synthetic fuels

quarterly report

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CAMERON ENGINEERS, INC.
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OIL SHALE  ○  COAL  ○  OIL SANDS

VOLUME 11 – NUMBER 2  JUNE, 1975

quarterly report

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Congress and the Ford Administration Now Appear to Agree That a Synthetic Fuels Industry Based on Coal and Oil Shale is a Necessity and the Sooner We get Started the Better

Opinions differ, however, on how we achieve President Ford's goal of 1 MMBPD of coal and oil shale synthetics by 1985. There is a growing sentiment in Congress toward complete government ownership of synthetic fuels plants with industry participating primarily as operators. The administration, on the other hand, prefers industry to play a major role in financing, building, and operating the plants. As a national energy policy begins to unfold, this is one of the more controversial issues, i.e., government or industry ownership of plants?

An Intensive Effort to Design a One MMBPD Synthetic Fuels Program that Will Win Congressional and Industry Approval is Nearing Final Review within the Ford Administration

Coordinated by OMB, nine task forces plus special analysis teams have been working on the program since January when President Ford first announced the National Synthetic Fuels Commercialization Program. Among the participants are ERDA, Interior, FEA and the State Department. Details are expected later this summer.

The Administration views government's role as assisting the birth of a new industry which would ultimately be owned and operated by private enterprise. But if the program resulting from the current effort is unacceptable to private industry, government ownership and operations of a synfuels industry may be the alternative.

Assuming the ultimate program wins the approval of both Congress and industry, a question still remaining is "who in government will administer the program?" Right now, Interior, ERDA and FEA appear to still be in the running. See page l-3l for more information and analysis.

Provision of Adequate Financial Incentives Appears to be Key To Successful Program

FEA has the task of developing various incentive plans to spur synfuels development and they are now in the third and final phase of a study that began nearly one year ago. Reports from the first two phases of the study include information on policies and financial factors that either constrain or stimulate oil shale and coal conversion development. The third phase will result in 7 or 8 recommended incentive plans, based on detailed interviews with industry representatives. More details are presented on page l-ll.
TOSCO Responds To FEA By Postulating Conditions for Reviving Dow West Oil Shale Project

TOSCO's proposal describes three basic alternatives including government participation through guaranteed loans and purchase contracts that yield differing prices for a hydrotreated shale oil. The alternative yielding the lowest purchase contract price of $11.15 assumes that 75 percent of the capital cost would be financed by 8 1/2 percent government loans. If no government loans are considered, the required purchase price is $16.75, according to TOSCO.

TOSCO's proposal also provides the most detailed cost estimate concerning the Dow West project ever publicly available. The proposal is described in more detail on page 2-1 and is reproduced in the Appendix on page A-48.

Surprisingly Little Response to TOSCO Proposal - So Far

Not only have public officials been quiet, but there has been virtually no reaction from consumer oriented opponents of subsidized oil shale development and higher energy prices.

TOSCO's cost estimates appear reasonable and their proposal sets the stage for some straight talk. TOSCO, in effect, says different plans necessitate different oil prices. Far from a take-it or leave-it proposal, the concepts warrant open discussion. Rapid investment write-offs & expensing of capital costs are possible counter proposals, but TOSCO has studied the problem longer than anyone and its views should carry weight.

FPC Ruling in WESCO Coal Gasification Rate Case Termed Unsatisfactory

The decision came in late April and authorizes a gas price of $1.38 per MCF during the first six months of plant operation, after which WESCO could ask FPC for an adjusted price to reflect actual operating costs and a 15% return on equity. On May 22, WESCO asked for a new hearing because the FPC decision "fails to provide a cost recovery mechanism which would enable the project to be financed." This is simply another way of stating that the possible financial rewards are not sufficient to attract investment capital. It reinforces the argument for providing adequate financial incentives to ensure synfuels development. FPC decision is described in more detail on page 4-13 and a copy is reproduced in the Appendix at page A-31.

The one encouraging note in FPC's decision is that they acknowledge the need for synthetic gas from coal.
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El Paso Meanwhile Asked FPC to Defer Their Decision Pending Resolution of Water Supply Problems

The water supply of El Paso's Burnham coal gasification complex in northwest New Mexico was intended to come from Navajo Reservoir, a federal facility straddling the Colorado New Mexico border. This requires a contract with the Bureau of Reclamation which in turn must be approved by Congress, but so far, there is no indication as to when or if the contract will be authorized.

In a related action, El Paso announced that they will not exercise an option to acquire Consolidation Coal Company's 50% interest in the Indian coal lease the two firms share. But El Paso's share of the coal reserves appear adequate to support their coal gasification plans anyhow, and speculation that these recent actions may lead to cancellation have been denied by El Paso officials. Meanwhile, however, demonstration of a commercial scale Lurgi retort has been postponed. More details concerning El Paso's situation may be found on page 4-14.

Panhandle Eastern Adds to a Growing List of Project Postponements

Their plans for a coal gasification complex near Douglas, Wyoming have been delayed for at least one year because of higher costs, changing state and federal laws, and uncertainty over national energy policy. Sound familiar? See page 4-15 for more details.

Paraho Announces Proposal for Expansion to A Commercial-Size Retort

The formal announcement came on May 28, although the intent to do so has been known for several months. A prospectus describing the expanded program indicates that total construction and operating costs for a four-year program will amount to $76 million. Harry Pforzheimer of Sohio Petroleum Company, managing operator of the current Paraho Project, said informal commitments from the 17 participants in the current program have been received. Paraho would like to proceed with some of the work this summer, but the possible requirement of an environmental impact statement may postpone it. A draft environmental assessment of the Anvil Points project is in Washington for review and decision on whether a full scale environmental impact statement is necessary. Large scale testing of a commercial-size retorting unit is long overdue. Much can still be learned from such a test. See page 2-43 for details.

Nominations for In Situ Lease Tracts Due June 30

The in situ program was finally launched on a formal basis with
HIGHLIGHTS

publication of Interior's call for tract nominations on April 17. Several nominations are expected, but none had been received by early June. Neither have there been any applications for special land use permits for informational coredrilling. The possibility that the nomination deadline will be extended in view of the short notice is discounted by Interior which wants to get the program going. A report describing the program is reviewed on page 2-28 and a copy of the report begins on page A-1.

Alberta Leasing Information is Available in Mines and Minerals Report

This excellent report contains all the pertinent data regarding who leases what land in the Alberta oil sands region. Furthermore, the report presents the data in readable graphs and charts. The report is reviewed on page 3-1.

House Committee Report Emphasizes Need for Federal Oil Sands Leasing Policy

This is because roughly 70% of the nation's oil sands reserves are on federally-owned land and current oil sands leasing policy is workable due to "built-in lawsuits." An article beginning on page 3-14 discusses this and other conclusions drawn by the government study.

GCOS Has Earned $2 Million So Far This Year

The firm has initiated a program to sell about 100,000 TPY of product sulfur. It was also reported that the cost of expanding the facility to 65,000 BPCD would exceed $100 million. An update of these and other GCOS activities may be found on page 3-18.

Syncrude Costs of $2 Billion Were Not Exaggerated

This was confirmed by independent studies performed by several engineering and financial firms. The probe was ordered by the Alberta provincial government. Even though costly, the project will still be economically viable, according to one of the reports. All of the results and conclusions are discussed beginning on page 3-21.

Coal Strip Mine Land Reclamation Law: To Be or Not to Be?

The odds on the bill vetoed May 20 by President Ford becoming law via a Congressional override fluctuated with the daily whim of Capitol Hill rumors. Industry has vigorously praised Ford's action while proponents of the bill react with dismay at fading prospects
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It will be enacted over the veto. The proponents have introduced another bill to prohibit leasing of federal coal without a national strip mine reclamation law. Interior, meanwhile, ready regulations to cope with either eventuality. See page 4-28 for summary and status of Interior reclamation regulations.

**American Natural Gas Becomes Third Firm to Seek FPC Approval of a Coal Gasification Plant**

The formal filing was made on March 26th by Michigan Wisconsin Pipe Line Co. and ANG Coal Gasification Co., both American Natural subsidiaries. It describes a 275-MMCFD gas plant to be located in Mercer County, North Dakota. Estimated capital cost of the complex is $900 million. The gas cost is estimated to be either $2.50 or $3.20 per MCF, depending on FPC's allowed treatment of construction funds. More details are presented on page 4-12.

**Interior/ERDA Energy Research Programs Slate $459 Million for Coal Extraction: $2.2 Billion for Coal Utilization: $174 Million for Oil Shale**

Synthetic fuels segments of the two agencies' budgets are combined for FY 1974-80 in a comprehensive presentation of total $4.6 billion R & D program. Table on page 1-3 details $2.2 billion coal utilization program including $363 million outlay in FY 1976. Oil shale funding is at $17.4 million for FY 1976 but is hiked to $36.9 million in FY 1977. Coal R & D is half of the budget which includes geothermal, uranium, advance power cycles and related investigations. Article begins on page I-1.

**The Oil Shale Industry Has Begun to Counter The Critics' Net Energy Claims**

A study performed by ARCO shows that a typical oil shale facility will unquestionably produce more energy than it consumes. Furthermore, by properly choosing the system boundaries, the net energy ratio can be driven to infinity. Paraho's studies show that not only will an oil shale plant produce net energy, but it will be as efficient as a coal conversion facility. In fact on the average, these two conversion processes are only 23% less efficient than conventional crude oil refineries. A discussion of these and other industry studies begins on page 2-30.

**Texaco Begins Environmental Work on Lake DeSmet Coal Property in Wyoming**

A 15-month contract for acquisition of baseline environmental
HIGHLIGHTS

data and preparation of an environmental impact assessment was awarded to Genge Resources, Inc. of Denver on June 4th. The resulting data will be used in preparing mining and reclamation plans, and in seeking state and federal approval for development of the property. Coal reserves on the 37,000-acre property are estimated to exceed 2 billion tons. A coal gasification project is a possibility.

HYGAS Pilot Plant Notches 20 Hours of Self-Sustained Operation

IGT officials were pleased with "successful" 203 hour lignite gasification test in Chicago. Test included 20 hours of self sustaining operation. Details on page 4-44.

West River Area Study by North Dakota Water Commission Provides Development Overview

A maximum degree of flexibility remains for using water from Missouri River tributaries and Lake Sakakawea. Initiated for agricultural water planning, the state study describes nearly two dozen projects with combined irrigation-lignite-municipal uses as well as foreseeable socio-economic impacts. Although first rate job, and a jump ahead of coal development the second phase of the study was not funded by the 1975 state legislature. See page 4-9 for more details.

Coal Severance Tax Subject of Legislation in Montana, North Dakota & Wyoming

A flat rate of 50¢ per ton was adopted in North Dakota or 17% based on $3.00 lignite. The Wyoming legislature increased its coal (and oil shale) severance tax from 3 to 4%, but tacked on a special coal severance tax that will peak in 1978 at 2% and remain at that level until a special impact mitigation fund of $120 million is accumulated.

The severance tax on a 9,000-Btu, surface-mined, bituminous coal in Montana was effectively tripled, at the least by the 1975 legislature. Montana's tax is on a sliding scale that varies with both heating value and method of mining. It varies from 3% for an underground mined lignite to 30% for a surface-mined bituminous coal. Their objective is clear: tax surface mines to death.

Other state legislation affecting coal and oil shale development in the Rocky Mountain and Northern Great Plains regions, in addition to the tax measures, are described on page 1-24.
COMING EVENTS


JUNE 11-15, 1975, SALT LAKE CITY, UTAH -- The Western States Technology Assessment Workshop will be sponsored by Utah's State Advisory Council on Science and Technology, Western Interstate Nuclear Board, and the Federation of Rocky Mountain States. For more information, contact the Division of Continuing Education, Conferences and Institutes, Box 200, Salt Lake City, Utah 84112.

JUNE 15-17, WASHINGTON, D. C. -- The National Coal Association's 58th Anniversary Convention will be held at the Washington Statler Hilton. For additional information, write the National Coal Association, 1100 Ring Building, Washington, D. C. 20036. The following will be among the speakers:

  Senator Robert C. Byrd, West Virginia
  Senator Wendell H. Ford, Kentucky
  William T. Coleman, Secretary of Transportation
  Jack Carlson, Assistant Secretary of Interior for Energy and Minerals
  Frank C. Zarb, Administrator, FEA
  Robert C. Seamans, Jr., Administrator, ERDA
  E. P. Berg, President, Bucyrus - Erie Co.
  T. P. Kroehle, President, Jeffrey Mining Machinery Co.
  John H. Perkins, President, Bechtel Corp.
  N. M. Lorentzen, President, Burlington Northern

JUNE 19-21, 1975, CHEYENNE, WYOMING -- Wyoming Mining Association 20th Annual convention at the Hitching Post Inn. For additional information, write the National Coal Association, 1150 17th Street, N.W., Washington, D. C. 20036.

JULY 21-23, 1975, PORTLAND, OREGON -- Conference on Magnitude and Deployment Schedule of Energy Resources to be held at the Portland Sheraton Motor Inn. The five types of energy resources to be discussed are solar, geothermal, coal, petroleum, and nuclear. For additional information, write the Office of Energy Research and Development, Covell Hall 219, Oregon State University, Corvallis, Oregon 97331.

JUNE 22-26, 1975, ASPEN, COLORADO -- Ninth National Seminar on Environmental Arts and Sciences sponsored by the Thorne Ecological Institute. For more information, write the Thorne Ecological Institute, 2356 Pearl Street, Boulder, Colorado 80302.


JUNE 26, AUGUST 28, OCTOBER 1-3, AND DECEMBER 18, 1975, DENVER, COLORADO -- Meetings of the Rocky Mountain Oil and Gas Association. For additional information, write C. S. Dietler, RMOGA, P.O. Box 640, Casper, Wyoming 82601.

JUNE 29-JULY 2, 1975, STEAMBOAT SPRINGS, COLORADO -- Annual Meeting of the Rocky Mountain Coal Mining Institute at the Steamboat Village Inn. For additional information, write the National Coal Association, 1130 17th Street, N.W., Washington, D. C. 20036.
JULY 17-19, 1975, RAPID CITY, SO. DAKOTA -- The 21st Annual Rocky Mountain Mineral Law Institute. For additional information, write the Rocky Mountain Mineral Law Foundation, Fleming Law Building, University of Colorado, Boulder, Colorado 80302. The tentative program is as follows:

- The U.S. Mineral Position in 1985
- Congressional History and Background of the Federal Coal Strip Mining Legislation
- Mine Planning to Meet Environmental Requirements
- The Preparation of Coal Leases and Related Documents
- The Acquisition of Rights to Prospect for and Mine Coal from Tribal and Allotted Indian Lands.
- Coal Mining, Development and Processing-The Associated Water Problems.
- Shale Oil: The Economics of Environmental Protection
- Drilling Contracts
- Federal Unitization
- FEA-Mandatory Allocation and Pricing
- Recent Oil and Gas Taxation Legislation and Its Effect on the Oil and Gas Industry
- Analysis of the Mechanics Lien Laws on Oil and Gas Leases in Various States
- Overview and Operation of the Mine Health and Safety Law
- Regulation of Mining Law Activities on Federal Lands
- The Jurisdiction of State Laws Affecting Mining on Indian Lands
- Minimum Work Clauses in Mining Leases
- The Law of Discovery Since Coleman: Marketability, Profitability, and the Prudent Investor Rule
- When To Locate and When To Lease?
- Coal Leasing-It's Different
- State In Lieu Selection and How It Can Affect Mineral Resource Development
- Current Concepts of the Nature and Scope of Indian Water Rights
- Equitable Apportionment of Interstate Ground Waters
- Interstate Water Compacts and Mineral Development - Legal & Administrative

AUGUST 4-8, 1975, GOLDEN, COLORADO -- A short course entitled, "Shale Oil: Its Production, Properties, and Utilization," at the Colorado School of Mines. The program is to be sponsored by the CSM Chemical and Petroleum-Refining Engineering Department. The tentative list of topics is as follows:

- Introduction, history, and reserves
- Above ground oil shale processing methods
- In situ oil shale processing methods
- Crude shale oil properties and analytical methods
- Comparison of shale oil with petroleum crude
- Special processing problems and possible solutions
- Environmental considerations: air pollution, water requirements and pollution, solids disposal and by-product recovery
- Economics of shale oil production and recovery
- Energy balance problems and net energy requirements

AUGUST 5-7, 1975, PITTSBURGH, PENNSYLVANIA -- Symposium on "Coal Gasification and Liquefaction: Best Prospects for Commercialization Time Table -- Update." To be held at the University of Pittsburgh. For additional information, contact M. C. Hawk, School of Engineering, 231 Benedum Engineering Hall, University of Pittsburgh, Pennsylvania 15261.

AUGUST 10-13, 1975, SAN FRANCISCO -- 15th National Heat Transfer Conference at the St. Francis Hotel. For additional information, contact the AIChE, 345 East 47th Street, New York, New York 10017.
AUGUST 12-14, 1975, HYANNIS, CAPE COD, MASSACHUSETTS -- The Institute for Briquetting and Agglomeration, 1975 Conference. For additional information, write Neal Rice, Secretary-Treasurer, Institute for Briquetting and Agglomeration, Box 912, Laramie, Wyoming 82070.

AUGUST 24-29, 1975, CHICAGO, ILLINOIS -- The 170th National Meeting of the American Chemical Society. For more information, write the ACS, 1155 16th Street, N.W., Washington, D.C. 20036.

SEPTEMBER 10-12, 1975, SALT LAKE CITY, UTAH -- Fall Meeting of the Society of Mining Engineers of AIME at the Salt Palace. For additional information, write the National Coal Association, 1150 17th Street, N.W., Washington, D.C. 20036.

SEPTEMBER 10-12, 1975, SALT LAKE CITY, UTAH -- Fall Meeting of the Society of Mining Engineers of AIME at the Salt Palace. For additional information, write the National Coal Association, 1150 17th Street, N.W., Washington, D.C. 20036.


SEPTEMBER 28-OCTOBER 1, 1975, SAN FRANCISCO -- 1975 American Mining Congress Mining Convention at the San Francisco Hilton Hotel. For more information, contact the American Mining Congress, 1100 Ring Building, Washington, D.C. 20036.

OCTOBER 21-23, 1975, LOUISVILLE, KENTUCKY -- National Coal Association's Second Coal and Environment Conference and Exposition at the Kentucky State Fair Grounds. For additional information, write the National Coal Association, 1130 17th Street, N.W., Washington, D.C. 20036.


OCTOBER 29-NOVEMBER 1, 1975, MILWAUKEE, WISCONSIN -- Society of Mining Engineers Fall Meeting and Exhibit at the Milwaukee Exposition and Convention Center and Arena.

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


Battelle Memorial Institute, "Fuels Chemistry - A Mid-Century Perspective," November 1974, a Battelle Energy Program Report. Copies are available from the Battelle Memorial Institute, 505 King Avenue, Columbus, Ohio 43201.


The Second Energy Technology Conference was held in Washington, D. C., in May 1975. The following were among the papers presented. For further information write Government Institutes, Inc., 4753 Bethesda Avenue, N.W., Washington, D.C. 20014.

- Dickson, R. L., "Congress and Energy"
- McTormack M., "Legislative Views on Energy Technology"
- Foster, J. S., "Policy Consideration"
- Zarb, F. G., "Energy Policy and Technology Role"
- Dahm, D. B., "Energy Research & Development Administration"
- LeGassie, R. W., "ERDA: Organization & Plans"
- Papamarcos, J., "Fossil Fuel Technology"
- Mills, G. A., Jr., "Coal Technology Efforts and Plans"
- Dunning, H. N., "Petroleum, Gas and Oil Shale Technology"
- Smith, C. H., "Canadian Energy Research & Development"


*University of Texas, "Spurring Synthetic Fuel Production," February 1975. Prepared as the final report of Phase II of the Federal Energy Administration and National Science Foundation Incentives Preference Project. Published by the University of Texas at Austin. Copies are available from the National Science Foundation, Washington, D.C. 20550. (See Page 1-11)


Reviewed in this issue.

