-	-		6
-	-	-	-	-	-	-		7
-	-	-	-	-	-	-		8
-	-	-	-	-	-	-	Evaluated in 1973 ^b	9
-	-	-	-	-	-	-	Evaluated in 1973 ^b	10
-	-	-	-	-	-	-	Evaluated in 1973 ^b	11
-	-	-	-	-	-	-	Evaluated in 1973 ^b	12
-	-	-	-	-	-	-	Evaluated in 1973 ^b	13
-	-	-	-	-	-	-		14
-	-	-	-	-	-	-		15
-	-	-	-	-	-	-	Evaluated in 1963 ^a	16
-	-	-	-	-	-	-	Average oil saturation	17
-	-	-	-	-	-	-	estimated at 5 per cent	18
-	-	-	-	-	-	-	by weight	19
-	-	-	-	-	-	-		20
-	-	-	-	-	-	-	Evaluated in 1974 ^c	21
-	-	-	-	-	-	-		22
-	-	-	-	-	-	-		23
-	-	-	-	-	-	-		24
-	-	-	-	-	-	-		25
-	-	-	-	-	-	-		26
-	-	-	-	-	-	-	Evaluated in 1963 ^a	27
-	-	-	-	-	-	-	Maximum oil saturation	28
-	-	-	-	-	-	-	estimated to be 12 per	29
-	-	-	-	-	-	-	cent by weight	30
-	-	-	-	-	-	-		31
-	-	-	-	-	-	-	Evaluated in 1972	32
138	37,900			26,600	97	26,500		33
				(4 300) ^e				34
								35

Note - Weight to volume conversion for the Athabasca Deposit is 1.95, for the Peace River Deposit it is a porosity dependent function having a weighted average of 2.22, for other deposits it is estimated to be 2.0.

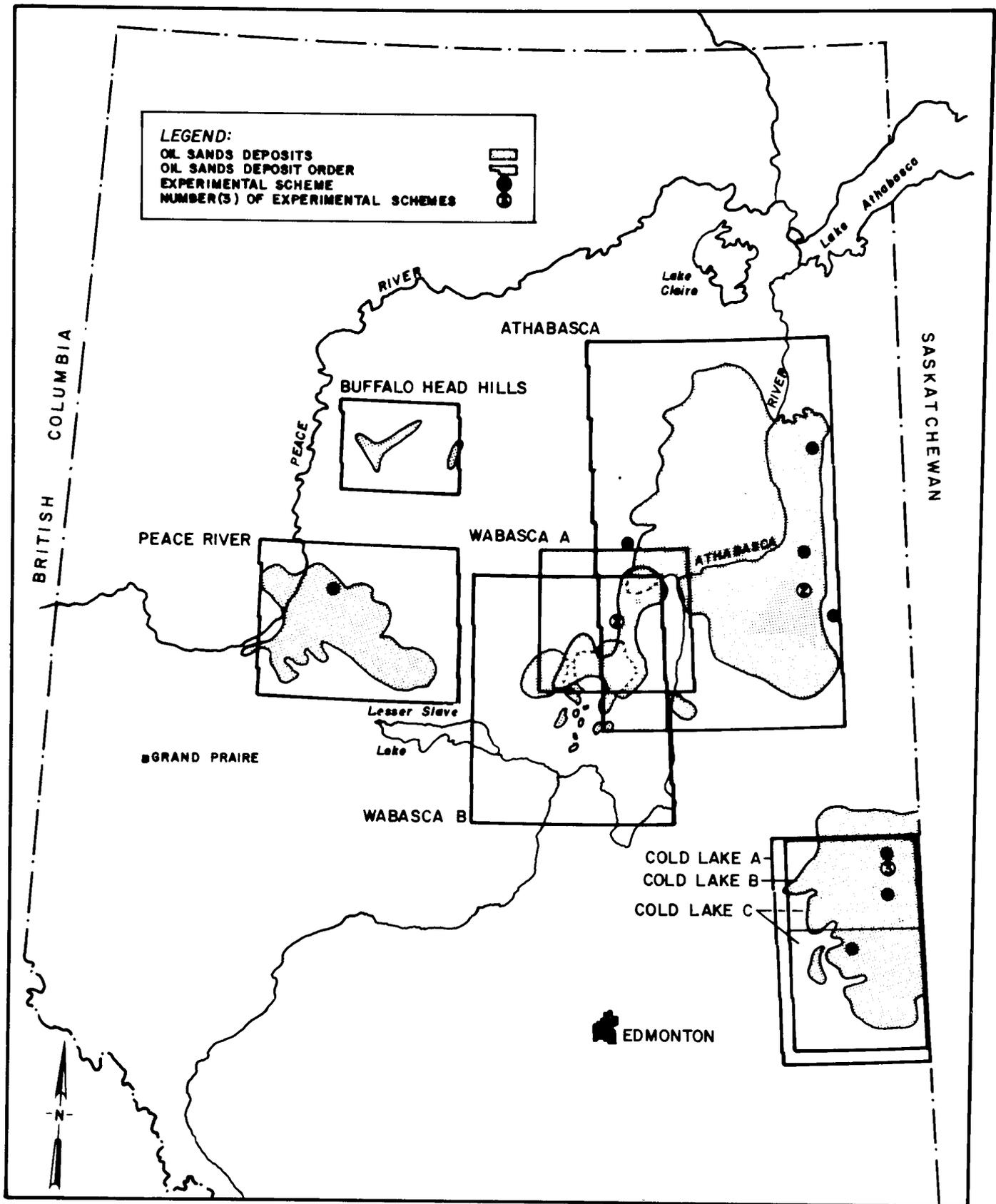


Figure 1. Oil Sands Deposits, Deposit Orders, and Location of Experimental Schemes in Alberta, Canada

The estimates of recoverable reserves shown in Table 1 are based "on the assumption that recoverability of crude bitumen by mining operations is presently proved to overburden depths not exceeding 150 feet provided that the ratio of overburden depth to average pay thickness does not exceed 1.0. For the purpose of evaluating the reserves recoverable by mining operations, the Board discounted the average pay thickness by that portion of the thickness which has a crude bitumen saturation of less than five weight percent. The decreasing crude bitumen recovery fraction with increasing overburden depth reflects discounting within the overburden depth intervals of in place reserves for overburden-to-pay-thickness ratios in excess of 1.0 and for bitumen saturation less than five weight percent."

Because of the unproved nature of in situ recovery techniques, the Board has refrained from including bitumen reserves underlying more than 150 feet of overburden in "proved" categories.

Copies of the ERCB report may be obtained from the Alberta Energy Resources Conservation Board, 603 - 6th Avenue, S.W., Calgary, Alberta, Canada, T2P 0T4 at a cost of \$40.00.

#

CORPORATIONS

LURGI SEEKS INDUSTRY SPONSORS FOR \$15 MM L-R PROCESS PILOT PLANT

Lurgi Canada Ltd. sponsored a one-day seminar in Calgary on October 7 to make a technical presentation of the features of the Lurgi-Ruhr gas process for treating Alberta oil sands. Invited attendees included representatives of companies which hold oil sands leases in Alberta and government officials. Lurgi Canada's president, Don Haines, and Dr. Brendl served as hosts, and Messrs. Rammner and Weiss made the technical presentations.

Lurgi Canada believes that the L-R process offers features which overcome several shortcomings of the conventional hot water separation process. Lurgi has described its process in the literature. In 1970, for example, R.W. Rammner's paper entitled, "The Production of Synthetic Crude Oil From Oil Sand by Application of the Lurgi-Ruhr gas Process" appeared in the October issue of the Canadian Journal of Chemical Engineering. While that particular article presented results of a pilot plant test of a California oil sand sample, Lurgi Canada believes a case can be made for testing Alberta oil sands in an existing pilot plant located in Germany.

Following a pilot plant demonstration on Alberta oil sands, Lurgi Canada proposes that industry, or industry and government combined, support a project for constructing and demonstrating a 5,000 BPD commercial-scale module to be located in the Athabasca oil sands area.

Simultaneous with this Lurgi Canada proposal for a demonstration oil sands plant, American Lurgi has a similar proposal for oil shale demonstration plant in Colorado. Also, the parent Lurgi company in Germany has agreed to furnish two 4,000 TPD oil shale L-R plants to Bulgaria. All of these plants are similar and all are of about the same size. A flowsheet for the L-R process and a description of the operation scheme are presented in the Oil Shale section of this quarterly in conjunction with the discussion of American Lurgi's oil shale proposal.

At the seminar in Calgary, Lurgi representatives promoted several features of their L-R process. First, they noted that the conventional hot water process loses about seven percent of the bitumen content of the sand during the separation process. An additional three percent loss occurs during extraction, and another two percent loss occurs in the naphtha processing side. The conventional process, as exemplified at Great Canadian Oil Sands and at the proposed Syncrude partners plant, requires a coking system. Syncrude plans to discard 2,400 tons of coke per day, unused. Syncrude also plans to use natural gas rather than coke as fuel. GCOS, however, uses some of its coke, but must discharge SO₂ to the atmosphere. This is done under permit from the Province of Alberta.

The L-R process makes coke during the pyrolysis of the organic matter (bitumen), but this coke is then used as fuel for the process. In addition to the residual carbon fuel, L-R will use some of the liquid heavy ends as fuel, because the carbon is not present in sufficient quantity to furnish all of the heat necessary.

In addition, Lurgi contends that the L-R process does not require as much water as does the hot water process, and many problems associated with water clarification are avoided.

Lurgi Canada's job now is to organize a consortium to provide funds for the pilot plant demonstration and for the construction of the common commercial-scale 5,000 BPD module in Alberta.

#

RECENT NOMINATIONS FOR GCOS SYNCRUDE LISTED

The actual nominations of companies and refineries which purchased synthetic crude from the Great Canadian Oil Sands (GCOS) plant during September and October are shown in Table 1. Also shown are the estimated requirements for synthetic crude oil for November and December. It is noted that the GCOS production rate has returned to normal after the scheduled biennial shutdown of last summer.

#

TABLE 1
 TABULATION OF NOMINATIONS
 FOR SYNTHETIC CRUDE OIL
 REPRODUCED FROM ATHABASCA BITUMINOUS SANDS
 (September and October of 1975)

<u>Purchaser/Destination</u>	<u>Sept.</u>	<u>Oct.</u>	<u>Estimated Requirements, B/D</u>	
			<u>Nov.</u>	<u>Dec.</u>
BP Oil Limited/Bronte, Ontario	--	--	--	--
Northwestern Refining Co./ St. Paul Park, Minnesota	8,000	8,000	8,000	8,000
Shell Canada Ltd./ St. Boniface, Manitoba Corunna, Ontario	10,200 7,400	7,300 3,900	6,700 6,000	7,300 6,000
Sun Oil Company Ltd./ Sarnia, Ontario Toledo, Ohio	18,000 <u>11,385</u>	18,000 <u>11,273</u>	18,000 <u>18,500</u>	18,000 <u>18,500</u>
TOTAL	54,985	48,473	59,200	59,500

ROOSEVELT, UTAH REFINERY MODIFICATIONS
 FOLLOW TAX SALE: EXPANSION ANTICIPATED

Plateau, Inc., of Farmington, N.M., bought the 7,000 BPD Major Oil Corp. refinery at Roosevelt, Utah, in a \$4.4 million deal based on a U.S. Internal Revenue Service tax sale September 24 in Salt Lake City.

Plateau bid \$2,830,000 at the IRS auction after IRS placed a lien on the property for nonpayment of \$425,000 in back taxes and penalties owed by Major. O. L. Garretson, president of Plateau, said payments of mortgages on the refinery and acquisition of other facilities and assets brought the total deal to the \$4.4 million figure.

Major has used the refinery to process crude oil from tar sands extracted in the Asphalt Ridge operations of Arizona Fuels Corp., one of Major's principal corporate stockholders.

Garretson said Plateau expects to put the refinery back into operation about December 1 following considerable expenditures on maintenance and engineering modifications

including work on heat exchangers, pumps, receiving trays, draw points, valves, and other features. There are no plans to handle any oil sands crude although the refinery would be capable of processing them. Expansion of the refinery is possible after operating factors are determined, Garretson said.

Eugene Dalton, president of Arizona Fuels, said work on a 190-acre Asphalt Ridge tract is continuing with production anticipated about January 1, 1976. The tar sand would be treated at the site and the crude trucked to Arizona Fuels' refinery at Fredonia, Ariz.

The improvement of the refinery by Plateau, a subsidiary of Suburban Propane Gas Corp., Whippany, N.J., could provide a solid base for more extensive oil sands demonstration projects in northeast Utah. The sale helped Arizona Fuels with some capital to continue work on oil sands.

Garretson said Plateau is interested in processing conventional crudes from the vicinity. Plateau is a producer, refiner and marketer of petroleum products.

#

IV

coal

TECHNOLOGY

OAK RIDGE PRESENTS PHASE I REPORT TO ERDA ON COAL HYDROCARBONIZATION PROJECT

Oak Ridge National Laboratory has issued a Phase I report of a three-phase project sponsored by the Energy Research and Development Administration. The objective of the project is to develop methods for producing clean gaseous, liquid, and char fuels from coal by hydrocarbonization.

The Phase I report concerns the evaluation of current carbonization and hydrocarbonization processes and the formulation of operating conditions for laboratory and bench-scale investigations.

Laboratory-scale evaluation of hydrocarbonization system components will be conducted in a second phase of this project, and a continuous bench-scale hydrocarbonizer will be constructed and tested in the third phase.

The Phase I report is entitled, "Hydrocarbonization Research Phase I Report: Review and Evaluation of Hydrocarbonization Data." It is Oak Ridge National Laboratory's Report No. ORNL-TM-4835. Copies are available from NTIS, Springfield, Virginia 22161, at \$7.60 for printed copies and \$2.25 for microfiche.

Hydrocarbonization processes emphasize the production of coal liquids. Hydrocarbonization processes are similar to low-temperature coal carbonization in that fluidized or entrained beds are used; however, air is excluded from the system and pressurized hydrogen is used as the fluidizing medium. Many investigators have found that the hydrogen tends to increase the yields of liquids, particularly as the partial pressure of hydrogen is increased. Hydrocarbonization has been proposed as a more attractive route to coal products than the high-pressure German Bergius hydrogenation process. Although the liquid yields for hydrocarbonization are somewhat lower than for hydrogenation, the overall yields of gas plus liquids are comparable; the difficult "pasting" oil recycle and heavy oil letdown problems are avoided in hydrocarbonization.

The objective of this project is to investigate the hydrocarbonization process with emphasis upon the production of liquid, char, and gaseous products all suitable for boiler fuel consumption. The first phase of the work, summarized in this report, has consisted of the review and evaluation of the available information.

Literature from eight carbonization and hydrocarbonization processes has been reviewed; these eight processes are summarized in Table 1, reproduced from the Oak Ridge National Laboratory's report. The process performances reported here are those claimed by the developer of each process.

The range of liquid yields from the eight processes reviewed is from 9.5 percent in the CSIRO - Australia tests to 55.0 percent in the Schroeder patent. In section four of this report, an attempt was made to correlate process performance with operating conditions and correlations of liquid yields with process temperature and hydrogen partial pressure are reported. However, the high liquid yield from the Garrett process cannot be accounted for on the basis of correlated temperature and pressure effects.

The distribution of the total heat available in the char, liquid, and gas products from the various carbonization and hydrocarbonization reactors was estimated, and results are shown in Table 1. These estimates represent the heat available from total combustion of the products leaving the reactor, but do not take the requirements for process heating within the plant and hydrogen generation into account. For example, in the coalcon process, the liquids and gases will be final products but the char will be consumed within the plant, possibly for hydrogen generation and other uses.

A comparison of the available heat distributions indicates that the CSIRO and Union Carbide chars contain the highest (83.8) and the lowest (42.8) percentages, respectively, of the total available heat in the reactor products. The Union Carbide

TABLE 1

SUMMARY OF CARBONIZATION AND HYDROCARBONIZATION PROCESSES

Process	Union Carbide	U.S. Steel	Garrett	COED	C.S.I.R.O.	Schroeder ^a	USBM	Consol Fluidized Bed
Coal	Lake de Smet	Illinois No. 6	Western Kentucky	Illinois No. 6	Wallarah, Australia	b	Hanna, Wyoming	Pitt Seam
Temp., °C	566	449-760	579	288-816	460	500	510	496
Pressure, psi	~1000	80-150	Approx. atmospheric	6 - 10	300-600	2000	Approx. atmospheric	10
Holdup time	5-11 min	~50 min	< 2 sec	1 - 4 hr	37 min	< 2 min	12 min	45-120 min
Yield ^c , %								
Char	38.4	66.4	56.7	60.7	83.0	b	60.9	b
Liquid	29.0	13.9	35.0	20.1	9.5	55.0	22.1	26.0
Water	19.2	5.1	1.7	5.7	5.5	b	6.5	b
Gas	16.2	14.6	6.6	15.1	3.0	37.3	7.3	b
Status of Process Development	15 tons/day; pilot plant has been operated successfully on noncaking coals.	A 0.25- to 0.5-ton/day PDU under development; 100-ton/day pilot plant under design.	Results based upon 1-in.-diam reactor. Process to be tested in an available 3.6-ton/day pilot plant.	36-ton/day pilot plant has been operated.	0.5-ton/day pilot plant has been operated.	Results from laboratory-scale experiments.	5-ton/day pilot plant has been operated.	1.5-ton/day pilot plant has been operated.

Estimate of Reactor Product Available Heat Distribution (Percentage of Total Heat From Combustion of Products)								
Char	42.8	60.2	50.4	63.5	83.8	-	65.2	-
Liquid	36.9	15.9	41.6	28.8	12.7	-	30.3	-
Gas	20.3	23.9	8.0	7.7	3.5	-	4.5	-
Liquid - Gas	57.2	39.8	49.6	36.5	16.2	-	34.8	-

^a Molybdenum catalyst used.

^b Not available.

^c Yields are presumably based on moisture- and ash-free coal, but for several references this could not be verified. Yields are reproduced as published and are not normalized.

and Garrett liquid products represent higher percentages (36.9 and 41.6 respectively) of the total product available heat than the other processes, while the Union Carbide and U.S. Steel processes produce more available heat in the gases than the other processes. If char is not desirable as a final product from hydrocarbonization, the results indicate that the Union Carbide and Garrett processes produce the highest percentages of the total available heat in the liquid plus the gaseous products (57.2 and 49.6 percent respectively).

Of the eight processes reviewed, only two (the Union Carbide hydrocarbonization process and the FMC COED process) are developed to the state where they can be scaled to large pilot or demonstration plants. Both of these processes involve relatively conventional technology, and the liquid yields are reasonably consistent with correlations based on temperature and hydrogen partial pressure. Of the other processes, the U.S. Steel "Clean Coke" process and the Garrett process are both in the pilot-plant stages of developing technology. The U.S. Steel Clean Coke process is based on relatively conventional technology and produces only modest liquid yields. On the other hand, the Garrett process presents a departure into new technology, and the liquid yields are remarkably high.

The final four processes - Schroeder, Consol, CSIRO, and Bureau of Mines - are neither far enough along in development nor directly relatable to hydrocarbonization to permit meaningful comparisons. The promise of high liquid yields from the Schroeder process has stimulated numerous experimental investigations attempting to confirm the claimed influence of short product-residence times and catalysis on liquid yields. Oil yields as high as 64 percent were obtained at the University of Utah under conditions of a short residence time and the addition of a stannous chloride catalyst.

In recommending process operating ranges, the ORNL report states that very little reaction takes place below 400°C, however, the yield of both oils and gases increases as the temperature is increased. A maximum

oil yield is obtained between 550 and 600°C. All studies covering this temperature range have reported a decrease in oil yield at temperatures over 600°C. This decrease is due to the thermal cracking of the larger hydrocarbon molecules. Unlike the oil yield, the yield of hydrocarbon gases does not exhibit a maximum, but increases monotonically with temperature. At very high temperatures (1200°C), hydrocarbon gases are the principal product and only a few percent of the oils are recovered. Hence, it is apparent that the optimum temperature for the production of oils would be between 500 and 600°C.

Both the oil and gas yields increase with the partial pressure of hydrogen. This trend appears to continue up to 6000 psig; since essentially no data exist for higher pressures, it is not possible to determine whether this trend continues. The oil yield apparently is a function of the square root of pressure, and further increases above 6000 psig will probably not increase the oil yields substantially. The optimum pressure will have to be determined by an economic trade-off between increased construction and operating costs at the higher pressure and the increased oil yields that could be obtained under these conditions. Most of the data are regrouped in two pressure ranges, below 1500 psig and 5000 to 6000 psig. Relatively few data exist for intermediate pressures. More experimental data in this pressure range (2000 to 4000 psig) would be extremely helpful.

Hydrogen consumption is well documented for pressures below 1000 psig. Apparently, the hydrogen consumption would be about 19,000 SCF of H₂ per ton of MAF (moisture- and ash-free) coal at 1000 psig and 550°C. This corresponds to a consumption of about five percent based on the weights of MAF coal fed. Almost no hydrogen consumption data exist for hydrocarbonization at higher pressures.

#

ALTERNATIVE SOLVENTS TESTED FOR USE IN THE SOLVENT REFINED COAL PROCESS

The Energy Research and Development Administration has published a report

prepared by The Pittsburgh and Midway Coal Mining Company entitled, "Development of a Process for Producing an Ashless, Low-Sulfur Fuel from Coal." The report is further identified as ERDA R&D Report No. 53, Interim Report No. 8, Volume II, Part 3, and is available as item FE-496-T1 from NTIS, Springfield, Virginia 22151, for \$7.50.

Reported are results of three series of experiments with petroleum derived solvents to dissolve Kentucky No. 9 coal in the continuous reactor. These runs were conducted between January 1973 and June 1974.

In the Solvent Refined Coal (SRC) process, coal is dissolved without catalyst under moderate hydrogen pressure in a solvent ultimately generated by the process itself. Most organic matter in the feed coal dissolves; the liquid can be filtered to remove mineral matter; the filtrate is subjected to vacuum distillation for solvent recovery; and the residue is the upgraded coal, high in BTU/lb and low in ash and sulfur. In this process, the composition of process derived solvent is crucial, and its evolution has been studied.

Much of the present work was founded on continuous reactor experiments with anthracene oil as initial solvent, experiments which developed operating procedures, sampling and analytical methods, or methods for management of feed and product samples. When it appeared that anthracene oil would not be available in quantities required for commercial plant startup, the laboratory began work with Gulf Carbon Black Feedstock FS 120, a petroleum based solvent, and then in the last runs with a 1:1 blend of FS 120 with U.S. Steel T-2 Bottoms, a more aromatic product which is like anthracene oil.

The objectives of the program were to study the SRC process with these new solvents, especially for startup of the (Tacoma) pilot plant; to develop the process to reclaim and recycle the solvent until it reached a steady state composition representing that of process derived solvent; to demonstrate continuing operation with only process derived solvent; and to remove a maximum of sulfur from the

vacuum bottoms by using this solvent.

Materials used in the SRC process tests were the solvents, high volatile B bituminous coal, and hydrogen. In the course of the experiments, several improvements were developed in both operating procedures and equipment. A change in handling of coal received from the mine has ensured a homogeneity of coal within each lot. Slurry pumping problems were substantially lessened by reducing all coal to under 150 mesh. The preheater fluidized sand bath was modified to provide a more uniform temperature, and the preheater coil was enlarged to match more closely the retention time in the pilot plant preheater.

The reactor used in the tests consists of a gas compression and metering system, which governs flow of the reducing gas at reactor pressure; a slurry pumping and metering system, which pumps a uniform slurry at a uniform rate and measures the rate; and reaction and sampling systems, which dissolve the coal and hydrogenate the initial reaction products, and provide for collecting gas and liquid products.

According to the report, the primary objective of this work, to demonstrate a satisfactory startup of the process with a petroleum derived oil, was met. The emphasis then shifted to recycling solvent in the process until recycle solvent reached a steady state composition. This objective arises from the desirability of operating with a solvent which is wholly derived from the process.

As the solvent is recycled, its composition gradually changes. The initial solvent is diluted by the solvent derived from the process, and both suffer some losses. Continuing reactions produce hydrocarbon gases and oils distilling below the recycle solvent distillation range. Dissolved fractions of the feed coal produce additional solvent, replacing the losses in lighter materials, and repeated recycling continues to alter the character of the solvent. Ultimately, the identity of the initial solvent is lost as the solvent composition approaches that of the solvent produced in the process. Because commercial plants will operate on a process-derived solvent, its composition

is of considerable interest. Even though the composition of the process-derived solvent was not unequivocally established in this work, it is claimed that a range of aromaticity in which it should lie is more firmly established than before.

Work planned by P&M Coal Mining Company for the future includes answering the still unanswered questions about the composition of process derived solvent and about how to maximize desulfurization in the SRC product. It will include the evaluation of other coals and a more complete evaluation of the process to recycle coal solution as the fluid component of the feed slurry. Equipment and procedures are being modified to permit rapid attainment of steady state conditions, including solvent composition. In this modified operation, solvent will be repeatedly recycled within a single experiment rather than in successive runs.

#

COAL-DERIVED SYNTHESIS GAS ASSUMING NEW IMPORTANCE IN MANY INDUSTRIES

By the year 2000, coal-derived synthesis gas will be relied upon heavily by many industries as feedstock for a large number of important products other than fuels. Consider the following products:

Ethylene Glycol

A.M. Brownstein of Chem Systems, Inc., states (Chem. Eng. Progress, V.71, No. 9, Sept. 1975, pg. 76) that under the economic conditions to be expected later in this century, synthesis gas technology for ethylene glycol manufacture will be attractive. He visualizes two shifts away from the present technology for ethylene glycol manufacture. The first, or near term shift, will be to the liquid phase acetoxylation processes. This will be followed by the longer term shift to synthesis gas-derived processes.

Ammonia

The Circle West Coal Project Development planned by Burlington Northern railroad (see Synthetic Fuels, September 1975 issue, page 4-4) is an example of a major

project which proposes to produce ammonia from coal-derived synthesis gas. Details of this proposed project will be known when BN files the necessary applications with Montana under that state's Utilities Siting Act of 1973.

Methanol

While plants for making methanol from coal-derived synthesis gas appear now to be costly, future economic conditions could easily cause coal-based plants to be competitive with natural gas-based plants. A major factor to be considered here is feedstock availability. Currently, a 20-year supply of coal for a coal-based methanol plant could be lined up rather easily. It is doubtful if a 20-year supply of natural gas could be lined up for such use.

An unusual proposal is one by Northwest Coal Corporation, a wholly-owned subsidiary of Northwest Pipeline, which has underway a feasibility study of a coal slurry pipeline from southwestern Wyoming to Boardman, Oregon, for transporting ten million tons of coal annually as a slurry of coal and methanol thereby supplying two energy fuels through one line.

Acetic Acid, Ethylene

Two additional products which may be produced economically from coal-derived synthesis gas in the future are acetic acid and ethylene. Warren Fuchs of Chem Systems, Inc., in a presentation to the Chemical Marketing Research Association at a May 1975 meeting in New York, predicted that ethylene manufactured via homologation of coal-based methanol to ethanol followed by dehydration could come "close in cost" to the product now made conventionally.

#

UNIVERSITY OF NORTH DAKOTA APPRAISES COAL CONVERSION PROCESSES

The University of North Dakota Engineering Experiment Station recently finished an evaluation of six gasification and five liquefaction processes plus one coal-oil-gas refining complex (combination of

gasification and liquefaction) for the conversion of North Dakota lignite. The evaluation was done under contract with the North Dakota Water Commission (Project No. 1543) as input to the final report of the West River Diversion Project. The study has been published in a report (dated July 1975) entitled "Evaluation of Gasification and Liquefaction Processes Using North Dakota Lignite," by Dorab N. Baria, Assistant Professor of Chemical Engineering. The contents and conclusions of the final report of the West River Diversion Study are discussed elsewhere in this issue of Synthetic Fuels.

The study examines the coal consumptions, water requirements, and thermal efficiencies and presents simplified flow diagrams, and cursory energy and material balances for twelve conversion processes. The six gasification processes considered are: Lurgi, Koppers-Totzek, Carbon Dioxide Acceptor, BI-GAS, Synthane, and Hygas. The five liquefaction processes reviewed are: Solvent Refined Coal (SRC), Synthoil, H-Coal, Consol Synthetic Fuel (CSF) and

COED. The coal-oil-gas refining complex (COG) considers the combination of the SRC, H-coal and BI-GAS processes. The study assumes the primary product of the COG complex to be liquid and, therefore, the study considers it to be a liquefaction process.

Of the eleven processes evaluated for lignite conversion, only two of the gasification steps and none of the liquefaction processes have been used commercially. All of the processes considered, however, are being actively developed at the pilot plant stage.

Processes Compared on Equal Basis

The gasification processes are compared on the basis of 269 billion BTU per stream day total energy production or the equivalent of 277 MMSCFD of synthetic natural gas. Assuming a 90 percent onstream factor, the daily average production (329 days a year) is 250 MMSCFD. For the purpose of the study, a representative analysis of lignite (see Table 1) was used

TABLE 1

AVERAGE PROXIMATE AND ULTIMATE ANALYSIS FOR NORTH DAKOTA NORTHERN GREAT PLAINS PROVINCE LIGNITE

	<u>Proximate Analysis %</u>		
	<u>As Received</u>	<u>Moisture Free</u>	<u>Moisture Ash Free (MAF)</u>
Moisture	37.2	--	--
Volatile Matter	26.3	41.9	46.5
Fixed Carbon	30.3	48.2	53.5
Ash	6.2	9.9	--
	<u>Ultimate Analysis %</u>		
H	6.9	4.43	4.92
C	40.7	65.08	72.25
N	0.6	0.96	1.07
O	44.97	18.60	20.64
S	0.62	0.99	1.10
Cl	0.01	0.02	0.02
Ash	6.2	9.92	--

Heating value (as received basis) = 6820 Btu/lb.

throughout to provide continuity to the calculations.

In calculating material and energy balances and thermal efficiencies for each process the author assumed that the only process differences lie in the gasification step and that additional steps required for lignite pretreating and downstream upgrading (shift conversion, purification, and methanation) are similar for each process. The study presents a brief description of gasification chemistry and the basic unit operations of a gasification facility.

The liquefaction processes are compared on the same basis as the gasification process or 269 billion BTU per stream day in products. The multi-product nature of liquefaction process, however, allows this comparison to be made two ways: on the basis of the primary product and on the basis of all products.

Evaluation Discussed

Thermal efficiencies of the various processes, calculated from energy and material flow data, are generated for the conversion step itself (gasification or liquefaction) and for the overall facility which includes steam and power generation. The process models used by the author to generate the thermal efficiency data are greatly simplified and do not reflect the complexity of the processes and the facilities. A summary of thermal efficiencies and water and lignite requirements are presented in Tables 2 and 3 for the gasification and liquefactions processes, respectively.

The lignite requirements presented in Table 2 are for gasification only and do not reflect the needs for steam and power generation. This is not to imply that these needs are insignificant, but to allow a means of comparing the quantities

TABLE 2

LIGNITE/WATER USE AND THERMAL EFFICIENCIES OF SELECTED GASIFICATION PROCESSES

(Basis: 269 Billion BTU Per Day Output
In Product Synfuel Stream)

<u>Process</u>	<u>Lignite¹ Consumption</u>		<u>Water² Consumption</u>	<u>Thermal³ Efficiency</u>	
	<u>(MMTPY)</u>	<u>(MTPSD)</u>	<u>(MAFY)</u>	<u>Gasification Process(%)</u>	<u>Overall Facility(%)</u>
Lurgi	9.3	28.3	14.9	80.8	64.6
Koppers Totzek	9.7	29.5	9.9	65.5	64.4
CO ₂ Acceptor	9.1	27.8	12.4	84.3	67.4
Synthane	10.3	31.3	19.5	73.9	64.0
BI-GAS	8.0	24.4	14.0	81.7	63.5
HYGAS	10.2	30.9	21.1	70.0	61.9

¹Lignite consumption does not include steam and power requirements.

²Water consumption is an estimate of total facility requirements to include mine and land rehabilitation.

³Gasification process thermal efficiency does not include steam and power requirements whereas overall facility efficiency does include steam and power needs.

TABLE 3

LIGNITE/WATER USE AND THERMAL EFFICIENCIES OF SELECTED LIQUEFACTION PROCESSES
(University of North Dakota 1975)

Process	Based on 269 Billion BTU PD of Primary Product			Based on 269 Billion BTU PD of all Products			Thermal Efficiency	
	Lignite Consumption ¹		Water Consumption ²	Lignite Consumption		Water Consumption	Liquefaction Process ³	Overall Facility ⁴
	(MTPD)	(MMTPY)	(MAFY)	(MTPD)	(MMTPY)	(MAFY)	(%)	(%)
SRC	41.1	13.5	20.2	26.6	8.8	13.4	75.6	73.3
Synthoil	55.2	18.2	27.6	27.8	9.1	14.6	74.4	71.1
H-Coal	38.7	12.7	10.8	22.5	7.4	7.0	91.9	77.7
CSF	37.1	12.2	14.6	22.5	7.4	9.1	92.6	77.1
COED	117.4	38.6	42.0	21.7	7.1	7.9	90.8	78.1
COG	47.8	15.7	18.6	24.9	8.2	9.8	99.2	79.4

¹Lignite consumption does not include steam and power requirements.

²Water consumption is an estimate of total facility requirements to include mine and land rehabilitation.

³Liquefaction process thermal efficiency does not include hydrogen production via coal or char gasification for SRC, Synthoil and H-Coal.

⁴Overall facility thermal efficiency includes steam and power generation as well as hydrogen production.

of lignite converted to a usable fuel. Data reflecting lignite use for steam and power generation are presented below as overall facility thermal efficiency. Consumptive water requirements in Table 2 are approximations for the complete facility to satisfy process, cooling, and mine needs (to include rehabilitation of mined lands). These values are presented here only to reflect the great differences between processes as determined by this study. Water requirements are highly dependent on specific facility design and operation.

In comparing the data presented in Tables 2 and 3 for gasification and liquefaction, it must be kept in mind that to varying degrees synthesis gas, or SNG via further upgrading, is also a product of liquefaction processes. Synthesis gas is produced by coal or char gasification to provide process hydrogen and is also a by-product of the liquefaction process. For this reason, the data in Table 3 are presented on two bases. The first is 269 billion BTU per day of main product (solvent refined coal, fuel oil, or syn-crude). The second is 269 billion BTU per day of products to include synthesis gas and all hydrocarbon streams.