GENERAL INTEREST - PATENTS

North American Rockwell Corp., Canadian Patent 966,076, "Pyrolysis Method." The patent relates to a cyclic process for the pyrolysis of carbonaceous materials where the materials are heated by contact with a hot molten salt to form the pyrolysis products.

OIL SHALE

"Accelerated Oil Shale In Situ Research," Report coordinated by the Interagency Oil Shale Planning Panel composed of representatives from the Laramie Research and Development Center, the Office of Research and Development, the Bartlesville Energy Research Center, the Morgantown Energy Research Center, the Mine Enforcement and Safety Administration, the Fish and Wildlife Service, and the Energy Research and Development Administration, March 1975. This report is included in the appendix of this issue of Synthetic Fuels. (See page 2-28)


Gromko, G. J., "A Study of the Use of Spent Oil Shale As Aggregate for Flexible Pavements." Paper presented at the 1975 Annual Meeting of the Association of Asphalt Paving Technologists in February 1975. For additional information, write the author at the Department of Civil and Environmental Engineering, University of Colorado at Denver, Denver, Colorado 80202.

*Reviewed in this issue.


Penner, S. S., "Report on Net Energy in Shale-Oil Recovery," January 21, 1975. Report based on discussions at a UCSD/NSF (RANN) workshop held at the University of California, San Diego, in January 1975. For additional information, write Dr. S. S. Penner, Energy Center, UCSD, La Jolla, California 92037.


Rocky Mountain Oil and Gas Association, "Summary of Industry Oil Shale Environmental Studies and Selected Bibliography of Oil Shale Environmental References," March 1975. Copies are available from RMOGA Oil Shale Subcommittee, 950 Petroleum Club Building, Denver, Colorado 80202.


The Eighth Oil Shale Symposium was held April 17-18, 1975, at the Colorado School of Mines, Golden, Colorado. The following papers were among those presented:

*Clark, C. F., and Varisco, D. C., Atlantic Richfield Company, "Net Energy and the TOSCO Shale Oil Process." (See page 2-30)
*Kunchal, S. K., Paraho Oil Shale Demonstration Inc., "Energy Requirements in an Oil Shale Industry: Input-Output Relationship Based on the Paraho Direct Combustion Retorting Process." (See page 2-30)
*Ridley, R. D., Occidental Oil Shale, Inc., "Energy Efficiency of the Occidental In Situ Shale Oil Recovery Process." (See page 2-21)
*Dutton, G., Sun Oil Company, "Methods of Achieving Energy Supply Independence for the U.S. by 1985"
*Keighin, C. W., United States Geological Survey, "Resource Appraisal of Oil Shale in the Green River Formation, Piceance Creek Basin, Colorado."
*Smith, J. W., and Young, N. B., Laramie Energy Research Center, U.S. Bureau of Mines, "Dawsonite: Its Geochemistry, Thermal Behavior and Extraction from Green River Oil Shale." (See page 2-12)
*Haas, F. C., and Atwood, M. T., The Oil Shale Corporation, "Recovery of Alumina from Dawsonitic Oil Shales." (See page 2-11)
The Society of Petroleum Engineers held the 45th Annual California Regional Meeting in Ventura in April 1975. The following papers were among those presented and are available from the SPE, 6200 No. Central Expressway, Dallas, Texas 75206:

- Chew, R. T., Garrett R & D Co., "Operating and Environmental Considerations -- Oxy In Situ Operations, Garfield County, Colorado," SPE 5388.

Tisot, P. R., "Structural Response of Propped Fracture in Green River Oil Shale as it Relates to Underground Retorting," 1975. Prepared as USBM RI 8021.


Whitcombe, J. A., and Vawter, R. G., "The TOSCO II Oil Shale Process," paper presented at the 79th National Meeting of the AIChE. The authors are from The Oil Shale Corporation.


OIL SHALE - PATENTS

The Oil Shale Corporation, Canadian Patent 965,721, "Process for Retorting Oil Shale in the Absence of Shale Ash." The process relates to a means of recovering shale oil from oil shale which contains substantial amounts of carbonate-containing minerals.

OIL SANDS


*Reviewed in this issue.


*Mungen, R., and Nicholls, J. H., "Recovery of Oil from Heavy Oil Deposits in Northern Alberta by In Situ Methods," May 1975. Paper No. PD22/2 presented at the Ninth World Petroleum Congress in Tokyo. (See page 3-13)

OIL SANDS - PATENTS

*Canada-Cities Service, Ltd., Atlantic Richfield Canada, Ltd., and Imperial Oil Limited, U.S. Patent 3,864,251, "Treatment of Middlings Stream from Hot Water Process for Recovering Bitumen from Tar Sands." This process relates to treating the middlings stream from the primary separation cell used in the hot water process for extracting bitumen from oil sands. The stream is diluted with hot water and settled in a quiescent zone. Froth is formed in the settler and is low in solids and water. The tailings stream from the settler is recycled to the front end of the extraction process and, thereby, conserves water. (See page 3-12)

*Canada-Cities Service Ltd., Imperial Oil Limited, Atlantic Richfield Canada Ltd., and Gulf Oil Canada Limited, U.S. Patent 3,869,384, "Tailings Disposal System for Tar Sands Plant." This patent describes a method of treating the tailings stream from a hot water extraction plant for recovering bitumen from tar sands when the stream is composed of water and coarse and fine solids. (See page 2-27)

*Texaco, Inc., U.S. Patent 3,858,654, "Hydraulic Mining Technique for Recovering Bitumen from Subsurface Tar Sand Deposits." The patent describes a means of recovering bitumen from deposits of tar sands too deep to strip mine. A hydraulic mining technique is discussed where the deposit is contacted by a hot, aqueous polyphosphate solution containing an alkaline substance such as caustic or sodium hydroxide. A single well bore is used both for injection and recovery. (See page 3-12)

COAL


Atlantic Richfield Co., "Development of Western Coal -- A Producer's View," April 14, 1975. For more information, write W. E. Wade, Jr., Atlantic Richfield Co., Synthetic Crude Division, Box 2679 T.A., Los Angeles, California 90051.


*Reviewed in this issue.
are available from the National Technical Information Service, Springfield, Virginia 22151.


*Chemical Engineering Progress, Volume 71, No. 4, April 1975. Entire issue devoted to coal processing, gasification, and liquefaction.


"Federal Coal Research -- Status and Problems to Be Resolved," February 18, 1975. A multi-agency report to Congress and coordinated by the Comptroller General's office. Copies are available at $1 from the General Accounting Office, Distribution Section, P.O. Box 1020, Washington, D. C. 20013.


*Reviewed in this issue.


Reviewed in this issue.


North Dakota University, "A Preliminary Engineering, Geological, and Hydrological Environmental Assessment of a Proposed 250 MMSCFD Coal Gasification Facility," August 1974. Copies are available from the University of North Dakota, College of Engineering, Experiment Station, Grand Forks, North Dakota 58201.


"Office of Field Utilization, "Coal Conversion Program, Draft Environmental Statement," DES 75-1, Section 2, 1975. DES prepared by the OFU of the FEA. For additional information, contact Phyllis Becherman, Federal Bldg., 1200 Pennsylvania Avenue, N.W., Washington, D. C. 20461. (See page 4-30)

Pennington, R. D., "Coal Liquefaction Technology," Society of Mining Engineers Preprint No. 75-F-135, February 1975. Copies are available from the SME/AIME, 540 Arapane Drive, Salt Lake City, Utah 84108.


*Reviewed in this issue.


The 5th Oklahoma State University conference on Synthetic Fuels From Coal was held on the Stillwater campus in May 1975. The following were among the papers presented. For additional information, contact Dr. B. L. Crynes, School of Chemical Engineering, O.S.U., Stillwater, Oklahoma 74074.

- "Coal Gasification for Industrial Fuel," E. Ferretti, Dravo Corp.

Thompson, D. G., "Squeezing Oil and Gas from Coal," Chilton's Oil and Gas Energy, February 1975, pages 34-37.

Thompson, D. G., "Comparison of Coal Drying Methods." SME-AIME Preprint 75-F-58, February 1975 Copies are available from the AIME, 540 Arapeen Drive, Salt Lake City, Utah 84108.


COAL - PATENTS

Atlantic Richfield Co., Canadian Patent 962618, "Coal Liquefaction." This patent claims to describe a new means for producing liquid hydrocarbonaceous products from coal. The patent further claims to provide a new method of performing the coal hydrogenation process, a new method of reducing asphaltenes, and a new method of liquefying coal without a slurry medium.

Atlantic Richfield Co., Canadian Patent 965,719, "Method for the Hydrogenation of Coal." The patent describes a way of hydrogenating coal for gasification and liquefaction in the absence of an externally supplied hydrogenation catalyst when using an ebulated bed of substantially solid contact particles composed of a material that is inert and non-catalytic to the hydrogenation reaction.

Hydrocarbon Research, Inc., Canadian Patent 962208, "Low Sulfur Fuel Oil from Coal." This describes a method of using hydrogenerated coal to produce low sulfur fuel oil. The patent claims that the "relatively low consumption of hydrogen, the high throughput of the reactor, and the substantial absence of down stream refining processing make it possible to produce the low sulfur residual fuel oil at a cost of about one half that for the production of gasoline."

Hydrocarbon Research, Inc., Canadian Patent 965,720, "Coal Hydrogenation (HR 845)." The invention disclosed in the patent claims to take advantage of ebulation in a new manner. It states, "... a liquid and a gas are reacted in a reaction zone in the presence of particulate solids contact material. With the solids maintained in random motion in the liquid it is possible to obtain a greatly improved reaction due to good contact, the limited pressure drop, and particularly due to the uniformity of temperature."
Synthetic Fuels From Oil Shale

DATES
 Italics denote changes since March 1975 issue.

COMMERCIAL PROJECTS

Environmental & exploratory work underway, DDP expected by end of 1975. (See page 1-42)

Suspended indefinitely (DDP suspended & project delayed or cancelled)

Awaiting decision on land exchange petition (See March 1974 issue, page 2-53)

Preliminary exploratory & environmental activities underway (See page 2-61)

Environmental & exploratory work underway, DDP expected by early 1976. (See June 1974 issue, page 2-56)

Project cost no estimate announced, but it may be expected to exceed $600 million for 50,000 BPCD.

Project cost estimated to exceed $600 million.

Environmental & exploratory work underway, DDP expected by end of 1975.

Estimated power and water requirements are 9,400 KW & 12,000 AFY, respectively. Peak construction force is 1,800. Estimated recoverable reserves are 4.7 billion barrels (by surface mining) & 1.3 billion barrels (by underground mining).

Effective date of lease on tract C-a is March 1, 1974. Estimated recoverable reserves (by underground mining) are 723 million barrels. Steel has replaced ARCO as project operator.

Project cost estimated to exceed $600 million.

ARCO, Ashland, Shell & TOSCO acquired rights to the 5,099-acre tract C-b for $117.8 million at lease sale on February 12, 1974. Preliminary development plan indicates a 50,000 BPCD operation by 1982 at the earliest. Underground room & pillar mining is envisioned. TOSCO II retorting anticipated. Some in situ recovery in later years a possibility. Upgrading will be conventional but product slate not indicated. Water requirements are 10,000 AFY. Power required is 650,000 KW. Estimated peak construction employment is 2,000. Permanent labor force estimated at 1,000. Ultimate expansion to 100,000 BPCD is a possibility. Effective date of lease on tract C-b is April 1, 1974. Estimated recoverable reserves (by underground mining) are 723 million barrels. Shell has replaced ARCO as project operator.

Project cost no estimate available, but may be expected to be in excess of $600 million.

Project costs now estimated at $300 million.

Project cost estimated to exceed $600 million.

Environmental & exploratory work underway. DDP expected in early 1976. (See page 2-53)

Effective date of lease on tract C-a is March 1, 1974. Estimated recoverable reserves (by underground mining) are 723 million barrels. Shell has replaced ARCO as project operator.

Effective date of lease on tract U-a is January 9, 1974. Preliminary development plan indicates an ultimate production of 50,000 to 300,000 BPCD, based on either underground or a combination of surface & underground mining. Initial production tentatively slated for 1980. Initial plans call for TOSCO II retorting but variations being tested by Paraho will likely be used also. Estimated power and water requirements are 9,400 KW & 12,000 AFY, respectively. Peak construction force is 1,800. Estimated recoverable reserves are 4.7 billion barrels (by surface mining) & 1.3 billion barrels (by underground mining).

Environmental & exploratory work underway, DDP expected by end of 1975. (See page 1-42)

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Environmental & exploratory work underway, DDP expected by end of 1975.
**STATUS OF SYNFUELS PROJECTS**

<table>
<thead>
<tr>
<th>OWNERS &amp; SPONSORS</th>
<th>PROJECT DESCRIPTION</th>
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<tbody>
<tr>
<td>Union Oil Co. of California</td>
<td>Proposed commercial project on private land in Colorado</td>
<td>Union has been quietly active in oil shale since they completed retorting tests in 1958. On 1/2/74, they announced plans for a commercial plant (50,000 BPCD or larger) to be built by 1980 on 25,000-acre fee property north of Grand Valley, Colorado. Ultimate decision is contingent upon &quot;favorable economic conditions and no major environmental obstacles.&quot; Union has resources, technology and water, all adequate for commercial venture. Total reserves on Parachute Creek property said to be enough for ultimate production of 350,000 BPCD. Steam Gas Recirculation retorting process announced in June, 1974. Several contractors conducting environmental studies. Construction of 1,000 TPD pilot plant announced in March 1974 has been postponed pending consideration of building a commercial scale retort. Project cost latest estimate is $750 million for a 50,000 BPCD project.</td>
<td>Early stages of planning. (See Sept, 1974 issue, page 2-32)</td>
</tr>
<tr>
<td>White River Shale Oil Corp., owned equally by Sun, Phillips &amp; Sohio</td>
<td>Commercial project on federal tract U-b in Utah</td>
<td>White River acquired rights to the 5,120-acre tract U-b for $45.1 million at lease sale on April 9, 1974. Effective date of tract U-b lease is 6/1/74. Estimated recoverable reserves on tract are 266 million barrels by underground mining. Preliminary development plan indicates a 50,000 BPCD operation with initial production slated for 1980. Underground room &amp; pillar mining with inclined or vertical shaft. Retorting by Paraho variation for coarse feed. Fines will either be discarded, briquetted &amp; fed to Paraho retort, or sold to TOSCO II retort. Anticipated products are refinery feedstock or fuel oil, ammonia (350 LTPD), coke (725 LTPD), &amp; sulfur (45 LTPD). Water &amp; power requirements are 8,250 AFY and 55,000 KW, respectively. Construction &amp; permanent employment are 1,375 &amp; 895, respectively. Joint development of tract U-a with Sun &amp; Phillips a probability. Project cost no announcements, but may be expected to exceed $600 million.</td>
<td>Environmental &amp; exploratory work underway. DIP expected by early 1976. (See June 1974 issue, page 2-56.)</td>
</tr>
<tr>
<td>Dow Chemical Co.</td>
<td>Proposed on site recovery project</td>
<td>Using a forward combustion recovery process, Dow proposes to produce liquid and gaseous products and low-BTU gas from oil shale located near Midland, Michigan. A request for a $35 million grant from ERDA has been made. The Antrim shale averages 300 ft. thick and underlies 70% of the state of Michigan. Project cost estimated to be $35 million.</td>
<td>Active (See page 2-61)</td>
</tr>
<tr>
<td>Institute of Gas Technology/American Gas Association</td>
<td>Oil Shale Gasification plant</td>
<td>IGTA is designing a 1 ton/hour batch process (8-hour charge) pilot plant in Chicago.</td>
<td>Under construction</td>
</tr>
<tr>
<td>National Science Foundation &amp; Denver Research Institute</td>
<td>Research on effects of solid wastes from oil shale</td>
<td>Two-year research study funded by the NSF-RANN program under Grant No. GI3428X1. First interim report entitled, &quot;Disposal &amp; Environmental Impact of Carbonaceous Solid Wastes from Commercial Oil Shale Operations,&quot; released in April 1974 covers activities and preliminary results obtained since grant was awarded in late 1972. Project cost $194,600 grant from NSF.</td>
<td>Active</td>
</tr>
<tr>
<td>National Science Foundation &amp; University of Southern California</td>
<td>Research on biochemical processing of oil shale</td>
<td>An 18-month investigation of the use of sulfur-oxidizing bacteria for releasing kerogen from oil shale. Project cost $120,000 NSF grant.</td>
<td>Active (See page 2-32)</td>
</tr>
<tr>
<td>Occidental Oil Shale, Inc.</td>
<td>Demonstration-scale in situ recovery of oil shale</td>
<td>An Oxy subsidiary, Garrett Research &amp; Development Co., has been developing a modified in situ recovery scheme for several years. Process involves first a limited amount of conventional underground mining followed by blasting of the overlying shale to form an underground NTU retort filled with broken oil shale and subsequent in situ retorting. Oil flow to sump at bottom of retort chamber, then pumped to underground storage. Mined shale is moved to surface where it may either be discarded or fed to surface retorts. Results of first field test in 1973 indicate 15 to 20% voids were created in retort. Some 1,200 barrels were recovered which indicates a recovery efficiency of 52.6% of Fischer assay commercial grade kerogen (60% C, 10% H, 8% N, and 8.7% S).</td>
<td>Active</td>
</tr>
</tbody>
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STATUS OF SYNFUELS PROJECTS