The primary conclusion of the study is that the selection of a coal conversion

process for a specific region must be made to match the needs of the region with the process that can meet those needs and not be made solely on the basis of lignite and water uses, and plant efficiencies.

The data presented for the Lurgi process are in part from a study the University of North Dakota Engineering Experiment Station is currently engaged in, under contract with Natural Gas Pipeline Company of America for evaluation of Northern's proposed Dunn Center, N.D. gasification project. The first phase of that project was published in August 1974 under the title "A Preliminary Engineering, Geological, and Hydrological Environmental Assessment of a Proposed 250 MMSCFD Coal Gasification Facility." The second phase report is expected to be finished in the first quarter of 1976.

#

SIX PROCESSES FOR DRYING WESTERN COAL DESCRIBED TO BOOST PER-TON HEAT YIELDS, LOWER TRANSPORTATION COSTS

Removing excess moisture from western coal prior to shipment has a wide range of benefits that can improve heating value, reduce shipping bulk and weight, and provide increased steam generation efficiencies is being largely overlooked by coal shippers.

In a paper entitled, "Drying of Western Coal," presented at the American Mining Congress 1975 convention in San Francisco in September, John W. Hand, of Cameron Engineers, outlined the parameters, including potential hazards, of moisture removal from coal.

In the low sulfur subbituminous coals and lignites of the West, inherent bed moisture ranges upward from 25 percent of the weight of mined coal. Removing most of this moisture can cost from \$2 to \$2.50 per ton. Where unit train rail costs of shipment top that sum, serious consideration should be given to coal drying, Hand claims.

Besides reducing shipping weights, water removal can avoid some handling problems, reduce bulk, maintain high pulverizer capacity, reduce bulk density of coal, improve quality of coal used for special purposes such as production of coke, briquettes and chemicals, and facilitate coal dry cleaning processes. At the point of use, dry coal can increase the heating value and increase plant efficiency since it is not necessary to waste heat to evaporate excess water from the fuel. Less water in exhaust gases also permits lower gas exit temperatures while minimizing corrosive factors. A one percent reduction in total coal moisture increases thermal efficiency about 0.1 percent, he reported.

Hand cited a study by Fluor Utah, Inc., for the Office of Coal Research comparing coal slurry costs with those of unit train coal transport. Cost equity between slurry and rail transportation was reached at 500 miles. In the case of rail transport, the distance could be extended to 1,000 miles if the coal is dried to 75 percent of its received weight.

The drying processes described by Hand were fluidized bed, entrained or suspended bed, multiple louvered, vertical tray or cascade, continuous carrier, and drum.

Drying gas, as hot as safety will permit (1,600 to 1,800°F), should have very low oxygen content and short contact time with the coal. Implementation of one or more safety procedures to control the handling and drying process is necessary. For example, coal of about 1.5 percent moisture

on the fine sizes can be sprayed with oil to reduce dusting.

Hand described the Parry dryer using the flash process. It is specifically designed to handle western coals. It has a short drying time to minimize volatile component loss. An experimental scale Parry dryer with a 400 pound per hour capacity at Colorado School of Mines reduces moisture content from 55 percent to 3 percent. It is fired with natural gas.

Coal samples from Colorado and the Powder River Basin ranging in moisture content from 28 percent to 35 percent with a top size of 3/8th inch were used to easily attain controlled moisture reduction to 0.3 to 20 percent. In all cases, there was considerable particle size reduction, with 60 percent shrinkage being average.

Bench scale experiments on treating dried lignite with No. 6 fuel oil and asphalt emulsions were also performed. Lignite dried to 12 percent moisture sprayed with one part hot fuel oil and blended, yielded a non-tarry, non-dusty compound with a heating value of 9000 BTU per pound, compared with the 6,300 BTU per pound analysis prior to drying.

Hand said it must be recognized special treatment, storage, and shipping equipment or procedures may be required. Still, the advantages of drying warrant further research and analysis.

Hand noted he knows of no producer who is drying coal to effect transportation savings. Moving dry coal from the arid west to the midwest for gasification or liquefaction should be part of any crystal ball gazing. Continually changing economic factors and supply uncertainties of natural gas and petroleum and petrochemical feedstocks could move coal drying out of the experimental category and into accepted daily practice.

The paper virtually ignored the hazards of coal drying--spontaneous combustion and increased explosivesness of coal dust--and how the drying process could be modified to alleviate them. The dangerous characteristics must be dealt with if coal drying is to receive realistic consideration.

Additional economic data would also have been helpful.

#

NORTH DAKOTA PSC MAKES FINAL DECISION ON ANG PROJECT

The North Dakota Public Service Commission stated in an order dated October 8, 1975, "That the application of ANG Coal Gasification Company for a certificate of public convenience and necessity to construct and operate a coal gasification plant near Beulah, North Dakota be dismissed."

This decision follows an application by ANG (received by the North Dakota Public Service Commission July 7, 1975) for certification by the North Dakota PSC in which ANG pleads "... (ANG) denies that the North Dakota Public Service Commission has jurisdiction over its proposed facilities. Applicant maintains that the Commerce Clause of the United States Constitution (Art. 1, 58, Cl. 3) requires that those areas of interstate commerce in which uniformity of regulation is required be free from State regulation; an attempt to control these matters constitutes an undue burden upon interstate commerce."

The argument placed before the Commission by ANG and the one the Commission yielded to in dismissing the application is that ANG will serve no customers at retail or wholesale within the State of North Dakota, and therefore, the North Dakota PSC lacks jurisdiction to consider the application or to regulate applicants' rates, its accounting, security issues, and other financing arrangements, its sales for resale of synthetic gas and methods of transacting the same, and the liquidation or sale of any of applicants' assets.

ANG Coal Gasification Company does fall under the jurisdiction of the North Dakota PSC in another matter; the Plant Siting and Transmission Line Routing Act of 1975. See page 1-28 of the June 1975 issue of Synthetic Fuels for a discussion of Senate Bill No. 250-Facility Siting Act. ANG has begun application procedures under this siting act.

Should ANG, at some time in the future, engage in the distribution and sale of SNG within the State of North Dakota, all of ANG's activities would then be subject to PSC jurisdiction.

Pursuant to certain requirements imposed by the Water Commission in ANG's conditional water permit, ANG has offered a contract to all of the gas distribution companies operating in North Dakota which would include a commitment to purchase a portion of the output of the proposed plant for distribution to North Dakota customers. None of the North Dakota gas distribution companies have committed themselves to the purchase of any of the synthetic gas to be marketed by ANG and by reason thereof, ANG proposes to sell all of its output to Michigan-Wisconsin Pipeline Company for out of state resale.

#

1,000 TONS OF COED PROCESS CHARS GASIFIED IN KOPPERS-TOTZEK PLANT IN SPAIN

About 1,000 tons of COED-process char and about 1,400 tons of petroleum coke were gasified in an oxygen-blown Koppers-Totzek burner in an ammonia synthesis plant in Puentes, Coruna, Spain. The gasification tests were conducted during August 1975.

FMC Corporation contracted with the Electric Power Research Institute (EPRI) to conduct the tests. EPRI brought in a team from the Koppers Company to assist in operating the Koppers-Totzek plant, to perform analytical work and to evaluate test results.

COED-process chars obtained from two types of coal, totaling 1,000 tons of char were used. The Spanish K-T plant was designed to grind and gasify lignite. As would be expected, minor problems were encountered while grinding and gasifying other substances, but the K-T gasifiers had little difficulty. Chars, obviously, contain but small amounts of volatile matter, as compared with coal. However, the high temperatures attained in oxygen-blown K-T gasifiers allowed the chars to gasify without encountering operating problems.

Data from the COED-char operations will ultimately be reported by EPRI. Data from the petroleum coke-gasification tests, however, must be purchased through the Koppers Company, with funds being used to defray part of the costs incurred by the oil company sponsors. Analyses of data will be completed by Koppers, probably in January.

#

SRC PILOT PLANT CONSTRUCTION REPORTED

The construction phase of the Solvent Refined Coal pilot plant being operated by Pittsburg and Midway Coal Mining Company at Fort Lewis, Washington, is described in ERDA R&D Report No. 53, Interim Report No. 9, dated May 1975. The title of the report is "Development of a Process for Producing an Ashless Low-Sulfur Fuel From Coal-Volume III-Pilot Plant Development Work Part 2-Construction of Pilot Plant," covering the period from June 1972 to June 1974.

This report includes an up-to-date description of the process and discussion of the design modifications which have been made since the original design report was issued. Areas of the plant design which were not modified are also discussed in complete detail with emphasis on the as-built configuration. In addition, this report provides a summary of the construction work, as-built drawings, a complete list of equipment and specifications, and photographs of the plant-site at various stages of the construction. The report is available from the National Technical Information Service, U.S. Department of Commerce, Springfield, Virginia 22151, as NTIS Report No. FE-496-T2.

Editors Note: The plot, process flow and engineering diagrams presented (38 total) are difficult to interpret due to the scale of reduction required to fit one drawing per page.

The "Reporting Plan" established for the publishing of work done by P and M Coal Mining Co. (subsidiary of Gulf Oil Corp.) under an ERDA contract for the development and commercialization of the SRC Process (in which the above mentioned report is included) is described in a separate article elsewhere in the Coal Technology section of this issue of Synthetic Fuels.

Original Pilot Plant Design Completed in 1968

The Office of Coal Research first contracted in October 1968 with P and M Coal Mining Co. to design, construct, and operate a pilot plant to develop and demonstrate the Solvent Refined Coal Process. The SRC process is based on research work that had been done under OCR contract with Spencer Chemical Co. (now a subsidiary of Gulf Oil Corp.).

On July 10, 1967, P and M contracted Stearns-Roger Corp. of Denver, Colorado, to design the SRC pilot plant. The plant design was completed in 1968 (nominal coal feed rate of two tons per hour). Because of limited funds, OCR did not accept construction proposals until 1972. The lowest cost proposal was submitted by Rust Engineering Co. Design review resulted in eliminations and modifications to the original design, decreasing cost.

Since the original design was completed by Stearns-Roger, several factors have given rise to changes in the process configuration and scope of the pilot project: emission control regulations, the need to resolve interferences in the initial design and to improve operability, the incorporation of results of the continuing bench scale research that is being done by P and M on the SRC process, and the passage of the Occupational Safety and Health Act.

Rust began final design on the revised plant in February 1972 and signed the final construction contract on June 4, 1972. Site preparation commenced June 26, 1972 on a 20-acre plot in North Fort Lewis, Washington. All plant units were in P and M's custody by September 1974 for start-up of the integrated pilot plant.

Engineering Design Basis Discussed

The pilot plant has been designed to allow the operation of plant sections and major equipment over a wide range of conditions to provide a broad base of experimental data for process evaluation and scale-up. Ranges of key operating parameters are:

- . Coal feed rate - 0.5 to 2.5 TPH
- . Dissolver pressure - 500 to 2,200 PSIG

- . Dissolver Temperature - 700 to 925°F
- . Solvent/coal ratio - 1.5 to 4 lbs/lb
- . Liquid residence time - 0.2 to 1.8 hrs
- . Hydrogen rate - 800 MSCFD
- . Synthesis gas rate - 600 MSCFD

The pilot plant does have the capability of using synthesis gas as a substitute for hydrogen in the dissolver unit.

Process Units Described

The plant consists of five major process units: slurry preparation, slurry preheating and dissolving, mineral separation, solvent recovery, and solvent refined coal processing. Other areas of the plant handle and treat process derived gases for hydrogen recovery and recycle as well as H₂S removal.

Pulverized coal is introduced into the process solvent stream and passed through a venturi throat to maximize solid-to-liquid contact before entering the slurry holding tank. Design coal and solvent rates are 4,000 and 12,000 pounds per hour, respectively. The start-up solvent is specified to be a mixture of carbon black feedstock FS-120 and a coal tar distillate. The working solvent will, over time, evolve to be essentially process derived.

The quality of the process derived solvent is an important factor in the development of the SRC process and a point that is receiving much attention during pilot operations.

The slurry is pumped under a recycle hydrogen blanket to between 500 psig and 2,000 psig and brought to between 775° to 925°F in the preheater (a natural gas-fired tube furnace). All heat necessary for coal dissolution and depolymerization is added in the preheater.

As the hydrogen-slurry mixture passes through the preheater, some solution of coal takes place, but the dissolvers are necessary to allow time for complete solution of the coal. The dissolver configuration selected for the pilot plant consists of two vertical towers in series. Each of the two dissolvers has an inside diameter of 24 inches and is 30 feet high. The normal outlet for each dissolver is at

the top (inlet at bottom), but the first dissolver has an additional outlet in the center to provide for operation at low residence times. The second dissolver can be bypassed, allowing a four-fold variation in reaction volume. Since the pumping rate can be varied from about one-third to full capacity, a twelve-fold variation in residence time is possible in this system. The total dissolver volume has been specified to allow a liquid residence time of about 0.6 hour at the nominal charge rate of two tons of coal per hour with a 3-to-1 solvent-to-coal ratio. This is in addition to the estimated volume occupied by the gas as it passes through the reactor.

The slurry is passed through two flash drums for pressure let-down and for removing unreacted hydrogen and process evolved gases before entering the filtration area.

The slurry entering the mineral separation area contains most of the original solvent, dissolved coal, undissolved coal material and undissolved minerals (ash). The filtration system centers around two pressure precoat filters with filtration areas of 80 and 40 square feet. The filter precoat medium is diatomaceous earth. The size of the undissolved particles being filtered ranges between one and 20 microns requiring pressure differentials across the filter cake between 100 and 200 psig. The viscosity of the solvent dissolved coal mixture is kept within filtering limits by maintaining the filter charge between 350° and 650°F. Filter rates between 50 and 200 pounds per hour per square foot are designed for.

Filter cake is washed with a light wash-solvent to remove and recover solvent. Wash solution is sent forward to the solvent recovery area. Clean cake is dried and stored.

Filtrate passes directly to the solvent recovery area where the bulk of the solvent is separated in a vacuum distillation unit. Overhead vapors are further fractionated to recover a light oil stream as well as recycle solvent. The vacuum bottoms are the principle plant product--Solvent Refined Coal. The SRC may be cooled and solidified on a water cooled, stainless steel cooling belt or formed into pillars in a prilling tower. The prilling unit is expected to be the

prime mode of product preparation. A system is provided to heat the molten SRC from the vacuum tower for experimentation with the prilling tower (air cooled).

#

SRC REPORTING PLAN REVEALED

Completed laboratory studies and pilot plant work conducted in the development of the solvent refined coal process (SRC) by Pittsburgh and Midway Coal Mining Company under an ERDA contract is to be reported in five volumes of ERDA R & D Report No. 53. The interim R & D reports are to be published as subparts to the various volumes as portions of the overall program are completed. The reporting outline for the report entitled, "Development of a Process for Producing an Ashless, Low Sulfur Fuel from Coal," ERDA R & D Report No. 3, Contract No. E (49-18)-496 is as follows:

- Volume I Engineering Studies
- Part 1 Economic Evaluation of a Process to Produce Ashless, Low-Sulfur Fuel from Coal (designated as Interim Report No. 1)*
- Part 2 COG Refinery Economic Evaluation - Phase I (Interim Report No. 3)*
- Part 3 COG Refinery Economic Evaluation - Phase II (Interim Report No. 4)*
- Part 4 Impact of the SRC Process (Interim Report No. 5)*
- Volume II Laboratory Studies
- Part 1 Autoclave Experiments (Interim Report No. 6)*
- Part 2 Continuous Reactor Experiments Using Anthracene Oil Solvent (Interim Report No. 7)
- Part 3 Continuous Reactor Experiments Using Petroleum Derived Solvents (Interim Report No. 8)*
- Volume III Pilot Plant Development Work
- Part 1 Design of Pilot Plant (Interim Report No. 2)*
- Part 2 Construction of Pilot Plant (Interim Report No. 9)*
- Part 3 Pilot Plant Start-up
- Part 4 Pilot Plant Operation

*Previously issued.

- Volume IV Product Studies
- Part 1 Catalysts Tailored for Hydroprocessing of Coal Liquids
- Part 2 An Annotated Bibliography on Mineral Fiber Production from Coal Minerals (Interim Report No. 10)*
- Part 3 Products from Coal Minerals (Interim Report No. 11)*
- Part 4 Sulfur Removal from Coal Minerals (Interim Report No. 12)*
- Part 5 Developmental and Rate Studies in Processing of Coal Mineral (Interim Report No. 13)*
- Volume V Process Design for Commercial Coal De-ashing Plant

#

PROJECT LIGNITE PDU DESCRIBED

Project Lignite is a research program being conducted by the University of North Dakota Engineering Experiment Station with ERDA funds. The program is bench scale with experimental runs being made to develop a process for the production of solvent refined lignite. The design of a 50 pound per hour Process Development Unit has been completed and is presented in ERDA R & D Report No. 106, Interim Report No. 1, covering the period from March 1972 to September 1974. It is entitled, "Process Development of Solvent Refined Lignite -- Design of Continuous 50 Pounds Per Hour PDU." It is available through NTIS.

It is expected that the PDU will produce 15 pounds of SRL per hour (0.33 lb SRL/lb of lignite feed) in the 300° to 400°F melting point range, as well as additional lighter liquids and gases. The report does not indicate the results of the tests conducted since September. It includes some material and energy balance data that were assumed at the time of design. The PDU design is based on previous batch autoclave studies of solvent refining lignite carried out at the N.D. experimental station.

The report describes details of design and proposed operation of all PDU units with discussions relating to anticipated mechanical and process problems and their proposed solutions. It is devoid of flow schemes or mechanical drawings.

The objectives of the process development study are, according to the report: (1) to determine whether the process will generate enough solvent for 100 percent recycle; (2) to determine the most favorable gas recycle ratio and the make-up gas requirements; (3) to provide process and equipment data to permit economic evaluation of the process; and (4) to provide design criteria for pilot plants.

Solvent refined lignite will also be prepared in the PDU for further studies of conversion to still lighter fuels. The product quality of the SRL will be strongly affected by the efficiency of separation from unreacted lignite and mineral matter. Thus, studies of solid-liquid separation will also be given high priority.

Design and Operation Presented

The lignite is crushed and pulverized in equipment designed to reduce the lignite to particle sizes such that 100 percent will pass 60 mesh and 90 percent will pass 200 mesh Tyler screens. The pulverized lignite is blended in a slurry mixing tank with a petroleum-derived solvent having a boiling range of 212° to 446°F at 1.6 millimeters of mercury absolute, with a recirculating loop to maintain the suspensions. A side stream of this slurry is pumped to high pressure, mixed with hydrogen and/or carbon monoxide gas, and fed into an electrically heated, fluidized solids preheater in which the mixture is heated to reaction temperature. It is anticipated that most operations will be in the range of 700°F to 800°F at 1500 psi, but the unit is designed for operation up to 950°F and 3000 psi.

Upon leaving the preheater, the mixture enters the dissolvers where reaction temperatures are maintained and residence time provided to allow sufficient time for solvation. The undissolved material consists of unreacted lignite and inorganic mineral matter. Upon leaving the dissolvers, the non-condensable gases and light hydrocarbon vapors are separated from the slurry in a series of five separation vessels in which pressure and temperature are decreased in stages.

The PDU is designed so that solvent can be recycled without operating the solid-liquid separation area. In this mode of

operation the slurry is heated to approximately 600°F in a Dowtherm preheater. Next it undergoes a vacuum flash distillation, separating the volatile liquids and solvent from the mixture of mineral residue, undissolved lignite and solvent refined lignite, which will be referred to as the vacuum flash bottoms. The overhead stream is condensed, combined with another light liquid stream from the primary separators, and fed to a second Dowtherm preheater preceding the main solvent recovery fractionators. In the latter the light ends, process solvent and heavy ends are separated. The process solvent is recycled.

The non-condensable gases from the initial high pressure separators are channeled through the gas recovery area; carbon dioxide and hydrogen sulfide are removed and a portion of the hydrogen and carbon monoxide gas is recycled.

For the solid-liquid separation, the vacuum flash bottoms are pumped to a mixing-surge vessel and mixed with benzene: (2:1 by volume). The mixture is pumped to a gravity settling tower operating above the critical pressure but slightly below the critical temperature of benzene. Additional wash benzene is fed countercurrently to the direction of settling ash and unreacted lignite. The dissolved SRL and benzene are withdrawn from the top of the settler and passed into a vessel in which the benzene is removed by flash distillation. The benzene is recycled and the SRL solidified and collected.

#

EPRI REPORTS ON OPERATING PERFORMANCE OF WILSONVILLE SRC PROCESS PILOT PLANT

The Electric Power Research Institute (EPRI) has published Interim Report No. 1234 entitled, "Status Report of Wilsonville Solvent Refined Coal Pilot Plant." The report, prepared by Southern Services, Inc., describes the development and operation of the six TPD Solvent Refined Coal (SRC) pilot plant located at the site of the Southern Electric Generating Company's Ernest C. Gaston Steam Plant near Wilsonville, Alabama.

Although SRC processes have been investigated for over sixty years, bench scale work

on the present SRC process concept was carried out from 1962 to 1965 by Spencer Chemical Company and the Office of Coal Research. Later work was sponsored by the Pittsburgh and Midway Coal Company, a Gulf Oil Corporation subsidiary. Southern Services, Inc., began studies of the SRC process for producing clean fuels for use in utility boilers in 1968, work which led to construction of the six TPD pilot plant at Wilsonville. This work has been sponsored in recent years by EPRI.

This current report describes the pilot plant operations through the year 1974--operations which were highlighted by a 75-day period of sustained operation. At the conclusion of this run, the pilot plant was shut down on December 23, as planned. During the operating period described in the report, two coals were processed. One of these was West Kentucky No. 14 coal, the other was Illinois No. 6 coal.

Six TPD Pilot Plant Described

In the SRC process pulverized coal which has been mixed with a solvent produced in the process is reacted with hydrogen at temperature in excess of 800°F and at pressures greater than 1000 psig. Under these conditions, most of the carbonaceous matter in the coal is dissolved and about 60 percent of the organic sulfur in the coal is converted to hydrogen sulfide. Hydrogen consumption is in the range of one to three percent of the weight of coal processed.

The effluent from the reactor flows to a high pressure separator where the slurry and gas phases are separated. The pressure on the slurry phase is reduced to 115 psig at which pressure the slurry is processed to separate the mineral residue. Filtration in a pressure-leaf filter is the primary method of mineral separation provided at the pilot plant. An installation for testing the effectiveness of hydroclones also is provided.

Solvent is recovered from the SRC product extract in a vacuum column. The process solvent is recovered overhead and is recycled in the preparation of a fresh coal slurry.

The SRC product (liquid coal) is the bottoms product from the vacuum column. The product solidifies in a temperature range of 300 to 400°F. In the pilot plant, solidification occurs in a water bath conveyor. The product specification of 0.96 percent maximum sulfur and 0.16 percent maximum ash is intended to provide a product which meets current EPA New Source Emission Standards so that no further processing of stack gases is required.

The gas phase from the high pressure separator flows to a caustic scrubber where the hydrogen sulfide is removed. In a large-scale plant the sulfur would be recovered as elemental sulfur.

The solid residue from the filter is discharged to a rotary dryer. The solvent in the filter cake is stripped under vacuum and recovered in a scrubber for recycle to the process. The dried solids are cooled and collected for disposal.

The EPRI report contains detailed engineering drawings of each section of the pilot plant. In addition, flow diagrams, vessel specifications, and detailed data on all pumps used in the pilot plant are presented.

Overall Pilot Plant Operations Were Successful

Tables 1 and 2, reproduced from the report, summarize the conditions and results of most of the 18 runs which were conducted with the pilot plant. In the 75-day run sustained operations began with Run No. 10, using Kentucky No. 14 coal, and continued through Run No. 18, with Runs 11 through 18 using Illinois No. 6 coal.

Data in Tables 3 and 4 are also reproduced from the report. They show the analyses of the coals used and the analyses of the process solvents (original solvent and coal-derived recycle solvent).

Related Report on SRC Process Now Available

EPRI funded an experimental program of three continuous bench unit runs conducted by Hydrocarbon Research, Inc. and utilizing laboratory facilities at HRI's Trenton Laboratory.

TABLE 1

SUMMARY OF CONDITIONS AND RESULTS FOR
MATERIAL BALANCE PERIODS WITH KENTUCKY NO. 14 COAL

Date (1974) Run	June 30 6	July 25-27 7D	July 31 8	October 6 9
Coal (MF) in Feed, wt %	23.5	22.4	23.8	23.1
<u>Operating Conditions</u>				
Coal (MF) Feed Rate, lb/hr	467	383	417	508
Coal in Dissolver, lb/hr-ft ³	22.9	18.9	20.6	25.0
Temperature, avg., °F	833	832	845	781
Pressure, psig	1700	2350	1700	1720
<u>Yields, Percent of MF Coal, wt %</u>				
SRC Product	62.9	48.3	50.9	69.0
SRC to Filter Cake	3.5	5.6	4.1	5.5
Light Organic Liquids (a)	7.5	13.7	16.6	-1.6
Process Solvent (b)	-	11.3	-	6.4
Water	0.8	1.1	2.7	3.2
Undissolved Coal to Filter Cake	6.9	4.6	7.1	4.7
<u>Gases</u>				
H ₂ S	2.0	1.4	1.8	0.5
CO-CO ₂	1.5	0.7	0.8	0.7
C ₁ -C ₅	7.7	8.6	9.6	4.6
Coal Ash to Filter Cake	7.6	8.1	9.3	3.8
Coal Ash in SRC Product	0.1	0.1	0.0	5.5
Total	100.5	103.5	102.9	102.3
Hydrogen Consumption, Percent of MF Coal, wt %	0.6(c)	3.2	2.5	2.3
<u>Conversion, Percent of MF Coal, wt %</u>				
Calculated (d)	91.8	94.8	92.4	87.8
Laboratory (e)	91.4	94.4	92.9	90.9
<u>SRC Product</u>				
Ash, wt %	0.18	0.14	0.08	7.03
Sulfur, wt %	0.79	0.71	0.70	1.51
<u>Process Solvent</u>				
<u>Boiling Fractions (f), wt %</u>				
IBP-350°F	2	1	4	3
350-450°F	18	21	26	22
450-550°F	30	30	33	30
550-650°F	26	26	19	25
650-EP	24	22	18	20

(a) Boiling below 350°F.

(b) Nominal boiling range is 350-780°F.

(c) 2.0% is more typical of entire run.

(d) From analyses of filter cake, filtrate, and material balance.

(e) From analysis of filter feed stream.

(f) Simulated distillation by gas chromatography. ASTM D2887 (modified)

TABLE 2

SUMMARY OF CONDITIONS AND RESULTS FOR
MATERIAL BALANCE PERIODS WITH ILLINOIS NO. 6 COAL

Date (1974)	October 19-20	October 21	November 1-3	November 9-11	November 16	December 3-5	December 8-10	December 10-11	December 20
Run	11	12	13B	13D	13E	15	16	17	18
Coal (MF) in Feed, wt. %	20.8	22.8	23.0	23.3	22.9	23.6	30.4	29.6	30.9
Operating Conditions									
Coal (MF) Feed Rate, lb/hr	288	460	499	274	403	313	374	478	613
Coal in Dissolver, lb/hr-ft ³	14.2	22.7	24.6	13.5	19.9	15.4	18.4	23.6	30.2
Temperature, avg., °F	827	838	836	828	825	826	827	827	832
Pressure, psig	1740	1750	1720	1700	1710	1350	1650	1650	1650
Yields, Percent of MF Coal, wt. %									
SRC Product	58.6	71.9(a)	44.7	53.3	47.9(b)	49.4	40.3	45.0	51.2(c)
SRC to Filter Cake	-	-	0.4	2.2	1.3	2.5	9.1(d)	4.2(d)	5.6(d)
Light Organic Liquids (e)	1.2	8.1	1.5	16.6	1.5	23.6	6.0	5.2	11.9
Process Solvent (f)	14.1	-5.7	29.3	-1.7	16.7	-8.4	12.8	13.6	2.0
Water	5.2	5.1	3.5	3.2	5.8	8.6	6.0	8.0	4.6
Undissolved Coal to Filter Cake	-	-	6.4	7.9	5.6	6.8	6.5	6.0	6.8
Gases									
H ₂ S	2.5	2.0	1.1	3.6	2.7	0.8	1.9	1.4	2.2
CO-CO ₂	4.8	1.9	0.8	1.0	3.0	2.0	2.6	2.3	2.1
C ₁ -C ₅	6.3	7.0	2.8	5.6	5.3	6.8	7.5	6.7	5.0
Coal Ash to Filter Cake	-	-	11.2	11.2	12.7	10.6	10.5	10.0	10.6
Coal Ash in SRC Product	10.1	12.2	0.1	0.1	0.1	0.1	0.1	0.1	0.2
Total	102.8	102.5	101.8	103.0	102.6	102.8	103.2	102.5	102.2
Hydrogen Consumption, Percent of MF Coal, wt. %									
Coal, wt. %	2.7	2.4	1.8	3.1	2.5	2.7	3.1	2.6	2.2
Conversion, Percent of MF Coal, wt. %									
Calculated (g)	94.0	92.7	92.6	90.7	93.5	91.9	90.3	92.9	-
Laboratory (h)	92.4	92.9	91.3	92.9	93.1	90.8	92.2	92.9	91.4
SRC Product									
Ash, wt. %	13.87	14.20	0.13	0.14	0.19	0.10	0.12	0.14	0.44
Sulfur, wt. %	1.45	1.65	0.94	0.71	0.78	0.69	0.63	0.68	0.80
Process Solvent									
Boiling Fractions (i), wt. %									
IBP-350°F	4	3	5	3	5	5	7	7	9
350-450°F	21	24	21	22	27	27	26	30	31
450-550°F	29	30	29	30	25	30	26	27	28
550-650°F	25	23	22	24	23	20	22	18	16
650-EP	21	20	23	21	20	18	19	18	16

- (a) Yield is more typical of results at a dissolver temperature of 825°F.
 (b) Yield is more typical of results at a coal feed rate of 280 lb/hr.
 (c) May not be representative because of short material balance period.
 (d) Filter cake was not washed.
 (e) Boiling below 350°F.

- (f) Nominal boiling range is 350-780°F.
 (g) From analyses of filter cake, filtrate, and material balance.
 (h) From analysis of filter feed stream.
 (i) Simulated distillation by gas chromatography. ASTM D2887 (modified).

TABLE 3
TYPICAL ANALYSES OF COALS USED

A. <u>Source</u>		
State	Kentucky	Illinois
Seam	No. 14(a)	No. 6
Mine	Colonial	Burning Star No. 2
County	Hopkins	Perry
Company	Pittsburgh & Midway Coal Mining Co.	Consolidation Coal Co.
B. <u>Proximate Analysis (dry basis), wt. %</u>		
Volatile Matter	38.03	42.30
Fixed Carbon	53.04	46.63
Ash	8.93	11.07
Moisture	4.21	6.14
Heating value, BTU/lb.	13,060	12,450
C. <u>Ultimate Analysis, wt. %</u>		
Carbon	72.94	70.47
Hydrogen	5.27	4.92
Nitrogen	1.14	0.84
Chlorine	0.13	0.10
Sulfur	3.07	3.10
Ash	8.93	11.12
Oxygen	8.52	9.45
D. <u>Sulfur Forms, wt. %</u>		
Pyritic	1.12	1.17
Sulfate	0.10	0.03
Organic	1.85	1.90
E. <u>Mineral Analysis of Ash, wt. %</u>		
Silica	41.10	42.61
Ferric Oxide	24.82	18.60
Alumina	23.70	17.23
Lime	2.73	7.92
Magnesia	0.49	0.94
Sodium Oxide	0.29	0.38
Potassium Oxide	2.30	1.89
Titania	0.98	0.69
Phosphorus Pentoxide	0.23	0.12
Sulfur Trioxide	2.76	5.57
Undetermined	0.60	4.05

(a) Also contained some coal from Kentucky No. 9 seam.

The first run investigated the effect of "backmixing" in the contactor during SRC operations on Illinois No. 6 coal. Backmixing was simulated by recycling hot reactor slurry directly from the reactor outlet to the reactor inlet without depressurizing the stream. The second run was made with low-sulfur (1.58 percent) Pittsburgh Seam coal and the third run was made with high-sulfur (2.64 percent) Pittsburgh Seam coal.

Details of these three specific laboratory tests are reported in EPRI Report No. 389 entitled, "Solvent Refining of Illinois No. 6 and Pittsburgh No. 8 Coals."

#

ERDA DEDICATES SYNTHANE PILOT PLANT

The Research and Development Administration (ERDA) dedicated, on November 5, 1975, the synthane pilot plant located at Bruceton, Pennsylvania. The plant was designed and is presently being operated by C-E Lummus Company of Bloomington, New Jersey, at an annual operating cost estimated at \$5 million. The plant is to process 72 TPD of caking and non-caking coals to produce about 1.2 million SCFD of medium BTU gas of which about 25 percent is to be methanated.

A description of the synthane pilot plant, constructed by Rust Engineering, was recently presented by Sam E. Carson (C-E Lummus), Plant Manager, at the 7th Synthetic

TABLE 4

TYPICAL ANALYSES OF PROCESS SOLVENT

		<u>Original Solvent (a)</u>	<u>Recycle Solvent (b)</u>
A. <u>Boiling Fractions (c)</u>			
Boiling range, °F	<u>Sp. gr.</u>	<u>Wt. %</u>	<u>Wt. %</u>
IBP - 350		--	5
350 - 450	1.00	9	27
450 - 550	1.02	36	25
550 - 650	1.05	29	23
650 - EP	1.12	26	20
B. <u>Ultimate Analysis, wt. %</u>			
Carbon		90.8	86.7
Hydrogen		6.1	7.4
Nitrogen		1.1	1.0
Sulfur		0.7	0.3
Cholorine		0.1	0.2
Ash		0.0	0.1
Oxygen		1.2	4.3
C. <u>Specific Gravity, @ 68°F</u>		1.096	1.054

(a) Allied Chemical Co. Creosote Oil 24 CB.

(b) Sampled November 16, 1974, after six days with no makeup solvent added to the system.

(c) Simulated distillation by gas chromatography, ASTM D2887 (modified).

Pipeline Gas Symposium. The symposium was sponsored by the AGA, ERDA, and the International Gas Union.

The \$15 million synthane pilot plant integrates three primary processing areas: coal pre-treatment -- to modify the caking properties of the coal for reducing agglomeration under gasifying conditions; gasification-reaction with steam and oxygen; and methanation-to include H₂:CO balancing (shifter conversion) and gas purification.

High Pressure Fluid Bed Reactor Described

The following is a brief description of the major process steps--refer to Figure 1 for a more comprehensive view of the total system. A 240-ton ROM coal storage silo accepts truck-delivered coal prior to crushing and further processing. Coal is subsequently dried and pulverized to 100 percent below 20 mesh. Pulverized feedstock passes into the pressurized feed hopper (five-ton capacity) alternately from two parallel coal lock hoppers (one-ton capacity). The coal is brought to the 1000 psig system pressure with process derived CO₂. The feed hopper charge is conveyed with high pressure steam (O₂ added) to the fluid bed pretreater where a mild surface oxidation at 800°F reduces the caking potential of the coal. Different coals will require varying degrees of pretreating--hence pretreater residence time is controlled by positioning the point of draw off from the bed.

Coal drawn from the pretreater bed flows by gravity to the devolatilizing region of the fluid bed reactor. The coal is brought to 1,800°F as it passes down twenty feet through the devolatilizing region of the reactor where it encounters rising product gas and steam prior to entering the fluid bed (20-foot expanded height) of reacting coal and char. The bed is fluidized with steam and oxygen.

Residence time in the upper (gasifying) section of the reactor may be adjusted to a certain extent by changing the inside diameter of the reactor. To effect this change in residence time, the reactor has been designed to allow the replacement of an Inconel shroud lining the inside of the reactor. The shroud, covering a six-

inch layer of castable insulating material and a three-inch layer of erosion-resistant alumina (low iron and silica), is nominally designed at five feet I.D. with an overall reactor height of 101 feet.

Particulate matter (char/ash and unreacted coal) entrained in the gases existing the reactor are returned to the bed by an internal cyclone and dip leg.

The lower portion of the reactor receives char "residue" from the reactor above. The char is quenched with water reducing its temperature to about 600°F before being de-pressurized through parallel, alternating, lock hoppers. The char is conveyed with low pressure steam to a 3,500-gallon char slurry holding tank prior to filtering (rotary vacuum) and disposal. The "residue" char from the synthane pilot plant would be used for steam generation in a commercial process.

The raw medium BTU gas leaving the reactor is quenched with water in a Venturi scrubber, shifted, purified, and methanated. The expected gas yield is about 16.7 MSCF per ton of coal (8.4 SCF per lb.). The BTU content of the product gas, assuming 72 TPD of coal input, could range between 480 and 840 MMBTU per day.

Shifting and Purification Described

The scrubbed gas (particulates and condensable hydrocarbons removed) is shifted with a cobalt-molybdenum catalyst packed into a 2.5 x 14-foot reactor. The H₂:CO ratio of the shifted gas is 3:1.

CO₂ and H₂S are removed with a Benfield unit in which hot potassium carbonate solution is circulated through a packed tower. The acid gases, stripped from the potassium carbonate absorbent, are sent forward: H₂S to a Stretford unit; and CO₂ to compression for delivery to the lock hopper pressurizing system.

The purified gas is split at this point in the process. About 25 percent or 0.3 MMSCFD are methanated to +900 BTU/SCF with the remaining 0.9 MMSCFD flared.

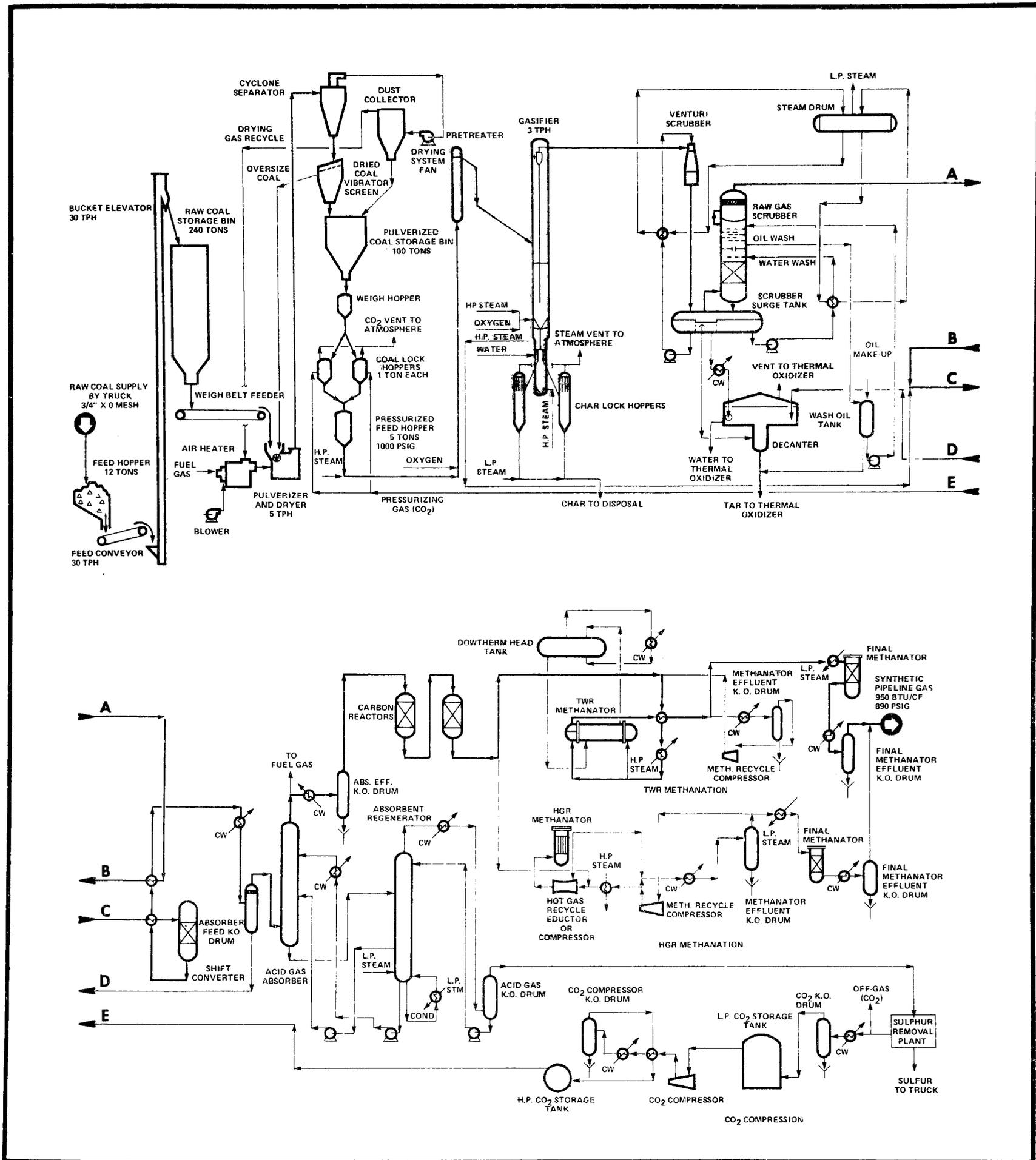


Figure 1. "Synthane Process, Bruceton, Pennsylvania"

Two Methanators To Be Tested

Two parallel methanation systems are installed at the Bruceton pilot plant to allow for further experimental development of this portion of the process. The two reactor configurations to be tested are TWR (tube wall reactor) and HGR (hot gas recycle). The flow scheme for these methanation units is shown in Figure 1.

Both systems use a Raney-Nickel catalyst but applied in distinct fashions: TWR-the catalyst is sprayed on the inside of the stainless steel 2-inch O.D. tubes; HGR-the catalyst is applied to flat rectangular plates suspended in the reactor shell. The principal functional difference between the two is the mode of removing the substantial heat of reaction generated during methanation."

"In the TWR type, the methanator consists of 22 tubes, 20 feet long, enclosed in a carbon steel shell, which is filled with Dowtherm. The heat of reaction, developed as the methanation reaction progresses, is transformed to the boiling Dowtherm through the walls of the tubes. The temperature is controlled at around 730°F.

"In the HGR methanator, no heat of reaction is removed in the vessel itself. The temperature rise is limited to 180°F by diluting the feed gas with about seven volumes of recycled product gas, which has been cooled in an external heat exchanger."

The final methanator is to remove trace quantities of CO and H₂ to produce pipeline quality gas. SNG leaves the process at about 890 psig with a heat content of about 950 BTU/SCF.

The water requirement for the plant, when processing 72 TPD, is 197 AFY: evaporative loss - 132 AFY (67 percent); clean effluent- 53 AFY (27 percent); and consumed in the gasification process-12 AFY (6 percent).

Commercial Plant Projections

Based on the present design and process performance assumptions (more reliable data will be available through plant generation) a plant producing 250 MMSCFD will require about 15,000 TPD of process coal (steam and

power generation requirements not included) and 41,000 AFY of water (based on 197 AFY for the present system). This water requirement appears to be high by a factor of four. Certainly, water use may be conserved in a commercial-scale plant.

Prestart-up Period Highlighted

C-E Lummus began to staff the plant in August 1974. At the present, 120 persons are at the site to include administration, engineering, operations, and subcontracted maintenance (Schneider, Inc.) personnel. Operating staff posed a problem as too few qualified local personnel were available. A subsequent training program was required.

By March, the utilities and coal handling areas were tested and turned over to operations staff. Check-out of the Stretford and Benfield units began in April.

A two-month delay was encountered when in May, during nitrogen high pressure testing of the main reactor vessel, a leak was detected and subsequently traced to a faulty weld at the mid-vessel flange.

Sealing of ball valves in the coal feed lock hoppers (300°F, 160 psig) and the char removal lock hoppers (625°F, 1000 psig) caused some problems. The valves in the coal feed system are presently functioning well; however, the char removal valves are undergoing redesign and installation.

Integrated plant start-up including low pressure cold fluidization tests is to begin in December 1975 with gasifier start-up in early 1976.

#

LURGI SLAGGING GASIFIER STATUS REPORTED

"This new gasifier will complement the 'dry bottom' Lurgi gasifier by extending the range of coals suitable for fixed bed steam and oxygen gasification at high pressure into the less reactive low fusion point ash types. The standard Lurgi gasifier is better suited to handle the high fusion point, high ash content, high reactivity coals which can be gasified at high load with low steam oxygen ratios. Coals with refractory ash present in quantities in excess of 15 percent

particularly if accompanied by high moisture contents are less suitable for slagging conditions.

"On the other hand, the less refractory ashes or refractory ash present in quantities less than about 15 percent by weight in coals of low or high reactivity having moisture contents not in excess of about twenty percent by weight are highly suited to slagging operation when full benefit can be derived from increased gasifier output, low steam consumption, low aqueous liquor production and higher gasification efficiency leading jointly to lower gas production costs. Thus, one sees a future for both gasifiers which, by complementing each other, will maintain fixed bed gasification in the forefront of gas manufacturing technology."

These comments, and ones to follow, concerning the operation of a modified Lurgi coal gasification unit under ash slagging conditions were offered by Dr. D. Hebden, British Gas Corporation, at the recent 7th Synthetic Pipeline Gas Symposium, sponsored by AGA, ERDA, and the International Gas Union. The development of the commercial slagging gasifier at the BGC Westfield Development Center, Westfield, Scotland, is being sponsored by the following U.S. companies in full collaboration with Lurgi of Frankfurt, Germany:

- . Cities Service Gas Company/Northern Natural Gas
- . Continental Oil
- . El Paso Natural Gas (commercial Lurgi project pending FPC certification)
- . Michigan Wisconsin Pipe Line (commercial Lurgi project pending FPC certification)
- . Natural Gas Pipeline
- . Panhandle Eastern Pipe Line
- . Standard Oil of Indiana
- . Southern Natural Gas
- . Sun Oil
- . Texas Eastern Transmission (commercial Lurgi project pending FPC certification)
- . Tennessee Gas Pipeline
- . Transcontinental Gas Pipeline
- . Electric Power Research Institute

The commercial gasifier that will result from this research will be known as the British Gas/Lurgi slagging gasifier with

licensing rights held by BGC on behalf of the participating companies.

Effect of Slagging Operation Described

Recent tests under slagging conditions in the modified Lurgi reactor were made with a "very low ash" petroleum coke over a wide range of operating parameters to establish the behavior of a fixed bed gasifier in that mode. The gas composition resulting over the range of steam:oxygen ratio between 1.0 and 8.0 (mol/mol) is shown in Figure 1. "The low ash (coke) permitted the otherwise inoperable clinkering range between about 6.0 and 2.0 mol/mol to be studied." It is noted in Figure 1 that the methane content remains constant at about two percent by volume of the reactor make gas and drops as the temperature increases in the gasification zone. This low methane yield and subsequent drop as slagging conditions are approached "... relates to a fuel of low volatile content being gasified at only 75 psig. With coal at higher pressure the methane yield is much higher and less influenced by changing to slagging operation."

The slagging mode, restricted by ash fusion temperature as mentioned above, is a function of the temperature in the combustion zone of the reactor which likewise is a function of the steam:oxygen ratio. At a given steam:oxygen ratio and other operating parameters held constant the temperature profile vertically through the bed becomes a function of the reactivity of the coal charge. Figure 2 depicts this profile. The temperature rises to a maximum in the combustion zone, but is limited by the endothermic steam decomposition reaction which continues in the gasification zone above, after oxygen depletion. Thus, the maximum temperature, hence the approach to ash fusion conditions, is primarily controlled by the steam:oxygen ratio or the extent to which these exothermic and endothermic reactions are allowed to compete. Gasification rate and agents (steam/oxygen, steam/air, carbon dioxide/oxygen) are significant factors affecting ash clinkering and fusion.

The greater yield or output of the modified Lurgi gasifier under slagging conditions is attributable to lower quantities of undecomposed steam leaving the gasifier. The lower process steam requirement coupled with

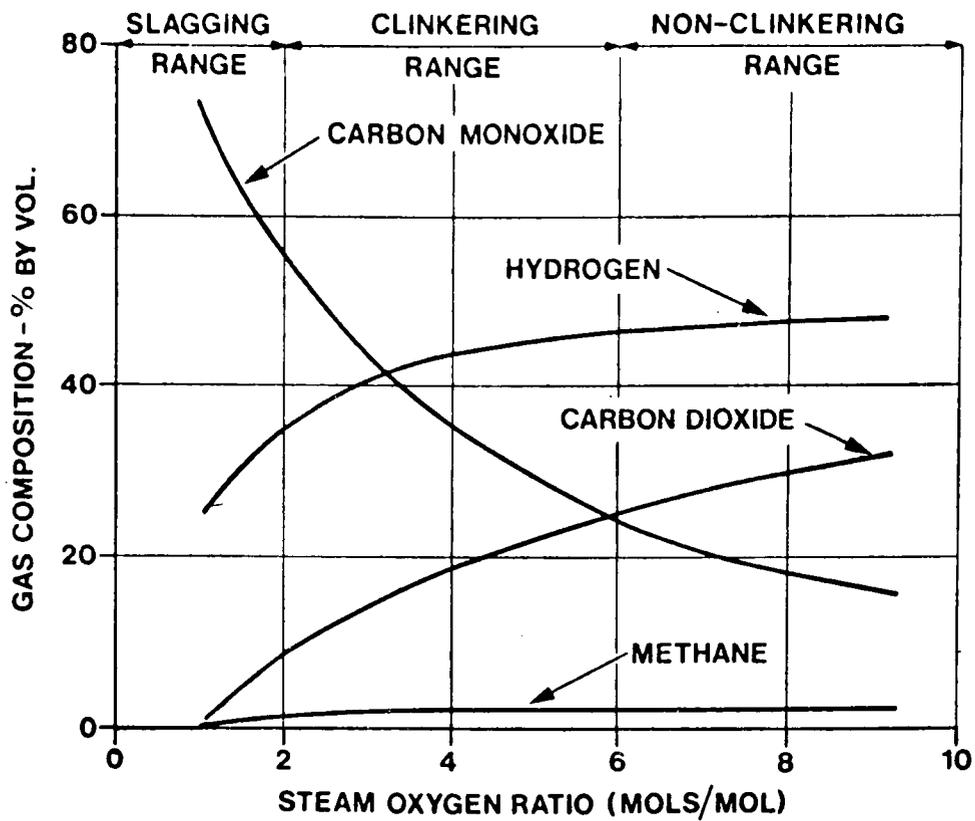


Figure 1. The Influence of Steam Oxygen Ratio on Gas Consumption

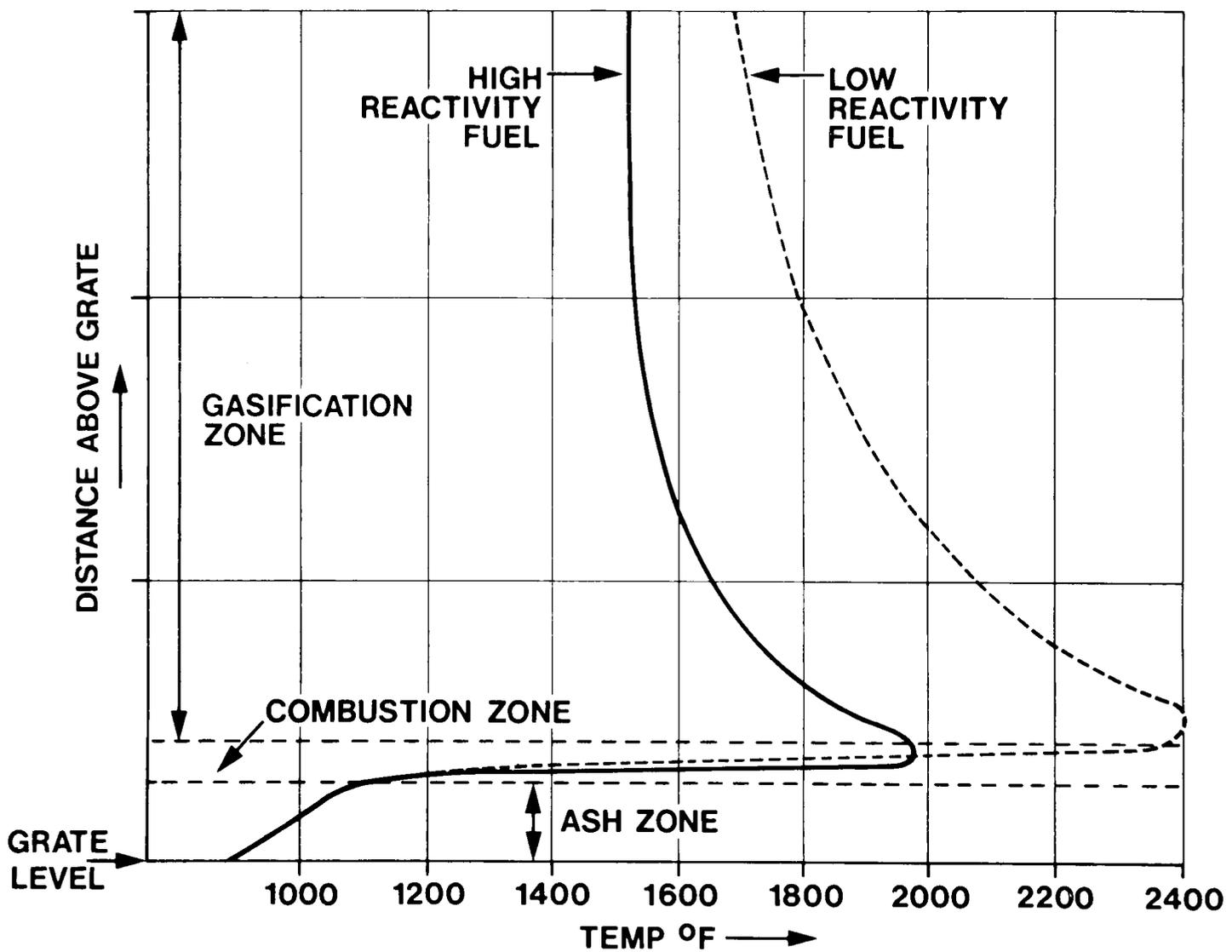


Figure 2. Temperature Distribution When Gasifying Fuels of Differing Reactivity in a Fixed Bed Under Identical Conditions.

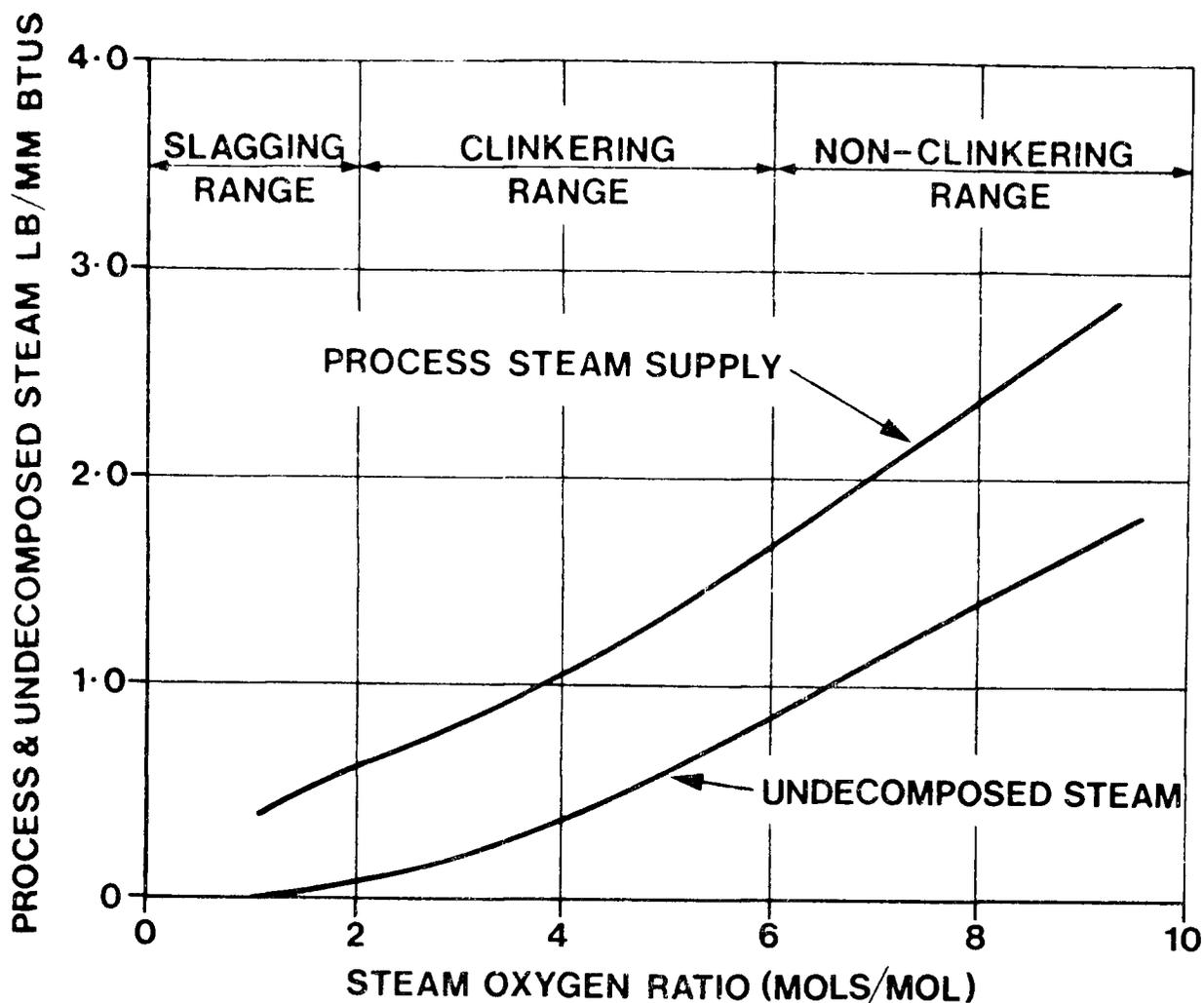


Figure 3. The Influence of Steam:Oxygen Ratio on Process Steam Consumption and Undecomposed Steam (per MM BTU's of Product Gas).

the higher operating temperatures explains the lower undecomposed steam flow. "The output of a gasifier, clinkering effects apart, is ultimately determined by the rate at which product gas and undecomposed steam can be passed through it without excessive carry over of fuel." Figure 3 plots steam:oxygen ratios versus process and undecomposed steam flow through the gasifier.

In conjunction with higher yield, higher thermal efficiency (by six percent) is reported from data taken during slagging operation (with petroleum coke) as compared to normal "dry-bottom" operation with coal. This higher thermal efficiency takes into account both lower steam and greater oxygen requirements. Greater oxygen consumption is due to the following:

- . "...ash leaves the combustion zone at a high temperature as liquid slag without heat exchange with either the fuel or the steam and oxygen."
- . "...the slagging and fluxing reactions are slightly endothermic and absorb some of the heat liberated by the oxygen."

- . "...there is a slightly lower production of methane by hydrogenation and the formation of carbon dioxide is also less, two exothermic reactions which contribute heat for the (endothermic) decomposition of steam."

Future experimental runs will be conducted at Westfield by BGC to test slagging and dry-bottom operations with the same coal feedstock to provide a comparable basis. Tests to date under slagging conditions have only been run with petroleum coke offering an unequal comparison with runs with coal.

###

BI-GAS PILOT PLANT NEARING COMPLETION

The BI-GAS coal gasification pilot plant, Homes City, Pennsylvania, is in the final stages of construction, and plant start-up is expected early in 1976. The cost of the pilot plant is estimated at \$24.8 million. Stearns-Roger, Inc., Denver, Colorado, designed and constructed the plant to convert five TPH of caking and non-caking coals

to medium BTU gas of which a portion is to be methanated to SNG.

The prime contractor for the project, Bituminous Coal Research, Inc., will provide consulting services to the program manager and operator, such as: research program planning, analytical laboratory work, data acquisition evaluation and related computer services. Phillips Petroleum Company, Bartlesville, Oklahoma, is to manage the pilot program.

The BI-GAS Process promises several advantages in the production of synthetic natural gas:

- . A high yield of methane is obtained directly from coal, thus reducing oxygen consumption and downstream processing.
- . Because it is an entrained rather than a fixed or fluidized-bed system, all types of coal can be gasified without prior treatment.
- . The rapid heating and reaction conditions in Stage II are such that no tar and oils are formed in the gasification process.
- . All the feed coal is consumed in the process; principal byproducts are slag for disposal and sulfur for sale.
- . The two-stage gasifier, being an integral unit, is relatively simple in design and amenable to scale-up to larger sizes.

High Pressure Slurry Feed System Described

Coal entering the process area is pulverized to 70 percent passing 200 mesh in a ball mill as a water slurry. The coal/water slurry leaving the pulverizer is thickened and repulped to adjust the density before entering the high pressure slurry pumps. Flux, to control slag formation in the reactor, is added to the slurry before being pumped to +1000 psig. The high pressure slurry is preheated and flashed into a spray drier where it enters a stream of hot recycle gas from the gasifier. The dry coal is conveyed with recycle gas and injected with steam into the lower portion of zone II of the reactor.

Entrained Flow Gasifier to be Tested

The BI-GAS reactor is shown in Figure 1.

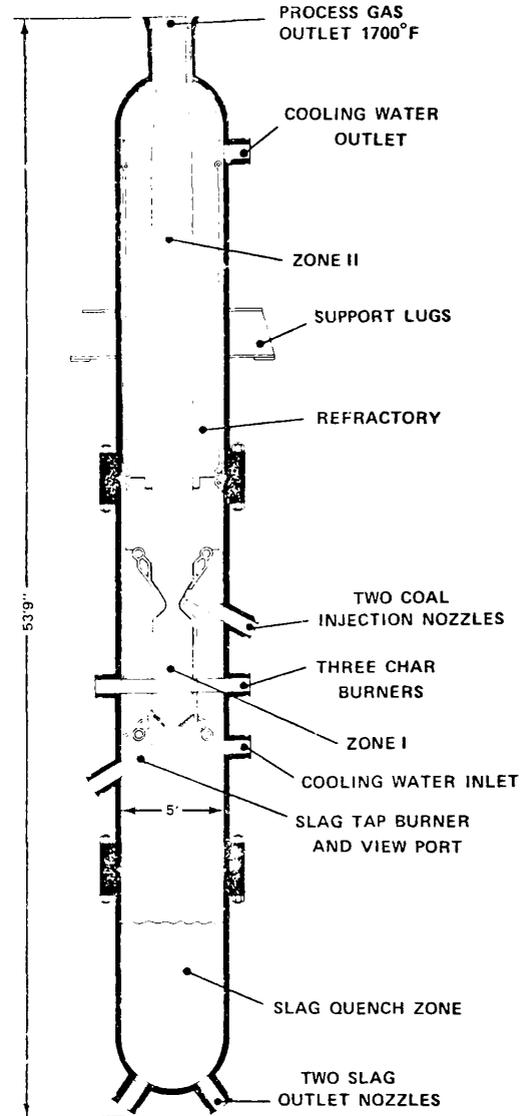


Figure 1. The BI-GAS Reactor

The reactor is to be operated in the 500 to 1500 psig range with product gas leaving the entrained flow gasifier section (zone II) of the reactor at about 1700°F. The residence time in the gasifier is expected to be about 8.5 seconds. The high pressure

low residence time gasification is designed to optimize methane production. Steam for gasification is injected simultaneously with the incoming coal in zone II.

On entering zone II, the coal steam mixture contacts upward flowing products of char combustion from zone I at about 3000 to 3200°F. Char formed in zone II is removed from raw gas by an external cyclone and conveyed by high pressure steam back to zone I for vortex combustion with oxygen. Ash slag is formed and deposited on the walls of zone I. A nine-inch throat between zones I and II restrains slag carry over to zone II.

Slag flows down through zone II into a water quench below. A dual lock hopper arrangement below the reactor allows pressure let-down and removal of the granular ash.

Fluid Bed Methanator Installed

Following char removal in a cyclone separator the remaining particulate matter and condensable hydrocarbons are scrubbed with water from the raw, medium BTU, gas stream in a counter-current baffled, tower. Shifted gas is sent forward to a combination of SELEXOL and Claus units for CO₂ and H₂S removal and processing.

Purified, shifted gas is upgraded in a fluid bed methanation unit--catalyst not specified. Heat removal from methanation is effected through water-cooled tubes in the fluid bed. SNG is again treated by the SELEXOL process for trace CO₂ removal before exiting the process and incineration.

The above information concerning the BI-GAS Process was contained in part in presentations before the 5th and 7th Synthetic Pipeline Gas Symposia (sponsored by AGA, ERDA, and the International Gas Union).

Material Balance Estimated

Table 1 presents an estimate of the material balance that is expected for a five TPH BI-GAS reactor. These data were submitted to OCR by Bituminous Coal Research in the report "Gas Generator

Research and Development--Survey and Evaluation", Phase I, Volumes 1 and 2, BCR report No. L-156, 1965.

TABLE 1

MATERIAL BALANCE FOR 5-TON PER HOUR BI-GAS GASIFIER

<u>Input</u>	<u>Wt, lb/hr</u>	
<u>Stage 2</u>		
Coal	10,000	
Transport Gas Recycle	(1,919)*	
Steam	<u>8,774</u>	18,774
<u>Stage 1</u>		
Char Recycle	(9,408)*	
Steam Feed Gas Recycle	(275)*	
Steam	2,880	
Oxygen (99.5%)	<u>6,361</u>	<u>9,241</u>
Total Input		<u>28,015</u>
<u>Output</u>		
<u>Stage 2</u>		
Raw Product Gas	27,331	
Recycle Gas	(2,194)*	
Recycle Char	<u>(9,408)*</u>	27,331
<u>Stage 1</u>		
Slag	<u>684</u>	<u>684</u>
Total Output		<u>28,015</u>

*Not included in totals.

#

SCENIC UPPER MISSOURI RIVER STATUS WOULD
BAR WATER DEVELOPMENT

The Upper Missouri Wild and Scenic River Draft Environmental Impact Statement, DES 75-45, was released by the Bureau of Outdoor Recreation in June. If the study area gains wild and scenic river status pursuant to the Wild and Scenic Rivers Act, water resource development along a 128-mile stretch of the river would be prohibited. This becomes important since the river runs through the lower half of the North Central Montana Coal Region.

The portion of the river recommended for preservation is between Coal Banks Landing on the west and the Rocky Point Historical Site on the east. Boundary limits would be approximately a quarter mile wide on either bank of the river. The land area is bounded on the east by Fort Peck reservoir including the C. M. Russell National Wildlife Range. Three alternative boundary plans were proposed. The first proposes protecting 170 miles of river and riverside between Coal Banks Landing and Fort Benton.

Alternative Number 2 retains the 170-mile length and widens and extends the corridor boundaries to sightline, about 1 1/2 miles on either side of the river.

The third concept visualizes a stretch from Coal Bank Landing to Robinson Bridge approximately 114 miles with a quarter mile strip of land on each bank. The region is a part of the Great Plains physiographic province, consisting primarily of high rolling plains of mixed prairie grasses. The climate is semi-arid. Precipitation averages about 13 inches annually.

Studies conducted by prospective developers in the area reveal water availability is a problem. It is doubtful existing developed resources could meet the demands of a gasification plant.

The addition of this portion of the Missouri River to the National River System should not cause any short range problems. There have been no active coal mines in the area since 1960. Before that, some small underground mines had produced coal for

local use.

The impact of eliminating water resource development in the study does not affect foreseeable coal development projects. There are no announced plans for any projects in the area. The region has good quality coal and considerable long range potential. It is not being considered at present because of mining problems and availability of more readily strippable coal deposits elsewhere.

Two water projects have been proposed in the area in recent years. One is the Fort Benton Dam concept of the U.S. Bureau of Reclamation. A detailed report released in 1971 by the Bureau concluded that the project to impound 880,000 acre-feet of water was not economically justifiable. The report stated that future reconsideration might be warranted, particularly relative to hydroelectric power production. Under the 128-mile proposal, the dam could be constructed but would be required to maintain a specified downstream flow. In the event the entire 170-mile segment was designated wild and scenic, the dam would not be allowed.

The second proposed project was the High Cow Creek Dam and Reservoir (see Figure 1). It was proposed in 1960 by the U.S. Army Corps of Engineers. A study report was made in 1965. The Governor of Montana opposed construction. The dam would have provided 4,200,000 acre-feet of usable storage. All of the segment proposals would block any future consideration.