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<td>Paraho Development Corp. Development Engineering, Inc.</td>
<td>Paraho Oil Shale Development Program</td>
<td>OIL leased from Mines Anvil Points oil shale experimental facility near Rifle, Colorado for five years. They are conducting a 30-month project to demonstrate vertical kiln technology as it applies to oil shale retorting. In essence, variations of Gas Combustion and Petrosíx retorts will be tested. Preliminary results of a 28-day run at the pilot plant in Rifle indicated 120% recovery and a lower oxygen consumption per metric ton than anticipated. An operating factor of 80% was achieved. 97% of of 800,000 BPCD gas was produced per ton. 120,000 BPCD of product was shipped at 200°F into their military fuels. These fuels are now being tested by the government.</td>
<td>Continued. (See Sept. 1974 issue, page 2-24)</td>
</tr>
<tr>
<td>Phillips Development Corporation</td>
<td>Prototype commercial-scale retort</td>
<td>The 1.4 ft. (D.O.) retort would be capable of processing 1,500 tons of oil shale per day and producing 750 BOPD of liquid product. Secondary smelting, screening, and reto tting are to be performed on a 5,000 tons benzene loaded retort at the existing road at the 7000 ft. level. The five-month program includes five months of shale-to-oil operations and six months of all-steel operation.</td>
<td>Active. (See March 1975 issue, page 2-26.)</td>
</tr>
<tr>
<td>Petrobras (Petroleo Brasiliiero, S.A.)</td>
<td>Prototype plant</td>
<td>A 2000-TPD Petrobras shale retorting facility is being operated at Sao Mateus do Sul, Brazil. Facility includes all necessary support operations including surface mine, crushing plant, retort, off-gas processing, power plant, worker housing, etc. Most recent report indicates operation at design capacity. Commercial project is almost completed.</td>
<td>No recent announcements.</td>
</tr>
<tr>
<td>The Oil Shale Corporation</td>
<td>Direct gasification of oil shale</td>
<td>At TOSCO's Research Center at Rocky Flats, near Denver, experimental studies have commenced on the direct gasification of oil shale to produce an intermediate BTU gas suitable for conversion to pipeline-quality gas.</td>
<td>No recent announcements.</td>
</tr>
<tr>
<td>U.S. Bureau of Mines sponsor, Development Engineering Inc. contractor</td>
<td>Research concerning spent shale handling &amp; disposal</td>
<td>Overall objectives of the 8-phase, 2-year study are to determine the physical properties of raw oil shale and spent shale from the Paraho retorting variations, then to evaluate the engineering and environmental problems associated with surface disposal of spent shale. Testing will be conducted at Anvil Points in conjunction with Paraho retorting demonstration.</td>
<td>Active. (See Sept. 1974 issue, page 2-24)</td>
</tr>
<tr>
<td>U.S. Department of the Interior</td>
<td>Prototype oil shale leasing program</td>
<td>Tract C-a went to Gulf &amp; Indiana Standard for $210.3 million. Tract C-b went to ARCO, Ashland, Shell &amp; TOSCO for $117.6 million. Sun &amp; Phillips acquired tract U-a for $75.6 million. White River Shale Oil Corp. (owed equally by Sun, Phillips &amp; Sohio) got tract U-b for $45.1 million. No bids were received for tracts W-a and W-b in Wyoming. Total exposed at 4 sales was $972 million. Total of successful bids was $449 million. Preliminary development plans indicate a maximum production from the 4 tracts of 250,000 BOPD by 1982 with potential expansion to 450,000 BOPD by 1985.</td>
<td>Active. (See Sept. 1974 issue, page 2-24)</td>
</tr>
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<tr>
<td>AOP Group, owned jointly by Petrofina Canada (35%) and Murphy Oil Co., Ltd. (11%)</td>
<td>Commercial plant</td>
<td>ERB granted approval to construct a 122,500 BPCD plant on Bituminous Sands Lease No. 12 and 34 held by Petrofina Canada at Daphne Island. Mining will be done with bucketwheel excavators, separation will use the KA Clark process, and upgrading will use fluid coking methods. An on-site power plant will use the by-product coke. Project cost estimated at $1.7 billion.</td>
<td>ERB approval granted (See March 1975 issue, page 3-15)</td>
</tr>
<tr>
<td>Great Canadian Oil Sands, Ltd., owned 97% by Sun Oil Co., Ltd. and 3% publicly owned</td>
<td>Commercial plant</td>
<td>Plant has been in operation since September 1967. Authorized annual production is 65,000 BPCD equivalent. Product is 38-40 gravity synthetic crude blended from gas oil, naphtha, and kerosene fractions from Unifining of delayed coke distillate. Coke bottoms are used for power plant fuel. Mining by bucketwheel excavators. Beginning sales of 100,000 MFT of sulfur. $2 million profit realised in first quarter 1974.</td>
<td>Operating (See page 3-18)</td>
</tr>
<tr>
<td>Home Oil, Ltd. and Alminex Corporation</td>
<td>Commercial plant</td>
<td>Plant will produce 103,000 BPCD of 30°API synthetic crude and 870 LT/D of sulfur. The plant will be located on Lease No. 30, between Shell’s Lease No. 13 and Syncrude’s Lease No. 29. Construction to begin in 1976. Plant life estimated at twenty-five years. Project cost estimated at $5.4 billion.</td>
<td>Approved by ERCB. Future plans uncertain. (See Sept. 1974 issue, page 3-18)</td>
</tr>
<tr>
<td>Shell Canada, Ltd.</td>
<td>Commercial plant</td>
<td>ERCB recommended approval of 100,000 BPCD operation on Lease No. 13. Surface mining will be done with large electric draglines. Shell estimates recoverable reserves on Lease No. 13 total 3 billion barrels. Construction to begin in 1976; production in 1980. Shell Explorer has withdrawn from active participation. Project cost now estimated $2 billion.</td>
<td>ERCB approval granted. Waiting ratification by provincial government (See December 1974 issue, page 3-8)</td>
</tr>
<tr>
<td>Syncrude Canada, Ltd., a joint venture consisting of Imperial Oil Ltd. (44.64%), Canada Cities Service Ltd. (31.43%) and Gulf Oil Canada Ltd. (23.93%), Province of Alberta (10%) and Province of Ontario (5%) and the Canadian Federal Government (1%)</td>
<td>Commercial plant</td>
<td>Commercial facility to be located on Bituminous Sands Lease No. 17. Allowable production is 125,000 BPCD of 30+ gravity syncrude and 5498 BPCD of residual oils. Mining by electric draglines, hot water process for bitumen extraction. Canadian Bechtel, Ltd. is the managing contractor. Startup expected in 1977 with initial production of 104,500 BPCD. Project cost now estimated at $2 billion.</td>
<td>Construction underway (See page 3-11)</td>
</tr>
<tr>
<td>Arizona Fuels, Inc. and Burnum Oil</td>
<td>Pilot plant modified hot water extraction process</td>
<td>Plant will be located on Sohio property on Asphalt Ridge, about seven miles south of Vernal, Utah. Initial production to be approximately 1,000 MFD. Extraction unit to be 51 feet high and 6 feet in diameter. Ore will be loaded in the top, heated by a gas-fired furnace, and bitumen will be separated in a water-filled chamber. 95% recovery is claimed. The bitumen will be transported to Arizona Fuels’ Roosevelt Refinery. Flying Diamond Oil allowed purchase option to expire. Project cost $3.0 million.</td>
<td>Construction underway (See March 1975 issue, page 3-12)</td>
</tr>
<tr>
<td>Bureau of Mines Laramie Energy Research Center</td>
<td>In situ field experiment</td>
<td>The site of the reverse combustion test will be on Northwest Asphalt Ridge, five miles west of Vernal, Utah. The 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 30-60 feet apart and the wells in each row will be 10-20 feet apart. The pattern should be burned out in 90 days after ignition. A minimum air flux of 60 SCF/hr-ft^2 will be maintained for the duration of the project. Site preparation is currently underway. Project cost $500,000.</td>
<td>Test now planned for summer of 1975. Approval received from Utah Division of Oil and Gas Conservation (See page 3-21)</td>
</tr>
<tr>
<td>Canadian Industrial Gas and Oil, Ltd. (CIGOL), Fuyo-Maru-beni Oil and Gas of Alberta, Ltd.</td>
<td>Experiment in situ project</td>
<td>CIGOL will be operator of a $16.5 million program funded mostly by the Japanese firm. A delineation drilling program is in progress. Location will be on Lease No. 60 in Cold Lake region. Successful completion of first phase will entitle Fuyo-Maru-beni to 50% interest in CIGOL holdings. CIGOL to merge with Northern &amp; Central Gas Corp. Ltd. Project cost $16.5 million. Total project $20 million.</td>
<td>Experimental project application filed with ERCB. Approval expected within 6 months. (See March 1975 issue, page 3-11)</td>
</tr>
</tbody>
</table>
### STATUS OF SYNFUELS PROJECTS

#### OWNERS & SPONSORS

**Canadian Javelin Ltd.**
- **Project Description:** Pilot plant Solvent extraction process
- **Details:** Small scale pilot plant studies being conducted in Montreal 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.
- **Status:** Active (See March 1975 issue, page 3-1)

**Fairbrim Company**
- **Project Description:** Pilot plant chemical extraction process
- **Details:** Aspahls Ridge project cancelled in favor of similar project near Bowling Green, Kentucky. Project has been under operation since August 1974.
- **Status:** Kentucky project action.

**Guardian Chemical Corporation**
- **Project Description:** Pilot plant chemical extraction process
- **Details:** The project will investigate the feasibility of using a low-concentrate solution of Polycarbonate A-11 to extract bitumen from oil sands. The chemical was originally designed to break up oil slicks. The process is expected to recover up to 95% of the bitumen from oil sands having 11.5 weight percent bitumen content. Pilot plant operates on 6000/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. Yates being made #1. Interested in developing a commercial plant. An in situ application project has been authorized by New Western Oil Sands Ltd., a subsidiary of Rainbow Resources, Ltd.
- **Status:** Pilot plant operations underway (See June 1974 issue, page 3-12)

**Imperial Oil, Ltd.**
- **Project Description:** Experimental in situ recovery project
- **Details:** Imperial has been conducting steam stimulation recovery tests in Cold Lake heavy oil deposit since 1971 under Experimental Approval No. 1503 issued by Alberta ERCB. AMOCO authorized increase production from 500 to 4000 BPCD. Imperial has sold data and ongoing program monitoring rights to five companies. New Leming project will use a 7-spot drilling pattern. Previous project used a 5-spot design, and is still producing about 1,000 BPCD. Current program involves drilling of 82 shallow wells.
- **Status:** Active (See September 1974 issue, page 3-15)

**Marconaflo, Inc.**
- **Project Description:** Slurry mining
- **Details:** Test will take place in the U.S. probably 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.
- **Status:** (See March 1975 issue, page 3-3)

**Murphy Oil Co. Ltd.**
- **Project Description:** Experimental in situ recovery project
- **Details:** Approval No. 1904 was granted in January, 1974. The project is located in Section 13-85-4 W4. Approval was granted for production of 600 BPCD.
- **Status:** Active (See June 1974 issue, page 3-19)

**Muskeg Oil Company, a wholly-owned subsidiary of AMOCO Canada, Ltd.**
- **Project Description:** Experimental in situ recovery project
- **Details:** Location is section 27-85-8 W4. Application submitted in October 1968 seeking provincial authority to produce 15 million barrels of crude bitumen at rates up to 80,000 BPCD. 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 OFCW process. AMOCO owns patent rights to both processes.
- **Status:** Expansion operations suspended pending clarification of government tax policies. (See September 1974 issue, page 3-15)

**Nunac Oil and Gas, Limited**
- **Project Description:** Experimental in situ recovery project
- **Details:** Experimental project approval number 2067 became effective on October 31, 1974. Location is 30-83-6 W4 on property covered by newly acquired oil sands permit number 22. 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.
- **Status:** Active (See December 1974 issue, page 3-3)

**Payette River Mines**
- **Project Description:** Experimental in situ project
- **Details:** Core hole data indicates a 500-foot thick zone of oil saturated dolomite in Sec 12, T3S, R2W in Duchesne County, Utah. 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 5790 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, up through the upper section. A ten-foot penetration is anticipated. Success on this test could lead to huff-and-puff in situ technique.
- **Status:** Project approval granted on August 28, 1974 by Utah O & G Conservation Board

**Shell Canada, Ltd.**
- **Project Description:** In situ pilot program
- **Details:** A three month extension of Approval No. 1904 was granted by ERCB; this will consist of 24 production wells, 7 steam injection wells, 12 observation wells, and 2 fuel gas wells, arranged in 5-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. Construction to begin in early 1975; operation in mid-1976. Hopes are for a commercial operation by 1985.
- **Project cost installation = $33 million.**
- **Overall program (9-year) = $85 million.**
- **Status:** Planning (See Sept. 1974 issue, page 3-16)
STATUS OF SYNFUELS PROJECTS

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<tr>
<td>Union Texas of Canada, Ltd.</td>
<td>Experimental in situ recovery project</td>
<td>Approval no. 1945 was granted in February, 1974 for the 1,000 BPCD project. The project will be located in Section 20-62-3 W4 in the Cold Lake deposit. The 16-well formation is expected to produce 500 BPCD using &quot;huff-and-puff&quot; techniques.</td>
<td>Initial production slated for January 1, 1975 (See June 1974 issue page 3-18)</td>
</tr>
<tr>
<td>Texaco Exploration Canada Ltd.</td>
<td>Experimental in situ recovery project</td>
<td>Texaco Exploration was issued experimental permit No. 1769 by the ERCB in June 1972 to conduct a pilot recovery project on Bituminous Sands No. 51 held by Texaco in the Athabasca deposit area. Overburden ratios in the area of the project suggest some form of in situ program. Application for amendments to original approval were recently approved.</td>
<td>Project commenced in June 1972</td>
</tr>
<tr>
<td>Tenneco Oil and Minerals</td>
<td>Experimental in situ recovery project</td>
<td>Approval No. 2010 was granted for the project by ERCB on April 29, 1974. Site is located in Section 27-96-7 W4 in the Athabasca deposit area. Project cost $3 million</td>
<td>Active (See December 1974 issue, page 3-7)</td>
</tr>
<tr>
<td>Union Oil Company of Canada (87% owned by Union Oil Company of California)</td>
<td>Experimental in situ recovery project</td>
<td>Union will be operating under approval number 2062. Operations use a steam injection technique.</td>
<td>Active (See December 1974 issue, page 3-7)</td>
</tr>
</tbody>
</table>

Synthetic Fuels From Coal

Italics denote changes since March 1975 issue.

COMMERCIAL PROJECTS

- **Cities Service Gas Co. and Northern Natural Gas Co.**
  - Commercial plant
  - Joint pursuit of coal gasification in Powder River Basin of Montana-Wyoming for gasification to 1,000 MMCFD SNG in four plants of 250 MMCFD capacity. Peabody Coal Co. has dedicated 500 million tons of coal from the northern Cheyenne Indian Reservation (Montana) to the project.
  - Pending FPC approval. (See September 1974 issue, page 4-29, and page 4-14 this issue)
  - Project cost $1 billion.

- **Colorado Interstate Gas Co.**
  - Commercial plant
  - CIG has a 10-year option on a long block of coal land in Montana from Westmoreland Resources. Estimated reserves are 300 million tons. CIG has helped to finance a pilot plant project by Occidental Petroleum's Garrett Research. CIG's parent company, Coastal States Gas Corp., is conducting process and economic evaluations.
  - No announcements since signing of the 10-year lease option, December 1971

- **El Paso Natural Gas Co.**
  - Burnham Coal Gasification Complex
  - Initial capacity of complex will be 288 MMCFD with sufficient water and coal reserves to support ultimate total capacity of 750 MMCFD.
  - Lurgi gasification technology will be used. Complex site is on coal lease held by El Paso on Navajo Indian Reservation in northwestern New Mexico. Application has been made to Bureau of Reclamation for 28,000 AFY from the Navajo Reservoir. Bureau's Draft Environmental Statement circulated July 1974. Congressional approval for water contract not yet forthcoming. 18-month feasibility study started in late 1974 to project. State has awarded a conditional water permit for 17,000 AFY. Project cost $400-$500 million for commercial plant.
  - Pending final FPC approval. (See September 1974 issue, page 4-29, and page 4-14 this issue)

- **El Paso Natural Gas Co.**
  - Commercial plant
  - North Dakota Project
  - El Paso has announced intentions of building four plants in North Dakota. Reserves of two billion tons are under lease in Bowan, Stark and Dunn counties. First plant scheduled on stream by 1981. El Paso recently withdrew an application for 81,000 AFY from Lake Sakakawea filed with the U.S. state water commission.
  - Planning (See page 4-11)

- **Exxon Corporation (Carter Oil)**
  - Commercial plant
  - 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, Wyoming, in Campbell County. Also, Carter has an industrial water contract for 50,000 AFY from the Yellowtail Unit on the Big Horn River.
  - 18-month feasibility study started in late 1973 (See December 1973 issue page 4-39)

- **Illinois Coal Gasification Group 8 companies**
  - Commercial plant
  - SNG from coal
  - Investigating feasibility

- **Michigan Wisconsin Pipeline Co., and AnG Coal Gasification Co. (wholly owned subsidiaries of American Natural Gas Co.)**
  - Commercial plants
  - SNG from coal
  - Overall plans call for four 250-MMCFD gasification plants in west central North Dakota. First plant planned for start-up in 1981; other plants scheduled at four-year intervals thereafter. North American Coal Corp. has dedicated a 3.7 billion ton lignite reserve to project. State has awarded a conditional water permit for 17,000 AFY from Lake Sakakawea to serve first plant. C.E. Lummus & Kaiser Engineers are committed to project thru first plant. Present schedule reflects a one-year postponement announced in January. Filed for first plant with FPC in April 1974. Final decision has been deferred at El Paso's request. Project cost $400-$500 million for commercial plant.
  - Pending FPC approval. See page 4-11.
# Status of Synfuels Projects

## Owners & Sponsors

<table>
<thead>
<tr>
<th>Owners &amp; Sponsors</th>
<th>Project Description</th>
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<tbody>
<tr>
<td>Natural Gas Pipeline Company of America</td>
<td>Dunn Center Coal Gasification Project Commercial Plants</td>
<td>On January 25, 1973 NGPL and the Nokota Company (formerly Star Drilling Inc.) entered into a 20-year lease agreement encompassing approximately 110,000 acres in central Dunn County, N.D. Under terms of the agreement, NGPL has exclusive rights to prove lignite reserves of 2.1 billion tons within the lease area. Reserves are adequate for up to eight plants. NGPL has applied to North Dakota for permission to eventually use 70,000 AF of water for both mining and gasification. First of four planned 250-MMCFD plants utilizing Lurgi technology currently envisioned to be operating by 1985 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.</td>
<td>Design and development is proceeding. (See page 4-12)</td>
</tr>
<tr>
<td>Panhandle Eastern Pipeline Co. and Peabody Coal Co.</td>
<td>Commercial plant SNG from coal</td>
<td>Capacity is 275 MMCFD. Lurgi gasification methanation processes will be used. The plant will be located in eastern Wyoming. Peabody has dedicated 665 MM tons of coal to the joint project. Plant start up delayed one year to 1980-81 period. Bechtel and Semco are the general and environmental contractors respectively. Sasso has been retained as consultant. State has issued water permit for 25,000 AF from North Platte River</td>
<td>Project cost now estimated at one billion dollars.</td>
</tr>
<tr>
<td>Texaco, Inc.</td>
<td>Commercial plant gasification or liquefaction of coal</td>
<td>On October 26, 1973, Texaco acquired 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 development system which will include a 5,100 AF impounding basin, a 1-mile 66-inch pipeline from Clear Creek to Lake Desmet and a pumping plant. Completion is expected by late 1975. Morrison-Judson Co. will do an engineering study of Texaco's coal, land, and water holdings near Lake Desmet. Texaco announced, June 5, 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.</td>
<td>Planning studies &amp; water development work underway. (See December 1973 issue, page 4-39)</td>
</tr>
<tr>
<td>Texas Eastern Transmission Corp. &amp; Pacific Lighting Corp., Western Gasification Co. (WESCO)</td>
<td>Commercial plant SNG from coal</td>
<td>Lurgi gasifier will produce 250 MMCFD of pipeline quality gas; could be expanded to 1,000 MMCFD. Plant will be located adjacent to coal reserves owned 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. and Cities Service Gas Co. 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. On April 21, 1975, FPC rendered a final decision which supports the need for the project but was not adequate for financing. Project cost $487 million.</td>
<td>Request for rehearing on final FPC decision filed May 31, 1976 (See page 4-12)</td>
</tr>
<tr>
<td>Texas Gas Transmission Corp.</td>
<td>Commercial plant SNG from coal</td>
<td>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 O&amp;G are recoverable from these reserves. Texas Gas has signed a formal agreement with the state of Kentucky to establish a two phase plan 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 1988. The plant will be located on the Ohio River in Western Kentucky.</td>
<td>Planning</td>
</tr>
<tr>
<td>TransCanada Pipelines, Ltd.</td>
<td>Proposed commercial gasification project</td>
<td>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 applied to HRB to include $8 million in their rate base to cover costs of the feasibility study.</td>
<td>Proposed</td>
</tr>
<tr>
<td>Transcontinental Gas Pipe Line Corporation, a subsidiary of Transco Companies, Inc.</td>
<td>Proposed commercial plant SNG from coal</td>
<td>Transco had an option agreement with Stoltz, Wagner &amp; Brown and Tipperary Corporation for joint development efforts of coal rights underlying more than 20,000 acres in the Powder River Basin of northeastern Wyoming. Transco did not exercise option because of insufficient time to evaluate commercial potential. Mobil later picked up &amp; exercised option.</td>
<td>No recent developments (See page 4-14 of June 1974 issue)</td>
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<tr>
<td>Catalysts &amp; Chemicals, Inc.</td>
<td>Pilot plant methanation of coal gas</td>
<td>The pilot plant consists of three methanation reactors to be used for proving a catalyst and designing a methanation process for use in commercial coal gasification plants. Plant located in Louisville, Kentucky has a capacity of 100 MMCFD pipeline gas. A commercial methanation catalyst to be used in coal gasification plants has been developed.</td>
<td>Methanation tests completed.</td>
</tr>
<tr>
<td>COGAS Development Company (CDC), joint venture of Consolidated Natural Gas, FMC Corp., Panhandle Eastern Pipeline, Republic Steel, and Tennessee Gas Pipeline</td>
<td>Pilot plants SNG and synthetic crude oil from coal</td>
<td>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. Rocky Mountain Energy Co. dropped out of COGAS.</td>
<td>Operational</td>
</tr>
<tr>
<td>Commonwealth Edison Co.</td>
<td>Demonstration plant clean fuels test facility</td>
<td>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 180 BTU/CF gas for a 70,000 MW generation unit. Edison hopes to gather enough data to scale up the process to feed a 500 MW unit. Fluor Corp. was recently named contractor for the operation. Details of the proposed project not available.</td>
<td>Active</td>
</tr>
<tr>
<td>Conoco Methanation Co. (subsidiary of Continental Oil Co.)</td>
<td>Demonstration plant methanation of coal gas</td>
<td>Plant is adjacent to and methanates 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 is acting as a consultant. There are 13 companies participating with Conoco. Plant is operating and has successfully produced high methane gas (95 percent) at rates of 2.5 MMCFD. It is being supplied to homes in Fife, Scotland. One year test project planned.</td>
<td>Operational (See Dec. 1973 issue, page 4-38)</td>
</tr>
<tr>
<td>Continental Oil Co. and 13 other U.S. companies</td>
<td>Demonstration plant coal gasification</td>
<td>Conoco will coordinate project and British Gas Corp. will be project operator. Lurgi will provide technical assistance. The three-year test will involve the modification of a Lurgi gasifier at the Westfield, Scotland gas plant for operation under slagging conditions. 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.</td>
<td>Operational (See June 1974 issue, page 4-14.)</td>
</tr>
<tr>
<td>Electric Power Research Institute and the Southern Services Co.</td>
<td>Pilot plant solvent refining of coal</td>
<td>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.</td>
<td>Operational</td>
</tr>
<tr>
<td>El Paso Natural Gas Co.</td>
<td>Development coal gasifier project</td>
<td>One Lurgi modual 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.</td>
<td>PFC approval pending final decision. See page 4-14.</td>
</tr>
<tr>
<td>Environmental Protection Agency Sponsor, Applied Technology Corporation Contractor</td>
<td>ATGAS project</td>
<td>EPA contract provided for work on design criteria for a 50-100 MW power generating plant utilizing a low-BTU gas produced by the ATGAS process. Process employs a unique molten-iron gasification technique to gasify all types of coal with steam and oxygen at low pressures.</td>
<td>Inactive</td>
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**Project cost:** Initial development program, including pilot plants, estimated at $8.5 million.
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<td>Environmental Protection Agency Sponsor, J.F. Pritchard &amp; Company Contractor</td>
<td>Engineering evaluation of ATGAS Process</td>
<td>Engineering evaluation of the SO2-free, two-stage combustion process developed by Applied Technology Corporation (called the ATGAS Process) applicable to a 1000 MW power generating plant.</td>
<td>Inactive</td>
</tr>
<tr>
<td>ERDA/Fossil Energy</td>
<td>Synthane project Pilot plant SNG from coal</td>
<td>This process, developed by the Bureau of Mines uses a steam-oxygen, fluid-bed gasifier to produce a pipeline-quality gas from 70 TPD of coal. Pilot plant located at the Bureau's brukton Station, Allegheny County, Pennsylvania.</td>
<td>Active</td>
</tr>
<tr>
<td>ERDA/Fossil Energy and American Gas Association</td>
<td>Lurgi process development</td>
<td>Modification of the Lurgi reactor to permit handling of coking and swelling American coals. Tests will be made in Scottish Gas Board's Lurgi plant at Westfield, Scotland. Lurgi is responsible for internal reactor modification while Woodhall-Duckham is to make necessary ancillary system modifications to isolate the single gasifier unit. Technological guidance will be provided by British Gas and Lurgi throughout the program. Some 20,000 tons of the following U.S. coals have been shipped to Scotland: Illinois No.5, Illinois No.6, Pittsburgh No.8, and Montana Rosebud coals.</td>
<td>Tests completed (See September 1974 issue, page 4-18.)</td>
</tr>
<tr>
<td>ERDA/Fossil Energy and Ventic Gas Association Sponsor, Battelle Columbus, Contractor</td>
<td>Pilot plant SNG from pulverized coal</td>
<td>A 25-TPD pilot plant is being built by Chemico at Battelle's West Jefferson, Ohio, Laboratories to investigate the Agglomeration Gunner Process proposed and developed by Battelle under sponsorship of Union Carbide Corporation.</td>
<td>Construction in progress.</td>
</tr>
<tr>
<td>ERDA/Fossil Energy and American Gas Association Sponsors, Coal Research, Inc. - Contractor</td>
<td>BI-GAS project Pilot plant SNG from coal</td>
<td>The process, developed by Bituminous Coal Research, Inc., reacts pulverized coal in a stream of oxygen and steam at high temperature and pressure to produce SNG. Steams-Roper 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.</td>
<td>Testing to begin in early 1975</td>
</tr>
<tr>
<td>ERDA/Fossil Energy, American Gas Association Sponsors, Chem Systems Contractor</td>
<td>Process development unit Liquid phase methanation (LPM)</td>
<td>A skid-mounted LPM development unit is being constructed by Davy Powergas for evaluation in a coal gasification pilot plant.</td>
<td>Development unit in construction phase</td>
</tr>
<tr>
<td>ERDA/Fossil Energy, American Gas Association Sponsors, Consolidation Coal Co. Contractor</td>
<td>CO Acceptor project Pilot plant SNG from coal</td>
<td>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 CO2 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 is preheated to 1900°F and introduced into the gasifier. A chemical reaction absorbs the carbon dioxide present in the gasifier and also releases additional heat. Methanation is then required to make pipeline quality gas. Longest run to date has been 125 hrs. Methanation tests set for early 1975.</td>
<td>Operational</td>
</tr>
<tr>
<td>ERDA/Fossil Energy, American Gas Association Sponsors, Institute of Gas Technology, Contractor</td>
<td>HYGAS project Pilot plant</td>
<td>Pilot plant capacity is 1.5 MMCFD 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. May 18th, 1974 reported a successful run of 30 hours under self-maintained operation with no external heat input. total run time of 600 hours.</td>
<td>Operational (See page 4-14 of this issue of Synthetic Fuels.)</td>
</tr>
<tr>
<td>ERDA/Fossil Energy Sponsor, Bituminous Coal Research Contractor</td>
<td>Process development unit Low-BTU gas</td>
<td>Total ERDA/AGA commitment since 1964 has been $55.1 million steam-oxygen development program, $6.5 million steam-iron development program, $18.2 million.</td>
<td>Construction underway</td>
</tr>
<tr>
<td>ERDA/Fossil Energy Sun, AECO, Ashland, Mobil, Dupont, Reynolds Martin Marietta, Consolidated Gas, Y and O Coal, and EPRI Sponsors, Coalan Contractor</td>
<td>Demonstration plant coal to clean boiler fuel</td>
<td>Coalcon will design, construct and operate a 2,600 TPD demonstration plant using a hydrocarboxylation process for producing 3,000 barrels/day of 17API 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.</td>
<td>Plant design and procurement underway (See March 1975 issue, page 4-24.)</td>
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<td><strong>ERDA/Fossil Energy</strong>&lt;br&gt;Sponsor, Combustion Engineering Contractor&lt;br&gt;Consolidation Coal Co. and Continental Oil Co. Sponsors</td>
<td>Process development unit - low-BTU gas from coal</td>
<td>Four-year, three-phase program to demonstrate the C-E atmospheric entrainment gasification system to produce low-BTU gas.  A 5 TPD 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.</td>
<td>Pilot plant under design (See March 1975 issue, page 4-25 and 4-34)</td>
</tr>
<tr>
<td><strong>ERDA/Fossil Energy</strong>&lt;br&gt;Sponsor, Eyring Research Institute Contractor&lt;br&gt;Fluor Corp. Contractor</td>
<td>Underground coal gasification project</td>
<td>The project is designed to assess the potential value of coal gasification with field in thin eastern coal beds.  Project site will be Grants District of Wetzel County, West Virginia. The West Virginia Department of Natural Resources will use directional drilling techniques to place parallel 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.</td>
<td>Testing is under way (see March 1975 issue, page 4-24)</td>
</tr>
<tr>
<td><strong>ERDA/Fossil Energy</strong>&lt;br&gt;Sponsor, Colton Continental Oil Co. Contractor</td>
<td>Bench scale coal liquefaction</td>
<td>Conoco Coal Development Division at Library, Pennsylvania is to test the potential application of a zinc-halide hydrocracking process to production of distillate fuel from coal.  Four barrels per ton is expected.  A 100 pound per hour test unit is under development. Shell Development Corporation is also participating. Project cost $6.5 million.</td>
<td>Studies in progress</td>
</tr>
<tr>
<td><strong>ERDA/Fossil Energy</strong>&lt;br&gt;Sponsor, Foster-Wheeler &lt;br&gt;Contractor&lt;br&gt;Fluor Corp. Contractor</td>
<td>Reactivation of Cresap facility</td>
<td>Fluor Engineers and Constructors has a contract to convert the former coal-to-gasoline pilot plant in Cresap, West Virginia to a multi-process 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.</td>
<td>Construction underway (See September 1974 issue, page 4-21)</td>
</tr>
<tr>
<td><strong>ERDA/Fossil Energy</strong>&lt;br&gt;Sponsor, PMC Corp. Contractor&lt;br&gt;Foster-Wheeler Contractor</td>
<td>COED project Pilot plant liquid fuels from coal</td>
<td>Pilot plant at Princeton, N.J. has had a capacity of 36 TPD and yields 30 BPD of refined feedstock plus char and fuel gas.  Plant has operated on seven coals from West to Mid-West and the East.  Char to be tested in July 1975 in a commercial Koppers-Totzek gasifier in Spain with report to be issued in fourth quarter.  Pilot plant data deemed to be complete and operations have been discontinued. Project cost Over $20,000,000.</td>
<td>Completed (final report to be issued late 1975).</td>
</tr>
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<td><strong>ERDA/Fossil Energy</strong>&lt;br&gt;Sponsor, Foster-Wheeler and Bethlehem Steel Co. Contractors</td>
<td>Pilot plant low-BTU gas from coal</td>
<td>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</td>
<td>Pilot plant design has begun (see March 1975 issue, page 4-23)</td>
</tr>
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<td><strong>ERDA/Fossil Energy</strong>&lt;br&gt;Sponsor, Foster-Wheeler and Bethlehem Steel Co. Contractors</td>
<td>Synthoil pilot plant</td>
<td>Foster Wheeler is to design an 8 TPD coal liquefaction pilot plant using the Bureau's Synthoil process.  The coal is converted catalytically while slurred 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. Project cost $14 million.</td>
<td>Design of pilot plant underway (see March 1975 issue, page 4-23)</td>
</tr>
<tr>
<td><strong>ERDA/Fossil Energy</strong>&lt;br&gt;Sponsor, Hydrocarbon Research Inc., Sun, Ashland, ARCO, Standard of Indiana, and CNRI</td>
<td>H-coal process pilot plant, low sulfur fuel oil and syncrude</td>
<td>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 3.5 percent coal.  The three-phase project will cover plant design, construction, and operation, respectively.  Under phase one NRI is completing testing at Trenton, New Jersey and gathering data for environmental, technical, and economic assessment.  Contract requires 1/3 participation by private contributors. Industry sponsors are Electric Power Research Institute, Ashland Oil Co., Atlantic Richfield Co., Standard Oil Co. of Indiana and Sun Oil. Project cost $5.1 million for phase one.</td>
<td>Pilot plant in design stage</td>
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### Status of Synfuels Projects

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<tr>
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<tr>
<td>ERDA/Fossil Energy, Sponsor, Lawrence Livermore Laboratory Operator</td>
<td>Underground coal gasification project</td>
<td>The LLL process calls for the fracturing of coal and shale sequences with chemical explosives in an array of drill holes 500 to 3000 feet deep. Gas collection is from the bottom of the fractured zone with oxygen/steam injected towards the top of the zone to sustain gasification and partial combustion. The process is under study with a 7-hole field test scheduled for FY '78. This test is designed to fracture a zone 100 to 150 feet in diameter and yield one to five MMCFD. LLL is currently investigating suitable coal deposits, extent of fracturing required, means to control gasification, and feasibility and impact of a commercial operation.</td>
<td>Planning (see page 4-8, Dec. 1974 issue)</td>
</tr>
<tr>
<td>ERDA/Fossil Energy, Sponsor, A.D.Little, Inc. Contractor</td>
<td>Bench scale extractive coking for sulfur fuels</td>
<td>Project consists of an exploratory experimental program at the bench scale and 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.</td>
<td>Study in progress</td>
</tr>
<tr>
<td>ERDA/Fossil Energy, Sponsor, Mobil Oil Co. Contractor</td>
<td>Bench scale - methanol to high octane gasoline</td>
<td>Process is being studied at continuous bench scale as prelude to scaleup to 100 BBL/day pilot plant and/or 5000 BBL/day commercialization. Compatibility of product for automobile use will be established.</td>
<td>Studies in progress</td>
</tr>
<tr>
<td>ERDA/Fossil Energy, Sponsor, University of North Dakota Engineering Experiment Station Contractor</td>
<td>Project lignite PDU - SNG and low-sulfur fuel oil?</td>
<td>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.</td>
<td>PDU tests underway</td>
</tr>
<tr>
<td>ERDA/Fossil Energy, Sponsor, Pittsburgh &amp; Midway Coal Mining Co. Contractor</td>
<td>Solvent refined coal project</td>
<td>Steam-Roger Corporation designed the plant which will be located at Fort Lewis, Washington. Rust Engineering is the builder. The plant will process 50 tons of coal daily to yield about 30 tons of extract. Developed by PAM through bench scale work, the process extracts coal with a recycle solvent which is then removed leaving a pitch-like coal extract.</td>
<td>Operational</td>
</tr>
<tr>
<td>ERDA/Fossil Energy, Sponsor, Ralph M. Parsons Contractor</td>
<td>Process design and evaluation</td>
<td>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.</td>
<td>Studies in progress (see March 1975 issue, page 4-25)</td>
</tr>
<tr>
<td>ERDA/Fossil Energy, Sponsor, Rockwell International Corp. Contractor</td>
<td>Process development unit - low-BTU gas from coal</td>
<td>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 5 atm. and will include a salt regeneration unit. Program to obtain scale-up data and investigate fly ash, sulfur dioxide and nitrogen oxide emission characteristics.</td>
<td>Plant design underway (see March 1975 issue, page 4-25)</td>
</tr>
<tr>
<td>ERDA/Fossil Energy, Sponsor, TVA Contractor</td>
<td>Pilot plant low-BTU gas</td>
<td>Pilot plant to develop large fixed-bed coal gasifier technology, to include gas cleanup systems, for power and industrial use.</td>
<td>Preliminary design underway</td>
</tr>
<tr>
<td>ERDA/Fossil Energy, Sponsor, Public Service Indiana, Bechtel Corp., AMAX Coal Co. and Peabody Coal Co. Contractors.</td>
<td>Hanna underground coal gasification project</td>
<td>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.</td>
<td>PDU tests active (see June 1973 issue, page 4-14)</td>
</tr>
<tr>
<td></td>
<td>Process development plant low-BTU gas from coal</td>
<td>Project cost total program cost estimated at $8.0 million; Westinghouse has an $8.2 million contract from ERDA for 70% of the initial R&amp;D cost.</td>
<td></td>
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*NOTE: Values are approximate and subject to change.*
## STATUS OF SYNFEULS PROJECTS

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<th>PROJECT DESCRIPTION</th>
<th>DETAILS</th>
<th>STATUS</th>
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</thead>
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<tr>
<td>ERDA/Fossil Energy Sponsor, Westinghouse Electric Corp. Contractor</td>
<td>Research project generation of electric power from coal</td>
<td>The three-year contract provides for work on the development of magnetic hydrogencams (MHD), solid electrolyte fuel cells, and gas turbine-steam turbine power plants. High temperature and pressure gas cleanup systems will be studied and evaluated, and the use of fuel cells for the production of hydrogen will be developed. An ancillary task includes development efforts on the transmission of large blocks of power for transcontinental distances in superconductors.</td>
<td>Active</td>
</tr>
<tr>
<td>Exxon Corporation</td>
<td>Research and pilot plant operation</td>
<td>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 100 TPD pilot plant. A companion project by Exxon to develop a coal gasification process was postponed in November 1974.</td>
<td>Active (See Dec. 1975 issue, page 4-39)</td>
</tr>
<tr>
<td>General Electric Co.</td>
<td>Pilot plant synthesis gas and SNG from coking coals</td>
<td>Work to date has been done at G.E.'s research and development center in Schenectady, New York on a feasibility unit operating at atmospheric pressure and consuming about 500 pounds of coal per day. Successful runs, using low-grade coals from Illinois and Missouri have been made. The unit is a fixed bed reactor using a unique extraction method of injecting coal into the gasifier. A 1000 TPD demonstration gasifier operating at 20 atmospheres will be built within the next two years. System plans call for construction of a prototype plant with full-scale gasifier, a liquid membrane scrubber system for sulfur removal will also be studied.</td>
<td>Operational</td>
</tr>
<tr>
<td>Gulf Research and Development</td>
<td>Catalytic Coal Liquefaction pilot plant</td>
<td>The CCL process passes slurried coal at 2000 psi over a fixed catalyst bed to yield 3 BBL of low sulfur liquid fuel per ton. The one TPD pilot plant began pre-start-up testing in January 1975.</td>
<td>Operational</td>
</tr>
<tr>
<td>Hydrocarbon Research, Inc. Operator, Financial sponsors</td>
<td>H-coal project Pilot plant low sulfur fuel oil and synccrudes</td>
<td>Testing of H-coal process is being done in a pilot plant at Trenton, New Jersey. Process uses an ebullated catalyst to liquefy coal under hydrogen pressure in the presence of a recycle oil. Product ranges from low-sulfur fuel oil to high quality gasoline and naphtha. Construction has begun on a prototype plant. See also the ERDA/Fossil Energy-HRI project in this listing.</td>
<td>Active</td>
</tr>
<tr>
<td>Institute of Gas Technology and Ralph M. Parsons Co.</td>
<td>U-Gas project Pilot plant low BTU gas from coal</td>
<td>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.</td>
<td>Active</td>
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<tr>
<td>Island Creek Coal Co. and Garrett Laboratories (both subsidiaries of Occidental Petroleum)</td>
<td>Pilot plant coal liquefaction</td>
<td>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 five year program.</td>
<td>Active</td>
</tr>
<tr>
<td>New Mexico Institute of Mining and Technology</td>
<td>In situ coal liquefaction</td>
<td>New Mexico Energy Program is funding studies of high temperature and pressure dissolution of in place coal at New Mexico Institute. Computer modeling of preliminary coal bed stressing is underway.</td>
<td>Preliminary studies underway</td>
</tr>
<tr>
<td>Oklahoma, State of</td>
<td>Study SNG from coal using nuclear heat</td>
<td>The process being studied involves solvent extraction of coal to obtain liquid extract which is then hydrogenated. Heat is supplied by hot helium from a high temperature graphite moderated nuclear reactor; coal conversion efficiency of 95 percent is claimed. General Atomic Co. is prime contractor; Stone &amp; Webster is participating, work thus far consists of a literature search, conceptual plant design, and preliminary economic study.</td>
<td>Completed, final report issued (See March 1975 issue, page 4-11)</td>
</tr>
<tr>
<td>Old Ben Coal Corp., a subsidiary of Standard Oil Co.</td>
<td>Demonstration plant clean fuels from coal</td>
<td>Plant capable of processing 900 tons of coal daily to produce 150 TPD of clean burning solid fuel and 600 BPD of low-sulfur distillate fuel or to produce 2600 BPD of low-sulfur distillate only will be built to further test process developed by Old Ben. Process details not available. Old Ben is organizing a multi-company (15 or more) group to support project. Consolidation Coal Co., Old Ben, and Sohio are presently members of the group. Old Ben and Consol jointly advanced $600,000 for engineering and equipment costs.</td>
<td>Active</td>
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Project cost estimated at $83.5 million.
## STATUS OF SYNFUELS PROJECTS

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<tr>
<td>Stone &amp; Webster Engineering Corp. and Gulf General Atomic Co.</td>
<td>Research and development program</td>
<td>Joint program to use Gulf's HTGC nuclear reactor to provide heat for S&amp;W's solution-hydrogasification coal conversion process. Two-year R&amp;D program to be managed by S&amp;W. Industry support being sought. Project cost first phase estimated at $650,000 (San Diego Gas &amp; Electric has committed $100,000.</td>
<td>Active</td>
</tr>
<tr>
<td>Texas Utilities Services, Inc.</td>
<td>In situ gasification of Texas lignite</td>
<td>Texas Utilities Services Inc., an affiliate of Dallas Power and Light Company, Texas Electric Service Company and Texas Power and Light Company, has purchased for $8 million 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.</td>
<td>Active (See page 4-44)</td>
</tr>
<tr>
<td>Universal Oil Products</td>
<td>Pilot plant coal liquefaction</td>
<td>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.</td>
<td>Active</td>
</tr>
<tr>
<td>University of Texas at Austin, National Science Foundation, Texas Utilities Service Co., Continental Oil Co. and Mobil Oil Corp.</td>
<td>In situ lignite gasification</td>
<td>In situ gasification to recover energy content of Texas lignite, which has now been estimated to be 100 billion tons below striping 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.</td>
<td>Preliminary studies underway.</td>
</tr>
<tr>
<td>Wheelabrator-Frye Inc.</td>
<td>Demonstration plant solvent refined coal</td>
<td>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.</td>
<td>Plant design has begun</td>
</tr>
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INTERIOR ISSUES COMPREHENSIVE REPORT ON FY 1976 ENERGY RESEARCH PROGRAM

Interior's report on its energy research program for the coming year is a 490-page document entitled, "Energy Research Program of the Department of the Interior, FY 1976." It includes programs recently transferred to the Energy Research and Development Administration (ERDA).