Debate over the issue has centered mainly on the division of administration between the National Park Service and the Bureau of Land Management.

A final draft of the impact statement will be drawn preparatory to legislative action. Proposed draft legislation also released in June asked for \$1,260,000 for river bank land acquisition and \$556,000 for related development.

#

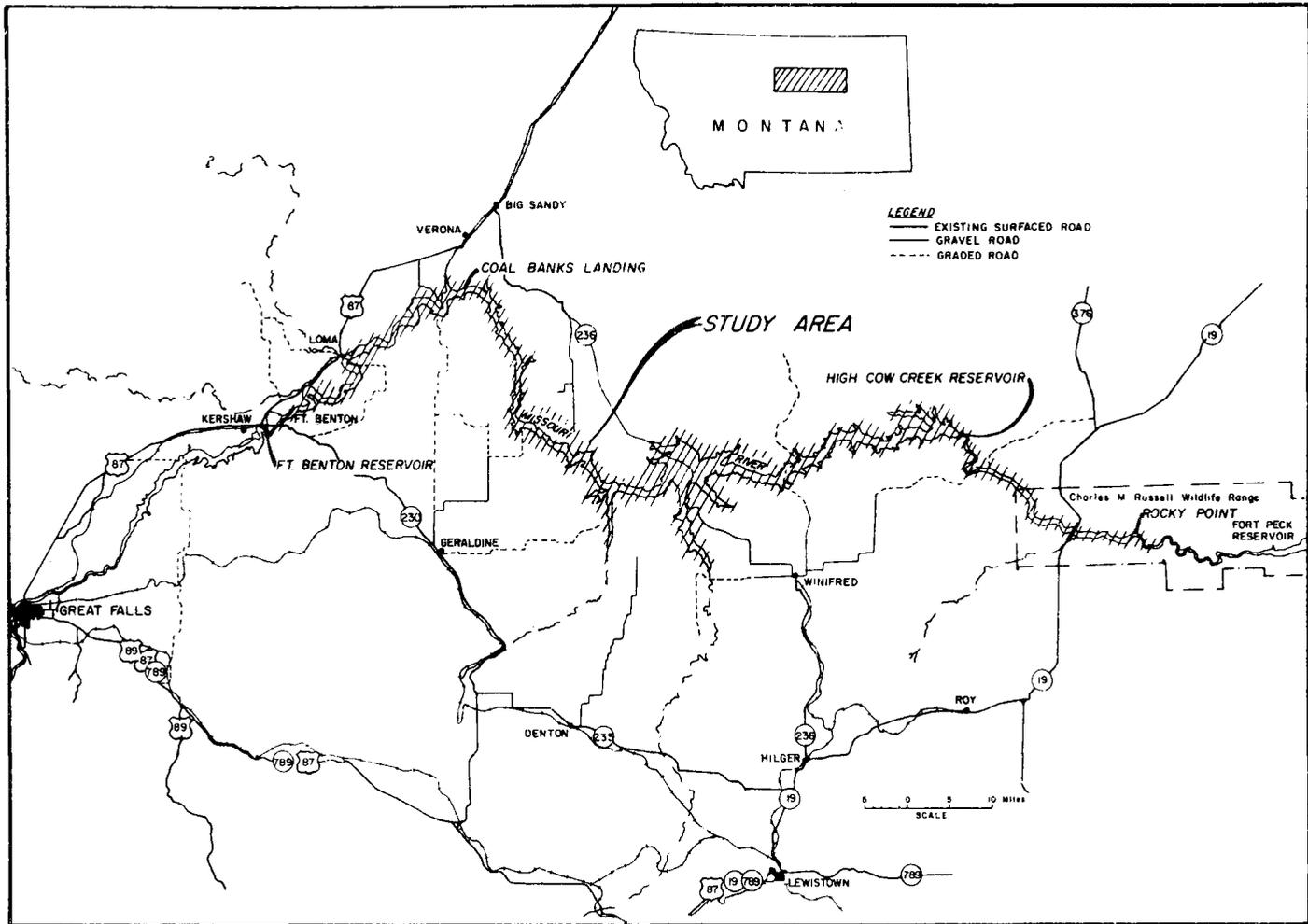


Figure 1. Upper Missouri River Wild and Scenic River Study Area.

WESTWIDE STUDY RELEASED

The United States Department of the Interior, Bureau of Land Management, released in October 1975, the foreshortened Westwide Study." The final report, dated April 1975, entitled "Critical Water Problems Facing the Eleven Western States," presents an analysis of present and past water availability and needs, and environmental, engineering, economic and social concerns surrounding future western water development.

The study was initiated in 1969 by authority of the Colorado River Basin Project Act (Public Law 90-537) and was to "conduct full and complete reconnaissance investigations for the purpose of developing a general plan to meet the future water needs of the Western United States."

The results of the study under original authorization were to be submitted to the President, Congress, and the Water Resources Council by June 30, 1977.

However, more recently, Congress through the Water Pollution Control Amendments Act-1972 has directed the Water Resources Council under the Water Resources Planning Act to prepared water resource plans by 1980 for river throughout the nation, to include the Western U.S.

In light of these factors, a decision was made to terminate field work on the Westwide Study by July 1, 1977, and to prepare a report based on data and information available at that time.

#

MADISON FORMATION STUDY PLANNED

A plan of study (POS) is being drafted by the U.S. Geological Survey to investigate in detail the hydrology of the Madison formation underlying much of the Northern Great plains. The Madison formation is to be studied to ascertain, among other items, the effect large withdrawals of water may have on the aquifer's recharge rate and the

approximate water resource available for development.

The study is expected to total \$11 million over a 5-year period. Funding has yet to receive Congressional approval. The present POS, funded by the Old West Regional Commission, being drafted by the USGS was initiated after coal companies expressed interest in withdrawing large amounts of water from the Madison for coal related projects. The final draft of the POS is available from the Study Coordinator, Water Resources Division, U.S. Geological Survey, Building 53, Box 25046, Denver Federal Center, Lakewood, Colorado 80225.

#

ENVIRONMENT

FINAL ENVIRONMENTAL IMPACT STATEMENT ISSUED BY U.S. DEPARTMENT OF INTERIOR ON PROPOSED FEDERAL COAL LEASING PROGRAM

When the Interior Department, last month, released its final environmental impact statement on leasing federal coal, its authors realized there was every reason to assume the EIS would face a court test. At least one national environmental organization had announced its intention of filing suit against Interior on the statement and was wooing other conservation oriented groups to join it.

It is certain charges of the EIS being inadequate will be raised. The major thrust of any litigation is most likely to challenge the necessity of additional federal coal leasing now. Opponents of coal development, whether the coal is sought to fuel electric power generation plants or for synthetic oil and gas, will continue to tout solar energy and geothermal power as if they were off-the-shelf alternatives that have no environmental impact themselves.

The EIS says Interior's objectives are environmental protection "to the maximum extent practicable"; achieve orderly and timely development ... and assure a fair rate of return for the sale of federal mineral resources. Environmentalists already have pinpointed the phrase "to the maximum extent practicable" as being vague, uncertain and, in their minds, allowing for insufficient protection of the land, water, and air.

Under Interior's proposal, historic coal leasing practices would be abandoned, particularly the practice of an individual simply applying for a lease and having it issued to him upon payment of twenty-five cents to one dollar per acre annual rental fees. The significant aspects of the new leasing procedures are:

- . Several leases in the same region will be covered by a single environmental impact statement wherever possible.
- . Diligence requirements will compel coal mining or surrender of the leases.

- . Non-competitive lease applications, some of which have been on file since 1971, will be processed in concert with comprehensive land use plans.
- . Interior will determine priority regions where coal development pressure is most intense and where leases can be processed rapidly; simultaneously, if possible. If non-competitive and competitive leases can be processed simultaneously, the BLM District Manager will set priorities for leasing based on market demand and ongoing mining operations.
- . New leases will be offered for competitive sale through the EMARS system.
- . The compilation of coal resource and rehabilitation potential which could eliminate some coal deposits from development.

The EIS does not address the need for coal. The issue was raised after the draft by a variety of organizations. The final EIS disposed of the question:

"An EIS is not to justify a proposal but to present facts to be used in the decision-making process. The facts are that federal coal leases in 1945 totaled only 80,000 acres. This soared to 778,000 acres in 1970, just before Interior declared a moratorium on further leasing. Production in that same period fell from about 10 million tons per year to 7.4 million tons in 1970. Of the total acreage under coal lease, ninety-one percent was within non-productive leases (in 1970)."

Coal production from federal leases has been increasing rapidly since the mid-1960's. Most growth in recent years in Western low-sulfur coal production has come from Indian land. Production from Indian land in 1960 amounted to one percent of the total production. This had expanded to about 17 percent in 1972.

Reserves Noted

Interior estimates there is a total of 1,580,987 million short tons of coal of all kinds, including 130,081 million short tons in Alaska. The reserves are within 3,000 feet of the surface and in beds at

least 14 inches thick for anthracite and bituminous coal, and for lignite and subbituminous beds 2 1/2 feet thick.

Again this much coal is believed at depths between 3,000 and 6,000 feet. The key factor, however, is that by 1990 some 284.7 million tons of federal coal are expected to be mined annually, most of it in the West. The states with the most federal coal acreage are: Alaska, 23.4 million; Colorado, 8.7 million; Montana, 24.6 million; New Mexico, 5.5 million; North Dakota, 5.6 million; Oklahoma, 400,000 acres; Utah, 4.1 million; and Wyoming, 11.8 million.

Highlights of leasing itself are that no coal will be leased where environmental damages would be unacceptable ... a determination for BLM using its Management Framework Plan. This is in keeping with the content of several recent bills before Congress, notably the controversial coal strip mine bill vetoed last June, which provides prohibitions to mineral development based on Environmental considerations, and H.R. 8435 which rewrites the Mineral Leasing Act.

Leasing will be permitted in amounts appropriately in relation to plans to produce coal in the near future. Diligence requirements and advance royalties will tend to assure this. It would keep companies from leasing vast acreages, only a small portion of which could be mined over a period of several decades because they would be paying production royalties on acreage not being mined.

The EIS endorses prospecting permits which would lead to preference right leases as long as diligence, environmental protection, and royalty payment features of competitive leases are met. In countering the argument that no new leases are necessary, Interior notes in the EIS: Because of changing conditions -- including demands for electricity, transportation rates, social factors -- some existing coal leases will not be economically competitive to other unleased deposits, which, if leased and developed, would be more profitable.

It may be impossible to comply with

diligence requirements to have coal in production in three years and paying royalty on production whether or not actual mining is underway. Therefore, a lease would be surrendered.

Some leases may be environmentally unsuitable for development or the coal reserves may not be economically extractable. Blocking up of federal-private-state coal leases will be necessary in some cases where federal coal leases are too remote or otherwise unsuitable, by themselves, for development. If the combined mineral rights cannot be assembled, along with satisfactory resolution of surface rights ownership, some federal leases will be allowed to expire.

Recommended by the EIS are nomination of leases to the BLM for no more than 2,560 acres in any one lease. Nominations may be as small as 40 acres. However, pending new laws, there would be no limit on the number of acres nominated per state.

BLM will set priority for leasing depending on interest and need. Those sites will be processed first. Thus, a considerable amount of leased coal lands may not be developed and new leases will be necessary if coal demands are to be met.

Previous coal leases were issued under rules far different from what is now envisioned by Interior. Currently, 33 of the 533 existing coal leases are over 40 years old. Less than half of the reserves for these leases are known to be planned for future production.

"Changes in regulations are now being considered which would define diligent development and continuous operations of these existing leaseholds." Proposed revisions to existing coal regulations to add definitions of a "Logical Mining Unit" and the terms "diligent development" and "continuous operations" were published in the Federal Register September 5, 1975.

This heralds problems for existing leases on which no development has occurred and on which none may be currently planned. Coupled with anticipated delays in resumption of federal leasing, it could further reduce the supply of coal available over

the short range.

EMARS To Be Implemented

New coal leases will be issued under the Energy Mineral Activity Recommendation System (EMARS).

The EMARS program is designed to evaluate data on rehabilitation potential, the overall resources base including water, forests, and minerals; surface and mineral ownership, socio-economic impacts; state and local government actions; national, regional and local demand for federal coal. regional and local demand for federal coal.

"EMARS answers the questions of where, when, how much, and at what cost and impact should the federal government offer coal for lease. The new federal leasing program, according to Interior, will be constrained "for the first year or two by the capacity of BLM and USGS to do necessary environmental and resource analysis...", the EIS states. The time lag seems exceedingly optimistic and could be multiplied by three without hesitation.

Colorado, of all the Western states, now is the only one prepared to proceed with a large scale coal leasing program. The Bureau of Land Management in Colorado has nearly completed its environmental assessment work in the north-western corner of the state and on the North Fork of the Gunnison River. It has scheduled assessment work in southern Colorado in the Raton Basin and in the Denver Basin by 1978. The U.S. Geological Survey has already done much of its coal economic evaluation in Colorado.

The draft EIS specified that these studies would be completed before leasing resumes. Thus, delay in resumption of federal leasing looms not only from possible court suits, but from the administrative workload of fulfilling these requirements.

The EIS presents numerous tables, charts and graphs on production, leases held, kinds of leases, a state-by-state breakdown of federal coal leased,

production levels and anticipated potential production. It also tabulates reserves on a state-by-state and coal grade basis. There are environmental descriptions of the six coal provinces--Pacific Coast, Rocky Mountain, Northern Great Plains, Interior (Midwest), Gulf Coast, and Eastern. It is not entirely a western coal report.

Non-restorable surfaces, diminished air quality, surface and underground hydro-logic changes, and disruption of wildlife habitat are described briefly along with leasing alternatives, and energy source options including oil shale.

The report is liberally illustrated with black and white photographs. Some of the studies are based on assumptions, which naturally, may or may not be valid. It does illustrate the value of environmental impact studies in that it compels some crystal ball gazing which in turn can be used to lessen development and reclamation costs, plan for employment demands, water management and minimizing undesirable social, as well, as natural environmental impacts.

Environmental Comment

A magnifying glass is useful to read 71 pages of reproductions of environmentalists' comments which have been reduced 75 percent in size from their original form .. to comprise more than 280 pages in all. Examination of these comments reveals a wide range of insights ranging from highly theoretical assumptions and unanswerable questions to some giving a solid insight into public concerns and grounds for legal action.

There were 44 program policy issues raised by a variety of organizations and individuals. There also are five legislative issues. Still, coal development questions elicit some peculiar responses from diverse sources, responses that take root in the vagaries of the overall energy problem and the lack of understanding of the complexities.

The Council on Environmental Quality asked: "What are the direct and indirect consequences of a potentially massive shift in the coal industry from the East

and Midwest to the West?"

The Environmental Protection Agency complains that the draft EIS failed (neither does the final EIS) to address the necessity for additional leases. This is the central thrust of 38 pages of EPA criticism of the draft EIS.

EPA did not confine itself to environmental issues. On page 18, there is this statement: "The question of royalty payments and bonuses needs to be addressed to establish a fair system of competition between small and large coal operators." Regardless of the validity of the statement, it seems an odd one to be found in a critique by the EPA. Perhaps the agency was only playing the role of the devil's advocate, but its 38-page statement seems a primer of the issues that could be raised against renewal of federal coal leasing.

The East versus West theme is the core of the input from the West Virginia Legislature. In a letter signed by the Speaker of the House and State Senator Alan L. Susman, the draft EIS was labeled as "erroneous, one-sided, flagrantly opinionated and full of mis-statements or misleading statements in developing the strongest possible case for the use of low-sulfur western coal ..." A 26-page detailed criticism of the draft EIS follows this theme-setting cover letter.

Whereas, West Virginia feared the loss of some coal mining to the West, Montana Governor Thomas L. Judge took "great" exception to the thrust, contents and conclusions of the report because "it is apparent that interest in future federal coal leasing will generally focus around coal deposits in Montana ..."

The contrasting statements are typical of other regional interests expressed and seem to indicate no early end to the political problems accompanying increased coal leasing and development.

The Sierra Club filed a 41-page criticism of the draft EIS, much of which attacks the presumed need for additional coal leasing, particularly in the West. Predictably, it also is laced with con-

tentions of the inadequacy of the draft EIS and it would appear that few of the points raised against the adequacy of the draft have been answered in the final, at least to the satisfaction of the Sierra Club.

While it is tempting to blame environmentalists for legal delays on coal and other energy development, it should be noted they merely file suit claiming the law isn't being followed. And, as is the case with the Sierra Club versus Morton litigation which has halted coal development on the Northern Great Plains, the court agreed. In that case and in the leasing EIS, environmentalists gave notice of legal shortcomings. When nothing was done about them, the litigation resulted.

Chapters deal with environmental impacts from various kinds of development -- including socio-economic reports; and with irreversible and irretrievable commitments foreseeable from federal coal leasing and its subsequent development. It is clearly a comprehensive picture of a vast range of factors to be considered. There is some merit in the environmentalists' allegations of inadequacies, particularly if one believes in perpetual data collection, tabulation, and updating, but that is a goal in itself unrelated to meeting national energy needs.

The EIS would have been more helpful if it had addressed the issues of coal transportation, the proliferation of electric power lines and railroad beds, Indian coal development, and the bearing of natural gas shortages on coal gasification potential.

While coal bearing states are also natural gas producing states, synthetic gas and crude facilities processing coal can fulfill increased domestic and industrial needs in a gas-short region. It is conceivable that a coal gasification facility would meet local needs, and alleviate the need for surface shipment to metropolitan use centers.

The report stops, however, at mining coal. What is to be done with it is for others to answer. It is interesting to observe that regional environmental assessments are called for. Should these become

part of Interior coal leasing regulations, additional delay in moving into production is virtually a certainty unless Congress limits the bases for lawsuits based on the National Environmental Policy Act.

The anticipated wave of environmental and consumer oriented legislation in the wake of the 1974 General Election has not materialized despite the revolt in the opening stages of the 94th Congress which unseated some committee chairmen and curbed the power of others. While columnists like Jack Anderson carp that many new members have "joined the club," they have in fact, merely learned something about how the system works.

In a matter related to getting coal mined, the House Interior Committee on October 7 opened hearings on repeal of Section 2 (c) of the 1920 Mineral Leasing Act. The law now prohibits railroads from mining coal from the public lands except for use in locomotives. Burlington Northern, for example, has extensive holdings in Montana, but the lands are in a checkerboard pattern. Repeal of the prohibition could be something of a bonanza for the Burlington Northern as well as other western railroads. It could be a bonanza in other ways, too, permitting assembly of the large, long-term blocks of coal reserves adjacent to railroads and that would be necessary to justify construction of a billion dollar synthetic fuels plant.

The House Interior Committee has scheduled a second meeting on the proposed repeal for October 23.

Tables 1 through 4, presented in the final EIS, provide data on past coal production, remaining resource estimates by state, and representative coal analyses by coal region.

#

ERDA REPORT CONCERNS THE SOCIAL, ECONOMIC, AND LAND-USE IMPACTS OF A FORT UNION COAL PROCESSING COMPLEX

"The Social, Economic, and Land-Use Impacts of a Fort Union Coal Processing Complex" is the title of a recent report to

the Energy Research and Development Administration concerning work done by the Denver Research Institute. This is ERDA's Research and Development Report No. 103, Interim Report No. 1, NTIS No. FE-1526-T1, and is available from the National Technical Information Service, Springfield, Virginia 22161. Its price is \$5.45.

This interim report prepares the basis for a later final report which will illustrate typical economic, social, and land use impacts resulting from development of one hypothetical coal-oil-gas (COG) complex which might consume 50 million tons of lignite per year and might be in production by the late 1980's in the Fort Union lignite region. A 24"x36" map of the Fort Union region in Montana, North Dakota and South Dakota, showing coal mineral right ownership, was presented in the March 1975 issue of Synthetic Fuels.)

This interim report and the final report which is yet to be published are intended to deal with questions such as:

- . What happens to sparsely populated, agriculturally-oriented areas when a large scale complex is built and operated? What lessons can be learned that are applicable to the possible development of a COG complex?
- . What would be the employment and population effects of a COG complex in the Fort Union region? How do these effects vary among sites within the region (extremely rural areas versus more urbanized areas?)
- . What are the positive and negative aspects of a COG complex in terms of economic, social, and land use considerations?
- . How do the public facility and service needs match the tax revenue flows? What are the gaps?
- . Can the impacted areas be expected to absorb a COG complex within present financial, institutional and growth management structures?
- . Can the methodology developed in this analysis be applied to other areas likely to be the sites of large scale coal processing complexes?

A hypothetical COG complex may be located at some future time in any area where

sufficiently large blocks of coal are accessible. Water will be an important locational consideration. The complex would be a multi-product facility the equivalent of a major steam power plant (1,000 MW), a moderate-sized petroleum refinery, and a large gasification plant (400 billion cubic feet of gas per year).

Since the impact analysis is based upon using a not-yet-mature technology and design, the actual timing is conjectural. However, following a construction period of perhaps five years duration, the refinery could go on stream in approximately 1986 or 1987.

It is expected that the capital investment (in 1975 dollars) could be as follows:

Four mines of 12.5 MMTPY capacity each	\$ 550,000,000
Refinery	1,000,000,000
Power plant (1,000 MW)	400,000,000
Start-up costs	100,000,000
Working capital	45,000,000
Total investment	<u>\$1,895,000,000</u>

This interim report then presents a description of a coal-oil-gas complex, presents estimates of employment in the COG area to the year 1990, and presents seven brief analyses (case studies) by DRI of other areas which, in the past, have been impacted by large scale developments.

The findings and the conclusions concerning the impact of a Fort Union COG will be in the final report.

###

TABLE 1
CHANGES IN U.S. AND WESTERN COAL PRODUCTION PATTERNS SINCE 1960

Sector	Actual				
	1960	1965	1971	1972	1973
U.S. total, Million tons ¹	415.5	512.1	552.2	595.4	592
Western States, Million tons ²	13.7	19.4	38.7	44.3	53.3
Percent	3%	3%	7%	7%	9%
Federal Land, Million tons ³	4.2	4.9	9.1	8.8	12.9
Percent of Western States	30%	25%	23%	20%	25%

¹Dupree, Walter G., and James A. West, U.S. Energy Through the Year 2000. U.S. Department of the Interior, Washington, D. C., December, 1972. Bituminous Coal Facts, 1972, National Coal Association, Washington, D. C., 1973. Tonnage based on calendar year figures.

²The six western States included in this report. Wyoming, New Mexico, Utah, North Dakota, Montana, Colorado. Broderick, Grace N., Supply and Demand for Energy in the U.S. by States and Regions, 1960 and 1965, 1. Coal Bureau of Mines Information Circular 8401, 1969. U.S. Energy Fact Sheets By States and Regions, U.S. Department of the Interior, Washington, D. C., February, 1973. Tonnage based on Fiscal Year figures.

³Public Land Statistics, Bureau of Land Management, U.S. Department of the Interior, Washington, D. C., 1960, 1965, 1971, and 1973. Tonnage based on Fiscal Year figures.

TABLE 2
 PRODUCTION DATA FROM FEDERAL COAL LEASES IN THE MAJOR FEDERAL COAL STATES

	<u>Acreage</u>		<u>No. of Present Leases</u>	<u>Production Tons</u>		<u>Age of Leases</u>					
	<u>Total</u>	<u>Private Surface</u>		<u>1973</u>	<u>Cumulative to 1972</u>	<u>Less Than 5 Years</u>	<u>5-10 Years</u>	<u>10-20 Years</u>	<u>20-30 Years</u>	<u>30-40 Years</u>	<u>Over 40 Years</u>
California	80	0	1		1,257	1					
<u>Wyoming*</u>	199,950.96	117,219.84	91	4,991,059	70,017,765	15	36	28	4	4	4
<u>New Mexico*</u>	40,958.12	26,197.78	28	259,646	3,639,181	2	9	8	3	4	2
Oregon	5,403.18	241.09	3	80	19,138			3			
Washington	521.09	521.09 (estimate)	2	214,668	838,669	1		1			
<u>Utah*</u>	266,712.39	13,335.62	195	2,415,764	92,268,910	18	93	42	15	17	10
<u>North Dakota*</u>	16,435.75	16,435.75	18	1,535,598	24,664,824	4	5	6	2	0	3
Oklahoma	87,014.18	85,692.34	53	336,732	6,285,309	8	5	36	4	0	0
<u>Montana*</u>	36,232.27	35,047.54	17	1,939,914	23,034,510	1	11	3	0	1	2
Alabama	200.00	200.00	1		1,551,018		1				
Ohio	144.14		1		489,461	1					
<u>Colorado*</u>	122,078.14	54,606.51	113	1,746,225	37,633,241	15	42	24	13	7	11
Alaska	<u>2,593.14</u>	<u>1,073.14</u>	<u>4</u>	<u>152,645</u>	<u>17,606,994</u>	<u>0</u>	<u>0</u>	<u>1</u>	<u>2</u>	<u>0</u>	<u>1</u>
TOTALS	778,323.37	350,570.70	527	13,592,331	278,050,277	65	202	152	44	33	33

*Major coal leasing States comprise 87.9% of the total outstanding coal leases.

TABLE 3

TOTAL ESTIMATED REMAINING COAL RESOURCES IN THE
UNITED STATES, JANUARY 1, 1972 BY U.S.G.S.

Millions of Short Tons

State	Bituminous Coal	Subbituminous Coal	Lignite	Anthracite and Semi-Anthracite	Total
Alabama	13,342	0	2,000	0	15,342
Alaska	19,413	110,668		0	130,081
Arizona	21,246	0	0	0	21,246
Arkansas	1,638	0	350	430	2,418
Colorado	62,339	18,242	0	78	80,659
Georgia	24	0	0	0	24
Illinois	139,124	0	0	0	139,124
Indiana	34,573	0	0	0	34,573
Iowa	6,509	0	0	0	6,509
Kansas	18,674	0	0	0	18,674
Kentucky	64,842	0	0	0	64,842
Maryland	1,158	0	0	0	1,158
Michigan	205	0	0	0	205
Missouri	31,014	0	0	0	31,014
Montana	2,299	181,855	87,521	0	221,675
New Mexico	10,752	50,671	0	4	61,427
North Carolina	110	0	0	0	110
North Dakota	0	0	350,630	0	350,630
Ohio	41,358	0	0	0	41,358
Oklahoma	3,281	0	0	0	3,281
Oregon	50	284	0	0	334
Pennsylvania	56,759	0	0	20,510	77,269
Rhode Island	0	0	0	0	0
South Dakota	0	0	2,031	0	2,031
Tennessee	2,572	0	0	0	2,572
Texas	6,048	0	6,824	0	12,872
Utah	23,541 ²	180 ²	0	0	23,721 ¹
Virginia	9,352	0	0	335	9,687
Washington	1,867	4,190	117	5	6,179
West Virginia	100,628	0	0	0	100,628
Wyoming	12,705	107,951	0	0	120,656
Other States	610	32	46	0	688
TOTAL	686,033	424,073	449,519	21,362	1,580,987

¹Small resources of lignite included under subbituminous coal.²Excludes coal in beds less than 4 ft. thick.Averitt, Paul, 1973, Coal, in the United States Mineral Resources U.S. Geological
Survey, Prof. Paper 820.

TABLE 4
ANALYSES OF COAL FROM THE PRINCIPAL COAL REGIONS

Coal Province and Region	Proximate Analysis (As Received)					
	Moisture Percent	Volatile Matter Percent	Fixed Carbon Percent	Ash Percent	Sulfur Percent	BTU Per lb.
Northern Great Plains						
Fort Union	30.5 - 42.8	24.5 - 27.7	25.1 - 35.9	4.1 - 9.6	0.2 - 1.2	5675 - 7660
Powder River	21.4 - 33.5	27.8 - 39.0	32.5 - 41.5	3.9 - 9.14	0.2 - 1.1	7220 - 9720
North-Central	6.6 - 22.6	28.2 - 30.2	36.6 - 46.4	8.8 - 18.2	0.6 - 2.7	8580 - 10210
Denver	15.5 - 35.0	37.3 - 41.8	51.5 - 56.2	2.3 - 18.2	0.1 - 1.1	5510 - 10660
Raton	1.0 - 10.2	22.9 - 40.0	50.0 - 54.5	5.3 - 21.8	0.4 - 1.3	10310 - 13970
Interior Province						
Western (E. Oklahoma area)	2.2 - 3.5	17.3 - 37.2	68.1 - 72.7	5.5 - 8.5	0.5 - 1.1	13010 - 14310
Rocky Mountain Province						
Big Horn	9.5 - 17.2	33.6 - 34.2	38.1 - 47.4	2.8 - 12.0	0.4 - 1.1	9470 - 11650
Hams Fork	5.6 - 22.7	33.5 - 38.4	40.5 - 49.8	1.7 - 6.2	0.6 - 0.8	9720 - 12650
Wind River	22.3 - 24.6	27.7 - 32.5	39.9 - 40.0	5.2 - 7.8	0.5 - 1.1	8610 - 9530
Green River	6.5 - 25.0	28.0 - 45.6	27.0 - 54.6	3.5 - 25.0	0.4 - 5.0	5000 - 12572
Hanna Field*	11.1 - 14.1	33.3 - 39.4	41.6 - 50.1	3.8 - 7.8	0.5 - 1.1	10290 - 11450
Uinta (Utah)	4.1 - 16.3	35.9 - 41.9	42.4 - 51.7	5.4 - 11.0	0.5 - 1.3	10400 - 13220
Uinta (Colorado)	2.2 - 14.6	8.4 - 37.6	45.4 - 80.2	3.2 - 13.6	0.4 - 1.1	10830 - 14120
San Juan River	3.3 - 16.2	35.4 - 40.9	38.0 - 50.8	3.1 - 11.8	0.4 - 0.9	10150 - 10120
Southwestern Utah	12.0 - 17.4	36.0 - 42.2	30.0 - 46.0	4.0 - 15.8	0.7 - 6.1	10390 - 11020

Data from Fieldner, A. C., Rice, W. E., and Moran, H. E., 1942, Typical analyses of coal of the United States: U.S. Bureau of Mines Bulletin 446, p. 45 modified by data from Keystone Coal Industry Manual, 1972; Class, 1972; Hombaker and Holt, 1973; and Millmore, C. L., 1970.

*Smith, J. B., et al, 1972, Strippable Coal Resources of Wyoming; U.S. Bureau of Mines Information Circular 8028, p. 47.

SUIT FILED TO BLOCK RENEWED FEDERAL COAL LEASING

Three environmental organizations have filed suit in the U.S. District Court for the District of Columbia to enjoin the Department of the Interior from resuming federal coal leasing. The Final Environmental Impact Statement (EIS) for the proposed leasing program was released September 19 (see article elsewhere in this issue). Within hours after the EIS was released, John D. Leshy, of Palo Alto, California, a lawyer for the Natural Resources Defense Council, told the New York Times that a lawsuit was "almost certain".

On October 21, the NRDF, the Environmental Defense Fund, Northern Plains Resource Council, and the Powder River Basin Resource Council filed the suit for injunction against renewed coal leasing on the grounds that the EIS "is inadequate to comply with the National Environmental Policy Act of 1969."

Specific Allegations

Specifically, the complaint alleges that "serious, major inadequacies exist in the final EIS. These include, but are not limited to, the following:

- a. "the final EIS contains an inadequate discussion of reasonable alternatives to the proposed action, including alternative federal leasing regimes and particularly the alternative of continuing present leasing policy;
- b. "it discusses neither the environmental impacts of the new coal leasing system and program it proposes, nor measures which could be taken to mitigate those impacts, but rather only discusses environmental impacts of coal development in a general way, without reference to any program of renewed leasing;
- c. "it fails to include, consider, discuss and respond meaningfully to the comments received on the draft EIS from interested federal, state and local agencies and the public; and
- d. "it fails to correct many of the deficiencies...that were identified in the draft EIS."

Draft "Failures" Cited

Six "failures" of the draft EIS are cited in the complaint. These, as identified by the Council on Environmental Quality, Environmental Protection Agency, plaintiffs and others in their comments, were:

- a. "the failure to describe or define a system or policy for renewed federal coal leasing, even though the Department proposed renewed leasing therein;
- b. "the failure to describe the environmental impacts of implementing the system or policy of renewed leasing, because of the failure set forth in a. above;
- c. "the failure to discuss the reasonable and relevant alternatives to the program, including whether the status quo--...moratorium on federal coal leasing--ought to be continued;
- d. "the failure to discuss the comparative environmental merits of developing eastern versus western coal;
- e. "the failure to analyze and discuss the Proposed Coal Leasing Program in light of the large acreage and coal reserves already under federal lease but on which no development has taken place;
- f. "the failure to discuss the environmental impacts of, and alternatives to, new regulations which were proposed to control environmental damage from coal mining operations on federal leases..."

Relief Sought

The relief sought includes a declaratory judgement declaring that the final EIS is legally inadequate and invalid under NEPA and that implementation of the leasing program is unlawful. The plaintiffs ask that Interior be barred from issuing any federal coal leases "other than leases expressly allowed under the limited short-term exceptions to the leasing moratorium announced by the Secretary of the Department of the Interior on February 17, 1973."

The short-term leasing policy provides that coal leases will only be issued when coal is needed to maintain an existing operation or as a reserve for production in the near future and then only when an

environmental impact statement covering the proposed lease has been prepared.

Plaintiffs also asked the court to order Interior to prepare a final EIS on the leasing program which complies with NEPA "if defendants take any steps to implement the new Federal Coal Leasing Program..."

Plaintiffs also asked the court to award them the costs of their suit "and such further relief as may be appropriate."

Prior articles appearing in Synthetic Fuels on coal leasing problems include "Interior Preparing Appeal of Sierra Club Lawsuit", September 1975 issue, page 4-42; "Federal Leasing Outlook Remains Uncertain", June 1974 issue, page 4-1; "Sierra Club Sues Interior over Northern Plains Coal Development", September 1973 issue, page 4-34. These articles provide background information and analysis that is pertinent to this case.

Plaintiff Organizations

Natural Resources Defense Council, Inc., is headquartered at 15 West 44th Street, New York 10036, and has branches in Washington and Palo Alto, California. "Since its establishment in 1970, approximately 25,000 persons have contributed to NRDC and 18,000 are members of NRDC. In the seven states in which there are particularly large amounts of federally-owned coal deposits subject to lease (Colorado, Montana, New Mexico, North Dakota, Oklahoma, Utah and Wyoming), NRDC has over 600 members."