This FY 1976 report is the product of nearly two years planning of the Administration's accelerated fossil energy programs. Recapping the earlier events of this program, Interior formed (in 1973) an Office of Research and Development to oversee the accelerated program. Then, as a result of a government-wide review of R&D activities, a report entitled, "The Nation's Energy Future," was issued. The Department's FY 1975 programs were then described in, "Energy Research Program of the U.S. Department of the Interior," published in 1974. Another interagency energy report followed in 1974 entitled, "Fossil Fuel Research in the President's Five-Year Energy R&D Program." That report addressed the following six areas in which Interior was given lead-agency roles:

- Coal extraction and reclamation
- Coal utilization
- Improved conversion efficiency (advanced power cycles)
- Oil and gas
- Oil shale
- Improved (power) transmission efficiency

These efforts formed the basis for the FY 1976 report. With the creation of ERDA, most similar activities will be

TABLE 1
U.S. DEPARTMENT OF THE INTERIOR/ERDA ENERGY RESEARCH AND DEVELOPMENT PROJECT FUNDING IN $ MILLION (BA)

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| Total           | DOI    | 21.1 | 146.3| 177.3| 44.2 | 261.1| 204.6| 284.6| 246.4   | 1,218.5 |
|                 | ERDA   | 154.0| 356.0| 419.7| 113.7| 666.5| 829.7| 620.0| 691.7   | 3,171.6 |
|                 | TOTAL  | 189.1| 496.3| 597.2| 157.9| 927.6| 1,134.3| 904.6| 936.1   | 4,390.1 |
### TABLE 2

**ENERGY RESEARCH AND DEVELOPMENT**

**PROJECTED FUNDING IN $ MILLION (BA)**

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<td><strong>A. Exploration</strong></td>
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1/ Does not include $2.3 M passed through to USGS and FSW. Includes $1.8 M coal preparation, waste disposal, and spoil bank restoration, previously reported as part of coal utilization program.

The program would entail federal incentives (possibly including price guarantees, purchase agreements, capital subsidies, leasing programs, etc., granted competitively, and would be aimed at producing selected types of gaseous and liquid fuels from both coal and oil shale.

The program will rely on existing legislative authorities, including those contained in the Non-Nuclear Energy Research and Development Act of 1974, but new legislative authorities will be requested if necessary.

The present report, then, gathers in one place the research activities which will be conducted by Interior in FY 1976, including programs transferred to ERDA in FY 1976.

The report is in two parts, strategy, and tactics. The strategy part concerns program development, funding (complete with summary tables for FY 1974 through 1980), constraints which may inhibit new technology, and indentification of environmental components of the program.
The tactics part concerns coal extraction, coal utilization, advanced power cycles, oil and gas, oil shale, geothermal, uranium, power transmission and storage, and related programs. Those subjects which are underlined concern "synthetic" fuels and will be reviewed here under separate headings. In addition, notes concerning tar sands investigations are included at the end of this review.

Funding of Energy R&D Programs Summarized

Table 1 presents the overall DOI/ERDA energy research and development project funding. Table 2 concerns funding for the coal extraction program. Table 4 concerns funding for the oil shale program.

**Coal Extraction Program**

Table 2 concerns funding of the coal extraction program. Referring first to sub-program A of Table 2, which is coal extraction, the Geological Survey is proceeding on projects such as the establishment of a computerized national coal resource data system. From this it will be possible to locate areas containing coal that meets specific industrial and environmental requirements. Attempts

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(1) ERDA - Fossil Energy January 1975.
(2) Bureau of Mines (Metallurgy) Citrate Process (Does Not Transfer to ERDA).
(3) Bureau of Mines (Mining) Coal preparation research, mining reclamation, and coal analysis with FY 75 funding at $1.5 does not transfer to ERDA and is shown in Chapter I, Coal Extraction.
(4) For OCR, Administration, and Supervision, is a separate budget item; for BM/Mines, this is the estimated proportional contribution for the programs transferring to ERDA.
will be made to adapt geophysical techniques to coal exploration.

Under sub-program B (coal extraction), studies will result in defining total water needs of coal extraction, in exploring for new underground water sources, and in evaluating improved coal transportation methods.

Under sub-program C, the Bureau of Mines will research new mining technologies and under sub-program D, the Fish and Wildlife Service will engage in numerous environmental studies. Under sub-program E, the Office of Water Research and Technology will study methods of using only the natural precipitation to re-vegetate strip-mined areas. Under sub-program F, the Bureau of Land Management will initiate its Energy Minerals Rehabilitation Inventory and Analysis (EMRIA) program with respect to coal. Soil types will be inventoried, plant sites will be investigated for their rehabilitation potentials, and data gathering instruments and stations will be placed in operation.

**Oil Shale Program**

**Strategy:** The oil shale program focuses on in situ retorting instead of surface retorting. The government believes that surface retorting is a known technology and the private sector has the responsibility to verify its economics.

**Tactics:** The question of the government's role in stimulating in situ development techniques is undergoing separate evaluation. This reassessment of government programs stems from the unsuccessful effort to have industry undertake development of in situ processing technologies through the Department's prototype oil shale leasing program. Under that program, two tracts believed to be amenable to this approach were offered for development. No bids were received for the right to develop these tracts, suggesting the need for further government involvement to stimulate the development of this processing option.

Accordingly, an in situ program has been framed by the Office of Research

**TABLE 4**

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<th>U.S. DEPARTMENT OF THE INTERIOR</th>
<th>ENERGY RESEARCH AND DEVELOPMENT</th>
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<tr>
<td>PROJECTED FUNDING IN $ MILLION (BA)</td>
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Program: Oil Shale

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*Energy Minerals Rehabilitation Inventory and Analysis.
TABLE 5

PRINCIPAL METHODS FOR CONVERTING COAL TO LIQUIDS

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<th>Laboratory to PDU</th>
<th>Pilot Plants</th>
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<td>Synthoil Throwaway catalyst (Bergius)</td>
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<td>Solvent Extraction (Product may be catalytically upgraded)</td>
<td>Zinc Chloride Exploratory</td>
<td>2. Fixed Bed</td>
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<td>Pyrolysis</td>
<td>CO-Steam Extract-Delayed Coke Exploratory</td>
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<td>Indirect Synthesis</td>
<td>Alcohol Fuel</td>
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Design of Prototype Plant
Initial Pilot Plant Designs
Characterization and Refining of Crude Products (Boiler Fuel, Transportation, Chemicals)
Supporting Research and Development
  - Materials of Construction and Special Equipment
  - Engineering Evaluations and Cost Estimates
  - Novel Liquefaction Processes
  - Environmental Research
  - Liquefaction of Lignite and Western Subbituminous Coals
Desulfurization

and Development that will enable maximum industry participation. The essential program elements are: (1) re-offer under competitive conditions, prototype tracts for development by in situ means only, and (2) draft the government/industry programs to support and complement expected development under the leasing program.

Referring to Table 4, sub-program A, the BLM, in FY 1976, is conducting soil inventories and development site investigations, and is installing instrumentation for data platforms. In sub-program B, the Fish and Wildlife Service is conducting biological mapping and inventory work. Under sub-topic C, the Geological Survey is continuing the mapping of the Piceance and Uinta basin areas and is contracting for the drilling of 11 coreholes in the Piceance basin and six coreholes in the Uinta basin. Under sub-topic D, the Bureau of Mines plans to sink a large diameter shaft near the center of the Piceance Creek basin to evaluate deep-mining problems. The shaft will be 10 to 14 feet in diameter and will penetrate to 2600 feet. This will make available for metallurgical testing large amounts of the associated minerals nahcolite and dawsonite. Under sub-program E, the BM will conduct comprehensive laboratory testing on nahcolite and dawsonite. Ultimately a large process development unit (PDU) will be built. Under sub-
heading F, ERDA will attempt to advance the technology for in situ shale processing by test work at the field test site in SW Wyoming. Reserves as deep as 400 feet will be tested by various in situ methods, with hopes of testing to 1000 feet. Under sub-program G, ERDA will study the refining of in situ shale oils.

Coal Utilization Program

Over 50 percent of the total R&D funds are assigned for use in the 1975-1980 coal utilization program.

The overall goals of the coal utilization program are to develop processes for the production of clean gaseous and liquid fuels from coal and also to develop processes for the indirect combustion of coal in an environmentally acceptable manner. However, the relative emphasis on the different program elements (liquefaction, low-BTU gas, high-BTU gas, direct combustion) will relate to the particular energy shortage (i.e., transporation, utility, industry, etc.) and to the technological potentials and environmental impacts.

As noted in Table 3, coal liquefaction projects will receive $97.6 million in FY 1976 and $396.2 million in the '76-'80 period. Four principal methods for converting coal to liquids will be investigated involving a number of process develop units (PDU's) and involving five pilot plants, as shown in Table 5.

The high-BTU gasification program, for which $63.4 million has been allocated for FY 1976, consists of:

Pilot Plants
1. HYGAS - in operation
2. CO, Acceptor - in operation
3. Synthane - operation in late 1974
4. Bi-Gas - operation in late 1975
5. Self-Agglomerating Fluid Bed

Process Development Units
6. Hydrane

Supporting R&D

Hydrogen Generation

Methanation

Chemical and Engineering Development

Materials and Component Research

Environmental Control

Novel Gasification Processes

The low-BTU gasification program, for which $45 million has been allocated for FY 1976, involves the following projects:

1. Fixed Bed PDU and Pilot Plant at TVA
2. Underground Coal Gasification
   Hanna, Wyoming (underway)
   Eastern Location (to be investigated)
3. Molten Salt (dormant)
4. Entrained-Bed PDU (final design)
5. Fluid-Bed PDU
6. Entrained-Bed Pilot Plant (final design)
7. Coal Conversion Data Handbook (being compiled)

Tar sands R&D are included in the Oil and Gas element of the overall program. The main effort consists of an in situ field test now being set up in tar sands formations at a site in Uintah County, Utah. In addition to this field test, tar sands and heavy oil deposits are being studied to determine their distribution, quantity and quality, chemical characteristics, and trace element contents.

# # # #

SELECTED ENERGY RESEARCH PROPOSALS FUNDED BY CERI SUMMARIZED

The Colorado Energy Research Institute was created by the 1974 Colorado General Assembly to develop and coordinate energy research and education programs. It is based at Colorado School of Mines (CSM) Golden. The University of Colorado (CU) and Colorado State University (CSU) are also participating in the studies.

# # # #

SYNTHETIC FUELS, JUNE, 1975
<table>
<thead>
<tr>
<th>Proposal</th>
</tr>
</thead>
<tbody>
<tr>
<td>ECOLOGICAL &amp; EVOLUTIONARY EFFECTS OF SELENIUM TAILINGS AND SPENT SHALE</td>
</tr>
<tr>
<td>REHABILITATION POTENTIAL AND PRACTICES OF COLORADO OIL SHALE LANDS</td>
</tr>
</tbody>
</table>

**Abstract**

The effect of selenium and spent shale on the ecosystem; plant adaptations.

Most of work will focus on Piceance Basin.

1. Identification and characterization of ecosystems including risk factors of each ecosystem.
2. Selection of ecotypes of native shrub species - collect and propagate seeds and cuttings.
3. Improvement of plant materials for rehabilitation.
5. Fertility requirements. Identify soils and long-term requirements.
7. Interaction between plant species, soil material, cultural practices and environmental parameters on rate and direction of succession.
8. Determine nutritional quality and quantity of habitats available to large herbivores. Obtain baseline data that would indicate best revegetation practices to support these animals.

**Cost**

$13,990

**Investigator & Institution**

Bock, CU

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**TRACE ELEMENTS IN OIL SHALE**

Study of concentrations, transport, and fate of trace elements in oil shale.

1. Regional survey of trace element concentrations,
2. Mass balance study of oil shale retorting processes
3. Study of fate and biological availability of trace elements in spent shale and disturbed soils.

**Cost**

$16,957 ($213,800) Chappell, et al

**Investigator & Institution**

CU, CSM, CSU

---

* Number in parentheses indicates total contract potential.
<table>
<thead>
<tr>
<th>Proposal</th>
<th>Abstract</th>
<th>Cost</th>
<th>Investigator &amp; Institution</th>
</tr>
</thead>
<tbody>
<tr>
<td>THERMAL PROPERTIES OF GREEN RIVER OIL SHALE OF INTEREST TO IN SITU FRACTURING &amp; RETORTING SCHEMES</td>
<td>Collect information on the thermal conductivity and heat capacity of oil shale in the Green River area to be used in helping develop the most economic means of in situ recovery of oil. Develop models that can be used in analyzing similar data on other oil shale deposits.</td>
<td>$27,000</td>
<td>Collins &amp; DuBow CSU</td>
</tr>
<tr>
<td>SPENT SHALE BACK FILLING APPLIED TO OIL SHALE MINING</td>
<td>Determine if spent shale back filling can reduce environmental impact and increase extraction ratios. Will also investigate pneumatic transport and placement.</td>
<td>$20,000</td>
<td>Wang, CSM</td>
</tr>
<tr>
<td>A NEW TECHNIQUE FOR OIL SHALE EXCAVATION USING MECHANICAL IMPACT PICKS AND UNDERCUTTING</td>
<td>Develop method of creating an undercutting slot in the face and using a mechanical hydraulic pick to exploit the rocks' natural weakness by breaking to the free face created by the slot. Will allow high rates of extraction and cause minimal damage to surrounding rock.</td>
<td>$20,000</td>
<td>Wang, CSM</td>
</tr>
<tr>
<td>COAL</td>
<td>Adapt knowledge of erosion and sedimentation to specific problems of open pit mining. Phase I: Develop manual for evaluating erosion potential and prevention methods. Phase II: Outline training program for site planners in fundamentals of hydraulics, erosion, sediment, and river mechanics.</td>
<td>$10,000</td>
<td>Richardson &amp; Mahmood CSU</td>
</tr>
<tr>
<td>NUCLEATION PROPERTIES OF RESPIRABLE COAL DUST</td>
<td>Use cloud chamber techniques to study nucleation and precipitation efficiencies of coal dust. Lay scientific foundation for the development of more effective methods of controlling respirable coal dust in underground mines.</td>
<td>$9,000</td>
<td>Schowengerdt, CSM</td>
</tr>
<tr>
<td>INVESTIGATION OF COAL DUST EXPLOSION IN AIR</td>
<td>Will use a shock tube to simulate explosions and determine most effective means of preventing them.</td>
<td>$14,804</td>
<td>Edwards, CSU</td>
</tr>
<tr>
<td>OVERALL KINETICS OF THE REMOVAL OF SULFUR FORMS FROM COAL BY HYDROGENATION IN SOLUTION</td>
<td>1. Determination of overall kinetic parameters. 2. Identify sulfur form determinations.</td>
<td>$7,858</td>
<td>Dickson, CSM</td>
</tr>
<tr>
<td>Proposal</td>
<td>Abstract</td>
<td>Cost</td>
<td>Investigator &amp; Institution</td>
</tr>
<tr>
<td>------------------------------------------------------------------------</td>
<td>----------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------</td>
<td>-----------------------------</td>
<td>----------------------------</td>
</tr>
<tr>
<td>OPTIMIZATION OF PARTICLE SIZE DISTRIBUTION FOR COAL SLURRY PIPELINES</td>
<td>Construct a mathematical model using geometric programming for determining cost functions of slurry preparation, pipeline transportation and slurry separation to determine the optimum particle size distribution.</td>
<td>$10,013 ($22,000)</td>
<td>Faddick, CSM</td>
</tr>
<tr>
<td>ECONOMIC FEASIBILITY OF RECOVERING METHANE EMITTED FROM COAL</td>
<td>Will study the following methods for methane recovery: 1. gas absorption, 2. potential of the physical adsorption (ambient), 3. chemical separation, 4. physical adsorption (cryogenic) 5. combustion.</td>
<td>$7,984 ($280,000)</td>
<td>Kidnay, CSM</td>
</tr>
<tr>
<td>INFORMATION AND EDUCATION PROGRAMS</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>DEVELOPMENT OF COLORADO'S ENERGY RESOURCES</td>
<td>Four semester hour credit course for junior and senior high school teachers. Will discuss development of coal, oil shale, hydroelectric, solar, geothermal power.</td>
<td>$11,967</td>
<td>Shimoda, CSM</td>
</tr>
<tr>
<td>DEVELOPMENT OF A SUPPLY-DEMAND MODEL FOR ENERGY IN COLORADO</td>
<td>Develop model which will analyze impact of different energy policies on industrial and commercial activities. Will relate energy consumption to sales, income, and employment.</td>
<td>$10,626 ($149,000)</td>
<td>Petrick, CSM</td>
</tr>
<tr>
<td>CONSERVATION</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>HIGH TRANSITION TEMPERATURE SUPERCONDUCTOR</td>
<td>Will test properties of novel compounds which could be used in electrical transmission to effect great energy savings.</td>
<td>$7,780</td>
<td>Geller, CU</td>
</tr>
<tr>
<td>RESEARCH ON ENERGY USE DECISIONS IN COLORADO RESIDENTIAL UNITS</td>
<td>1. Determine factors involved in energy-use decisions. 2. Select a number of homes and interview residents as to energy consumption pattern. 3. Perform a construction analysis of each house to determine conservation measures. 4. Survey attitude of construction and real estate industry. 5. Publish conservation and energy-use guidelines for designers, builders, users.</td>
<td>$12,625 ($19,000)</td>
<td>Feng, CU</td>
</tr>
</tbody>
</table>
ABSTRACTS OF PROPOSALS FUNDED BY CERI (Continued)

<table>
<thead>
<tr>
<th>Proposal</th>
<th>Abstract</th>
<th>Cost</th>
<th>Investigator &amp; Institution</th>
</tr>
</thead>
</table>
| WATER RESOURCES                                                          | 1. Identify data insufficiencies of present Water Bank.  
2. Define analysis needed to evaluate water rights and total availability.  
3. Identify hydraulic, economic, social, and legal models to meet project objectives. Debut models.  
4. Develop scenarios of water resource reallocation.                                                                                      | $18,531               | Longenbaugh, CSU          |
| ANALYSIS OF WATER AVAILABILITY FOR ENERGY DEVELOPMENT                    | A compilation of information on 400 researchers with expertise in a wide variety of energy fields. The main objective of the Directory is to create more communication between researchers and provide information to state officials and federal funding sources regarding available expertise in Colorado. | $4,480                | Vories, CERI              |
| GENERAL                                                                  | Will determine energy input and outputs, including energy and energy equivalents of materials, for energy production systems of fossil fuels. Production systems will be examined for each research from exploration, extraction, conversion, and transportation/transmission to the point of end use. Objectives are: to examine policy-related matters; to analyze energy accounting method; to develop an overall methodology and solid data on energy balances. | $100,000              | Melcher, CERI             |
| DIRECTORY OF COLORADO ENERGY RESEARCHERS 1975                           | Will develop a complete system with adequate data and analytic techniques to outline alternative scenarios for energy systems in the state. The system will assess supplies, new development, uses and impacts of energy for a 20-year time frame. It will be carried out in three increasingly sophisticated phases with each phase producing a set of scenarios based on information and tools available and will indicate tools and data needed for the next phase. | Approx. $50,000        | York, CERI                |
## PROPOSALS REVIEWED AND AWAITING ESTABLISHMENT OF FUNDING PRIORITIES/OR REVISIONS

<table>
<thead>
<tr>
<th>Category</th>
<th>Title</th>
<th>Source</th>
<th>Contract Potential</th>
</tr>
</thead>
<tbody>
<tr>
<td>OIL SHALE/ENVIRONMENT</td>
<td>1. Assessment of Oil Shale Development in Colorado on Water Quality &amp; Quantity (Flack) P002-01</td>
<td>CU (with CSU)</td>
<td>$127,000</td>
</tr>
<tr>
<td>OIL SHALE/TECHNOLOGY</td>
<td>1. A comprehensive Geological-Geochemical Study of Colorado Oil Shale (Slaughter) 031-01</td>
<td>CSM</td>
<td>344,000</td>
</tr>
<tr>
<td>INFORMATION AND EDUCATION PROGRAMS</td>
<td>1. A Study of Energy Information Needs in Colorado (Porter) Po41-13</td>
<td>Porter (Consultant)</td>
<td>5,000</td>
</tr>
</tbody>
</table>

**ADDITIONAL DATA FORTHCOMING ON FEA/NGF SYNTHETIC FUELS INCENTIVES STUDY**

Drafts of results of Phase III of the Federal Energy Administration-National Science Foundation Synthetic Fuels Incentive Preference Project are being readied for Office of Management and Budget review prior to the scheduled June 30 publication date.

The study uses data collected in Phases I and II and includes an expanded survey of energy executives on non-technical aspects of synthetic fuels.

Since the project was revealed in Denver in February (see March 1975 issue of Synthetic Fuels, page 1-4) Donald B. Craven has been named acting FEA assistant administrator for energy resource development. He succeeds Duke Ligon in the job.

Craven said, "Phase III is moving ahead pretty well and we expect to have the final report ready for the President about June 30."

Phase I was an interview survey seeking baseline data on expectations for development of four synthetic fuels systems. It identified incentives to accelerate them.

Phase II obtained details of the six most promising of the incentives cited in Phase I.

With these steps completed, Phase III is expected to present quantitative measurements of the potential effectiveness of the selected incentives.

**Phase I Synthetic Fuels Incentives Preference Project**

Executives of 17 oil companies, four utilities and two banks were surveyed by an FEA/NSF team on non-technical problems affecting development of commercial scale production of liquefied coal; high-BTU gas from coal, low-BTU gas from coal and shale oil.

Responses were based on the premise there would be no new federal incentives, crude oil in the $10 per barrel range, timely processing of environmental impact statements, availability of government minerals and lands and a generally favorable political-economic climate for synthetic fuels development.

The study also cited constraints. Foremost among them were "excessive red tape" and delay from environmental and government regulations closely allied to a lack of a national energy policy.

The expression 'time is money,' clearly dominates the study findings as reflected in uncertain market conditions and unpredictable construction, operation, and other costs including delays from environmentally motivated lawsuits.
There is a general belief that Congress and the Executive Branch may change their policies and initial incentives as public opinion wavers over the 15 to 20-year incentive program.

Unable to fathom the bubbling cauldron of uncertainties, the executives firmly cited a need for federal risk sharing for development of synthetic fuels.

The study presents 45 incentives, including 17 proposed initially to stimulate the process. The consensus of preferred incentives was:

1. Firm government policy on availability of federal natural resources, environmental control standards, anti-trust policies, levels and tax incentives, etc. This must be backed with assurances the policies will endure during the life of a synthetic fuels program.
2. Guaranteed procurement of specific amounts of coal synthetics and shale on a cost-plus basis negotiated independently with each supplier. (Risk guarantee was the most important single incentive cited.)
3. Deregulation of gas.
4. Availability of federal land.
5. Removal of price controls on crude oil and refinery products.
6. Free market. This incentive implies a crude oil price at near $10 per barrel (1973 dollars) and assumes no federal incentives program.
7. Coordinated federal-state regulations and procedural approval practices.
8. Consistent, clear, and expedited processing of environmental rules and regulations.
9. Tax incentives including federally authorized investment tax credits of 7 to 10 percent on commercial size synfuels plants.
10. Loan guarantees up to 90 percent of construction costs on demonstration plants.
11. Direct grants up to 100 percent of complete financing of the first "most promising" commercial synfuels plants of the four respective types. Private industry would design, build and operate the facilities with the government paying the bills.

The inconsistencies apparent in the list are explained as representing only the most appealing incentives. Clearly the free market incentive is incompatible with the others.

Overall is the necessity for profitability and the awareness of the massive capital requirements and exceptionally long payout time. While federal risk absorption is cited at 100 percent, the executives recognized that the industry must share the risks.

The survey disclosed a wariness of artificial markets for synfuels.

Comment

Unfortunately, the report shys away from involvement of the general public in determining a national energy policy through its influence on Congress and its acceptance of an incentives program linked to employment and the national economic health.

This vital nourishment for a synthetic fuels incentive program is also absent from the Phase II report.

COMPANIES SURVEYED FOR PHASE I WERE:

Large Industries
Atlantic Richfield Company
Continental Oil Company
E. I. DuPont de Nemours & Co., Inc.
Exxon Corporation
Gulf Oil Corporation
Mobil Oil Corporation
Shell Oil Company
Standard Oil of California
Standard Oil of Indiana
Sun Oil Company
Texaco Inc.
Union Carbide Corporation
Union Oil of California
Phase II Report Entitled, "Spurring Synthetic Fuels Production"

In Phase II of the FEA/NSF Synthetic Fuels Incentives Study, government and industry teams simulated negotiation of hypothetical terms and conditions for six selected incentives. They were:

- Direct grant for pilot plant
- Direct grant for demonstration plant
- Convertible grant
- Loan guarantee (90 percent)
- Guaranteed procurement (fixed-price)
- Guaranteed procurement (cost plus fixed fee)

Six incentives were selected from 45 possible incentives in the Phase I study to accelerate commercial production of:

- Oil from oil shale
- Liquid fuels from coal
- Low-BTU gas from coal
- High-BTU gas from coal

The week-long of simulated negotiations were held in Washington, D.C., in October 1974. The government team developed incentive propositions, hypothetical terms and conditions.

The industry team, organized by the University of Texas, Graduate School of Business Research Center, reviewed and revised the assumptions. Figure 1, reproduced from the Phase II report, was developed to provide a framework for discussion. The figure shows step-by-step development of a commercial synfuels plant.

Facing one another across a table, the two teams went through the steps normally involved in negotiating definitive contracts.

For the simulated negotiations, the teams hazarded guesses, shown in Table 1, of the cost of plant facilities. The guesses were a compromise between business as usual and accelerated development estimates.

It is our opinion that the estimated costs are too low for oil for shale and very, very low for high-BTU pipeline gas from coal because of several discrepancies in the study. The teams calculated a combined cost of $3.5 billion for one of each type of plant.

Results of the Negotiations

Both teams concluded that if it is urgent to produce synthetic fuels commercially, it is necessary to remove "crucial roadblocks." It is desirable to:

- Assure a steady flow of funds.
- Foster long-term production of specific kinds of synfuels, in definable amounts, through new or amended regulations and policies on patents and leases.
- Amend Executive Order 10789 to list synfuels specifically as items that federal agencies are authorized to procure under Public Law 85-804.
- Obtain new federal legislation (enabling acts, authorizations, appropriations, and others) to facilitate commercial production.
- Coordinate existing federal, state, and local regulations, leasing, and other policies and practices,
- Use existing federal, state and local programs relating to housing, public works, education, community development, and transportation to support rapid growth and public acceptance of the synfuels industry.
TABLE 1
MAGNITUDE OF INVESTMENT

<table>
<thead>
<tr>
<th>Type of Plant</th>
<th>Cost (million dollars)</th>
<th>Capacity (barrels per day of oil or oil equivalent)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Oil from oil shale</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Pilot plant</td>
<td>70</td>
<td></td>
</tr>
<tr>
<td>Demonstration plant</td>
<td>223</td>
<td></td>
</tr>
<tr>
<td>Commercial plant</td>
<td>700</td>
<td>100,000</td>
</tr>
<tr>
<td>Liquid fuels from coal</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Pilot plant</td>
<td>100</td>
<td></td>
</tr>
<tr>
<td>Demonstration plant</td>
<td>333</td>
<td></td>
</tr>
<tr>
<td>Commercial plant</td>
<td>1,000</td>
<td>200,000</td>
</tr>
<tr>
<td>Low-BTU (utility) gas</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Pilot plant</td>
<td>40</td>
<td></td>
</tr>
<tr>
<td>Demonstration plant</td>
<td>133</td>
<td></td>
</tr>
<tr>
<td>Commercial plant</td>
<td>400</td>
<td>115,000</td>
</tr>
<tr>
<td>High-BTU (pipeline) gas</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Pilot plant</td>
<td>30</td>
<td></td>
</tr>
<tr>
<td>Demonstration plant</td>
<td>100</td>
<td></td>
</tr>
<tr>
<td>Commercial plant</td>
<td>300</td>
<td>150,000</td>
</tr>
</tbody>
</table>

Figure 1. Step-by-Step Development of a Commercial Synfuel Plant.
(Reproduced From: "Spurring Synthetic Fuels Production")
The Phase II "contract" negotiations identified many specific factors which both partners need to effectively accelerate investment in synthetic fuels technology. In the opinion of both teams, the solutions to many issues are within the existing negotiating authority of federal agencies and industrial managements. The exercise also identified fundamental issues which cannot be dealt with successfully under existing policy and law. These should become the subject of early executive and legislative consideration if there is to be a successful incentive program. These issues include:

- Government recognition of total project costs— including community development, support transportation, and waste disposal.
- The allowability of costs of capital—for the life of the projects.
- Provision for multiyear funding and lease/sale of government-owned feedstock.
- Contractual agreement for government participation to get timely resolution of environmental problems.

# # #

NATIONAL ACADEMY OF SCIENCES REPORTS ON MINERALS AND THE ENVIRONMENT

A Committee on Mineral Resources and the Environment (COMRATE) has prepared a report to the National Academy of Sciences entitled, "Mineral Resources and the Environment." Members of the reporting committee found themselves divided into two polarized camps each camp having views unacceptable to the other concerning the future adequacy of mineral resources and the environmental costs of winning them.

The "doomsters" see a future in which catastrophic exhaustion of resources is inevitable unless drastic measures are taken to reduce economic growth. In opposition, the "cornucopian" view maintains that mineral resources are economically, and, for any future that may concern us, physically infinite.

B.J. Skinner, the committee chairman, observed in the report's executive summary that there are fallacious assumptions and potentially dangerous consequences inherent in both extremes. The "doomsters" pay too little attention to the adjustment potential of the market mechanism, and generally fail to understand the distinction between "reserves" and "resources." Their gloomy outlook is based on a "fixed" supply of materials and fails to recognize that the supply available changes as price rises and technical advances make lower grade resources economically and physically more accessible. The danger of this approach lies in its encouragement of alarmist overreaction on the part of policymakers, which may in turn have unnecessarily disruptive effects on the economy and society as a whole.

The "cornucopians," on the other hand, rely too heavily on the market mechanism for inducing the transformation of "infinite" resources into almost infinite reserves, and on the technological miracle for providing the physical wherewithal. Their hypothesis insufficiently represents the increasingly, large capital costs of technological advance, the long lead times involved, the "net energy" factor (the energy cost involved in the technology of increasing production), and the fact that although technology has always come up with an answer in the past, its solutions have always had their social, environmental, or economic costs. These costs can no longer be ignored and are in fact setting a practical limit to the economic/technologic transformation of resources into reserves. More importantly, the economic/technological basis of the cornucopian argument is derived from the very assumption its adherents are concerned to disprove: it is shortages and public awareness of shortages which provide the incentive for increased production, technological solutions, and increased efficiency of use. The paradoxical result of the cornucopian message may thus be the fulfillment of the Cassandras' prophecies:
in the relaxed climate fostered by anticipation of plenty, there will be no apparent urgency for setting in motion the economic and technological machinery for maintaining that plenty. This is a particularly important problem for the United States where maintenance or attainment or self-sufficiency in mineral resources is concerned. COMRATE believes that the United States will face serious difficulties in attempting to increase some supplies of energy and mineral raw materials from domestic sources. Indeed, COMRATE believes it is doubtful whether even current levels of supply can be maintained for all materials.

Concerning the Reserves and Resources of Fossil Fuels:

World resources of coal are large relative to current energy requirements. Resources appear adequate for hundreds of years, even at considerably expanded rates of production, but world distribution of coal is uneven, the principal deposits being in China, the USSR, and the United States. World resources of petroleum and natural gas are more limited and will be substantially consumed by the first quarter of the twenty-first century if world trends of production and consumption continue.

Undiscovered recoverable resources of oil and natural gas, onshore and offshore, in the United States including Alaska, are considerably smaller than indicated by figures currently accepted within government circles. In the judgement of the Panel, the figure approximates 15 billion metric tons (113 billion barrels) for crude oil and Natural Gas Liquids (NGL) and 15 X 10^{12} cubic meters (530 X 10^{12} cubic feet) for gas. A large increase in rates of United States production of petroleum and natural gas is extremely unlikely.

Both world and United States resources of petroleum in oil shales and tar sands are large, but many technical, economic, and environmental problems must be resolved before significant rates of production from these resources can be achieved.

According to COMRATE, estimates of proved reserves and undiscovered resources of petroleum and natural gas indicate that a large increase in annual production from conventional domestic sources is extremely unlikely. In view of this and the importance of petroleum as a source of both energy and chemical raw materials, and because a decade or more will be required for large-scale development of alternative sources of energy and hydrocarbons, COMRATE recommends that policy toward the use of petroleum and natural gas place a strong emphasis on conservation.

# # # #

ERDA PRESENTS ITS BUDGET ESTIMATES FOR FY 1976


The Fossil Energy Development section of the ERDA report is similar to the like section from Interior's report of its FY 1976 energy research program (reviewed under a separate heading). This is to be expected since most of the fossil energy program is being transferred from Interior to ERDA this year. Because of the similarity between the synthetic fuels sections, the ERDA report will not be reviewed.

# # # #

OREGON ENERGY RESEARCH STUDY REPORT FANS "NET ENERGY" CONTROVERSY

The State of Oregon has published "Transition," the final report of an 18-month energy research study conducted by Oregon's Office of Research and Planning.

The first of two sections in this one-volume report presents facts and trends concerning energy, with the presentation done, unfortunately, in a manner intended to formulate the opinions of the reader.
The second section is a reprinting of the study committee's "Interim Report," a faulted document which first appeared in July 1974. An obvious criticism of the Interim Report, by anyone who has read it, is that it made use of questionable and downright false data to develop "net energy" values for obtaining various fuels such as domestic natural gas, LNG from the North Slope, coal gasification, high grade shale oil, etc.

The net result of the appearance of this rather imposing official State study, "Transition," will be the intensification of the controversy concerning the net energy of the various fuels.

It is too bad that the state-of-the-art of conducting net energy studies is so ill defined. Each investigator has free license to place any desired parameters around his study. For example, consider the net energy for producing oil from shale. A shale oil facility may require employees. An investigator of the net energy to be produced may penalize the facility for the energy needed to produce the food, fiber, fuel, and transportation needed by the workers. Another investigator may not do this, as these employees would consume food, fuel, fiber, and transportation whether they were producing shale oil in Colorado or whether they were producing pin wheels in Cleveland. Then, one investigator may go to the next level and penalize the shale oil facility for the energy represented in providing food, fuel, fiber, and transportation for the workers who produce the needs of the workers in the shale oil plant. Where does one quit? Each net energy study can be made to show anything a particular investigator desires.

In the case of the Oregon net energy study, we wish to point out that misleading data are used. For example: At page A-93, the Oregon study is considering the net energy of the High Grade Oil Shale alternative. As an external input, the report states, "Harry Johnson, Deputy Coordinator of the U.S.D.I. Oil Shale Program, quoted in the September 6, 1973 issue of Energy Use Report, puts the research costs of a commercial production of a barrel of shale at $4." Now, the Oregon study takes that $4/barrel figure, multiplies it by 100,000 bbl/day (the daily production of the oil shale plant) then multiplies again by 365 (the number of days in a year), then multiplies again by 20 (years) to arrive at a completely phoney $2,920,000,000 penalty which is assessed against the shale oil facility! It is phoney because there is no such $4/barrel "research" cost for all that shale oil in the first place. Harry Johnson did not make the quoted statement, and, by letter dated March 6, 1975 Mr. Johnson so informed Joel Schatz, the Director of Oregon's Office of Energy Research and Planning. A copy of the March 6 letter is in our company files.

The Oregon study further compounds its gross error on the net energy of oil from shale by converting the $2,920,000,000 penalty to BTU's by using a conversion factor of 68,000 BTU/$. That is quite a factor, being equivalent to $14.70 per million BTU! Middle East crude oil, at $11/barrel, is equivalent to just $0.62 per million BTU. Multiplication gives 198,000,000,000,000 BTU, which is the "research" penalty assessed against oil shale. As would be expected, and after making other erroneous penalties, the net energy of shale oil is "shown" to be pretty poor.

Our only suggestion is that when you read "Transition" resist accepting without questioning the many philosophical conclusions which the authors impose on the readers in the first part of the report. Don't accept, without question, any part of the second section (the Interim Report) of the report.

The Interim Report cited above was reproduced in the Appendix of the December 1974 issue of Synthetic Fuels.