Environmental Defense Fund, Inc., is headquartered at 162 Old Town Road, East Setauket, New York, with branch offices in Denver, Washington, and Berkeley California. It claims a nationwide membership of over 56,000 scientists, educators, lawyers, and others. "In the seven states in which there are particularly large amounts of federal coal deposits subject to lease, EDF has over 1,800 members."

The Northern Plains Resource Council is headquartered in Billings, Montana. "It has 800 members, primarily ranchers, farmers, and families in Montana, North Dakota, and Wyoming."

The Powder River Basin Resource Council is headquartered in Sheridan, Wyoming. "It has 500 members, including ranchers, farmers, and other interested citizens, most of whom live in Sheridan, Johnson and Campbell counties Wyoming."

Defendants

Specifically named as defendants in the suit are Royston C. Hughes, Assistant Secretary of the Interior; Thomas S. Kleppe, Secretary of the Interior, and Curtis J. Berklund, director of the Bureau of Land Management.

#

KAIPAROWITS PROJECT SUMMARIZED

The Kaiparowits Project is a proposed 3,000 MW coal fired, electrical generating station to be located on the Kaiparowits Plateau of South Central Utah intended to provide baseload capacity by 1982 for portions of Arizona and southern California. Participating in the joint venture project are Southern California Edison Company (40.0 percent of output), San Diego Gas and Electric (23.4 percent of output), and Arizona Public Service Company (18.0 percent of output). The remaining 18.6 percent of capacity is presently uncommitted. The Salt River Project, whose system provides electrical service to central Arizona, recently withdrew from the Kaiparowits Project. The power gener-

GOVERNMENT

ated by Kaiparowits would be transmitted for distribution in the areas shown in Figure 1.

The Department of the Interior, under specific supervision by the Bureau of Land Management, issued the Draft Kaiparowits Environmental Impact Statement on July 30, 1975. The document contains much information concerning the projected energy needs that will be placed on the participating utilities as well as the expected environmental changes resulting from the construction of the station. Much of the following information was extracted from that EIS.

The 3,000 MW generating plant as planned is to be supported by four underground

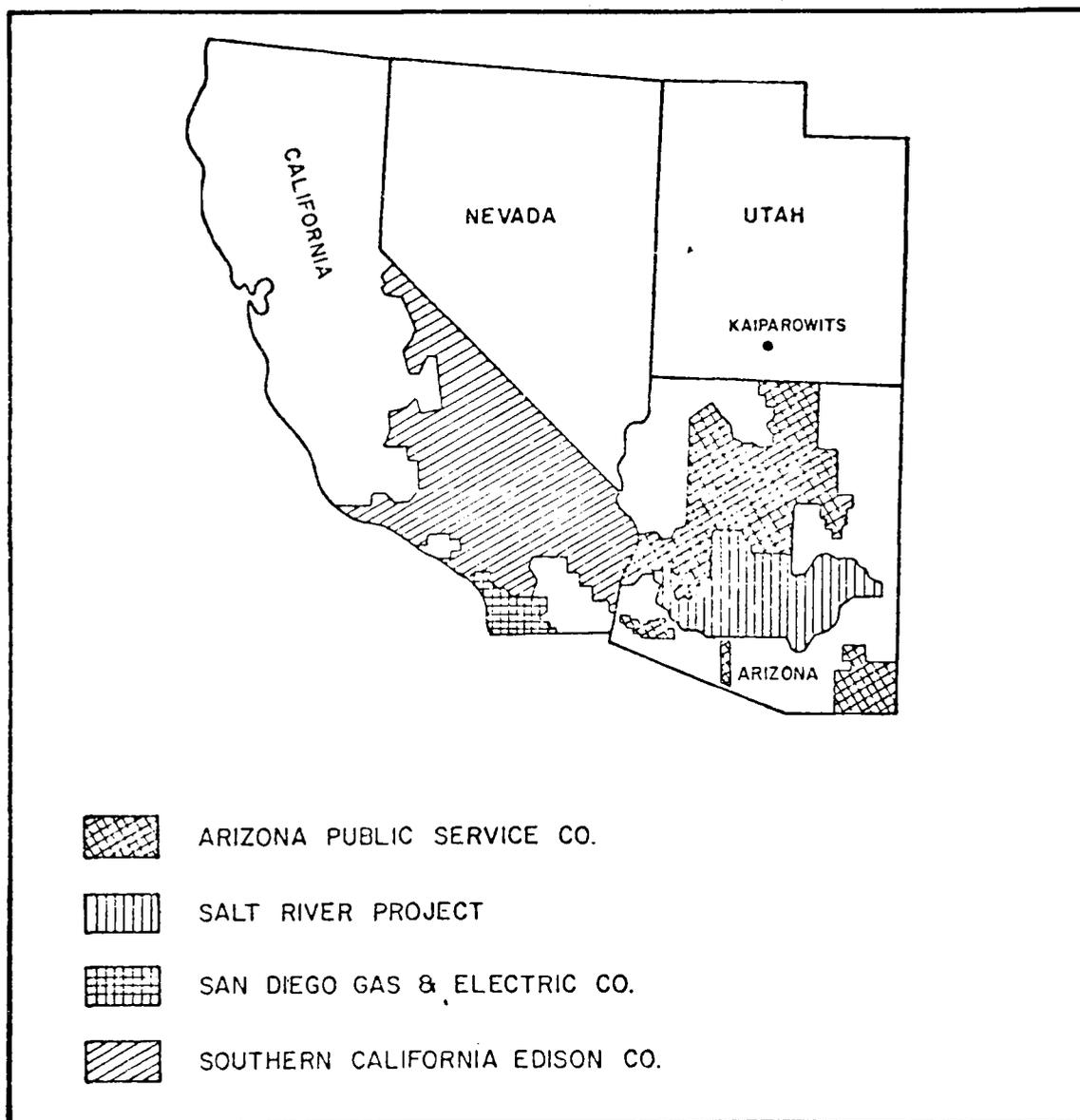


Figure 1. "Kaiparowits Participant's Service Areas."

mines producing a total of 12 million TPY of run-of-mine coal (nine million TPY washed coal), a water intake and 30 miles of transmission system to supply 44,500 AFY for the plant and mine from the Warm Creek arm of Lake Powell, a limestone quarry to supply about 237,000 tons per year of crude limestone for the SO₂ abatement system and approximately 1,450 miles of additional 500 KV transmission lines extending into Arizona and California. The project will entail the construction of a new town in the vicinity of the power plant/mine facilities. The coal lease and plant site in the vicinity of R40S-R3E, Kane County Utah. This property held by subsidiaries of the participants is shown as lease No. 3 on the Coal Mineral Right Ownership Map-Southwestern Utah Coal Region enclosed with the September 1975 issue of Synthetic Fuels.

The Kaiparowits generating facility would use coal from a 47,128 acre lease held by Resources Company (wholly owned subsidiary of Arizona Public Service), New Albion Resources Company (wholly owned subsidiary of San Diego Gas and Electric), and Mono Power Company (wholly owned subsidiary of Southern California Edison). Proximate and ultimate analyses representing the coal in the Kaiparowits Plateau Coal Field are presented in Table 1. The reserve base under lease is estimated to provide 420 million tons of ROM coal over a 35-year plant life at 50 percent extraction efficiency. The power plant site (identified as, "Four Mile Bench Site") is currently under the jurisdiction of the Bureau of Land Management. The State of Utah, in exercise of its lieu selection rights, has requested the BLM to transfer land to be occupied by the power plant to state control. The state, upon acquisition of title, would sell the land to the participants. The transfer of federal land to state ownership for the plant site plus various federal rights-of-way constitute the major federal actions for which the Draft Kaiparowits Environmental Statement was issued by BLM.

Consumptive water demand of approximately 45,000 AFY will be required primarily for cooling purposes. Roughly 5,900 AFY will be required by the new town and other purposes. The participating

TABLE 1

COAL ANALYSIS BY RESOURCES COMPANY

<u>Proximate Analysis</u>	<u>Percent by Weight¹</u>
Moisture	12.55
Ash	9.25
Volatile Matter	36.60
Fixed Carbon	41.60
TOTAL	100.00
Sulfur	0.52
Heating Value, btu/lb. (as received)	10,800
<u>Ultimate Analysis - %</u>	
Moisture	12.55
Carbon	61.32
Hydrogen	4.33
Nitrogen	0.95
Chlorine	0.02
Sulfur	0.52
Ash	9.25
Oxygen (by differential)	11.06

¹The table is based upon analysis of 103 core samples taken from 50 bore holes during the coal drilling exploration program through 1972. Analyses were performed by Commercial Testing and Engineering Company in Denver, Colorado and were checked by the Colorado School of Mines Research Institute of Golden, Colorado. Results are based upon a washed coal product and are representative of actual coal to be burned at the generating station.

utilities have contractual agreements with the State of Utah and the Department of the Interior which permit use of up to 102,000 AFY for activities related to electric power generation in Utah. This amount was based upon original plans that Kaiparowits generating capacity would eventually be at a power level of 6,000 MW. Table 2 summarizes resource use by the various facility components.

Kaiparowits Will Increase Baseload Capacity

The owner-companies have determined that there is a need for a power plant of the size and type of Kaiparowits to meet projected demands for baseload capacity. Electric power consumption in the Kaiparowits market area is projected to expand at an annual compound rate of between 6.5 and 7.0 percent. Baseload

TABLE 2
SUMMARY OF RESOURCE USE-KAIPAROWITZ PROJECT

	Quantity -- Summation						Total
	Power Plant	Coal Mine	Transmission System	Limestone Quarry	New Highway	New Town	
Land	4,160 acres of state and federal land transferred to private ownership of companies. 930 acres permanently occupied by improvements. 225 acres permanently occupied by waterline R/W 30 miles long.	47,128 acres of state & federal land leased. 1,710 acres would be occupied with improvements.	95 acres occupied by towers (all types). 1,480 acres occupied by permanent roads. 140 acres occupied by substations & microwave sites.	1,400 acres of state & federal land leased. 240 acres permanently occupied.	280 acres included in R/W, 67 miles long.	8,960 acres of state & federal land transferred to private ownership. 2,240 acres permanently occupied by facilities.	62,148 acres of state & federal land leased or transferred. 7,265 acres permanently occupied by roads, improvements, etc.
Coal		12,000,000 tons/year mined. 9,000,000 tons/year washed coal burned in power plant. 420 million tons mined over 35 year life of plant. 315 million tons washed coal burned over life of plant.					420 million tons mined over 35 year life of plant. 315 million tons washed coal burned over 35 year life of plant.
Water	41,400 a/f/year lost by cooling tower & other plant uses	3,100 a/f/year used for coal washery & mine operation.	1 a/f for concrete 120 a/f for dust control	2 a/f/year used for dust suppression & quarry operations		5,900 a/f/year	50,400 a/f/year
Solid Waste	Over the 35 year life of the plant: 40 million cu. yds. ash, 16 million cu. yds. scrubber sludge, 2.5 million cu. yds. excavated material & 1.5 million cu. yds. limestone kiln waste to be disposed of in area 450 acres, 90 ft. deep.	Over the life of the coal mine: 26 million cubic yards of coarse refuse to be disposed of in an area 550 acres, 29 ft. deep. 43 million cu. yds. of fine refuse to be disposed of in an area 550 acres, 50 ft. deep.		53,425 cu.yds./year waste rock mined. 4,619 cu.yds./year top soil removed. 5,657,534 cu.yds. waste rock over 35 year life. 161,904 cu.yds. topsoil over 35 year life. Waste material to be placed back in quarry area.			134.8 million cu. yds. of waste material over 35 year life of plant.
Aggregate	200,000 cubic yards	71,000 cubic yards	32,000 cubic yards for T/L 400 cubic yards for microwave stations		780,00 cubic yards	549,000 cubic yards	1,632,400 cubic yards
Limestone	82,000 cubic yards /year for SO ₂ scrubber	26,000 cu. yds./year for rock dusting		108,000 cu. yds./yr. mined. 3.8 million cu. yds. over 35 years			3.8 million cu. yds. over 35 year life of plant
People	Peak construction - 2,405 @ year 4 Peak Operation - 510 @ year 8	Peak construction - 700 @ year 4 Peak Operation - 2,560 @ year 8		Peak construction - 36 @ year 1 Peak Operation - 65 @ year 4		Peak pop. of 10,928 @ year 7	Total population increase due to power plant 16,000 & mine

generating capacity should be increased to minimize system operation costs. (Characteristics of baseload generation are: operation at or near full capacity during all hours that the generating unit is available and low energy costs per kilowatt hour of generation.) For example, while southern California Edison's objective is that 40 to 50 percent of its capacity be baseload resources (nuclear, coal and hydroelectric), only 16 percent of its capacity will be so in the 1974-79 period. By 1983, Edison's baseload capacity will be increased to 25 percent of its total capacity. The scarcity of natural gas and increasing oil costs are requiring that new baseload stations be situated and constructed to use coal resources (nuclear energy may be an alternative in some situations). Kaiparowits will require the equivalent of 80,000 barrels of oil per day. The peak demand

for the participants for 1974 and projected demands for 1980 and 1985 are shown in Table 3. Even if the peak demands fall short of those indicated in Table 3, the Kaiparowits capacity would still be desirable as a means of displacing present oil and gas fired units. The demand projections in Table 3 were compiled by the respective utilities. Recognizing that demand forecasts must necessarily reflect many subjective judgments, the FEA believes it important that there be forecasts compiled independently of those produced within the electric utility industry. Such forecasts would help to ensure balance, they would lend greater credence to government decisions permitting construction of generation and transmission facilities and they would lead to more widespread participation in the economic planning process. The FEA is considering means by which independent

TABLE 3
PROJECTED PEAK ELECTRICAL DEMAND TO 1985
(Megawatts)

	<u>1974</u>	<u>1980</u>	<u>1985</u>
Southern California Edison	14,000	14,300 (39%) ¹	18,000 (73%)
San Diego Gas and Electric	1,600	2,700 (69%)	3,600 (125%)
Arizona Public Service	2,100	3,300 (48%)	4,800 (114%)

¹ percent increase over 1974

forecasts might be encouraged.

Alternate Uses to Kaiparowits Resources
Are Possible

The coal and water resources available under present leases and contracts for development on the Kaiparowits Plateau could be committed to one or more alternative uses to include synthetic pipeline gas, or electrical generation at an alternative site closer to load centers (Phoenix, Los Angeles, and San Diego). Constraints to possible alternative uses or points of use of the 102,000 AFY of Utah's Upper Colorado River Basin allocation committed to this project would be the most difficult to overcome. Participating utilities have contractual agreements with the State of Utah and the Department of the Interior which allow this water to be used solely in association with electric power generation at the Kaiparowits site. The water contracts conceivably could be renegotiated to release the water for use in synthetic gas production either at Kaiparowits or other sites, coal liquefaction, coal transportation by slurry pipeline (615 AF required per one million tons transported) or for use in shale oil production in the Upper Basin portion of the Colorado River. The approximate value of the 45,000 AFY to be used in the proposed project for alternative projects is presented in Table 4. The 45,000 AF required each year for condenser cooling is approximately:

- 0.7-0.8 percent of total estimated available Upper Colorado Basin flow
- 1.6-2.0 percent of currently estimated unused Upper Colorado Basin flow

- 3.0-3.4 percent of Utah's total share of Upper Colorado Basin flow
- 4.8-5.8 percent of unused portion of Utah's share of Upper Colorado Basin flow

These data are from the Department of the Interior Water for Energy Management Team's, "Report on Water for Energy in the Upper Colorado Basin (July 1974)."

Related to the water question is that the Upper Colorado River basin surface water supply is overappropriated in Utah; i.e., water rights exceed supply. However the matter is resolved, the fact of overappropriation is unlikely to affect the Kaiparowits Project schedule.

Coal is a relatively plentiful resource in the Kaiparowits Plateau coal region (including neighboring coal fields) whose development is not constrained by availability but by factors surrounding the siting of conversion facilities. The primary constraints to siting large conversion facilities include air quality maintenance, uncertainties associated with the creation of new communities and land disturbance required by mining and conversion operations. These factors are mitigated to varying degrees depending on the site alternatives. Kaiparowits coal could be transported from the plateau area in southern Utah to allow expansion of the Mohave station in southern Nevada and/or the Navajo Station in northern Arizona. Transportation costs of coal as compared to electric power from alternative sites must be considered (see Table 5). However, whatever the cost differential is, it is likely to be overshadowed in deliberations of where to locate the plant, by con-

TABLE 4

ALTERNATIVE USES OF 45,000 ACRE FEET TO BE USED IN CONDENSOR
COOLING AT THE KAIPAROWITS PROJECT

	Approx Impact on Oil Supply	Approx value of annual Output (\$ millions)
Kaiparowits (3000 megawatts, excludes water requirements for coal mine and associated community which might require an additional 7000 acre feet.)	Displaces 80,000 bpd	483 at generating station @ \$0.023/kwh
Oil Shale Production	200,000 to 600,000 bpd ¹	730-2,190 @ \$10 per bbl
Coal Liquefaction	60,000 to 400,000 bpd; (40,000 to 300,000 bpd net) ²	220-1,460 @ \$10 per bbl
Coal Gasification	100,000 to 400,000 bpd equivalent; (50,000 to 260,000 bpd net) ³	365-1,460 @ \$10 per bbl
Coal Slurry	Sufficient for transport of approximately 200,000 tons of coal per day (equivalent of 700,000 barrels of oil per day)	
Irrigation of approximately 30,000 acres with typical Utah crop pattern ⁴		

¹No net energy figure is given since the oil shale process, which consumes approximately 0.4 barrels of shale oil for each barrel produced, consumes energy which otherwise would not be used; therefore, the concept of net efficiency of the process is not meaningful in so far as questions of alternative uses of resources are concerned.

²W. W. Bodle and K. C. Vyan, "Clean Fuels From Coal," The Oil and Gas Journal, August 26, 1974; p. 74.

³High BTU gas; ibid.

⁴From information supplied to FEA by Upper Colorado River Office, Bureau of Reclamation in letter dated August 13, 1974.

TABLE 5

RELATIVE COST OF TRANSPORTATION TO MARKET AREAS
(Mills/kwh)

	Rail (Unit Train)		Slurry Pipeline	Electric Transmission
Kaiparowits to Southern California ¹	7.0 ²	3.8 ⁶	(2.0-6.0) ⁶	3.5 (4.2-8.4) ⁶
Kaiparowits to Phoenix, Ariz. ⁴	10.0 ³	6.0 ⁶	(1.2-3.6) ⁵	2.0 (2.4-4.9) ⁶

¹Rail and transmission line distance to Southern California approximately 500 miles.

²Based on Southern California Edison data.

³Extrapolated from Southern California Edison data.

⁴Rail distance to Phoenix approximately 800 miles; 500 miles longer than direct route because of lack of Colorado River crossings.

⁵Transmission line distance to Phoenix area approximately 300 miles.

⁶Extrapolated from 1972 Southwest Energy Study; assumes 20% increase over the Study's 1972 cost estimates.

⁷Assumes slurry pipeline routed over Glen Canyon Dam.

siderations relating to water availability, environmental effects, and socio-economic factors involving the region in which the plant would be built.

The State of Utah indicated during its last legislative session, its approval of siting the conversion facility in Utah on the Kaiparowits Plateau in the form of Senate Joint Resolution No. 24; requesting the Secretary of the Interior to approve the transfer of federal lands needed for the plant site (Four Mile Bench Site) to state ownership. This is a significant action and is in contrast to California's reluctance to site coal fired, baseload, stations in that state. The participating utilities do not consider southern California a feasible site.

The use of Kaiparowits coal to fire existing stations or new stations that may be built off of the plateau should not preclude the siting of the proposed facility as planned.

SNG Production of Kaiparowits is an Alternative

The siting of a synthetic pipeline gas plant within the above mentioned marketing region, again excluding California, to convert Kaiparowits coal could be done independently or in coordination with the expansion of existing or siting of new generating facilities. The combination of these two activities is being considered by American Natural Gas Company and Basin Electric Power Co-operative for a proposed site in Mercer County, North Dakota.

The siting of a coal gasification facility on the Kaiparowits Plateau in concert with the proposed facility has advantages over siting at a different location. Admittedly, environmental aspects would require more extensive consideration, but should not necessarily rule out that kind of multiple use of the resource.

The primary advantage would be mine mouth resource conversion, eliminating out of region coal and water export. The water requirements could be met through the existing contracts with necessary adjustments to remove the stipulation that it be used for power generation. Approximately 57,000 AFY would be available from the 102,000 AFY allotment, assuming the consumption of 45,000 AFY at the proposed generating station. The facilities that could be shared are: water intake and supply; coal mine (the mine required for the SNG plant would be roughly 12 MM TPY ROM); coal preparation (under size to power plant); and pollution abatement and water treatment. The proposed new town would be located to serve both projects.

#

INTERIOR PROPOSES SURFACE COAL MINING/ LEASING REGULATIONS

The Department of the Interior published on September 5, 1975, proposed regulations pertaining to surface management of federal coal resources, and surface coal mining operations. These proposed regulations, appearing in the Federal Register, closely followed a series of events surrounding the management policies of federal coal lands to include renewed leasing, development requirements for existing and potential leases, and surface mined land rehabilitation. The following is a brief review of these events.

On January 30, 1975, texts of proposed revisions to the coal mining operating regulations of the U.S. Geological Survey were published in the Federal Register. Those regulations govern operations conducted under coal permits, leases, and licenses on public and acquired lands of the United States and Indian lands administered by the Department of the Interior.

Prior to the publication of the regulations proposed on January 30, the President had withheld his signature from S. 425, the surface mining legislation passed by the 93rd Congress. On February 6, new proposed Federal surface mining legislation was submitted by the Administration along with a detailed analysis of the

unacceptable adverse effects which S. 425 would have had. Thereafter, the Congress passed H.R. 25, which failed to meet the objections which had led to the President's disapproval of S. 425, and would have resulted in greater adverse impacts than that bill. The President vetoed H.R. 25 on May 20 and that veto was sustained by the House of Representatives on June 10.

Following the sustained veto of the most recent federal surface mining legislation, Interior published on September 5 proposed regulations in an attempt to place more comprehensive control over surface mining operations (particularly surface rehabilitation) and to define more explicitly federal coal leasing policy in preparation for possible renewed leasing activities. In support of the proposed regulations (43CFR3041) relating to the leasing, permitting, and licensing of coal and rehabilitation regulations by the BLM, Interior published the final environmental impact statement covering the Proposed Federal Coal Leasing Program on September 19. This EIS is also discussed in this issue of Synthetic Fuels. The proposed regulations (30CFR211) relating to coal exploration and mining operations, and rehabilitation of affected land do not pertain explicitly to leasing procedure, but by their nature are an integral part of the development of federal coal resources.

The subject of mined land rehabilitation is addressed in both sets of regulations. Clearly, it is the least understood portion of surface mining operations and has the potential to cause a weak point in the overall mining plan. The regulations require that the land be returned as contemporaneously as practicable with operations, to conditions at least fully capable of supporting previous uses or equal or better uses. Original contour is to be approximated under rehabilitation operations. The regulations set forth the time limitations within which liability upon the operator's land for revegetation will apply. In substance, the proposed regulations on mining operations, to include rehabilitation, address the same points that past federal legislation has attempted to do. The proposed regulations place a great deal of responsibility on

the local mining supervisor and give to him more decision making power than the federal legislation would have.

The combination of the overall federal coal leasing policy as explained in the final EIS and the proposed regulations governing leasing and operating procedures constitute a comprehensive program that will:

- . Identify potential mineable resources
- . Select environmentally suitable reserves for leasing
- . Lease nominated tracts through competitive bidding for exploration and production (Note: The processing of the 183 pending preference right lease applications will not be competitive--at least for the near-term, the moratorium on issuance of the prospecting permits will be continued to gain experience with the leasing program.)
- . Approve environmentally and technically sound exploration, mining and mined land rehabilitation plans prior to development.
- . Require maximum resource recovery.
- . Assure mining and rehabilitation plans are adhered to until property abandonment.

Prior to publishing the final regulations, Interior has invited comments in two areas pertaining to the proposed regulations. The first is the relationship between federal and state jurisdiction to impose rehabilitation standards. The second is the method of applying the proposed regulatory mechanism to existing operations and the timing of such application.

#

COAL FEEDING SYSTEMS STUDIED BY LOCKHEED

Lockheed Missiles and Space Company, Inc., Sunnyvale, California, has received a \$180,000 contract from ERDA to study coal feed injector concepts for overcoming the many mechanical problems associated with coal conversion process feeder systems.

Lockheed will try to achieve the following objectives:

- . Develop candidate coal feed injector concepts based on a detailed examination of the system requirements imposed by the various coal conversion processes.
- . Develop laboratory-scale critical component testing to determine concept feasibility.
- . Design, fabricate, and test complete laboratory-scale coal feed injector systems to demonstrate system capabilities.

#

FLUOR TO EVALUATE H-COAL PROCESS

The H-Coal liquefaction project is to receive technical assistance from Fluor Engineers and Constructors, Inc., Los Angeles, California, under a \$268,000 contract from ERDA. The goal is to ascertain the economic feasibility of the H-Coal process for manufacture of liquid products.

Fluor will assist ERDA in the evaluation obtaining additional data from bench scale units and the 2.5 TPD process development unit at Trenton, New Jersey, and designing a 600 TPD pilot plant to be located at Catlettsburg, Kentucky.

The firm will review existing H-Coal process data, including assessment of expected catalyst life, physical and thermal property, kinetic and thermodynamic data required for plant design.

Fluor will develop and provide to ERDA a design basis for the H-Coal process when operated in the fuel oil and the syncrude modes. Following agreement on the design basis, the contractor will develop preliminary designs, capital investment estimates, and economic analyses for commercial plants using the two process modes.

#

ROCKETDYNE PROCESS TESTS FOR COAL CONVERSION ANNOUNCED

Rockwell International Corporation, Rocketdyne Division, Canoga Park, California re-

cently contracted with ERDA to develop the Rocketdyne Process for coal liquefaction. The process encompasses the mixing and conditioning of two streams of reactants--coal and hydrogen--to effect instantaneous reaction.

The mixing concept is used in liquid rocket engines for propellant injection. ERDA feels that the concept merits a closer look as applied to coal conversion. In announcing the \$1 million, two-year contract Dr. Phillip White, ERDA's Assistant Administrator for Fossil Energy, stated the process is "a promising new approach to the conversion of coal."

The conversion process forms light hydrocarbon liquids and gases while preventing subsequent breaking down of the larger, heavier, and more complex hydrocarbon molecules into simpler and lighter molecules.

The project is divided into two parts. Phase I includes cold-flow testing and related studies to provide sufficient information for a determination to continue with Phase II, the reactor testing.

Phase II would include design and fabrication of a large-scale reactor, allowing for variations in design of multiple injection elements. The reactor would be operated for 25 two-minute tests over a range of conditions to determine the most effective way for demonstration of the process.

Results of full-scale testing would be analyzed to determine the best reactor operation and to establish criteria for large scale plant designs.

#

ERDA TO REPORT COAL CONVERSION RESEARCH QUARTERLY

Quarterly reports covering developments in coal conversion projects under the direction of the Energy Research and Development Administration will soon be forthcoming from Tera Tech, Inc., Arlington, Virginia, under a \$811,000 contract with the agency. The reports will cover coal gasification, liquefaction, and direct

combustion of clean-burning coals from demonstration plants.

The preparation of these reports for ERDA's Fossil Energy Section, Division of Coal Conversion Utilization are to be forthcoming as early as March of 1976.

#

SYNFUELS CONSULTING CONTRACT LET BY ERDA

Four private consulting firms have been awarded separate contracts totaling \$229,000 to aid ERDA in the design of synthetic fuels processes and coal conversion concepts. The consultants are to evaluate:

- . Coal Liquefaction; direct hydrogenation, extraction, hydrogenation, and carbonization with hydrogenation.
- . Coal Gasification; pipeline gas systems, fuel gas systems, and synthesis gas processes.
- . Supporting Systems; char gasification, catalyst conversion, and gas clean-up and separation trains.

The contracts call for each contractor to address a specific process or proposed plant system. The tasks include:

- . Providing simple, low-cost, engineering analyses and evaluations of process alternatives for selected coal conversion plant processes, or proposed plant designs, applying all aspects of fuels technology.
- . Investigating independently proposed concepts and plant processes, and evaluate technical cost and schedule tradeoffs.
- . Performing analyses to identify weaknesses or validate total plant concepts.
- . Identifying technical areas wherein plant processes can be improved by substitution of process alternatives.

The contractors are:

- . Energy Resources Company, Cambridge, Massachusetts (\$23,574).
- . Purvin & Gertz, Inc. Dallas, Texas (\$99,000).
- . F. Kunreuther Associates, Inc.,

New York City (\$81,800).
. R. H. Lamb, Alcoa, Tennessee (\$25,000).

#

MONTANA STUDIES POSSIBLE STATE ROLE IN COAL GASIFICATION PLANT

Faced with the prospect of severe natural gas shortages, Montana is considering state participation in a coal gasification project strictly to meet in-state needs. Montana presently imports 66 percent its gas supply from Canada, which is expected to phase out exports by 1983-85, or earlier.

Governor Thomas L. Judge has appointed a special task force to investigate environmental, technological, legal, and financial aspects of the proposed project. One of the task force's first steps will be to select a contractor to do preliminary environmental work, process evaluation, and to initiate the permit application and approval process. A minimum two-year lead time is required to comply with Montana's Utility Siting Act. Montana environmental groups so far are supporting the task force study, as long as the gas would be produced exclusively for in-state consumption.

Since the cost of a gasification plant is considered to be beyond the means of private industry, a state-industry joint venture approach is one of the alternatives to be examined. Such an arrangement would require an ammendment of Montana's state constitution. The task force is also looking into sources of federal funding for a technology demonstration type project. Plant capacity is expected to be approximately 175 MMCFD. A decision on whether to go ahead with such a plant will be made by mid-1976.

Chairman of the coal gasification task force is James Hodge, director of the Montana International Trade Commission. For further information contact his office at (406) 723-3228.

#

ENERGY AUTHORITY TEMPORARILY SHELVED

A proposal was made in September to create a \$100 billion government corporation to be known as the Energy Independence Authority. Its purpose would be to provide financing and assistance for Development of alternative fuel sources.

The announcement by Vice President Nelson Rockefeller that he would not be a candidate in the 1976 general election, effectively removed the controversial proposal from immediate consideration.

The concept, or one similar to it, is bound to re-emerge in one form or another to move budding technology into commercial scale energy yielding projects.

As written, the EIA would be able to make direct loans up to \$1 billion, purchase and leaseback plans, make loan guarantees to creditors and purchase convertible or equity securities.

Projects eligible for aid under the plan would have to show that they would make a significant contribution to the achievement of "energy independence" and meet some general guidelines. The basic guidelines are: (1) the process would have to be essential to energy development production or transportation by pipeline and employ technology not already in widespread domestic commercial use, (2) processes related to production and use of nuclear power would be eligible, (3) processes that would generate electricity by use of fuels other than oil and natural gas are eligible, and (4) the technology must have passed the research and development stage.

Projects that are submitted for possible aid and meet the general guidelines would then be screened by an authority review board with power to grant or withhold assistance. Financial assistance could be given to businesses which are regulated by a state or local agency if a regulatory body issues a certificate of necessity for the project under an agreement with the EIA. Quarterly

rate hikes without prior public hearings could be granted in advance so net earnings would cover interest charges.

The EIA would be set up as a Government Corporation governed by five Directors appointed by the President and confirmed by the Senate. The authority would issue \$25 billion in capital stock and would be allowed to have additional outstanding obligations of \$75 billion. The EIA would be incorporated for 11 years and would be liquidated on June 30, 1986.

The release of this amount of money for synthetic fuels projects would allow many commercial operations to be started that up to now have been too expensive for a company or consortium of companies.

The plan itself was the brain child of Vice President Rockefeller and his domestic council staff. It received only lukewarm support on Capital Hill.

#

RILEY STOKER CORP. OFFERS COMMERCIAL MODEL COAL GASIFIER

The Riley Stoker Corporation of Worcester, Massachusetts, has announced the development of a coal-gasifying retort which it is offering to industry in a standard model size. Known as the Riley-Morgan gas producer, it is a moving bed, very low pressure, partial oxidation, coal gas producer which manufactures fuel gas of 150-180 BTU/ft³ if air-blown, or fuel gas of 275-325 BTU/ft³ if oxygen blown.

The standard model offered to industry has an inside diameter (measured inside the refractory lining) of 10-1/2 feet. It is claimed that one standard unit, operating in the oxygen-blown mode, will produce 3.05 billion BTU day at 100 percent load factor. From 2 to 6-1/2 tons coal per hour may be processed, depending on the type of coal feed and on whether the unit is air-blown or oxygen-blown.

The Riley-Morgan gas producer consists of a slowly rotating water cooled vertical walled cylinder and ash collecting launder (chute) plus a stationary water cooled head. Coal is fed from the top of the unit, is spread evenly in the cylinder and flows downward, counter-current to the upward flow of gases. Coal passes through volatilization, reduction, partial oxidation, and ash zones before being discharged as ash. Steam and air or oxygen are introduced into the bottom of the unit in quantities which permit partial oxidation of coal. The configuration of the Riley-Morgan gas producer is illustrated in Figure 1.

Typical analyses of the fuel gases produced from various types of fuel are claimed by Riley Stoker Corporation to be approximately as is shown in Table 1.