# # # #

FEDERAL SYNFUELS LEGISLATION SUMMARIZED

As this article was being written, President Ford announced he has vetoed the Surface Mining Control and Reclamation Act of 1975. This act was introduced both as S.7 and H.R. 25 and will be discussed in greater detail when the bill's fate is more clear. Table 1 lists other energy-related bills.
<table>
<thead>
<tr>
<th>Bill No.</th>
<th>Sponsor</th>
<th>State</th>
<th>Description</th>
<th>Status</th>
</tr>
</thead>
<tbody>
<tr>
<td>H.R. 4</td>
<td>Various</td>
<td></td>
<td>Bill to establish university coal research laboratories &amp; energy resource fellowships.</td>
<td>No action taken. Pending in Committee on Science &amp; Technology.</td>
</tr>
<tr>
<td>502</td>
<td>Udall</td>
<td>Arizona</td>
<td>Bill to regulate surface coal mining operation.</td>
<td>H.R. 25 passed the House with amendments.</td>
</tr>
<tr>
<td>3836</td>
<td>Various</td>
<td></td>
<td>Bill to establish national petroleum reserves on certain federal lands.</td>
<td>No action taken. Pending in Committee on Interior &amp; Insular Affairs.</td>
</tr>
<tr>
<td>1679</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>26</td>
<td>Various</td>
<td></td>
<td>Bill to establish national petroleum reserves on certain federal lands.</td>
<td>No action taken. Pending in Committee on Interior &amp; Insular Affairs.</td>
</tr>
<tr>
<td>27</td>
<td>Bennett</td>
<td>Florida</td>
<td>Bill to amend the Trade Expansion Act of 1972 to prohibit imposing duties, taxes, or fees on imported petroleum or petroleum products.</td>
<td>No action taken. Pending in Committee on Ways &amp; Means.</td>
</tr>
<tr>
<td>28</td>
<td>Lehman</td>
<td>Florida</td>
<td>Bill to prohibit public utilities from increasing rates for electricity by adding fuel adjustment clause to rate schedules to reflect increased fuel costs.</td>
<td>No action taken. Pending in Committee on Interstate &amp; Foreign Commerce.</td>
</tr>
<tr>
<td>3119</td>
<td>Various</td>
<td></td>
<td>Bill to regulate surface coal mining operation.</td>
<td>H.R. 25 passed the House with amendments.</td>
</tr>
<tr>
<td>2587</td>
<td>Various</td>
<td></td>
<td>Bill to establish national petroleum reserves on certain federal lands.</td>
<td>No action taken. Pending in Committee on Interior &amp; Insular Affairs.</td>
</tr>
<tr>
<td>H.R. 124</td>
<td>Bennett</td>
<td>Florida</td>
<td>Bill to amend the Trade Expansion Act of 1972 to prohibit imposing duties, taxes, or fees on imported petroleum or petroleum products.</td>
<td>No action taken. Pending in Committee on Ways &amp; Means.</td>
</tr>
<tr>
<td>49</td>
<td>Various</td>
<td></td>
<td>Bill to establish national petroleum reserves on certain federal lands.</td>
<td>No action taken. Pending in Committee on Interior &amp; Insular Affairs.</td>
</tr>
<tr>
<td>H.J. Res. 31</td>
<td>Bennett</td>
<td>Florida</td>
<td>Bill to amend the Trade Expansion Act of 1972 to prohibit imposing duties, taxes, or fees on imported petroleum or petroleum products.</td>
<td>No action taken. Pending in Committee on Ways &amp; Means.</td>
</tr>
<tr>
<td>H.R. 617 3877</td>
<td>Various</td>
<td></td>
<td>Bill to tax new cars in proportion to their fuel consumption &amp; to provide an energy R &amp; D Fund.</td>
<td>No action taken. Pending in Committee on Ways &amp; Means.</td>
</tr>
<tr>
<td>1128 5201</td>
<td>Various</td>
<td></td>
<td>Bill to tax new cars in proportion to their fuel consumption &amp; to provide an energy R &amp; D Fund.</td>
<td>No action taken. Pending in Committee on Ways &amp; Means.</td>
</tr>
<tr>
<td>4432 5817</td>
<td>Various</td>
<td></td>
<td>Bill to tax new cars in proportion to their fuel consumption &amp; to provide an energy R &amp; D Fund.</td>
<td>No action taken. Pending in Committee on Ways &amp; Means.</td>
</tr>
<tr>
<td>4729 5844 3733</td>
<td>Various</td>
<td></td>
<td>Bill to tax new cars in proportion to their fuel consumption &amp; to provide an energy R &amp; D Fund.</td>
<td>No action taken. Pending in Committee on Ways &amp; Means.</td>
</tr>
<tr>
<td>H.R. 634</td>
<td>Meeds</td>
<td>Washington</td>
<td>Bill to promote land use planning.</td>
<td>No action taken. Pending in Committee on Interior &amp; Insular Affairs.</td>
</tr>
<tr>
<td>635</td>
<td>Meeds</td>
<td>Washington</td>
<td>Bill to amend the Mineral Lands Leasing Act to aid development of oil shale on federal lands.</td>
<td>No action taken. Pending in Committee on Interior &amp; Insular Affairs.</td>
</tr>
<tr>
<td>640</td>
<td>Milford</td>
<td>Texas</td>
<td>Bill to deregulate natural gas.</td>
<td>No action taken. Pending in Committee on Interior &amp; Insular Affairs.</td>
</tr>
<tr>
<td>Bill No.</td>
<td>Sponsor</td>
<td>State</td>
<td>Description</td>
<td>Status</td>
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</tr>
<tr>
<td>H.R. 810</td>
<td>Perkins</td>
<td>Kentucky</td>
<td>Bill to promote R &amp; D in production of synthetic liquid fuels.</td>
<td>No action taken. Pending in Committee on Science &amp; Technology.</td>
</tr>
<tr>
<td>H.R. 812</td>
<td>Perkins</td>
<td>Kentucky</td>
<td>Bill to provide incentives to develop new facilities to produce oil from shale and develop coal conversion.</td>
<td>No action taken. Pending in Committee on Ways &amp; Means.</td>
</tr>
<tr>
<td>H.R. 916</td>
<td>Price</td>
<td>Illinois</td>
<td>Bill to encourage increased coal production.</td>
<td>No action taken. Pending in Committee on Ways &amp; Means.</td>
</tr>
<tr>
<td>H.R. 917</td>
<td>Price</td>
<td>Illinois</td>
<td>Bill to amend Internal Revenue Code to encourage development of processes to convert coal to synthetic fuels.</td>
<td>No action taken. Pending in Committee on Ways &amp; Means.</td>
</tr>
<tr>
<td>H.R. 1000</td>
<td>Hechler</td>
<td>West Virginia</td>
<td>Bill to end surface coal mining and add controls for underground coal mining practices that adversely affect environmental quality.</td>
<td>No action taken. Pending in Committee on Interior &amp; Insular Affairs.</td>
</tr>
<tr>
<td>H.R. 1045</td>
<td>Spence</td>
<td>South Carolina</td>
<td>Bill to encourage R &amp; D to generate energy from solid wastes.</td>
<td>No action taken. Pending in Committee on Interstate &amp; Foreign Commerce.</td>
</tr>
<tr>
<td>H.R. 1046</td>
<td>Spence</td>
<td>South Carolina</td>
<td>Bill to encourage R &amp; D to use solid wastes as a heat source.</td>
<td>No action taken. Pending in Committee on Ways &amp; Means.</td>
</tr>
<tr>
<td>H.R. 1114</td>
<td>Teague</td>
<td>Texas</td>
<td>Bill to encourage R &amp; D to find uses for solid wastes from coal mining and processing.</td>
<td>No action taken. Pending in Committee on Interior &amp; Insular Affairs.</td>
</tr>
<tr>
<td>H.R. 1356</td>
<td>Perkins</td>
<td>Kentucky</td>
<td>Bill to establish an Emergency Coal Office in the FEA.</td>
<td>No action taken. Pending in Committee on Interior &amp; Insular Affairs.</td>
</tr>
<tr>
<td>H.R. 1358</td>
<td>Perkins</td>
<td>Kentucky</td>
<td>Bill to establish the Mineral Gasification and Liquefaction Administration.</td>
<td>No action taken. Pending in Committee on Interior &amp; Insular Affairs.</td>
</tr>
<tr>
<td>H.R. 1370</td>
<td>Price</td>
<td>Illinois</td>
<td>Bill to establish an Emergency Coal Administration within the FEA.</td>
<td>No action taken. Pending in Committee on Interstate and Foreign Commerce.</td>
</tr>
<tr>
<td>H.R. 1388</td>
<td>Domenici</td>
<td>New Mexico</td>
<td>Bill to review public lands withdrawn by executive action from exploration, development, and production of energy and mineral production.</td>
<td>No action taken. Pending in Committee on Interior and Insular Affairs.</td>
</tr>
<tr>
<td>Bill No.</td>
<td>Sponsor</td>
<td>State</td>
<td>Description</td>
<td>Status</td>
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<tr>
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<td>-----------------------------------------------------------------------------</td>
<td>------------------------------------------------------------------------</td>
</tr>
<tr>
<td>H.R. 1473</td>
<td>Price</td>
<td>Illinois</td>
<td>Bill to require study of possible uses of solid wastes resulting from mining and processing coal.</td>
<td>No action taken. Pending in Committee on Interior and Insular Affairs.</td>
</tr>
<tr>
<td>H.R. 1622</td>
<td>Schroeder</td>
<td>Colorado</td>
<td>A bill to prohibit the dumping of spent oil shale on any federal land other than that land leased for operation of shale oil recovery facilities and to provide for the recovery of damages for injury to federal land caused by the unlawful dumping of spent oil shale.</td>
<td>No action taken. Pending in Committee on Interior &amp; Insular Affairs.</td>
</tr>
<tr>
<td>H.R. 1847</td>
<td>Brenzel</td>
<td>Minnesota</td>
<td>Bill to require Interior to maintain a mineral fuels inventory.</td>
<td>No action taken. Pending in Committee on Interior &amp; Insular Affairs.</td>
</tr>
<tr>
<td>H.R. 2121</td>
<td>Hechler</td>
<td>West Virginia</td>
<td>Joint resolution to prevent surface mining operations on public lands &amp; deep mining in national forests.</td>
<td>No action taken. Pending in Committee on Interior &amp; Insular Affairs.</td>
</tr>
<tr>
<td>H.R. 2823</td>
<td>McDade</td>
<td>Pennsylvania</td>
<td>Bill to provide for reclamation of abandoned coal mines.</td>
<td>No action taken. Pending in Committee on Interior &amp; Insular Affairs.</td>
</tr>
<tr>
<td>H.R. 2873</td>
<td>Conte</td>
<td>Massachusetts</td>
<td>Bill to promote competition among producers of oil, natural gas, coal, shale oil, uranium, geothermal steam, &amp; solar energy.</td>
<td>No action taken. Pending in House Judiciary Committee.</td>
</tr>
<tr>
<td>H.R. 2994</td>
<td>Duncan</td>
<td>Tennessee</td>
<td>Bill to encourage increased coal production.</td>
<td>No action taken. Pending in Committee on Ways &amp; Means.</td>
</tr>
<tr>
<td>H.R. 3041</td>
<td>Pickel</td>
<td>Texas</td>
<td>Bill to amend the Emergency Petroleum Act of 1973 to exempt state-owned oil.</td>
<td>No action taken. Pending in Committee on Interstate and Foreign Commerce</td>
</tr>
<tr>
<td>Bill No.</td>
<td>Sponsor</td>
<td>State</td>
<td>Description</td>
<td>Status</td>
</tr>
<tr>
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</tr>
<tr>
<td>H.R. 3085</td>
<td>Helstoski</td>
<td>New Jersey</td>
<td>Bill to prohibit foreign oil producing countries and their residents from acquiring controlling interests in any domestic petroleum-related or energy producing industry.</td>
<td>No action taken. Pending in Committee on Interstate &amp; Foreign Commerce.</td>
</tr>
<tr>
<td>H.R. 3217</td>
<td>Duncan</td>
<td>Tennessee</td>
<td>Bill to encourage development of processes to convert coal to synthetic fuels.</td>
<td>No action taken. Pending in Committee on Ways &amp; Means.</td>
</tr>
<tr>
<td>H.R. 3265</td>
<td>Mink</td>
<td>Hawaii</td>
<td>Bill to authorize Interior to offer public lands for coal leasing by competitive bidding on a bonus bidding system only.</td>
<td>No action taken. Pending in Committee on Interior and Insular Affairs.</td>
</tr>
<tr>
<td>H.R. 3594</td>
<td>Johnson</td>
<td>Colorado</td>
<td>Bill to provide that money due states under the Mineral Leasing Act of 1920 derived from development of oil shale may be used for purposes other than public roads and schools.</td>
<td>No action taken. Pending in Committee on Interior &amp; Insular Affairs.</td>
</tr>
<tr>
<td>H.R. 3735</td>
<td>Mink</td>
<td>Hawaii</td>
<td>Bill to amend Mineral Lands Leasing Act to provide more efficient and equitable exploration and development of federal oil shale resources.</td>
<td>No action taken. Pending in Committee on Interior &amp; Insular Affairs.</td>
</tr>
<tr>
<td>H.R. 4958</td>
<td>Perkins</td>
<td>Kentucky</td>
<td>Bill to impose a severance tax on oil, gas, and coal and to return the proceeds to the counties from which the products were taken.</td>
<td>No action taken. Pending in Committee on Ways &amp; Means.</td>
</tr>
<tr>
<td>S.4</td>
<td>Mathias</td>
<td>California</td>
<td>Bill to systematically reduce imports of foreign crude oil and petroleum products.</td>
<td>No action taken. Pending in Committee on Finance.</td>
</tr>
<tr>
<td>S.7</td>
<td>Jackson</td>
<td>Washington</td>
<td>Surface Mining Act of 1975. This is identical to S.425 introduced in the 93rd Congress, and S.652 is similar to S.425.</td>
<td>S.7 passed the Senate with amendments.</td>
</tr>
<tr>
<td>S.652</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>S.26</td>
<td>Moss</td>
<td>California</td>
<td>Bill to establish mining and mineral research centers.</td>
<td>No action taken. Pending in Committee on Interior &amp; Insular Affairs.</td>
</tr>
<tr>
<td>S.27</td>
<td>Moss</td>
<td>California</td>
<td>Bill to establish a department of natural resources and environment.</td>
<td>No action taken. Pending in Committee on Government Operations.</td>
</tr>
</tbody>
</table>
Table 1 (Continued)

<table>
<thead>
<tr>
<th>Bill No.</th>
<th>Sponsor</th>
<th>State</th>
<th>Description</th>
<th>Status</th>
</tr>
</thead>
<tbody>
<tr>
<td>S. 30</td>
<td>Moss</td>
<td>California</td>
<td>Bill to amend the Mineral Leasing Act of 1920.</td>
<td>No action taken. Pending in Committee on Interior &amp; Insular Affairs.</td>
</tr>
<tr>
<td>S. 33</td>
<td>McGee</td>
<td>Wyoming</td>
<td>Bill to establish a moratorium on federal coal leasing.</td>
<td>No action taken. Pending in Committee on Interior &amp; Insular Affairs.</td>
</tr>
<tr>
<td>S. 62</td>
<td>Scott</td>
<td>Pennsylvania</td>
<td>Bill to establish university coal research laboratories and grants.</td>
<td>No action taken. Pending in Committee on Interior &amp; Insular Affairs.</td>
</tr>
<tr>
<td>S. 154</td>
<td>Hansen</td>
<td>Wyoming</td>
<td>Bill to grant mineral rights to certain homestead patentees.</td>
<td>No action taken. Pending in Committee on Interior &amp; Insular Affairs.</td>
</tr>
<tr>
<td>S. 191</td>
<td>Hansen</td>
<td>Wyoming</td>
<td>Bill relating to rehabilitation of areas damaged by deleterious mining practices.</td>
<td>No action taken. Pending in Committee on Interior &amp; Insular Affairs.</td>
</tr>
<tr>
<td>S. 210</td>
<td>McGee</td>
<td>Wyoming</td>
<td>Bill to amend the Mineral Leasing Act of 1920 regarding disposition of proceeds of sales, etc. under such act.</td>
<td>No action taken. Pending in Committee on Interior &amp; Insular Affairs.</td>
</tr>
<tr>
<td>S. 271</td>
<td>Baker</td>
<td>Tennessee</td>
<td>Bill to regulate surface mining of coal to protect the environment.</td>
<td>No action taken. Pending in Committee on Interior &amp; Insular Affairs.</td>
</tr>
<tr>
<td>S. 412</td>
<td>Cannon</td>
<td>Nevada</td>
<td>Bill to extend certain aid to certain people engaged in mineral exploration and development.</td>
<td>No action taken. Pending in Committee on Interior &amp; Insular Affairs.</td>
</tr>
<tr>
<td>S. 456</td>
<td>Church</td>
<td>Idaho</td>
<td>Bill to authorize funds to support the Federal Non-Nuclear Energy Research and Development Act of 1974 for FY 76.</td>
<td>No action taken. Pending in Committee on Interior &amp; Insular Affairs.</td>
</tr>
<tr>
<td>S. 507</td>
<td>Haskell</td>
<td>Colorado</td>
<td>Bill to provide for the management, protection, and development of the national resource lands. This is the BLM Organic Act.</td>
<td>No action taken. Pending in Committee on Interior &amp; Insular Affairs.</td>
</tr>
<tr>
<td>Bill No.</td>
<td>Sponsor</td>
<td>State</td>
<td>Description</td>
<td>Status</td>
</tr>
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</tr>
<tr>
<td>S. 552</td>
<td>Domenici</td>
<td>New Mexico</td>
<td>Bill to amend the Mining and Minerals Policy Act of 1970 to create within the Executive Branch a Council on Mineral Resources.</td>
<td>No action taken. Pending in the Senate Interior Committee.</td>
</tr>
<tr>
<td>S. 598</td>
<td>Pastore</td>
<td>Rhode Island</td>
<td>Funding authorization for ERDA.</td>
<td>No action taken. Pending in Committee on Interior &amp; Insular Affairs.</td>
</tr>
<tr>
<td>S. 764</td>
<td>Scott</td>
<td>Pennsylvania</td>
<td>Bill to provide for the reclamation of abandoned coal mines.</td>
<td>No action taken. Pending in Committee on Interior &amp; Insular Affairs.</td>
</tr>
<tr>
<td>S. 834</td>
<td>Haskell</td>
<td>Colorado</td>
<td>Bill to provide that money due states under the Mineral Leasing Act of 1920 derived from the development of oil shale may be used for purposes other than public roads and schools.</td>
<td>Passed the Senate.</td>
</tr>
<tr>
<td>S. 973</td>
<td>Bentsen</td>
<td>Texas</td>
<td>Bill to encourage use of coal and development of synthetic fuels by amending the Internal Revenue Code of 1954.</td>
<td>No action taken. Pending in Committee on Finance.</td>
</tr>
<tr>
<td>S. 984</td>
<td>Jackson</td>
<td>Washington</td>
<td>Bill to authorize $800 million in grants to states to assist states &amp; Indian reservations in developing land use planning programs.</td>
<td>No action taken. Pending in Committee on Interior &amp; Insular Affairs.</td>
</tr>
</tbody>
</table>
ACTIONS OF THE 1975 STATE LEGISLATIVE ASSEMBLIES

The legislative action of the six western coal states this year has been significant. The coal industry is being affected in several ways with some states taking a cautious stance towards development resulting in delay and higher costs. The action in the legislatures as a whole, however, shows an encouraging trend toward longer range community and public facility planning on the part of county and state government in areas that are experiencing rapid growth.

North Dakota, Montana, Colorado, and New Mexico have been in session this year and spent much effort on resolving the many problems of present and anticipated energy resource development. The legislation they passed reflects the concern of rapid and uncontrolled development of coal, particularly in the Northern Great Plains. North Dakota and Montana clearly would like to move much slower in the development of coal than Utah and Wyoming as reflected in the severance tax measures, ranging from 30 percent in Montana to four percent in Wyoming. Land planning and mined land reclamation received much attention as well as assistance to rapidly developing communities. Plant siting measures were passed in North Dakota and Wyoming. Wyoming initiated a land use planning program that promises to coordinate plans developed at the county level to establish a statewide use/development pattern.

The Colorado legislature, not yet adjourned, is undecided on tax, reclamation, community development, and land use measures. The significant actions of the states are as follows:

Colorado

The Colorado legislature is still in session with measures pending that concern severance tax of coal and oil shale (also metaliferous minerals), tax mechanisms and assessment procedures, land planning, community development and assistance, mined land reclamation, water use, and conservation of energy resources. Measures of immediate interest to the minerals industry are the proposed six percent severance tax on coal and oil shale submitted by Governor Lamm (House Bill No. 1196), amendments to the Open Mining Reclamation Act of 1973 (House Bill No. 1053), and amendments to the land use program of 1974 (House Bill No. 1006); however, it appears that bills 1196 and 1053 have been indefinitely tabled.