#

SYNFUELS LOAN GUARANTEE SUPPORTED

Hearings on multi-billion dollar loan guarantees for commercial-size synthetic fuels demonstration plants through a \$6 billion ERDA budget amendment drew comment

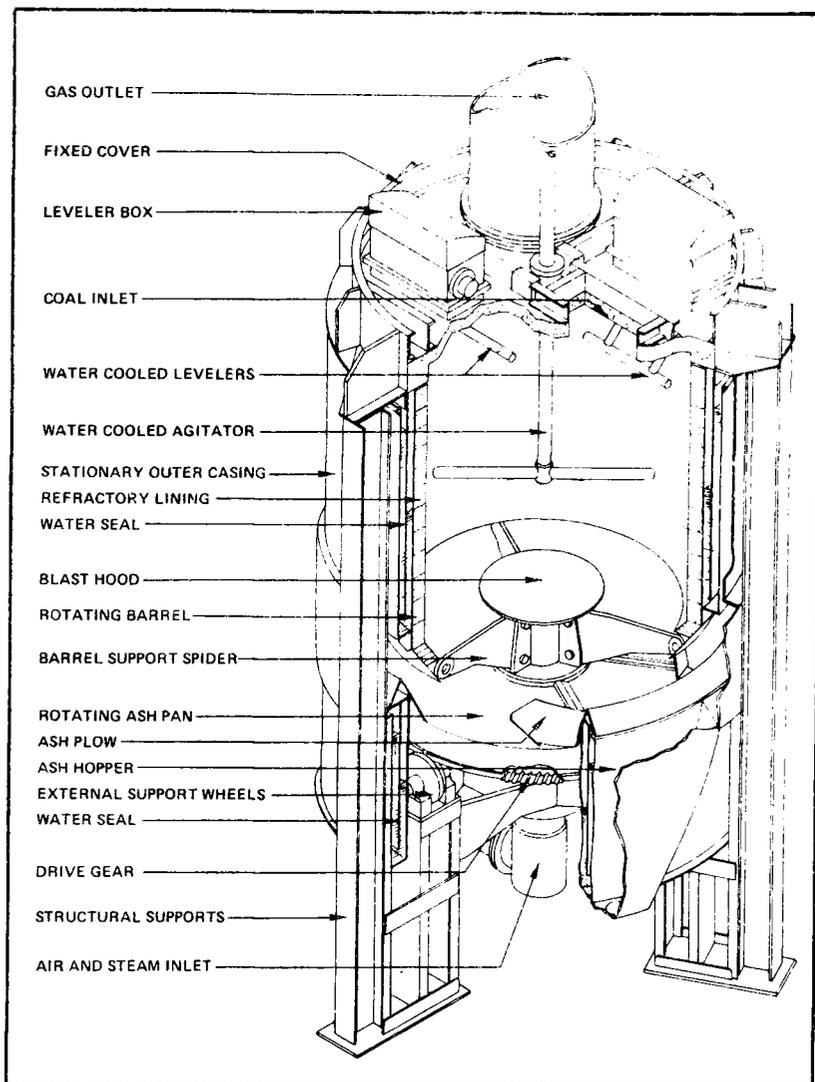


Figure 1. Riley-Morgan Gas Producer

from Arthur R. Seder, Jr., President of American Natural Gas System and J.E. Bixby, Vice President and Chief Financial Officer of Texas Eastern Transmission Corporation. Both of these corporations have advanced plans and applications before the FPC for commercial coal gasification projects. The summation of their testimony before the Subcommittee on Energy Research, Development, and Demonstration (Fossil Fuels), Committee on Science and Technology, October 21, 1975, is that plant construction is contingent on congressional approval of federal loan guarantees, or an equivalent program to assist in the financing of synthetic fuels projects--specifically coal gasification.

ANG Coal Gasification Company, a subsidiary of American Natural Gas, has plans to construct one or more 250 MMSCFD SNG

TABLE 1

TYPICAL GASES FROM VARIOUS FUELS

I Fuel Content	Fuel Type					
	Bituminous		Anthracite		Coke	
Moisture	7.2		5.9		9.2	
Volatile	34.4		4.5		1.0	
Fixed Carbon	42.7		80.9		81.2	
Ash	15.7		8.7		8.6	
	100.0		100.0		100.0	
Heat Value BTU/lb	11,315		12,655		12,430	
II Gas Analysis	Fuel Type					
	Bituminous		Anthracite		Coke	
Percent Volume	Air-Steam	O ₂ -Steam	Air-Steam	O ₂ -Steam	Air-Steam	O ₂ -Steam
CO	26.0	41.2	24.1	38.1	26.4	44.5
H ₂	18.4	38.9	18.4	42.5	11.6	36.2
CH ₄	1.6	2.8	0.5	0.6	0.2	0.3
CO ₂	3.8	15.9	6.6	18.4	6.5	18.2
CnHn	0.2	0.7	0.0	0.0	0.0	0.0
N ₂ +Ar	50.0	0.5	50.4	0.4	55.3	0.8
	100.0	100.0	100.0	100.0	100.0	100.0
Gross BTU/SCF	163	305	142	264	125	262
Spec. Gravity	0.82	0.7	0.84	0.69	0.9	0.74

plants in Mercer County, North Dakota. Texas Eastern and Pacific Lighting Corporation through the joint venture company WESCO, are planning a similar project in San Juan County, New Mexico.

our present annual gas supply."

#

Testimony points out two candidate sources of credit to support the debt: (1) "... the ability of the sponsoring company to support the loan based on its own (the company's) credit"; (2) "...the anticipated revenues from the project itself." The following comment of Arthur R. Seder helps to explain the situation surrounding debt support.

"American Natural is a company of moderate size. My company's net plant investment, as of June 30, 1975, was approximately \$1.6 billion. And the total cost of our project, when completed in 1981, is estimated at almost exactly the same: \$1.6 billion. A coal gas plant producing 91 billion cubic feet of fuel a year is essential if our system is to adequately serve its customers six years from now. But, as you see, it requires a doubling of our net investment although it will provide but one-tenth of

LAND

CROW INDIANS SUE INTERIOR TO INVALIDATE COAL LEASES AND PERMITS ON MONTANA RESERVATION

The Crow Indian tribe filed suit September 19 in the U.S. District Court for the District of Columbia asking that the Department of the Interior be directed either to cancel existing coal leases or rewrite them to give the tribe more favorable lease terms. The basis for the legal action affecting Shell Oil Co., AMAX Inc., Peabody Coal Co., and Gulf Oil Co. are alleged violations of the National Environmental Policy Act and the Department of the Interior Bureau of Indian Affairs' (BIA) regulations regarding leasing.

In alleging Interior and BIA have "utterly failed to protect" the economic interests of the 4,500 members of the Crow tribe, the 20-page complaint charges the defendants failed to investigate or realize the economic potential of the Crow coal resources; neglected to bargain for equitable rates and terms; recommended and approved terms and rates which are "one-sided, improvident and unconscionable..." including setting lease terms and royalty rates before the quality and quantity of the coal was determined.

The leases and exploration permits were issued in 1968 and subsequent years based on Interior and BIA practices of recommending and approving two-year exploration permits prior to bidding at lease sales; recommending advance approval and conversion of permits into coal leases on both the southern Montana reservation itself and the ceded strip, several thousand acres of land north of the reservation to which the tribe surrendered the surface several years ago while retaining the mineral rights.

Violations Cited

The Indians claim Interior did not inform the tribe the leases and permits would lead to coal strip mining and related coal development including construction and operation of coal burning power plants; facilities for making synthetic gas from coal; and the resultant environmental and social impacts, including the influx of large numbers of non-Indians onto the re-

servation so as to threaten the cultural foundations of the tribe.

The suit asserts violations of BIA regulations pertaining to:

Issuance of a prospecting permit on 84,907 acres to Shell Oil Co. on June 6, 1968; its extension two years later and subsequent leasing of 30,247 acres;

Issuance to Gulf Oil Co. of prospecting permits on 73,303 acres and the refusal of BIA since 1973 to act upon Gulf's subsequent request to convert the entire acreage into four leases;

Issuance of a prospecting permit in 1970 to AMAX covering 16,167 acres and the subsequent leasing of 14,236 acres in 1973.

The complaint notes federal law restricts leases to 2,560 acres without a special action of the Commissioner of Indian Affairs and does not allow prospecting permit holders to exercise exclusive options to lease. Among other regulatory and legal violations cited in the complaint are failure to enforce requirements for bonding, detailed operational reports, and tract configuration.

The tribe also asserts Interior and BIA worked through a six-member oil and gas committee of the tribe rather than the Tribal Council and ignored a 1974 Tribal resolution declaring the permits and leases null and void.

The petition asks the court to declare violations of the National Environmental Policy Act as well as determine that federal regulations have been violated and Interior and BIA have violated their fiduciary trust to the Crow tribe. It is also asked to declare the leases and permits invalid or require Interior and BIA to free the lands involved from any claims on the mineral rights or require that the laws be obeyed and that monies received by the defendants in trust for the tribe come under jurisdiction of the court. An injunction ordering the defendants not to take any further action regarding the challenged leases until the lawsuit is resolved is also sought.

Impact on Shell Oil

Shell, the only firm with on-going development operations on the Crow lands, promptly suspended work until the lawsuit and the Sierra Club versus Morton case, which has held up Northern Great Plains coal development indefinitely, is resolved.

Shell has paid more than \$1.1 million to the Crows in permit, leasing fees, and advance royalties from a 30,250-acre lease. After the 1974 Tribal resolution seeking cancellation of the lease, Shell agreed to raise the royalty from 17 1/2 cents to 45 cents a ton, or 8 percent of the FOB price, which ever was greater. The tribe rejected the offer as too low even when accompanied by a \$200 per capita incentive.

Shell estimates the lease includes reserves of 1.3 billion tons. Initial mining was set at 8 million TPY.

The suit illustrates an increasingly significant factor in contemporary resource management; the necessity for flexible open negotiations in the development of public--in this case the Crow tribe is the public--resources. It also illustrates the need for energy companies to protect their own best interests by knowing federal regulations and seeing to it that federal agencies comply with their own rules and the law. While this approach may raise initial costs, it can go a long way toward preventing the kinds of prolonged delays which evolve from asking the courts to resolve differences, correct and revise contracts.

Speaking in Denver in mid-October at a White House sponsored domestic policy conference, Angela Russell, a representative of the Crow Tribal Council, put it succinctly: "If you want our coal, you will have to pay our price. The price is heavy."

Indian Lawsuits Not Isolated Events

It should be noted that the Crow tribe is not the only one involved in development hobbling litigation. The Northern Cheyenne Tribe in 1973 raised essentially the same points in seeking Interior

administrative action. The issue is still unsettled.

The Navajo declare they will call the shots on what happens on their reservation concerning the development of coal and water for coal gasification. In Alberta, Canada, Indians are after a \$100 MM to \$400 MM slice of revenue from development of the Athabasca oil sands and have threatened to sue the provincial government and other partners in oil sands development.

Also, it is significant that the Crow lawsuit was filed in Washington, D. C. rather than in a federal court in Montana. It is in the District of Columbia that the Sierra Club lawsuit was filed. It is in D. C. that the district court has been ruling against environmentalists who then appeal and prevail in the circuit court of appeals, thus prolonging the litigation and possibly thrusting the issues into the U.S. Supreme Court. In these cases, federal agencies have been accused of not following the law and the courts have agreed.

#

COAL LEASING ACTIVITY REPORTED

"Coal Resources of the United States, January 1, 1974", U.S. Geological Survey Bulletin 1412, by Paul Averitt has recently been published. This document is a summary of information concerning the quantity and distribution of coal in the U.S. and supersedes Bulletin 1275. Bulletin 1412 may be obtained from Superintendent of Documents, U.S. G.P.O., Washington, D. C. (Stock No. 024-001-02703-8).

The Montana Energy Advisory Council has recently released "Supplement 1" to "Coal Development", published in December, 1974. "Coal Development" is a summary of present and potential coal development in Montana.

Western Coal Land Activities Table 1, following, summarizes state and federal coal lands leasing and prospecting transactions.

#

WESTERN COAL LAND ACTIVITIES
(State and Federal Lands Only)

<u>Name</u>	<u>Action</u>	<u>Acres</u>	<u>County</u>
COLORADO			
Adolph Coors Co.	State Lease Assignee, Clayton Coal Co., Assignor	640	Weld
Arjay Oil Co.	State Lease Assignee, Rio Vista Oil Ltd., Assignor	6737	Weld
Bill's Coal Co.	State Lease Assignee, Paul S. Coupey Assignor	760 333	Routt Moffat
Burton, P. A.	Federal Competitive Lease Application	8319	Routt
The Carter Oil Co.	State Lease Assignee, Arnold R. Gilbert, Assignor	1268	Moffat
The Carter Oil Co.	State Lease Assignee, John J. Wanner, Assignor	1120	Moffat
Coal Fuels Corp.	Federal Competitive Lease Application	440	Jackson
Colorado Consolidated Coal Company	Federal Competitive Lease Application	2878	Delta
Consolidation Coal Co.	Federal Lease Assignment Pending Permit Application, James C. Goodwin, Assignor	9048	Moffat
Consolidation Coal Co.	Federal Lease Assignment Pending Preference Right Lease Application, Ember Mining Co., Assignor	9625	Rio Blanco
Consolidation Coal Co.	State Lease Partially Canceled	360	Jackson
Energy Fuels Corp.	State Lease Assignee, Pittsburgh and Midway Coal Mining Co., Assignor	80	Routt
Franklin Real Estate Co.	Federal Lease Assignee, Silengo Brothers, Assignor	634	Routt
Fulton, Caesar	State Lease Assignee, Roy A. Bennett, Assignor	640	Weld
W. R. Grace and Co.	Federal Competitive Lease Application	6033	Moffat
W. R. Grace and Co.	Federal Lease Assignee, Colo-Wyo. Coal Co., Assignor	1160	Moffat
	Federal Lease Partially Relinquished	1160	Moffat
	Federal Lease Present Total	2565	Moffat
	(See note following page)		

<u>Name</u>	<u>Action</u>	<u>Acres</u>	<u>County</u>
COLORADO (Continued)			
Note: Lease was modified 5011-66 to include additional lands, making a total of 3724.73 acres. Assignment of 2564.73 acres to W. R. Grace & Co. was approved 12-1-73. Assignment of the remaining lands was approved so that W. R. Grace & Co. could then relinquish excess acreage to bring total to required 2560.00 acres.			
Holly Sugar Corp.	Federal Competitive Lease Application	1920	Delta
Kerr Coal Co.	Federal Competitive Lease Application	440	Jackson
Material Service Corp.	Federal Lease Assignee, The United Electric Coal Co., Assignor	4842	Routt
Mintech Corp.	Federal Competitive Lease Application	320	Adams
Morgan Coal Co.	Federal Preference Right lease Issued	475	Routt
Peabody Coal Co.	Federal Competitive Lease Application	160	Routt
Porter, K. D.	Federal Competitive Lease Application	12,200	Garfield
Rio Vista Oil Ltd.	State Lease Partially Relinquished	11,598	Weld
Roller, J. L. and Assoc.	State Lease Issued	80	Routt
Roller, J. L. and Assoc.	Federal Competitive Lease Application	8319	Routt
Sunflower Corp.	State Lease Terminated	2069	Moffat
Sunflower Energy Corp.	Federal Competitive Lease Application	6033	Moffat
Tatum, James D.	Federal Competitive Lease Application	8319	Routt

MONTANA

AMAX Coal Co.	State Prospecting Permit Issued	2 2	Treasure Powder River
Burlington Northern	State Prospecting Permit Issued	21	McCone
The Carter Oil Co.	State Lease Assignee, Woodsen, Fred C., Assignor	3976 3120 1280 1120	Big Horn Dawson Powder River Rosebud

<u>Name</u>	<u>Action</u>	<u>Acre</u>	<u>County</u>
MONTANA (Continued)			
Consolidation Coal Co.	State Prospecting Permit Issued	9 6	Richland Rosebud
Consolidation Coal Co.	State Prospecting Permit Issued	6	Rosebud
Crissafulli, Joe	State Prospecting Permit Expired	2	Dawson
Decker Coal Co.	Federal Lease Modification Application Issued Now In Lease : Application to Add:	2560 720	Big Horn Big Horn
Gulf Mineral Resources	State Prospecting Permit Expired	11	Custer
Hauptman, Charles M.	Federal Competitive Lease Application	45,426	Dawson
McCartney, Clay H.	State Prospecting Permit Expired	7 3	Blaine Mill
McDough, P. J.	State Prospecting Permit Application	1	Rosebud
Mobil Oil Corp.	State Prospecting Permit Renewed	1	Powder River
Mobil Oil Corp.	State Prospecting Permit Application	2	Custer
Montana Bureau of Mines/ College of Mineral Science	State Prospecting Permit Issued	3	McCone
Montana Bureau of Mines/ College of Mineral Science	State Prospecting Permit Application	2	Richland
Montana College of Mineral Science	State Prospecting Permit Application	23	Powder River
Pacific Power and Light Co.	State Prospecting Permit Application	2	Big Horn
Public Service Co. of Okla.	State Prospecting Permit Issued	5	Big Horn
Red Lodge Bear Creek Coal Partners	State Prospecting Permit Application	5	Carbon
Rosebud Coal Sales Co.	State Prospecting Permit Issued	2 2	Treasure Powder River
Shell Oil Co.	State Lease Assignee, Farmers Union Central Exchange, Assignor	429	Wibaux
Shell Oil Co.	State Prospecting Permit Application	2	Big Horn
Shell Oil Co.	Federal Lease Assignee, Concho Petroleum Co., Assignor	541	Big Horn

<u>Name</u>	<u>Action</u>	<u>Acre</u>	<u>County</u>
MONTANA (Continued)			
Shell Oil Co.	State Prospecting Permit Issued	2	Big Horn
Sun Oil Co.	State Prospecting Permit Issued	2 9	Richland Dawson
Utah International Inc.	State Prospecting Permit Issued	7	Powder River
Western Coal Co.	Federal Competitive Lease Application	2960	Musselshell
Western Energy Corp.	State Prospecting Permit Issued	4 35	Carter Fallon
Western Minerals, Inc. and Wytana Inc. d/b/a/ Decker Coal Co.	Federal Lease Assignee, Montana Royalty Co. Ltd., Assignor (third assignment) Montana Royalty Co. Ltd. Federal Lease Assignee, Resources Development Co., Assignor (second assignment) Resources Development Co. Assignee, Pacific Power and Light, Assignor (first assignment)	720	Big Horn
Wesco Resources	State Prospecting Permit Issued	1	Powder River
Westmoreland Resources	State Prospecting Permit Issued	1	Big Horn
Westmoreland Resources	State Prospecting Permit Application	63	Big Horn
Westmoreland Tract II	State Prospecting Permit Issued	63	Big Horn
Wold, John S.	State Prospecting Permit Expired	1	Dawson
NEW MEXICO			
El Paso Natural Gas Co.	State Lease Terminated	640	Sandoval
New Mexico Resources Co.	State Lease Assignee, Lone Star Producing Co., Assignor	1482	McKinley
NORTH DAKOTA			
Baukol-Noonan, Inc.	Federal Lease Terminated	160	Burke
Consolidation Coal Co.	Federal Competitive Lease Application	120	Ward

<u>Name</u>	<u>Action</u>		<u>Acre</u>	<u>County</u>
	UTAH	f		
Adams, Dirk	State Lease Application		640	Grand
Adams, John D.	State Lease Application		640	Grand
Adams, John D.	State Lease Application Closed		43,814	Grand
Adams, John D. and Shumway, Wilene	State Lease Issued		80,778 4320	Grand Uintah
Anderson, D. C.	Federal Prospecting Permit Application		11,491	Emery
Anderson, D. C.	State Lease Issued		7111	Emery
Anderson, John R.	State Lease Issued		640 40	Kane Garfield
Anderson, Michael C.	State Lease Issued		1920	San Juan
Arjay Oil Co.	State Lease Issued		16,491	San Juan
Collard, LeRoy	State Lease Issued		637	Wayne
Davis, Richard L.	State Lease Issued		320	Grand
Dickman, Charleen	Federal Prospecting Permit Application Closed		42,662	Emery
Dickman, Vernon W.	Federal Prospecting Permit Application Closed		28,247 15,250	Emery Grand
Earth Science, Inc.	State Lease Assignee, R. J. Hollberg, Jr., Assignor (second assignment)		7392	Carbon
	R. J. Hollberg, Jr., Assignee, Rio Vista Oil Ltd. and M. R. Hays, Assignors (first assignment)			
Earth Science, Inc.	State Lease Assignee, Emery Coal, Inc. Assignor		3189	Carbon
Earth Science, Inc.	State Lease Assignee, R. J. Hollberg, Jr., Assignor		5378	Carbon
Earth Science, Inc.	State Lease Issued		346	Carbon
Earth Science, Inc.	State Lease Application		8764 640	Carbon Emery
Emery Coal, Inc.	State Lease Terminated		626	San Juan
Emery Coal, Inc.	State Lease Application Closed		6757	Emery

<u>Name</u>	<u>Action</u>	<u>Acre</u>	<u>County</u>
UTAH (Continued)			
Emery Coal, Inc.	State Lease Issued	1441	Emery
Franklin Real Estate Co.	State Lease Assignee, Braztah Corp., Assignor	1307	Carbon
Greene and Weed In- vestments	State Lease Issued	360	Kane
Guin, Jerome B.	State Lease Application	160	Wayne
Gulf Oil Corp.	State Lease Assignee, Hiko Bell Mining and Oil, Assignor	1280	Garfield
Hansen, L. R.	State Lease Assignee, Ray Hansen, Assignor	162	Sevier
Harlan Management Corp.	State Lease Assignee, Allied Shumway Minerals Inc., Assignor	1920	Grand
Hays, Al. T.	State Lease Application	2002	Sanpete
Hollberg, R. J., Jr.	State Lease Application	2560	San Juan
Hollberg, R. J., Jr.	State Lease Partially Relinquished: Remaining in Lease:	320 1840	San Juan San Juan
Hollberg, R. J., Jr.	State Lease Terminated	22,368	San Juan
Hollberg, R. J., Jr.	Federal Prospecting Permit Application Closed	10,211	Grand
Hollberg, R. J., Jr.	State Lease Issued	2560	San Juan
Hunter, Dan H.	State Lease Assignee, James R. Dickert, Assignor	440	Emery
Hunter, Dan H.	Federal Prospecting Permit Application Closed	9446	Carbon
Hunter, Thomas E.	Federal Prospecting Permit Application Rejected	14,977	Grand
Jordan Industries, Inc.	State Lease Issued	4266	Emery
Kamawha and Mocking Coal and Coke Co.	Federal Competitive Lease Application	160	Carbon
Kamawha and Hocking Coal and Coke Co. (50%) and Dan H. Hunter (50%)	State Lease Assignee, Dan H. Hunter, Assignor	160	Sanpete
Knight, David M.	State Lease Issued	995	Emery

<u>Name</u>	<u>Action</u>	<u>Acre</u>	<u>County</u>
UTAH (Continued)			
Manhattan Resources Inc.	State Lease Assignee, Heath B. Fowler, Assignor	758	Emery
Manhattan Resources Inc.	State Lease Assignee, John R. Shelburne, Assignor	1600	Emery
Mid-West Petroleum Development Corp.	State Lease Issued	714	Carbon
Mid-West Petroleum Development Corp.	State Lease Application Closed	200	Emery
Mid-West Petroleum Development Corp.	State Lease Application	715	Carbon
Morgan, J. H., Sr.	State Lease Application Withdrawn	1058	Uintah
Morgan, J. H., Sr.	State Lease Issued	8466	Uintah
Morrison-Knudson Co., Inc.	State Lease Application	38,875	Grand
Mulford, LaMar	State Lease Issued	640	Wayne
Nielsen, George W.	State Coal Lease Terminated	1280	San Juan
Swisher Coal Co.	State Lease Assignee, Francis Skaggs, Assignor	40	Carbon
United States Steel Corp.	Federal Prospecting Permit Application Rejected	32,435	Carbon
Utah Resources International	State Lease Issued	360	Uintah
Utah Resources International	State Lease Application	2560	Uintah
Wardle, James H.	State Lease Issued	320 2165	Carbon Wayne and Garfield
Wardle, James H.	State Lease Issued	640	Wayne
WYOMING			
AMAX Coal Co.	State Lease Renewed	640	Campbell
American Nuclear Corp. (50%) Tennessee Valley Authority (50%)	State Lease Renewed	640	Campbell

<u>Name</u>	<u>Action</u>	<u>Acre</u>	<u>County</u>
WYOMING (continued)			
Andrikopolos, A. G.	State Lease Issued	2345	Johnson
Andrikopoulos, George B.	State Lease Issued	1602	Johnson
Andrikopoulos, John C.	State Lease Issued	1142	Johnson
ARCO	State Lease Renewed	38,518	Campbell
Arkland Co.	State Lease Renewed	320	Campbell
Carroll, Thomas J., Wilson, W. M.	State Lease Terminated	959	Fremont
Carter Oil Co.	State Lease Renewed	15,632 61,266 62,416 640	Johnson Campbell Sheridan Converse
Columbine Mining Co.	Federal Lease Assignee, Gunn- Quely Coal Co., Assignor	1752	Sweetwater
Consolidation Coal Co.	State Lease Renewed	640	Campbell
David, Robert W.	State Lease Assignee, Discovery Oil Ltd., Assignor	5160	Natrona
David, Robert W.	State Lease Terminated	6119	Hot Springs
David, Robert W.	State Lease Partially Relinquished: Land In Lease:	240 320	Hot Springs Hot Springs
Dinneen, W. J., Jr.	State Lease Issued	919	Campbell
Dol Resources, Inc.	State Lease Assignee, Graham P. Stewart, Assignor	640	Natrona
Discovery Oil Ltd.	State Lease Terminated	27,039 16,720 640	Goshin Laramie Sweetwater
Fisher, J. H. and Fisher, Dr. J. H., Jr.	Federal Lease Assignee, Summit Explora- tion and Development, Assignor	720	Converse
	Note: Intermediate assignments to Texas Western Industries, Inc., and Texas Western, Inc.		
Gallivan, Frank M.	State Lease Terminated	8634	Johnson
Gulf Oil Corp.	State Lease Terminated	40	Johnson
Heck, Orval E.	State Lease Terminated	640	Campbell

<u>Name</u>	<u>Action</u>	<u>Acre</u>	<u>County</u>
WYOMING (continued)			
HFC Oil Co., Inc.	State Lease Terminated	2560	Washakie
		1000	Hot Springs
		3624	Park
Hergert, Elmer	State Lease Terminated	13,100	Natrona
J and P Corp.	Preference Right Lease Application Reinstated	80	Campbell
J and P Corp.	Preference Right Lease Application Closed	1557	Campbell
Jenkins, Page T.	Federal Prospecting Permit Application For Extention Withdrawn	19,990	Converse
Karcher, J. C. (20%) Concho Petroleum Co. (80%)	State Lease Modification Application Rejected Lands Requested : Lands In Lease:	1122	Campbell
		1571	Campbell
Kemmerer Coal Co.	Federal Competitive Lease Application	3715	Campbell
		2982	Converse
Leeman, Don J.	State Lease Assignee, John M. Beard, Assignor	159	Campbell
		2400	Converse
		3200	Johnson
		2120	Western
MAPCO Inc.	State Lease Renewed	22,760	Johnson
		76,230	Sheridan
		3840	Campbell
Maurer, A. J., Jr.	State Lease Issued	151	Campbell
		80	Converse
		80	Natrona
		40	Niobrara
		40	Western
Mills, Dowe, Jr.	State Lease Terminated	641	Big Horn
Mobil Oil Corp.	State Lease Renewed	17,122	Johnson
		3080	Sheridan
		640	Campbell
N. R. G. Assoc. (50%)	State Lease Assignee, Western Standard Corp., Assignor (50% to N.R.G. Assoc.)	35,474	Converse
Pace, T. S., Wilson, W. M.	State Lease Terminated	640	Fremont
Peabody Coal Co.	Federal Competitive Lease Application	3715	Campbell
		2982	Converse
Peterson, Richard L.	State Lease Issued	120	Weston

<u>Name</u>	<u>Action</u>	<u>Acre</u>	<u>County</u>
WYOMING (Continued)			
Purwell, M. J.	Federal Competitive Lease Application	2320	Lincoln
Shell Oil Co.	Federal Lease Assignee, Farmers Union Central, Assignor	599	Campbell
Stansbury Coal Co.	Federal Lease Assignee, Badger Service Co., Assignor	1645	Sweetwater
Stoltz, Wagner and Brown (50%) Tipperary Resources (50%)	State Lease Renewed	17,122	Johnson
		3080	Sheridan
		640	Campbell
Stoltz, Wagner and Brown (50%) Tipperary Resources (50%)	State Lease Terminated	5754	Johnson
		480	Sheridan
Sun Oil Co.	Federal Lease Assignee, Humac Co., and Haneline, L. A., Assignor	3359	Converse
Sun Oil Co.	State Lease Assignee, Humac Oil. (50%) and Eugene Stevens (50%) Assignor	640	Converse
Texaco, Inc.	State Lease Renewed	2120	Johnson
Tri-State Generation and Transmission Assoc.	State Lease Terminated	5520	Weston
Tsangaraskis, Matthew, Wilson, W. M.	State Lease Terminated	240	Sweetwater
Western Nuclear, Inc.	Federal Lease Assignee, Alfred T. Graham, Assignor	80	Hot Springs
Wilson, W. M.	State Lease Terminated	3720	Sweetwater
Wold, John S.	State Lease Terminated	919	Campbell
Woodward, Lucy L.	State Lease Terminated	1280	Campbell
		915	Weston
Wyoming Coal Corp.	State Lease Issued	640	Washakie

APPENDIX

Copy of "Order of Remand" by U.S. Court of Appeals in Combined Oil Shale Civil
Action Cases 5-1

Interior's Recommendations Regarding In Situ Oil Shale Tract Nominations 5-6

Interior-Sponsored Bill Authorizing Leasing of Off-Tract Oil Shale Disposal
Lands 5-19

Proposed Severance Tax Legislation May Become Model for Several States 5-20

SEPTEMBER TERM - SEPTEMBER 22, 1975

Before The Honorable Delmas C. Hill, The Honorable William J. Holloway, Jr., and The Honorable James E. Barrett, Circuit Judges

UNITED STATES COURT OF APPEALS
TENTH CIRCUIT

FILE COPY

THE OIL SHALE CORPORATION; ENERGY RESOURCES TECHNOLOGY LAND, INC; JOSEPH B. UMPLEBY; WASATCH DEVELOPMENT CO.; BARNETT T. NAPIER; GRACE A. SAVAGE; JOAN L. SAVAGE; MAUDE B. FARNUM; ST. CLAIR NAPIER CATLIN; WILLIAM H. FARNUM, JR.; JOHN R. FARNUM; JOHN W. SAVAGE; NEIL S. MINCER; GARDNER C. CATLIN; ELIZABETH YOUNG FARNUM HINDS; and PENELOPE CHASE BROWN, individually and as Trustee,)	
)	Nos. 74-1344
)	74-1345
)	74-1346
Plaintiffs-Appellees,)	74-1347
)	(Consolidated
v.)	cases)
)	
ROGERS C. B. MORTON, Secretary of the Interior,)	
)	
Defendant-Appellant.)	

DO NOT REMOVE

APPEALS FROM THE UNITED STATES DISTRICT COURT
FOR THE DISTRICT OF COLORADO
(D.C. 8680, 8685, 8691, 9202)

Thomas L. McKeivitt (Wallace H. Johnson, Assistant Attorney General; James L. Treece, United States Attorney, Denver, Colorado; Edmund B. Clark, Robert L. Klarquist, Attorneys, Department of Justice, on the brief), Washington, D. C., for Defendant-Appellant United States.

Fowler Hamilton (Warren O. Martin, Denver, Colorado, on the brief for Plaintiffs-Appellees in 74-1345; David G. Manter, Denver, Colorado, on the brief for Plaintiffs-Appellees in 74-1346; James B. Dean, Denver, Colorado; Richard W. Halbert, New York, New York; and Donald L. Morgan, Washington, D. C., on the brief for Plaintiffs-Appellees in 74-1344 and 74-1347), New York, New York, for Plaintiffs-Appellees.

Before HILL, HOLLOWAY and BARRETT, United States Circuit Judges.

PER CURIAM.

ORDER OF REMAND

The first stage of this litigation focused on a very narrow issue--the Interior Department's subject matter jurisdiction over contests involving the performance of assessment work. That issue was ultimately decided adversely to the claimants by the Supreme Court in *Hickel v. Oil Shale Corp.*, 400 U.S. 48 (1970). The Supreme Court, in reversing and remanding, provided the following instructions:

Respondents [claimants-appellees] rely upon the response of the Department of the Interior to the Virginia-Colorado case in which the Secretary declared the contest in that case to be "void." He also declared that "other Departmental decisions in conflict with this decision are hereby overruled." This decision, they argue, nullified the previous contest proceedings in which their claims were voided. Moreover, they contend that this administrative rule of 35 years, upon which the Department itself has relied, may not now be retroactively changed. In addition, they claim that these contest decisions, if still valid, are subject to direct judicial review at this time, testing both substantive and procedural errors, such as lack of notice.

These contentions present questions not decided below. Therefore, on remand all issues relevant to the current validity of those contest proceedings will be open, including the availability of judicial review at this time. To the extent that they are found void, not controlling, or subject to review, all issues relevant to the invalidity

COPY OF "ORDER OF REMAND" BY U.S. COURT OF APPEALS IN COMBINED OIL SHALE CIVIL ACTION CASES

of the claims will be open, including inadequate assessment work, abandonment, fraud, and the like. Likewise all issues concerning the time, amount, and nature of the assessment work will be open so that the claimants will have an opportunity to bring their claims within the narrow ambit of *Krushnic and Virginia-Colorado*, as we have construed and limited these opinions.

In the instant matter before this Court, again a very small matter in the total controversy has been adjudicated. Relying on three substantive grounds, the trial court held that the assessment work contests could not be used to bar patents on these claims. The substantive grounds relied on by the trial court were (1) the vacating effect of the *Shale Oil* decision; (2) the "rule" of Interior allowing claims which had previously been declared void in the assessment work contests to be patented; and (3) estoppel. Grounds 1 and 2 relate directly to issues mentioned by the Supreme Court in its mandate; estoppel would also be encompassed within the language "all issues relevant to the current validity of those contest proceedings will be open...." The trial court also found Interior had committed procedural errors in the processing of patent applications for the claimants in 74-1345, 74-1346 and 74-1347. The court held these procedural errors, in addition to the incorrect substantive decisions, warranted a remand to Interior for reprocessing.

The trial court did not reach the issue of the

propriety of direct judicial review of possible substantive and procedural errors (including lack of notice) in the old assessment work proceedings. Having determined the assessment work contests could not be the basis for barring these patents, the trial court held it did not need to consider if direct judicial review of those proceedings was possible at this time or whether any errors had been committed in those proceedings.

The assessment work contests are simply one ground for challenging the claimants' right to patents. The trial court determined the contests could not be used to deny these claimants' patents. That meant the court reached consideration of the second prong of the Supreme Court's mandate--the "...other issues relevant to invalidity of these claims... including inadequate assessment work, abandonment, fraud, and the like." These possible obstacles have not been the subject of any administrative hearing or adjudication. It should be noted that the parties apparently stipulated that the issues of "...abandonment, fraud, lack of a valid discovery or other critical infirmity..." would not be considered by the trial court. *Oil Shale Corp. v. Morton*, 370 F.Supp. 108, 127, n.24 (D.Colo. 1973). In cases 74-1345, 74-1346 and 74-1347, where the claimants had applied for patents and been denied them, the trial court remanded the cases to Interior for reprocessing of the patent applications and ordered

Interior "to consider and rule upon all possible obstacles to the patenting of these claims. That reprocessing has not begun pending this appeal's outcome.

This litigation has been protracted. The claimants in this case who have sought patents did so from 1955 to 1962. The Secretary of the Interior decided the matter, on appeal, adversely to the claimants in 1964. Union Oil Co., 71 I.D. 169. Litigation to compel Interior to issue the patents to the denied claimants and to get declaratory relief for claimants who have not sought patents on their claims was instigated in the district court in 1964 and 1965. The end to this litigation is not in sight.

Good judicial husbandry demands that litigation be brought to a conclusion within a reasonable time frame. The energy situation in which this country finds itself compels a sense of urgency be brought to this action by this Court and the litigants. As the case now stands, many issues concerning the ultimate validity of these claims remain for determination. Should this Court or the Supreme Court determine that all three substantive bases relied upon by the trial court did not prevent use of assessment work contests to bar these claims, issues concerning the effect of these very same contests would remain: whether direct judicial review of them for substantive and procedural errors is possible at

this time; and whether any errors occurred. Affirmance of the decision below would not prevent the assertion of the other bases for invalidity. Consequently, the validity or invalidity of the claims will not be determined by any decision this Court or the Supreme Court could make with the case in its present posture. In the hope that a speedier end can be brought to this important litigation, and by means of this Court's inherent power to regulate litigation in the interest of judicial economy, the following order of remand is hereby entered.

✓ No. 74-1344

1. The case is remanded to the district court.
2. As claimants have not applied for patents, there can be no remand to Interior for ultimate determination of these claims. However, the Court suggests that these claimants apply for patents and, if such applications are made, Interior handle the matters on an expedited basis, allowing a consolidation, as appropriate, of these cases with the other remanded cases. In those proceedings, any and all bases for invalidity of the claims which Interior should desire to rely upon must be asserted. Also, with reference to the issue of estoppel, the Department shall receive all competent evidence presented upon the question of individual reliance by claimants upon the prior actions of Interior regarding the effect of the

assessment work contests.

3. Following any proceedings in Interior, the district court shall supplement its present findings of fact and conclusions of law as needed to dispose of the new matters presented. The district court shall proceed, after administrative proceedings are completed in all the remanded cases--whether or not patents are applied for--to determine the propriety of judicial review of the assessment contests and to determine if substantive or procedural errors occurred in those proceedings. This latter determination may require the taking of additional evidence. If no proceedings have been conducted in Interior as suggested above, the district court shall, following determinations by Interior in the other remanded cases, receive all competent evidence presented upon the question of individual reliance by claimants upon the prior actions of Interior regarding the effect of the assessment work contests. This evidence, of course, is relevant to the estoppel issue.

Nos. 74-1345, 74-1346 and 74-1347

1. These cases are remanded to the district court and, in turn, that court shall remand the matter to the Department of the Interior with the following directions:

- a. Interior is to consider and rule upon all possible obstacles to the patenting of these claims;

- b. Interior is requested to handle these matters in an expedited fashion;

- c. with reference to the issue of estoppel, the Department shall receive all competent evidence presented upon the question of individual reliance by claimants upon the prior actions of Interior regarding the effect of the assessment work contests; and

- d. Interior will have the opportunity to correct any existing procedural errors.

2. Following the completion of the administrative process, the district court shall supplement its present findings of fact and conclusions of law as needed to dispose of any new matters which may be presented. The district court shall also determine whether present judicial review of the assessment work contests is proper and whether substantive or procedural errors occurred in those proceedings. This latter determination may require the taking of additional evidence.

3. Should Interior not desire to assert any additional bases of invalidity against any of these claims (or at least against those claims involved in 74-1345, 74-1346 and 74-1347), a stipulation of the parties may be entered and the district court may proceed to complete the remainder of its remanded task concerning the propriety of judicial review. That remanded task, in the event of such a stipulation, also shall include the receiving of all competent evidence presented upon the question of individual reliance by

claimants upon the prior actions of Interior regarding the effect of the assessment work contests.

Therefore, the judgments appealed from are vacated and the cases are remanded in accordance herewith. However, we retain jurisdiction of the cases pending compliance with this mandate and for such other purposes as we deem appropriate, including a final determination of the cases upon the merits.



United States Department of the Interior
OFFICE OF THE SECRETARY
MISSOURI BASIN REGION
DENVER, COLORADO 80225



Oil Shale
Environmental Advisory Panel
Room 690, Building 67
Denver Federal Center
September 15, 1975

Memorandum

To: Members of the Oil Shale Environmental Advisory Panel

From: Chairman, Oil Shale Environmental Advisory Panel

Subject: Request from Assistant Secretary Norton for Panel Review of In Situ Tract Selection Committee Report and Information on October Panel Meeting

Enclosed are the Assistant Secretary's memorandum together with the Tract Selection Committee report and recommendations with backup material. Pursuant to the plan adopted at the Rangely meeting, the material is being provided to all members with the in situ workgroup (members listed below) to have the lead in the panel's review. Please provide your comments to the workgroup Chairman Mike Strang by October 6 with copies to the panel office. Mike will convene his workgroup as necessary to develop proposed advice for consideration by the full panel at the next meeting.

Copies of the items identified in the report as Appendixes 1, 2, 5, and 6 were previously provided to panel members and are not included with the material.

The next meeting will be during the period October 22-24 in Grand Junction, Colorado, at the Howard Johnson Motor Lodge. We are attempting to arrange a premeeting field trip for panel members and staff only for Wednesday afternoon October 22 with the meeting planned for all day Thursday and one-half day Friday. A preliminary Wednesday evening session is possible also so you should plan your travel accordingly. A block of rooms has been reserved and Eleanor will make reservations for panel members and staff. However, you must advise the panel office of your plans by October 7 to be assured of a room at Howard Johnson's.

In Situ Workgroup Members

Mike Strang, Chairman
Nancy Dick
Gordon Hamston
Charles Henderson
Bob Kessler
Estella Leopold
Cooper Wayman
Vin Wright

W. Strang



United States Department of the Interior

OFFICE OF THE SECRETARY
WASHINGTON, D.C. 20240

SEP 12 1975

Memorandum

To: Chairman, Oil Shale Environmental Advisory Panel

From: Assistant Secretary *John Norton* and Water Resources

Subject: In Situ Tract Nominations

Enclosed is a copy of the recently completed report from the Departmental In Situ Oil Shale Tract Selection Committee. The Department requests that the Panel review the report of the Committee at its next meeting. In order to facilitate informed discussion, we are requesting that appropriate members of the in situ committee attend the next OSEAP meeting so any Panel questions can be expeditiously answered. In addition, we will request the BLM to brief the Panel on the resource values in the area of the nominated tracts.

We would like the Panel's advice on this matter no later than the first week in November, so that the Secretary can make a preliminary determination on which tracts to offer for lease. A detailed analysis of environmental impacts would then begin culminating in a supplemental EIS. We plan to ask the Panel to review this document when the draft is completed sometime in February.

Enclosure



INTERIOR'S RECOMMENDATIONS REGARDING IN SITU
OIL SHALE TRACT NOMINATIONS



United States Department of the Interior

OFFICE OF THE SECRETARY
WASHINGTON, D.C. 20240

Appendix 3

August 5, 1975

Dear Governor Lamm:

On April 23, 1975, the Department published in the Federal Register a call for nominations of possible leasing areas for "in situ" oil shale prototype research and development. As you may recall, the previous lease sites, expected to be developed by "in situ" technologies, received no bids when offered for lease last year. New leases, if issued, would be replacements for the earlier proposed leases and for the purpose of fulfilling the initial objectives of the prototype oil shale program. The Oil Shale Environmental Advisory Panel (OSEAP) has reviewed and generally supports the proposal to proceed further with a prototype program for "in situ" development.

The call for "in situ" nominations closed on July 31, with the nomination of 10 areas in Colorado and Utah. The final decisions on which tracts should be offered for lease will be made after analysis and recommendations by a tract selection committee and after further review by the Oil Shale Environmental Panel. The State of Colorado, as you know, is represented on OSEAP. Further, leases will not be issued until the requirements of the National Environmental Policy Act have been met and a determination is made that it is environmentally acceptable to issue them.

We are pleased to invite you to designate a representative for your State on the tract selection committee, which is presently being formed and is expected to meet in Denver in the very near future. If you desire to be represented, please submit to me by August 15 the name and address of your designee.

Sincerely yours,

/s/Jack Horton

Assistant Secretary of the Interior

Honorable Richard D. Lamm
Governor of Colorado
State Capitol
Denver, Colorado 80203

IDENTICAL LETTER SENT to Governor Rampton, SLC, Utah



United States Department of the Interior

BUREAU OF LAND MANAGEMENT

COLORADO STATE OFFICE
ROOM 700, COLORADO STATE BANK BUILDING
1600 BROADWAY
DENVER, COLORADO 80202

September 5, 1975

Memorandum

To: Assistant Secretary of the Interior, Lands and Water Resources
From: Chairman, Interagency In Situ Oil Shale Tract Selection Committee
Subject: Report and Recommendations re In Situ Oil Shale Tract Nominations

Recommendations

Based on our deliberations, analyses, and ratings, it is the consensus of this committee that of the nine tracts nominated, Tract 2 in Colorado and Tract 8 in Utah are the best suited, both from a resource and environmental standpoint, for prototype in situ oil shale development. It is the consensus that Tracts 7 and 9, both in Utah, are best suited as alternate tracts.

Introduction

In accordance with the charge set forth by the Assistant Secretary of the Interior - Lands and Water Resources, the following report is submitted. The charge to the committee was to review all nominated tracts and to prepare a report, analyzing all nominated areas and recommending two tracts for leasing along with two alternate tracts. The report was to be submitted to the Assistant Secretary of the Interior - Land and Water Resources, by September 12, 1975. This report, except that section titled Major Factors and Concerns, is the consensus of the Interagency In Situ Oil Shale Tract Selection Committee.

In Federal Register, Vol. 40, No. 79 - Wednesday, April 23, 1975, (Appendix 1), Under Secretary of the Interior John C. Whitaker called for nomination of areas for possible oil shale leasing. Nominations were to be submitted not later than June 30, 1975. In addition to other information to be submitted with the nomination, the notice provided that each tract nomination include a description of the type of in situ technology that might be used to develop the tract.

In Federal Register, Vol. 40, No. 125 - Friday, June 27, 1975, (Appendix 2), Assistant Secretary of the Interior Jack O. Horton extended the time for receiving nominations until July 31, 1975.

INTERIOR'S RECOMMENDATIONS REGARDING IN SITU OIL SHALE TRACT NOMINATIONS

Industry responded by nominating six tracts in Colorado and three tracts in Utah.

Subsequent to July 31, 1975, the closing date for tract nominations, an interagency tract selection committee was appointed by the Assistant Secretary of the Interior - Land and Water Resources. By letter of August 5, the Assistant Secretary - Land and Water Resources, asked the Governors of Colorado and Utah to designate a representative to this committee. (Appendix 3) The committee was made up of the following:

1. H. Roy McBroom, Chairman--Chief, Branch of Energy and Minerals, Colorado State Office, Bureau of Land Management, Denver, Colorado.
2. Donald L. Pendleton--District Manager, Vernal District, Bureau of Land Management, Vernal, Utah.
3. John R. Donnell--Chief, Oil Shale Section, U. S. Geological Survey, Denver, Colorado.
4. Eric G. Hoffman--Environmental Geologist, Area Oil Shale Office, U. S. Geological Survey, Grand Junction, Colorado.
5. Jerald Stroebale--Regional Assistant, Energy Activities Leader, U. S. Fish and Wildlife Service, Denver, Colorado.
6. Paul L. Russell--Research Director, U. S. Bureau of Mines, Denver, Colorado.
7. John Ward Smith--Research Supervisor, Laramie Energy Research Center, ERDA, Laramie, Wyoming.
8. Lowell L. Madsen--Attorney, Office of the Solicitor, Denver, Colorado.
9. Howard Ritzma--Utah State Geologist, Salt Lake City, Utah.
10. Burman H. Lorenson--Governor's Oil Shale Coordinator, Denver, Colorado.
11. Gerald D. Sjaastad--Deputy Director, Colorado Department of Natural Resources, Denver, Colorado.
12. D. Keith Murray--Chief, Mineral Fuels Section, Colorado Geological Survey, Denver, Colorado.

Initiation of Deliberations

Chairman H. Roy McBroom convened the committee at 9:00 a.m. on Monday, August 11, 1975, in the Bureau of Land Management, Colorado State Office conference room, located in the Colorado State Bank Building, 1600 Broadway, Denver, Colorado 80202. The Governor of Colorado was represented by only Burman Lorenson at this meeting.

The charge to the committee and our approach to the problem was discussed. We were briefed on the resource values and the BLM Management Plans for the areas in the vicinity of the tracts nominated in Colorado and Utah, by Ray Brady of the BLM Colorado White River Resource Area Office and District Manager Don Pendleton of the Vernal, Utah, District Office.

The meeting was recessed until further notice upon a request by the Governor of Colorado to the Assistant Secretary of the Interior - Lands and Water Resources.

The Chairman reconvened the committee on Monday, August 25, 1975, at the same location as the initial meeting. The Governor of Utah was not represented at this meeting. However, upon being contacted by telephone on August 25, Howard Ritzma of the Utah Geological Survey, formerly designated as the Utah Governor's representative, informed the chairman of the committee of the following:

The Governor declined to have a representative attend the committee meetings in Denver. In addition, based on an analysis by Howard Ritzma with concurrence by the Governor, the tract nominations in Utah were preferred in the following order: 8, 7, 9. Without going into detail, they had strong misgivings as to the acceptability of Tract 9.

Establishment of Criteria

To accomplish the task assigned in an orderly and timely manner, the committee first determined the criteria to be used in reviewing the nine nominated tracts. The legal descriptions and maps showing the location of these nine tracts are shown in Appendix 4. The tracts are numbered in consecutive order, 1 through 9.

In order to establish meaningful criteria, the committee first reviewed the following publications:

1. "Accelerated Oil Shale In Situ Research - A National Program", coordinated by the Interagency Oil Shale Planning Panel, March 1975 (Appendix 5). Particular attention was given to Section III. Need for In-Situ Program, and to Section IV. In-Situ Research Program.
2. "A Strategy To Stimulate Oil Shale Development by In Situ Processing", prepared by The Office of Research and Development, U. S. Department of the Interior, April 2, 1974 (Appendix 6).

In addition to these, and after considerable discussion, the environmental factors and socio-economic factors which would have a decided bearing on our recommendations were determined.

Our consensus was that the following three major criteria must be considered:

1. Development Potential
2. Environmental Considerations
3. Socio-Economic Factors

Numerous individual items under each of these major criteria were evaluated. Although the worksheet (Appendix 7) does not reflect it, equal weight was given to each of the three major criteria.

Data to Provide Base for Analysis

Due to the makeup of the committee, it was felt that expertise, particularly in the areas of socio-economics and environmental concerns, was necessary. The committee was briefed in these areas, in order to provide a base for analysis and review, as follows:

1. Ray Brady, BLM geologist in the Colorado White River Resource Area Office, and Don Pendleton, BLM Vernal, Utah, District Manager, presented detailed information on the resource values on and in the near vicinity of the tracts nominated both in Colorado and Utah. In addition, they briefed the committee on the proposed plans for management of these areas. This information was available to the committee throughout the week in the form of map overlays and detailed written narratives.
2. Knowledgeable committee members provided detailed mineral resource information and geology on the nominated tracts.
3. Dr. Calvin H. Jennings, Department of Anthropology, Colorado State University, Fort Collins, Colorado, discussed the archeological values and their significance on or in the vicinity of the tracts being reviewed.
4. E. G. Weir, Hydrologist, U. S. Geological Survey, Denver, Colorado, discussed both surface and subsurface water which would be affected by proposed in situ oil shale development.
5. Larry Roper, Colorado State Fish and Game Department, Denver, Colorado, and Ed Roberts, Wildlife Specialist, BLM Wildlife Biologist, Colorado State Office, Denver, Colorado, discussed wildlife, endangered species, habitat, and hunter recreation on or in the vicinity of the tracts under review.
6. Ed Parsons, Economist, BLM Colorado State Office, Denver, Colorado, participated in the discussions on socio-economics.
7. In addition, knowledgeable committee members explained the extraction methods proposed by the nominees for oil shale leasing sites in Colorado and Utah. (Appendix 8)

Deliberations, Analysis and Ratings

By means of open discussion on each of the criteria previously established, throughout the week of August 25, 1975, each factor was rated collectively. Analysis of these ratings enabled selection of two tracts plus two alternate tracts.

A more subjective method was also used by the committee. Each committee member independently rated the tracts, using as a basis his personal knowledge, opinions, and considerations. Comparison determined that each method yielded essentially the same recommendations and the same tract selections.

OSEAP Recommended Criteria

The committee was informed by W. L. Rogers, Special Assistant to the Secretary, that at the August 27 meeting of the Oil Shale Environmental Advisory Panel, certain panel members stated that the following criteria should be used in determining our recommendations:

1. Tracts containing State-owned surface lands should not be recommended.
2. Maximum use of existing service and access corridors should be made.
3. If the proposed process would result in dewatering, sites should be recommended that were away from any existing prototype oil shale project where dewatering is/will occur.

After deliberations were completed and consensus reached, the OSEAP recommended criteria were reviewed with respect to the tracts recommended, using criteria detailed in Appendix 7. It was agreed that those major areas of concern to OSEAP had been considered in the rating system.

Major Factors and Concerns

The following are major factors or concerns which were discussed in detail and which the committee as a whole, or in part, recommends the Secretary consider in his decision to lease or not lease tracts for prototype in situ oil shale development.

1. All members of the committee were in agreement that the recommendations were based on those tracts nominated and represent the best judgment as to which tracts would provide the best technological gains and minimum environmental impact. However, the tracts nominated may not necessarily have been situated at the best locations.
2. Tract 2 is moderately dry or free of ground water problems and suitable for development by modified in situ methods.
3. Tracts 7 and 8 are dry or free of ground water problems and suitable for development by modified in situ methods.

4. Tract 9 is dry. It may offer the best opportunity for early production of shale oil in commercial quantities by a true in-situ technique. Technology developed here may be applicable to a relatively large area adjacent to the tract and to oil shales in Wyoming, but may not be necessarily applicable to other deep Utan and Colorado shales. This tract meets the outlines in the "Accelerated Oil-Shale In-Situ Research" paper because it could provide an in-situ process reaching the point of commercial application by 1980.

5. Tracts 1, 3, 4, 5, and 6, could also be developed by modified in situ techniques, although with greater difficulty due to depth of overburden and abundant ground water.

6. The sites in the center of Piceance Creek Basin, namely Tracts 1, 3, 4, 5, and 6, contain the largest oil-shale resources but have serious deficiencies relative to the following items:

- a. Wildlife concentrations and the joint federal/state plan which is just getting underway.
- b. Hydrologic problems.
- c. Potential air quality problems.
- d. Reservations concerning availability of present technology for full recovery of saline minerals.

In addition, these tracts were not given high priorities because the techniques proposed do not lend themselves to the extraction of saline minerals, nahcolite and decahydrate. However, the development of a technique or method that will recover the saline minerals and shale oil simultaneously should be encouraged.

7. The existence on Tract 7 and part of Tract 8 of unpatented pre-1920 mining claims was noted. It was assumed the claims were located for oil shale or other hydrocarbons. Because of the period of time since the claims were located, during which time no mineral development has taken place on the claims, their existence was not considered to be a determining factor in deciding which tracts should be selected. If Tract 7 is ultimately selected, the pre-1920 mining claims will have to be cleared through appropriate administrative proceedings by the Bureau of Land Management. In this connection, it is the Department's position, in view of the decision issued in U. S. v. Frank W. Wingard, et al., IBLA 70-549, decided June 28, 1974, that there are no valid pre-1920 oil shale claims on federal lands.

It was noted that Tract 3 is covered by an existing sodium lease. This lease would effectively prevent a prototype in situ oil shale lessee from producing sodium minerals. Such minerals would be available to lessees of other tracts. Tract 1 is covered by a sodium preference right lease application. The issuance of a preference right lease for this land would effectively prevent the recovery of sodium by a prototype in situ oil shale lessee.

The existence of the lease, and perhaps the lease application, would discourage, if not eliminate, potential bidders for Tracts 1 and 3 except the lessee and lease applicant. All of the nominated tracts are covered by oil and gas leases. The existence of these oil and gas leases was not considered to be a significant factor in determining which of the nominated tracts should be selected. It should also be noted that some of the nominated tracts cover two noncontiguous sites. However, The Mineral Leasing Act of 1920 (30 U.S.C. 241) does not contain a requirement that tracts included in one lease be contiguous.

8. Tracts 1 and 3 were eliminated, not only on the basis of their adverse environmental impact, but also on their low competitiveness due to a conflicting sodium lease on Tract 3 and a sodium lease application for Tract 1.

9. Tract 7 in Utah was considered unacceptable by some members due to socio-economic impacts that would likely occur to Rangely, Colorado. Utah would get the monies from bonuses and royalties, and Colorado would get the people. Off-lease housing and services should be given consideration. Consideration should be given to future federal laws providing for land distribution to towns and other entities that are under energy development pressure. Similarly, consideration should be given to the setting aside of federal funds to aid communities in the areas affected by any future lease sites, for the development of those communities. On any of the sites considered for lease, some accommodation needs to be made regarding revenues, i.e., royalties, bonuses, property taxes, etc., and distribution of these revenues to the impacted areas irrespective of state lines. If any tract is leased, the successful bidder should be required to submit a more complete initial plan, including off-site impacts, than the plan required for the tracts previously leased.

10. Some members expressed concern over the recommendation of Tract 8 because of the depth of the oil shale below the surface. This depth is approximately twice that of other tracts nominated and, accordingly, would require considerably more development capital and incur higher operational expense. This factor may limit its attractiveness to some bidders.

11. In view of the fact that Utah declined to send a representative to serve on the committee on August 25, 1975, the recommendations may not be entirely in harmony with their views. Since there was no designated representative from Utah, this report was not sent for their review before its submission to the Assistant Secretary.

12. The modified in situ method, if used, may involve limited above-ground retorting of that portion of the oil shale mined along development headings and beneath areas to be rubbleized. This retorting could take place either on site or in retorts on presently existing prototype leases. If this results, potential impacts on air quality may deserve additional weighting, even though compliance with State air quality standards would be required.

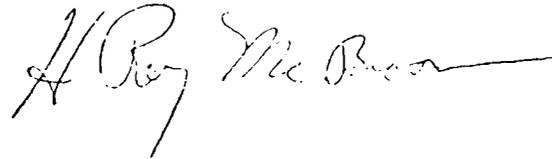
13. The committee recognized there was a basic development bias in the nine nominated tracts. This was considered normal since they were nominated by industry, which would expect to develop them for commercial purposes.

14. Some committee members felt that the charge to recommend two primary sites plus two alternate sites was based on an assumption, not necessarily true, that there are four fully acceptable sites. These members felt that there were only three acceptable sites, namely Tracts 2, 8 and 9.

15. The committee assumes that the spirit, intent, and procedures required by NEPA will be followed.

16. One member felt that the economic relationship and scientific values of the migrating Piceance Creek Basin deer herd should not be further degraded, and that these values in Piceance Creek override consideration of the fragile environment of the arid tracts in Utah. This was considered in not recommending tracts in the center of Piceance Creek Basin.

Attachments
Appendices 1 - 8



TRACTS NOMINATED FOR IN SITU LEASING

COLORADO

(Separate tracts are divided by double underscoring)

<u>Township, Range & Section</u>	<u>Subdivision Description</u>	<u>Acres</u>
<u>All 6th Principal Meridian</u>		
T. 1 S., R. 97 W., Sec. 15.....	NW1/4, E1/2NW1/4, SW1/4SW1/4, E1/2SE1/4.....	240.00
16.....	All	640.00
17.....	All	640.00
18.....	E1/2, E1/4S, Lots 1, 2, 3, 4 (all)...	641.69
21.....	NW1/4, NE1/4NE1/4, NE1/4SW1/4.....	240.00
<u>TRACT 1</u>		<u>Total.....</u>
19.....	Lots 1, 2, 3, 4, E1/2E1/2, E1/2.....	640.95
20.....	All.....	640.00
21.....	S1/2SW1/4, E1/2SE1/4.....	160.00
22.....	Lots 1, 2, 3, 4, 5, 6, 7, 8, 9, 10, 11, 12, 13, 14 (Lots 1 thru 14)....	591.93
28.....	W1/2NW1/4, SW1/4NE1/4, E1/2NE1/4.....	200.00
29.....	N1/2.....	329.00
		<u>Total.....</u>
		2,662.98
		4,954.43
<hr/>		
T. 3 S., R. 97 W., Sec. 27.....	NW1/4, N1/2SW1/4, SW1/4SW1/4.....	280.00
28.....	All	640.00
29.....	All	640.00
30.....	S1/2SE1/4, NE1/2SE1/4.....	120.00
31.....	E1/2, E1/2SW1/4, SE1/4NW1/4.....	440.00
<u>TRACT 2</u>		<u>Total.....</u>
32.....	All	640.00
33.....	All	640.00
34.....	NW1/4SW1/4.....	40.00
T. 4 S., R. 97 W., Sec. 4.....	W1/2, NW1/2NE1/4.....	294.18
5.....	All	639.90
6.....	All	604.23
7.....	NW1/4NE1/4 (Lot 1).....	40.06
		<u>Total.....</u>
		5,053.37

INTERIOR'S RECOMMENDATIONS REGARDING IN SITU OIL SHALE TRACT NOMINATIONS

Township, Range & Section	Subdivision Description	Acreage
<u>All 6th Principal Meridian</u>		
T. 1 S., R. 98 W., Sec. 19	SE $\frac{1}{2}$ NE $\frac{1}{4}$, E $\frac{1}{2}$ SE $\frac{1}{4}$	120.00
20	W $\frac{1}{2}$, W $\frac{1}{2}$ E $\frac{1}{2}$, SE $\frac{1}{4}$ NE $\frac{1}{4}$	520.00
21	SW $\frac{1}{4}$ NE $\frac{1}{4}$	40.00
29	NW $\frac{1}{4}$	160.00
TRACT 3	30.....Lots 1, 2, 4, NE $\frac{1}{4}$, E $\frac{1}{2}$ NW $\frac{1}{4}$, SE $\frac{1}{4}$ SW $\frac{1}{4}$, S $\frac{1}{2}$ SE $\frac{1}{4}$	463.89
Total		1,303.89

T. 2 S., R. 98 W., Sec. 15	Lots 1 thru 8, S $\frac{1}{2}$	659.25
16	S $\frac{1}{2}$, S $\frac{1}{2}$ N $\frac{1}{2}$, NE $\frac{1}{4}$ NE $\frac{1}{4}$, NE $\frac{1}{4}$ NW $\frac{1}{4}$	600.00
20	N $\frac{1}{2}$, Lots 1 thru 8	620.66
21	All	640.00
22	All	640.00
27	NW $\frac{1}{4}$	160.00
28	N $\frac{1}{2}$ S $\frac{1}{2}$, S $\frac{1}{2}$ SW $\frac{1}{4}$, SW $\frac{1}{4}$ SE $\frac{1}{4}$, Lots 1 thru 8	580.87
29	Lots 1 thru 16..(All)	598.72
30	E $\frac{1}{2}$, E $\frac{1}{2}$ N $\frac{1}{2}$, Lots 2, 3, 4	598.83
Total		5,098.33

T. 1 S., R. 98 W., Sec. 34	S $\frac{1}{2}$, NE $\frac{1}{4}$	480.00
35	All	640.00
36	All	640.00
T. 2 S., R. 98 W., Sec. 1	Lots 5 thru 20 (all)	522.89
2	Lots 5 thru 20 (all)	578.72
3	Lots 2 thru 7, 12, SW $\frac{1}{4}$ NE $\frac{1}{4}$, S $\frac{1}{2}$ NW $\frac{1}{4}$, N $\frac{1}{2}$ SW $\frac{1}{4}$	469.02
TRACT 5	9.....SE $\frac{1}{4}$ NE $\frac{1}{4}$	40.00
10	Lots 1 thru 8 (or N $\frac{1}{2}$)	301.41
11	N $\frac{1}{2}$, E $\frac{1}{2}$ SE $\frac{1}{4}$	400.00
12	Lots 1 thru 10, NE $\frac{1}{4}$ NW $\frac{1}{4}$, S $\frac{1}{2}$ NW $\frac{1}{4}$, SW $\frac{1}{4}$, NW $\frac{1}{4}$ SE $\frac{1}{4}$ (or All)	534.26
T. 2 S., R. 97 W., Sec. 6	W $\frac{1}{2}$ Lot 3, Lots 4 thru 7, W $\frac{1}{2}$, SE $\frac{1}{4}$ NW $\frac{1}{4}$, W $\frac{1}{2}$ N $\frac{1}{2}$ SW $\frac{1}{4}$	242.77
7	Lots 1 thru 4, NE $\frac{1}{4}$ NW $\frac{1}{4}$, W $\frac{1}{2}$ SE $\frac{1}{4}$ NW $\frac{1}{4}$, W $\frac{1}{2}$ SE $\frac{1}{4}$ SW $\frac{1}{4}$	262.40
Total		5,111.31

Township, Range & Section	Subdivision Description	Acreage
<u>All 6th Principal Meridian</u>		
T. 2 S., R. 98 W., Sec. 9	S $\frac{1}{2}$ SE $\frac{1}{4}$	80.00
10	S $\frac{1}{2}$ S $\frac{1}{2}$	160.00
11	S $\frac{1}{2}$ SW $\frac{1}{4}$, SW $\frac{1}{4}$ SE $\frac{1}{4}$	120.00
13	Lots 1 thru 12, SW $\frac{1}{4}$ (or all)	604.12
14	Lots 1 thru 8, S $\frac{1}{2}$ (or all)	657.48
15	Lots 1 thru 8, S $\frac{1}{2}$ (or all)	659.22
TRACT 6	16.....NE $\frac{1}{4}$, E $\frac{1}{2}$ NW $\frac{1}{4}$, SW $\frac{1}{4}$ NW $\frac{1}{4}$, S $\frac{1}{2}$	600.00
21	All	640.00
22	All	640.00
23	N $\frac{1}{2}$, N $\frac{1}{2}$ S $\frac{1}{2}$	480.00
24	N $\frac{1}{2}$, N $\frac{1}{2}$ S $\frac{1}{2}$	480.00
Total		5,120.82

UTAH

All Salt Lake Meridian

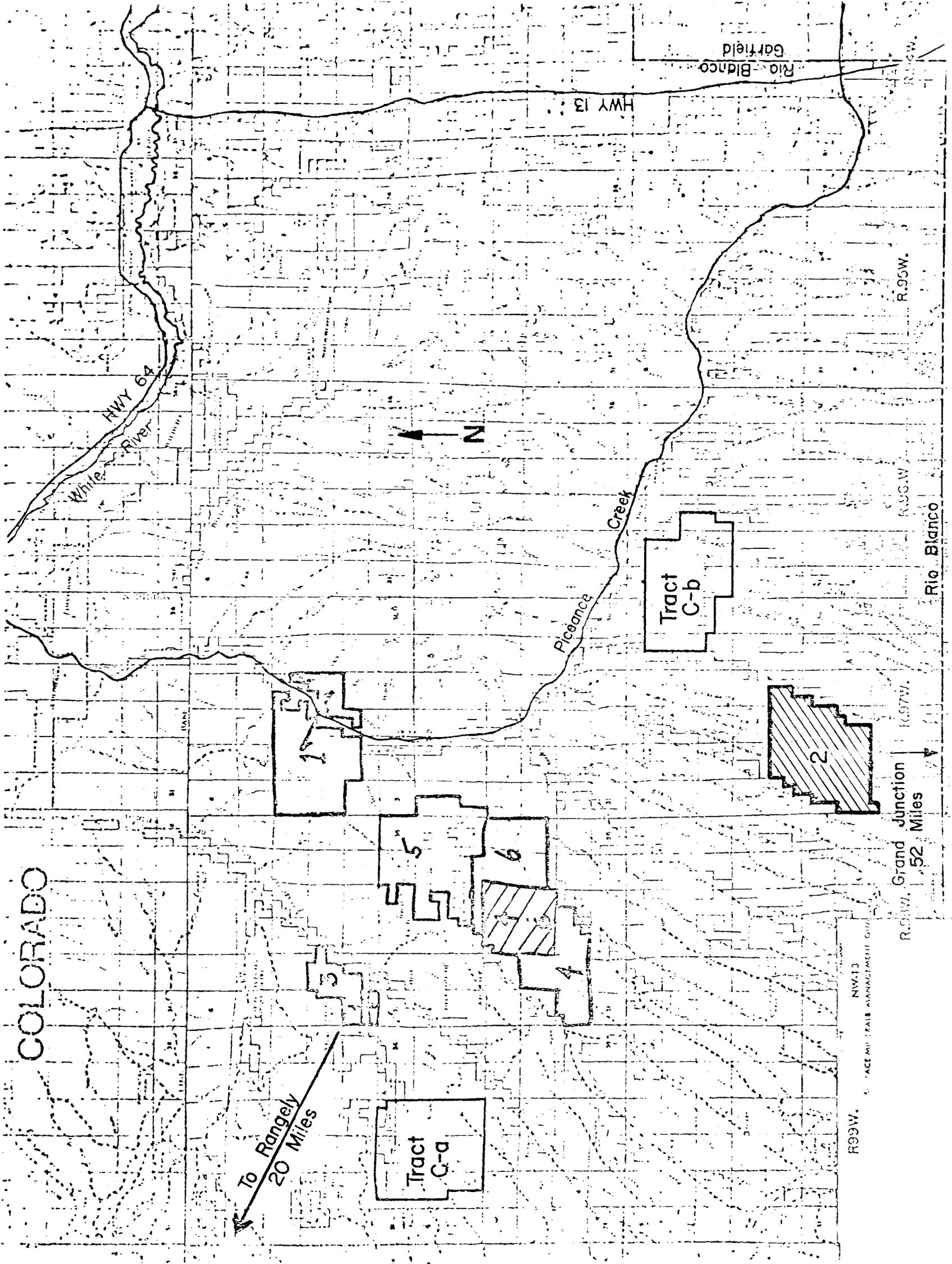
T. 9 S., R. 24 E., Sec. 1	All	
T. 9 S., R. 25 E., Secs. 3 thru 9	All	4,912.13 acres

TRACT 7

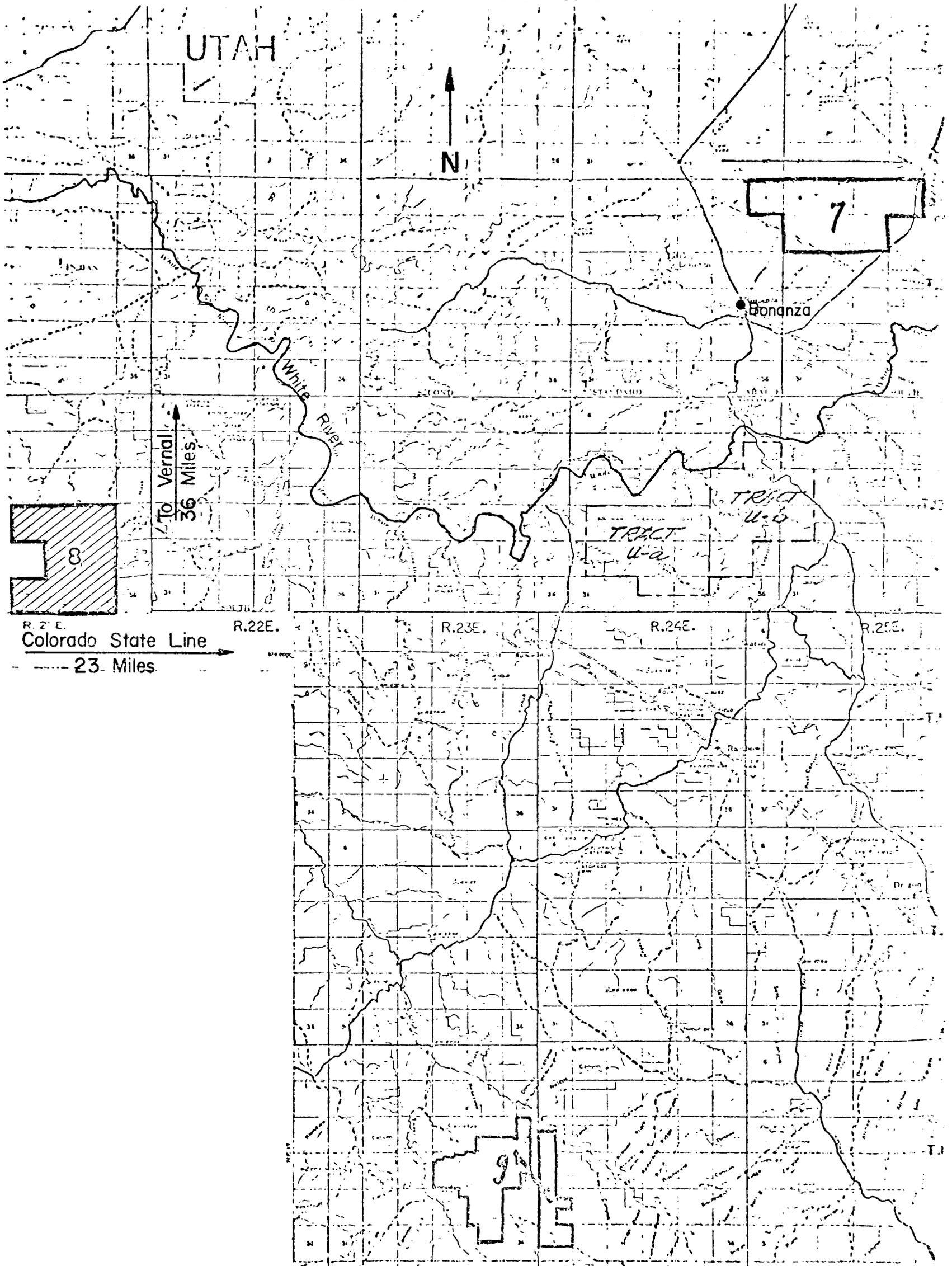
T. 10 S., R. 21 E., Secs. 21, 22, 23, 26, 27, 33, 34, 35	All	TRACT 8 ...5,120.00 acres
----------------------------------------------------------	-----	-------------------------------------

T. 13 S., R. 23 E., Sec. 13	W $\frac{1}{2}$ E $\frac{1}{2}$, E $\frac{1}{2}$ E $\frac{1}{2}$ NW $\frac{1}{4}$, SW $\frac{1}{4}$	TRACT 9
14	SE $\frac{1}{4}$, E $\frac{1}{2}$ SW $\frac{1}{4}$, E $\frac{1}{2}$ E $\frac{1}{2}$ SW $\frac{1}{4}$	
22	S $\frac{1}{2}$, S $\frac{1}{2}$ N $\frac{1}{2}$, S $\frac{1}{2}$ SE $\frac{1}{4}$ NW $\frac{1}{4}$, SE $\frac{1}{4}$ NE $\frac{1}{4}$ NW $\frac{1}{4}$, S $\frac{1}{2}$ SW $\frac{1}{4}$ NE $\frac{1}{4}$ NW $\frac{1}{4}$, NE $\frac{1}{4}$ SW $\frac{1}{4}$ NE $\frac{1}{4}$ NW $\frac{1}{4}$, S $\frac{1}{2}$ N $\frac{1}{2}$ NE $\frac{1}{4}$ NW $\frac{1}{4}$, S $\frac{1}{2}$ N $\frac{1}{2}$ NE $\frac{1}{4}$ NW $\frac{1}{4}$, NE $\frac{1}{4}$ NE $\frac{1}{4}$ NE $\frac{1}{4}$ NW $\frac{1}{4}$, S $\frac{1}{2}$ NE $\frac{1}{4}$ NE $\frac{1}{4}$ NW $\frac{1}{4}$	
23	All	
24	W $\frac{1}{2}$, W $\frac{1}{2}$ NE $\frac{1}{4}$	
26	All	
27	NE $\frac{1}{4}$ NE $\frac{1}{4}$	
35	NE $\frac{1}{4}$, E $\frac{1}{2}$ NW $\frac{1}{4}$	
T. 13 S., R. 24 E., Sec. 18	SW $\frac{1}{4}$, S $\frac{1}{2}$ S $\frac{1}{2}$ NW $\frac{1}{4}$	
19	W $\frac{1}{2}$	
30	W $\frac{1}{2}$, S $\frac{1}{2}$ NE $\frac{1}{4}$	
31	N $\frac{1}{2}$, N $\frac{1}{2}$ S $\frac{1}{2}$	4,429.44 acres

INTERIOR'S RECOMMENDATIONS REGARDING IN SITU
OIL SHALE TRACT NOMINATIONS



INTERIOR'S RECOMMENDATIONS REGARDING IN SITU
OIL SHALE TRACT NOMINATIONS



INTERIOR'S RECOMMENDATIONS REGARDING IN SITU OIL SHALE TRACT NOMINATIONS

APPENDIX 7

RATING WORKSHEET FOR NOMINATED IN SITU OIL SHALE TRACTS

DEVELOPMENT POTENTIAL									
A. Available Oil Shale Resource									
1. Physical									
2. Economic									
B. Other Mineral/Fuel Resource (s)									
C. Competitiveness									
D. Potential Technologic Gains									
E. Accessibility									
F. Appropriateness of Proposed Development Scheme									
G. Responsiveness to National Program Goals									
1. Determine technical & economic feasibility									
2. Determine environmental costs/effects									
3. Determine best fracturing/rubblizing techniques									
4. Determine optimum operating conditions									
5. Determine demands on other resources									
6. Determine recovery efficiencies									
H. Conflicting legal issues									
1. Other leasing actions									
2. Mineral claims									
3. Surface/mineral estate ownership									
I. Physical Factors									
1. Location									
a. Relationship to cultural development									
b. Relationship to other mineral/fuels development									
c. Relationship to other economic development/land use									

2. Geology									
a. Land form									
b. Major geologic structure									
c. Geologic hazards									
II. ENVIRONMENTAL CONSIDERATIONS									
A. Socio-Economic Factors									
1. Existing land use									
2. Relation of land use to infrastructure									
3. Value of land use									
4. Existing trends in economic development									
5. Relationship to existing communities									
6. Relationship to existing roads									
7. Potential impacts on social structure									
a. Population									
b. Living space/quality									
c. Life style									
d. Negative impacts									
e. Beneficial impacts									
8. Potential impacts on economic structure									
a. Employment									
b. Income levels									
c. Available services									
d. Negative impacts									
e. Beneficial impacts									
9. Land area needs									
a. Service and access corridors									
b. Impoundments									
c. Support facilities									

INTERIOR'S RECOMMENDATIONS REGARDING IN SITU OIL SHALE TRACT NOMINATIONS

B. ENVIRONMENTAL FACTORS																			
1. Hydrology																			
a. Surface																			
(i) Availability/Quantity																			
(ii) Water Quality																			
(iii) Current water resource commitments																			
(iv) Potential development impacts																			
(v) Potential development benefits																			
b. Subsurface																			
(i) Major ground water systems																			
(ii) Availability/Quantity																			
(iii) Water quality																			
(iv) Current water resource commitments																			
(v) Potential development impacts																			
(vi) Potential development benefits																			
c. Hydrologic Hazards																			
2. Meteorology																			
a. Air quality																			
b. Potential development impacts																			
c. Potential development benefits																			
3. Soils																			
a. Current productivity																			
b. Erodability/Stability																			
c. Potential development impacts																			
d. Potential development benefits																			
4. Flora																			
a. Major plant communities																			
b. Economic value or use																			
c. Potential development impacts																			
d. Potential development benefits																			
5. Fauna																			
a. Wildlife																			
b. Migratory patterns																			
c. Domestic																			
d. Economic value or use																			
e. Potential development impacts																			
f. Potential development benefits																			
6. Aquatic																			
a. Fisheries																			
b. Economic value or use																			
c. Potential development impacts																			
d. Potential development benefits																			
7. Cultural																			
a. Recreation value																			
b. Cultural/Archeological value																			
c. Potential development impacts																			
d. Potential development benefits																			
8. Aesthetic value																			
a. Potential development impacts																			
b. Potential development benefits																			
9. Availability of suitable siting																			
a. Waste disposal areas																			
b. Plant, stockpile & product storage areas																			
c. Impoundment and reservoir areas																			
10. Reclamation potential																			
a. Lasting development impacts																			
b. Lasting development benefits																			
11. Potential irretrievable commitments																			
a. Land area																			
b. Resource (s)																			
c. Water																			
d. Other(s)																			
12. Potential long-term impacts																			
a. Subsidence																			
b. Modification of surface and subsurface drainage																			
c. Water quality																			
d. Other(s)																			
III. OVERALL RATINGS																			
A. Development Potential																			
B. Environmental Considerations																			
C. Socio-economics																			
D. Reclaimability																			
E. Mitigating Factors																			



United States Department of the Interior

BUREAU OF LAND MANAGEMENT
WASHINGTON, D.C. 20240

APPENDIX 8
IN REPLY REFER TO
3500 (721)

AUG 26 1975

Memorandum

To: AD, Mineral Management *FAE*

From: Mineral Leasing Specialist

Through: Chief, Division of Minerals Resources *U/M 8/24/75*

Subject: Abstract of Extraction Methods Proposed by the Nominees
for Oil Shale Leasing Sites in Colorado and Utah

Six companies have submitted nominations for oil shale leasing tracts. Each company included within its nomination a description of their intended method of extraction. Without naming the companies, the following is a resume of these methods.

Company number one's process consists of injecting a heated fluid into the "leached" or "permeable" zone at a temperature sufficient to retort the oil shale in place thus converting the kerogen present in the oil shale to oil which can be produced along with the cooled heating fluid. This company has field tested the use of natural gas and steam as heat carrying fluids, and two different well configurations have been used. The process proposed by this company believes they can utilize equipment already in common use in the petroleum industry.

The second company's method of extraction is experimental. The experiment being designed will include three 50' x 50' x 100' vertical chimneys to investigate rock breakage techniques and acceptable void fractions. In addition, three 50' x 50' x 300' vertical chimneys are being designed which will be amenable to retorting; two by the combustion method (one lean shale, and one rich and lean shale), and one with a hot gas sweep (rich and lean shale). The knowledge gained from this experiment, if carried out, would be utilized in establishing the specifications for chimneys that might be economically retorted on the lands being recommended for nomination.

It is anticipated that commercial chimneys would be formed using overcuts, undercuts, and vertical slots mined out from two or more mining levels within the deposit. The retorting method would be determined from the results of the experiment. It is expected that this method would involve a vertical burn commencing at the top of the chimney with the retorted oil and combustion gases being collected from galleries at the base of the chimney.

Total thickness of the section to be retorted could exceed that of the 15 gpt interval depending upon the measure of success achieved in retorting the leaner intervals of the section chosen for retorting in the current experiment design. Additional experimentation would be required, however, to determine the minimum acceptable thickness of pillars separating chimneys. Determination of these two parameters along with a minimum acceptable void fraction and optimum burn rate of the chimneys should enable the maximum utilization of the resource.

Probable Proportion of the Resource to the
Removed by Mining and Its Disposition

Insignificant amounts of the resource would be removed as a result of sinking shafts or incline drifts and drilling of holes for exhausting combustion gases. Material removed in these operations would be disposed of along with the material removed to provide void space for efficient rubbleization of the chimneys.

Currently, it is anticipated that the resource may be effectively exploited by removal of 20% of the material within or underlying the interval to be retorted. However, it is anticipated that experiments would be carried out to determine if this percentage can be further reduced.

If the experiment currently being designed demonstrates that the rich material (30+ gpt) can be effectively retorted, then the barren material below the interval to be exploited would be removed as well as the leanest interval(s) practicable higher in the interval so as to minimize the amount of rich material not retorted. On the other hand, should the rich material not be amenable to in situ retorting, the rich material would be excavated for retorting in a surface retort constructed on the nominated tracts or else in a facility of another operator in the Uintah Basin. The vertical slots mined out for lateral expansion of the rock during blasting would necessarily include substantial quantities of rich material. This rich material would be isolated from the lean material and stockpiled for later use in a surface retort.

The lean material to be excavated would be used to fill in depressions in the landscape and would be contoured to provide an esthetically pleasing landscape. If the rich material were to be retorted on the nominated tracts, the disposal area for the spent shale would be selected so that the sparse precipitation that does occur in the area would not run through spent shale and then into surface drainage channels which would lead to any potable water supplies. The spent shale would be covered by the lean unretorted shale in a sequence which would allow for a minimum utilization of water to control dust.

INTERIOR'S RECOMMENDATIONS REGARDING IN SITU
OIL SHALE TRACT NOMINATIONS



Nominator number three describes a modified in-situ oil shale extraction process. This process is best illustrated by Figure 3 and 4 attached herein. The process is started with hot flue gas from a burner heating the top shale layer to decompose it into shale oil, a small amount of gas, and some residual carbon which is left in the shale. Once the top several feet have been retorted, the fuel to the burner is discontinued and gas flow and oxygen concentration through the chimney are maintained at the design conditions. The oxygen in the gas burns the residual carbon, the combustible components of the recycle gas, and a small amount of the shale oil produced. The heat from these reactions heats the shale below to form more oil, gas, and carbon, and the process becomes self-sustaining. About 70% recovery of the oil in the rock is expected.

The proposed method of operation of the Colorado site by the fourth company would require the use of underground mine workings to provide access to the oil shale. An oil shale section of 300 to 700 feet thick, and with an average grade of 20 gallons per ton would be treated. The oil shale bed would be shattered and rendered permeable by means of chemical explosives emplaced in holes drilled from the underground workings. The bulking of the rock that accompanies the breaking induced by the explosives will be accommodated by mining out a volume of rock equal to 5% to 20% of the oil shale to be treated. This mined rock may be either low grade oil shale, or barren rock, which would not be retorted, or high grade shale which would be treated in a surface retort.

The initial experiments will include a series of underground retorts to test both the vertical and the horizontal movements of the retorting front. The method that demonstrates the most advantages will be selected for the development phase of the operation.

The fourth company proposes an alternative development method to be used on the Utah parcels. These parcels would be developed by a "true" in situ method. This method would require no underground mine workings to provide access to the oil shale, and no oil shale would be mined and brought to the surface. The oil shale would be fractured and retorted in situ. The operation would be conducted in the following manner:

- A. Blast holes would be drilled down from the surface through the overburden and on through the oil shale.
- B. The blast holes would be spaced, loaded, and fired in such a manner that fragmentation would be maximized in the oil shale and be minimized in the overburden.
- C. Any fractures created by blasting, connecting the retort to the surface of the ground, would be sealed.
- D. After the shale in a retort is broken by blasting and the surface sealed, it would be processed by means of a horizontally moving fire front. Large diameter drill holes would be used for air input and output. Air blowers and mist extractors would be located directly adjacent to the operating retorts.

- E. Part of the oil would be produced as a mist with the retort off gases and part would be recovered as a liquid from producing wells located at the downstream end of the retort.
- F. The product would be crude shale oil that would initially be trucked out but later would be pumped via pipeline to an off-site plant for further treatment, or directly to a crude oil pipeline, depending upon its characteristics.

The fifth company proposes to use the patented "Shell process" for extraction of a combination of minerals including shale oil.

The Shell patent, #3,779,602, describes a process to solution mine nahcolite by injecting superheated water to 400°F under high pressure (1000 psi) into the nahcolite bearing oil shale. The water readily dissolves the nahcolite and results in a highly concentrated solution of 60% NaHCO₃.

Figure 1 shows the patent abstract. This data can be used by knowledgeable solution mining experts to compute costs of product. Soda ash sells for \$42/ton FOB mine. A solution mining plant for nahcolite derived soda ash can be a very profitable venture whether or not retorting of oil follows the solution mining, since it replaces the conventional capital investment for mines with smaller investments for injection and withdrawal wells.

Once permeabilized, oil shale can be retorted in situ by a variety of methods not dissimilar to surface retorting methods.

(NOTE: Shell has reported this system as not economically feasible.)

The final nominator proposes to use this identical method just described as the "Shell process."

David M. Carty

Enclosures

A B I L L

To amend section 21 of the Mineral Leasing Act (41 Stat. 445), as amended (30 U.S.C. 241).

Be it enacted by the Senate and House of Representatives of the United States of America in Congress assembled, That a new subsection (d) is hereby added to section 21 of the Mineral Leasing Act (41 Stat. 445); as amended (30 U.S.C. § 241), reading as follows:

"(d) The Secretary of the Interior is hereby authorized to grant to any person, association, or corporation, holding a lease for oil shale under the provisions of subsection (a) of this section, additional leases for lands outside the oil shale lease lands for any purpose, other than the actual mining of oil shale, connected with operations pursuant to that oil shale lease except that no additional leases may be granted for lands excluded from disposition by the provisions of section 1 of this Act. Any lease issued under this subsection (d) shall be granted only in connection with a specific oil shale lease issued under subsection (a) and only to the same parties as those owning that specific oil shale lease; the total land which may be leased under this subsection (d) in connection with any one oil shale lease issued under subsection (a) shall not be more than 6,400 acres. Any lease under this subsection for any lands the surface of which is under the jurisdiction of a Federal agency other than the Department of the Interior shall be issued only with the consent of that other Federal agency and subject to such terms and conditions as that other Federal agency may prescribe. The additional land leased pursuant to this subsection may be used only for such purposes as the Secretary may prescribe in the lease which may include the disposal of oil shale waste and other materials removed from the lands leased under subsection (a), the building of plants, reduction works and other facilities connected with the operations under the oil shale lease, and any other purposes connected with lease operations (except mining) which the Secretary may deem advisable. No mining of any kind may be performed under leases issued pursuant to this subsection. The Secretary shall not

issue an additional lease (i) unless the oil shale lessee shall demonstrate to the Secretary's satisfaction that the additional land is needed for proper operations under the oil shale lease and that he will be able to conduct all operations on the land leased under this subsection in an environmentally proper manner and (ii) unless the Secretary shall determine that the issuance of the additional lease is in the public interest. Any lease issued under this subsection shall provide for the payment to the United States of an annual rental which shall reflect the fair market value of the rights granted and which shall be subject to such revision as may be needed from time to time to continue to reflect the fair market value. The leases issued under this subsection shall be for such periods of time as the Secretary may determine to be necessary for the purposes for which they are granted and shall contain such provisions as may be needed for proper environmental protection. Lands leased under this subsection shall remain subject to leasing under the other provisions of this Act where such leasing would not be incompatible with the lease issued under this subsection."

C A M E R O N E N G I N E E R S

C A M E R O N E N G I N E E R S

INTERIOR-SPONSORED BILL AUTHORIZING LEASING OF
OFF-TRACT OIL SHALE DISPOSAL LANDS

MEMORANDUM NO. 9

September 24, 1975

TO: Committee on Mineral Taxation
 FROM: Legislative Council Staff
 SUBJECT: Proposed Severance Tax Legislation

The attached bill was prepared at the request of, and under the direction of, Representative Smith. The bill, and an accompanying analysis, is distributed prior to the October 1 meeting in order that persons interested in this subject may review the proposal and comment at the meeting. It should be emphasized that the bill is a first draft and may need revision, including enforcement powers for the Department of Revenue.

The proposed bill would impose a five percent severance tax on the gross proceeds from metals, including oil shale, oil and gas, and coal. The definition of "gross proceeds" generally corresponds to the value of the mineral at the point of severance. The bill contains exemptions to limit or eliminate its impact on small producers. In addition, the present production tax on oil and gas and the coal inspection fee would be repealed.

The following is an analysis of the major provisions of the proposed bill. The revenue projections are preliminary and are based on estimated calendar 1975 gross proceeds of operators.

Metals (Including oil shale)

Base. Gross proceeds as defined for ad valorem tax purposes in section 39-6-106 (1), C.R.S. 1973. This is essentially the value of the mineral at the point of severance which is determined by subtracting from gross value "costs of treatment, reduction, transportation, and sale of such ore or any products derived therefrom".

Rate. Five percent of gross proceeds.

Exemptions. First \$10,000,000 of gross proceeds and, for oil shale, (Option 1) all persons operating at less than 60 percent of design capacity with a phase-in exemption thereafter of 25 percent of the tax in the first year, 50 percent

in the second, 75 percent in the third, and 100 percent in the fourth and succeeding years, or (Option 2) all persons producing less than 10,000 barrels per day with a phase-in exemption, in lieu of the \$10,000,000 exemption, of three-fourths of gross proceeds in the first year, one-half in the second, and one-fourth in the third.

Revenue Projection. (1975) \$4,250,000. Growth of revenue largely dependent on development of molybdenum and oil shale.

Oil and Gas

Base. Gross proceeds, meaning the entire amount realized from the sale or other disposition of all oil and gas produced or extracted from petroleum deposits. (This is the same definition as the current statute for the oil and gas production tax).

Rate. Five percent of gross proceeds.

Exemptions. All stripper wells producing less than 10 bbl/day average and all wells producing less than (Option 1) 60,000 or (Option 2) 300,000 cubic feet of gas per day average.

Revenue Projection. (1975) \$8,500,000 (\$3,000,000 in addition to existing production tax revenue). Growth of revenue largely dependent on price of oil and gas; substantial increase if price of oil decontrolled.

Coal

Base. Gross proceeds meaning the value at the point of severance which is determined by subtracting from the value at the first point of sale all costs of cleaning, sizing, washing, breaking, crushing, screening, drying, dust allaying, treatment to prevent freezing, oiling, loading for shipment, and shipment incurred after severance and before sale.

Rate. Five percent of gross proceeds.

Exemptions. First 5,000 tons of coal extracted each quarter and for coal produced from underground mines an amount equal to 20 percent of the tax liability.

Revenue Projection. (1975) \$2,500,000. Growth of revenue largely dependent on the development of the industry.

PROPOSED SEVERANCE TAX LEGISLATION MAY BECOME MODEL FOR SEVERAL STATES

MINERAL TAXATION COMMITTEE
1 October 1975
DISCUSSION DRAFT

A BILL FOR AN ACT

1 CONCERNING SEVERANCE TAXATION, AND PROVIDING FOR THE DISPOSITION
2 THEREOF UPON METALLIC MINERALS, OIL AND GAS, AND COAL.

Bill Summary

(NOTE: This summary applies to this bill as introduced and does not necessarily reflect any amendments which may be subsequently adopted.)

3 Be it enacted by the General Assembly of the State of Colorado:

4 SECTION 1. Title 39, Colorado Revised Statutes 1973, as
5 amended, is amended BY THE ADDITION OF A NEW ARTICLE to read:

6 ARTICLE 29

7 Severance Taxes

8 39-29-101. Definitions. As used in this article, unless
9 the context otherwise requires:

10 (1) "Gross proceeds" for metallic minerals means the gross
11 proceeds from production as filed with the county assessor
12 pursuant to section 39-6-106 (1).

13 (2) "Gross proceeds" for oil and gas means the entire
14 amount realized from the sale or other disposition of all oil and
15 gas produced or extracted during any taxable year from petroleum

1 deposits located within this state.

2 (3) "Gross proceeds" for coal means the value of the coal
3 immediately after extraction, which value is determined by
4 subtracting from the value of the coal at the first point of sale
5 all costs of cleaning, washing, breaking, crushing, screening,
6 sizing, drying, dust allaying, treatment to prevent freezing,
7 oiling, loading for shipment, and shipment incurred after
8 severance and before sale.

9 (4) "Metallic minerals" means all minerals, including oil
10 shale, subject to valuation for assessment for purposes of the
11 general property tax pursuant to section 39-6-104.

12 (5) "Oil and gas" means crude oil, natural gas, and oil and
13 gas.

14 (6) "Producer" means any person producing or extracting
15 metallic minerals, oil and gas, or coal within this state or
16 every first purchaser of such metallic minerals, oil and gas, or
17 coal.

18 39-29-102. Tax on severance of metallic minerals. (1) In
19 addition to any other tax, there shall be levied, collected, and
20 paid for each taxable year a tax upon the severance of all
21 metallic minerals in this state as to all such severance occurring
22 on and after July 1, 1976. Such tax shall be levied against
23 every person engaged in the severance of metallic minerals and
24 shall be based upon the entire amount of gross proceeds thereof.
25 Subject to the exemptions authorized in subsections [(2) and (3)]
26 [(2), (3), and (4)] of this section, the rate of such tax shall
27 be five percent of the gross proceeds.

PROPOSED SEVERANCE TAX LEGISLATION MAY BECOME
MODEL FOR SEVERAL STATES

1 plant first averages more than ten thousand barrels per calendar
 2 day during a taxable year:

<u>Year</u>	<u>Percentage of exemption</u>
4 First year	75 percent
5 Second year	50 percent
6 Third year	25 percent]

7 39-29-103. Tax on severance of oil and gas. (1) In
 8 addition to any other tax, there shall be levied, collected, and
 9 paid for each taxable year a tax upon the severance of all oil
 10 and gas in this state as to all such severance occurring on and
 11 after July 1, 1976. Such tax shall be levied against every
 12 person engaged in the severance of oil and gas and shall be based
 13 upon the entire amount of gross proceeds thereof. Subject to the
 14 exemption and credit authorized in subsections (2) and (3) of
 15 this section, the rate of such tax shall be five percent of the
 16 gross proceeds.

17 (2) There shall be allowed, as an exemption from the tax
 18 imposed by this subsection (1) of this section, the gross
 19 proceeds from any well producing less than ten barrels per day
 20 average of all producing days during the taxable year and less
 21 than [sixty thousand] [three hundred thousand] cubic feet of gas
 22 per day average of all producing days during the taxable year.

23 (3) There shall be allowed, as a credit against the tax
 24 imposed by subsection (1) of this section, the lesser amount of
 25 fifty percent of the severance tax liability or the equivalent of
 26 fifty percent of all ad valorem taxes levied, assessed, and paid
 27 during the taxable year upon oil and gas leaseholds, leasehold

1 (2) There shall be allowed, as an exemption from the tax
 2 imposed by subsection (1) of this section, the first ten million
 3 dollars of gross proceeds for each year.

4 OPTION 1:

5 [(3) Oil shale shall be subject to the tax imposed in
 6 subsection (1) of this section for the years following the
 7 twelve-month period in which it reaches a daily average of sixty
 8 percent of its design capacity in accordance with the following
 9 schedule:

<u>Year</u>	<u>Percentage of tax imposed by</u> <u>subsection (1)</u>
12 First year	25 percent
13 Second year	50 percent
14 Third year	75 percent
15 Fourth and each 16 succeeding year	100 percent]

17 OPTION 2:

18 [(3) There shall be allowed, as an exemption from the tax
 19 imposed by subsection (1) of this section, and in lieu of the
 20 exemption authorized by subsection (2) of this section, the
 21 entire gross proceeds from shale oil produced from a plant which
 22 produces an average of less than ten thousand barrels per
 23 calendar day during the taxable year.

24 (4) There shall be allowed, as an exemption from the tax
 25 imposed by subsection (1) of this section, and in lieu of the
 26 exemption authorized by subsection (2) of this section, the
 27 following percentages of gross proceeds after shale oil from a

1 interests, royalties, and royalty interests for state, county,
2 municipal, school district, and special district purposes
3 pursuant to section 39-7-102. Receipts evidencing payment during
4 the taxable year of such ad valorem taxes to the county
5 treasurers of the several counties of this state shall be prima
6 facie evidence for the allowance of such credit; except that the
7 executive director of the department of revenue may require such
8 additional evidence as he deems necessary.

9 39-29-104. Tax on the severance of coal. (1) In addition
10 to any other tax, there shall be levied, collected, and paid for
11 each taxable year a tax upon the severance of all coal in this
12 state as to all such severance occurring on and after July 1,
13 1976. Such tax shall be levied against every person engaged in
14 the severance of coal and shall be based upon the entire amount
15 of gross proceeds thereof. Subject to the exemption and credit
16 authorized in subsections (2) and (3) of this section, the rate
17 of the tax shall be five percent of such gross proceeds.

18 (2) There shall be allowed, as an exemption from the tax
19 imposed by subsection (1) of this section, the first five
20 thousand tons of coal severed each quarter by each producer.

21 (3) There shall be allowed, as a credit against the tax
22 imposed by subsection (1) of this section, an amount equal to
23 twenty percent of such tax for coal produced from underground
24 mines.

25 39-29-105. Withholding of royalty payments. (1) (a) On
26 and after July 1, 1976, every producer shall withhold from every
27 royalty payment made to any person claiming or having an interest

1 in any oil and gas except from royalty payments made to the
2 United States or the state of Colorado, an amount equal to three
3 percent of such royalty payment, and shall pay to the department
4 of revenue, on or before January 15, April 15, July 15, and
5 October 15 of each year, the aggregate of all such withholdings
6 made during the three preceding months, and shall file, no later
7 than such dates, reports covering such withholdings upon forms to
8 be prescribed by the executive director of the department of
9 revenue. Nothing in this section shall be so construed as to
10 reduce the tax imposed by this article.

11 (b) Every person making a return as required by section
12 39-29-106 may take credit for the amount withheld by the producer
13 or the first purchaser against the tax shown to be due upon such
14 return, and any overpayment shown on such return shall be
15 refunded to the taxpayer.

16 39-29-106. Procedures and reports. (1) Every person
17 subject to taxation under the provisions of this article shall
18 make an annual return to the department of revenue, separate and
19 apart from other returns required to be made under the provisions
20 of articles 20 to 28 of this title, upon a form to be prescribed
21 by the executive director of the department of revenue. The
22 return shall be filed with the department on or before the
23 fifteenth day of the fourth month following the end of the
24 taxable year and shall make payment of the tax shown to be due at
25 the time such return is filed.

26 (2) Every corporation subject to taxation under the
27 provisions of this article shall make a declaration of estimated

PROPOSED SEVERANCE TAX LEGISLATION MAY BECOME
MODEL FOR SEVERAL STATES

1 tax if the tax imposed by this article for the taxable year can
 2 reasonably be expected to exceed one thousand dollars. Such
 3 declaration shall be made to the department of revenue, separate
 4 and apart from other returns required under the provisions of
 5 articles 20 to 28 of this title, upon a form prescribed by the
 6 executive director of the department of revenue, which
 7 declaration shall be filed with the department in accordance with
 8 and pursuant to the provisions of 39-22-606.

9 (3) There is hereby created in the office of the state
 10 treasurer the metallic minerals, oil and gas, and coal severance
 11 tax withholding fund, and all unexpended balances in said fund
 12 established to carry out the purposes of this article as of June
 13 30, 1977, and on each June 30 thereafter or at any time
 14 determined by the controller, with the approval of the state
 15 treasurer, shall be credited to the general fund of the state.
 16 Such unexpended balances shall include all moneys which for any
 17 reason cannot be refunded. All warrants covering refunds from
 18 said severance tax withholding fund which cannot for any reason
 19 be delivered to the taxpayer to whom due and which are not
 20 presented for payment within six months after the date of
 21 issuance thereof shall be void, and the moneys represented
 22 thereby shall be included in the unexpended balance in said fund
 23 at the expiration of any fiscal year. Persons entitled to
 24 refunds of moneys represented by warrants which cannot be
 25 delivered to the taxpayer and which are not presented for payment
 26 within six months after the date of issuance thereof may file
 27 claims for refund at any time within four years after the date

1 the income tax return which establishes the right to the refund
 2 was required to be filed. Claims for refund not filed within the
 3 prescribed four-year period shall not be allowed or paid.

4 (4) The tax imposed by this article is declared to be a
 5 special classified and limited tax in accordance with the
 6 provisions of section 17 of article X of the state constitution.

7 SECTION 2. Repeal. 39-22-505 and 34-23-101 (1) (f),
 8 Colorado Revised Statutes 1973 are repealed.

9 SECTION 3. Effective date. This act shall take effect July
 10 1, 1976.

11 SECTION 2. Safety clause. The general assembly hereby
 12 finds, determines, and declares that this act is necessary for
 13 the immediate preservation of the public peace, health, and
 14 safety.