Montana

The Montana 44th Legislative Assembly adjourned on April 17, 1975, after passing an increased severance tax on coal (Senate Bill No. 13) and several measures providing for fees to accompany applications to state agencies for permits, etc., in cases where environmental analyses by the state are required. A measure to require the prepayment of property tax for certain new facilities is included in the list below of legislation considered by the 44th assembly.

House Bill No. 83 - Prohibiting change of use for water rights from agricultural to nonagricultural.

House Bill No. 113 - Provision for the prepayment of property tax for certain new major industrial facilities. An amount equal to three times the estimated property tax due the year the facility is completed is to be prepaid in portions "from time to time" on request from, and as needed by, the Board of County Commissioners of the county in which the facility is to be located for the purpose of mitigating impacts. Upon the first year of productive operation, the facility shall be subject to property tax as assessed by the Department of Revenue except that one-fifth of the amount prepaid shall be allowed as a credit against property taxes in each of the first five years after the start of productive operation. A major new industrial facility is a manufacturing or mining facility which will employ, on an average annual basis, at least 100 persons in construction or operation and will create a substantial adverse impact on existing state, county, or municipal services.

House Bill No. 340 - Allows the assessment of a fee by certain state agencies to cover the cost of the preparation of an environmental impact statement, if such a statement is required under the Montana Environmental Policy Act pursuant to an application for a permit, lease, license, or certificate.
filed with that agency. The maximum fee that may be imposed shall not exceed two percent of any estimated costs up to one million dollars; plus one percent of costs over one, and up to, $20 million; plus one-half of one percent of cost over $20 million and less than $100 million; plus one-quarter of one percent of cost over $100 million and less than $300 million; plus one-eighth of one percent of costs in excess of $300 million. A plant estimated to cost $400 million could be assessed up to $1.2 million, calculated in the following manner:

$$\begin{align*}
1 \text{ MM} \times 0.02 &= 20,000 \\
19 \text{ MM} \times 0.01 &= 190,000 \\
80 \text{ MM} \times 0.005 &= 400,000 \\
200 \text{ MM} \times 0.0025 &= 500,000 \\
100 \text{ MM} \times 0.00125 &= 125,000 \\
400 \text{ MM} &= \$1,235,000
\end{align*}$$

No fee may be assessed if application is made under the provisions of the Montana Utility Siting Act.

House Bill No. 341 Amending the Open-Space Land Act to include voluntary conservation easement.

House Bill No. 453 This act provides for the suspension of action on application with the Department of Natural Resources and Conservation for certificates of environmental compatibility and public need under the Montana Utility Siting Act of 1973 for only utility facilities meeting the following criteria:

1. Generating at 50 MW of electricity or more or any additions costing more than $250,000 with the exception of pollution control equipment.
2. Producing 100 MMcf/d of gas or more or any additions costing more than $250,000.
3. Producing 50 Mbd of liquid hydrocarbon or more or any additions costing more than $250,000.
4. Designed for or capable of enriching uranium minerals.

This will apply until the Governor has formulated a state energy conversion policy and the next legislature has acted on that policy.

It is provided that this act does not apply to any applications accepted by the department prior to passage of this bill.

House Bill No. 492 This measure provides for the assessment of fees for the preparation of environmental statements upon application for water right permits or approvals. This fee may be assessed if an environmental statement is required under the Montana Environmental Policy Act and the application involves the use of 10,000 AFY or 15 cfs or more of water. No fee may be assessed if application has also been made under the Montana Utility Siting Act of 1973. The fee assessed is defined as in House Bill No. 340 above.

House Bill No. 522 - The Board of Natural Resources and Conservation may exempt certain federal lands from the Montana Open Cut Mining Act if the Board has determined that the federal agency administering the land will impose federal regulations equal to or greater than those under Montana law for mined land reclamation and control.

House Bill No. 533 Revising the provisions governing coal-mining leases on state lands.

House Bill No. 535 - Requiring persons about to locate a major industrial facility or open a new strip mine to file an Educational Impact Statement with the County Superintendent of Schools.

House Bill No. 531 - This measure amends the Montana Utility Siting Act of 1973. Under this bill, title of the act is changed to the "Montana Major Facility Act." The facilities over which this act has jurisdiction have been broadened to include: (1) plants producing 25 mmcf/d of gas or more (changed from 100 mmcf/d); (2) plants producing 25 mbpd of liquid hydrocarbon or more (changed from 50 mbpd); (3) plants capable of using, refining, or converting 500 mtpy of coal or more or additions costing more than $250,000; and (4) any underground gasification of coal. The filing fee required under this act has been slightly modified and corresponds to the schedule described in House Bill No. 340. The act now provides that the Montana Department of Natural Resources and Conservation may contract with a potential applicants to develop
House Bill No. 642 - This act relates to the renewable resource development program of the state of Montana providing for funds for the program by appropriating monies generated from the taxing of non-renewable resources, and giving the authority for the state to issue bonds. The renewable resources referred to are primarily air, water, land, and multiple use recreational opportunities.

House Bill No. 650 - Provides for the control of surface effects of underground mining operations and the reclamation of lands and waters affected by underground mining.

Senate Bill No. 13 - This act provides for a severance tax to be imposed on each ton of coal produced in the state in accordance with the following schedule:

<table>
<thead>
<tr>
<th>Heating Value of Coal (BTU/lb.)</th>
<th>Surface Mine</th>
<th>Underground Mine</th>
</tr>
</thead>
<tbody>
<tr>
<td>under 7,000</td>
<td>12 cents or 20% of value</td>
<td>5 cents or 3% of value</td>
</tr>
<tr>
<td>7,000-8,000</td>
<td>22 cents or 30% of value</td>
<td>8 cents or 4% of value</td>
</tr>
<tr>
<td>8,000-9,000</td>
<td>34 cents or 30% of value</td>
<td>10 cents or 4% of value</td>
</tr>
<tr>
<td>over 9,000</td>
<td>40 cents or 30% value</td>
<td>12 cents or 4% of value</td>
</tr>
</tbody>
</table>

The value or contract sales price of the coal is the price of the coal extracted and prepared for shipment f.o.b. the mine, excluding that amount charged by the seller to pay taxes paid on production to include any tax paid to the federal, state, or local governments upon the quantity of coal produced as a function of either volume or the value of production, but not to include any tax upon the value of mining equipment, machinery, or buildings and lands, any tax upon a person's net income derived from the sale of coal, or any license fee. The value of the coal may be imputed by the state, as provided for in the act, for purposes of this tax in some cases to include the use of the coal by the mine operator in an energy conversion facility. Regarding the schedule of tax, the formula yielding the greater amount of tax in a particular case shall be used. The act provides for including the gross proceeds of coal mines in the county property tax structure with the deletion of coal from the provisions taxing the net proceeds of mines. It is expected that $66.8 million will be generated by this severance tax in the 1976-77 biennium. Hereafter, as also provided, Montana will set royalties on state coal leases as a percentage of value of the coal.

Senate Bill No. 92 - Regarding damage to a ground water supply by owners of surface mines.

Senate Bill No. 338 - Authorizes the Montana Department of Natural Resources and Conservation to acquire water from the federal government from Fort Peck Reservoir in a manner it sees fit for purposes of sale, rent, or distribution for industrial use at rates it considers appropriate.

Senate Bill No. 395 - An act to amend the Montana Water Use Act of 1973 as follows: (1) Deleting the power of the Board of Natural Resources and Conservation to adopt rules governing interim approval of a change of use of an appropriation right; (2) providing that the use of water for slurry export of coal from the state is not a beneficial use and, therefore, no water may be apportioned for that use; (3) clarifying the priority date for water rights; and (4) establishing variations to administrative procedures for processing and adjudication of water right applications and existing rights.

New Mexico

The New Mexico 32nd Legislative assembly adjourned on March 25, 1975, with the passage of two bills of interest. The session imposed a tax on electrical energy in the state for the purpose of sale, which is ex-
expected to be contested by Arizona Public Service. Also passed was the Energy Resources Act establishing the Energy Resources Board and providing a severance tax on coal.

Senate Bill No. 186 - The Energy Resources Act creates the Energy Resources Board whose primary functions are to maintain records of "fuel and power" production in the state, consumption in state, out of state export, and potential in-state reserves. The Board will formulate a general statewide plan for siting fuel and power production and refining facilities. The act makes the Oil Conservation Commission subordinate to the Energy Resources Board and extends the oil and gas conservation tax to all forms of energy resources severed from the soil. This places a severance tax on coal equal to 0.18% of its taxable value. This bill describes the administrative structure and procedures of the board as well as the duties of the state Petroleum Engineer and Geologist, who are both members of the board. The administrative officer of the board, the Energy Resources Administrator, is a member of the Governor's staff.

Senate Bill No. 258 - The Electrical Energy Tax Act imposes a tax of 0.4 mils ($0.004) on each net kilowatt hour of electrical energy generated in New Mexico for the purpose of sale, whether the sale takes place in or out of the state.

North Dakota

The North Dakota 44th Legislative Assembly adjourned on March 26, 1975, after passing several pieces of legislation which significantly affect the future of the rapidly developing lignite industry in the state. The measures passed included a coal severance tax (Senate Bill No. 2031), an energy conversion tax to be applied to thermal generating and coal gasification facilities, and an energy plant siting act. The severance tax measure passed this session on coal, based on a flat rate per ton, was opposed by Governor Link and became law without his signature. The Governor was unsuccessful in obtaining a tax based on percentage-of-value. Several other measures of interest were passed and are included in the following list:

House Bill No. 1057 - Provides a public policy on air pollution, authorizes the Health Department to regulate air quality through a system of permits and to collect by rule or regulation a reasonable fee for issuance of permits, and authorizes the department to set and enforce standards for control of air pollution.

House Bill No. 1062 - "Surface Owner Protection Act" requires written notice of interest to mine and approval by the surface owner before a permit to surface mine land is issued by the Public Service Commission; provides for surface damage and disruption payments to surface owner and provides for a financial obligation to reclaim land disturbed by a mining operation.

House Bill 1172 - Provides for classification of the Little Missouri River as a state scenic river and for its protection and preservation as a free flowing river. This measure corresponds to a decision, by this legislature, not to further fund the West River Diversion Project at this time.

House Bill No. 1221 - This act provides for a coal conversion privilege tax to be applied to all coal conversion facilities meeting the following criteria: a plant, other than an electrical generating plant, processing 500 mtpy of raw coal into a form substantially different in chemical and physical properties to include gasification and liquefaction plants; and electrical generating plants which have at least one unit with a capacity of at least 120 MW. Gasification plants will be taxed at 2.5 percent of gross receipts or 10 cents per MCF which ever is greater, liquefaction plants at 2.5 percent of gross receipts and power plants at 0.25 mills per kilowatt hour. Revenue derived from transportation, transmission or distribution of the products of the conversion facility are not included in "gross receipts."

Senate Bill No. 2031 - This act provides for a coal severance tax at a flat rate of 50 cents per ton. The rate of the tax is not fixed; with provisions that allow it to rise one cent per ton per three point rise in the federal whole sale price index. No provision is made for a decrease of the tax.
Governor Link was unsuccessful in passing a 30 percent of value coal tax this session. This law will come up for review in two years. This measure provides for the creation of the Coal Development Impact Office in the Office of the Governor to assist in the distribution of the tax monies as set forth in this bill and aid the Governor in dealing with and aiding communities adversely effected by coal development.

Senate Bill No. 2050 - This is the North Dakota Energy Conversion and Transmission Facility Siting Act. This act requires that any "utility" obtain a certificate of site compatibility from the North Dakota Public Service Commission prior to siting construction of any energy conversion or transportation facility meeting these criteria: (1) capable of generating 50 MW or more of electric power; (2) capable of producing or refining 100 mmcf/d or more of gas; (3) capable of producing or refining 50 mbpd or more of liquid hydrocarbon; (4) an electric transmission line with a design of 200 KV or more; and (5) a gas or liquid transmission line transporting coal, gas, liquid hydrocarbon, or water to or from any facility as described above with no criteria for quantity or flowrate. An initial filing fee to accompany an application for site certification under this act is not to exceed $500 per each one million dollars of capital investment or $150,000 as defined in the Federal Power Commission uniform system of accounts, but not less than $5000. Additional fees maybe assessed, at the commission's discretion, but may not exceed $1000 per each one million dollars of investment or $150,000. The fee money is to be used by the commission to evaluate the application in terms of the environmental, social, and economic implications of proposed projects and sites. The commission, under this act, is to initiate a planning program to establish criteria and standards for facility siting to assist in the preparation of a statewide inventory of potential acceptable sites as well as the evaluation of applications filed under this act. By July 1, 1976, the commission is to publish the site inventory and its siting criteria. The act provides for the filing with the commission by utilities or other operators, a ten-year facility development plan to be updated annually. This applies to any facility operating or planned to be operated within five years of the promulgation of the siting criteria in July 1976 as mentioned. An application filed for site certification shall contain the following information:

(1) A description of the size and type of facility
(2) A summary of any studies which have been made of the environmental impact of the facility
(3) A statement explaining the need for the facility
(4) An identification of the location of the preferred site and at least one alternative site for any energy conversion facility
(5) An identification of the location of the preferred corridors and at least one alternative corridor for any transmission facility
(6) A description of the comparative merits and detriments of each location identified, and a statement of the reasons why the preferred location is best suited for the facility
(7) Such other information as the applicant may consider relevant or the commission may require

Senate Bill No. 2095 - Provides a statement of policy and intent of the state regarding the control and extent of surface mining of coal and the reclamation of mined land. This measure requires a permit from the Public Service Commission to surface mine coal and provides that a non-refundable fee of $250 plus $10 per acre to be covered by the permit, a mining plan and a plan for reclamation to be submitted to the commission in application for the permit. A refundable bond of $1,500 per acre covered under the permit is also required to assure proper land reclamation. This bond may be increased at the discretion of the commission. This bond is refunded in portions as the reclamation program progresses. This measure provides in detail the data required in both the mining and reclamation plans.

Senate Bill No. 2147 Requires persons exploring for coal to maintain log books and to file basic data with State Geologist.
Senate Bill No. 2467 - Establishes a Natural Resources Council composed of members of several state agencies dealing with natural resources. The Council will review and discuss activities dealing with natural resources and recommend to the governor a long-range plan for use and management of the state's natural resources.

Utah

Utah's 41st Legislative Assembly adjourned on March 13, 1975, after passing several measures directed at the controlling and financing resource development related activities. "The Utah Mined Land Reclamation Act" (House Bill No 323 ) became law after four years of study and debate and appears to have broad support. No severance tax measures passed the session. Included in the list of passed bills below is one requesting approval of the Kaiparowits project.

House Bill No. 111 - This act authorizes Utah cities to participate with regulated electric utilities and cities of other states in the development of electrical generating facilities.

House Bill No. 243 - This act authorizes the Board and Division of Oil, Gas, and Mining (Utah Department of Natural Resources) to enter into cooperative agreements with the national, state, or local governments, and with independent organizations and institutions to conduct research and development experiments involving energy resources to the extent that the project is funded or partially funded and approval by the legislature.

House Bill No. 323 - This measure is the "Utah Mined Land Reclamation Act." The act applies to all mining operations in the state, regardless of land ownership, to include exploration, sub-surface and surface mineral extraction from land and water and on-site primary processing of materials. The act excludes oil, gas, and geothermal extractions and also operations disturbing two acres or less or removing 500 tons per year or less. The act is to be administered by the Division of Oil, Gas, and Mining (previously the Division of Oil and Gas Conservation) in the Utah State Department of Natural Resources. By July 1, 1977, every operator is required by the act to submit a "notice of intent" to the Board of Oil, Gas, and Mining including a mining and reclamation plan. The notice is to be updated every year. The board will require the operator to post a surety on approval of the plan to guarantee compliance with reclamation plans and rules. The amount and form of surety is at the discretion of the Board. The intent of the act is to require reclamation of land under rules recognizing differences in mineral deposits and mining operations and the diversity of topographic, chemical, climatic, biological, geologic, and economic conditions throughout the state.

Senate Bill No 5 - Provides a definition of terms relating to mines and minerals.

Senate Bill No. 84 - Provides that notice must be given to the Division of Health of plans to construct a new installation which will or might reasonably be a source of air pollution. The bill requires that the Division approve such plans and grant variances to existing emission standards where necessary.

Senate Bill No. 256 - This act provides for the prepayment of sales and use taxes by persons engaged in developing a natural resource for the purpose of financing public facilities in the area to be affected by the development. The prepayment of these taxes is not required by this act. Provision is made for the future crediting of prepaid taxes. Companion measures dealing with taxes and financing of public facilities are Senate Bills 257, 258, and 259.

Senate Joint Resolution No. 8 - Provides for changes in the assessment of non-metaliferous mineral deposits and the determination of ad-valorem taxes by the State Tax Commission.

Senate Joint Resolution No. 24 - Requests the Secretary of the Interior to approve a site for the construction of the Kaiparowits plant.

Wyoming

The Wyoming 43rd Legislative Assembly adjourned on March 1, 1975, after passing an increase in the severance tax on metaliferous and non-metaliferous deposits and the Indust-
Although the Wyoming legislature was successful in passing an increased severance tax on coal it is roughly only 26 percent of the tax now levied in North Dakota and only about 13 percent of the coal severance tax in Montana. It appears that the Wyoming legislature has taken a relatively different stance toward the development of the state's coal reserves than either North Dakota or Montana. Where Montana and North Dakota are attempting to slow and in some instances halt development of coal, Wyoming is indicating that it would rather develop in a controlled and deliberate manner. This is seen in the passage of a relatively moderate severance tax in conjunction with comprehensive land-use and plant siting measures. The land use program and plant siting measure are included in the list of passed bills below:

House Bill No. 125 - This is the Industrial Development Information and Siting Act. This act establishes in the office of the Governor the State Office of Industrial Siting Administration and the Industrial Siting Council whose members are selected by the Governor. The Council is authorized to promulgate rules and regulations to control the siting of industrial facilities meeting these criteria: (1) capable of producing 100 mmcfd of gas or more, or an additional of at least 100 mmcfd; (2) capable of producing, or an additional of at least, 50 mmbpd of liquid hydrocarbon; (3) generating at least 100 MW of electrical power or an addition of at least 100 MW; and (4) any industrial facility estimated to cost at least $50 million. The act requires that a permit be obtained, by application to the Office of Industrial Siting Administration, from the Council prior to construction of a facility meeting the above criteria. An application, to the Council, is to contain sufficient information, specified in the act, to allow the Council to evaluate the environmental, social, and economic aspects of the proposed facility and to render a decision on the issuance of a permit. A permit may be granted with attached stipulations to assure proper siting or compatibility with state land use and environmental codes. An initial filing fee to accompany the application, the amount of which shall be set by the Director of the Office, shall not exceed 0.5% percent of the estimated facility cost or $100,000 dollars. If after an initial decision, the Council feels that additional evaluation and study is necessary to render a final decision on a permit the Director may require an additional fee, on approval of the Council which may not exceed one million dollars. The additional fee is to be 0.5 percent of the estimated cost up to $100 million plus 0.25 percent of the estimated cost over $100 million. The Director shall consult with the applicant on the scope and design of additional studies. The act delineates areas of most concern to be studied to include: the need for the facility; land use for the alternatives and conflicts; water use and availability; air and water quality; and social and economic implications. Each person operating a facility, as defined by this act, shall furnish annually to the Office for its review, a long-range plan for the construction, expansion, and operation of the facility. Construction of railroads, electric transmission lines not exceeding 115,000 volts, oil and gas pipelines, coal slurry pipelines, and natural gas pipelines, and construction or operation of oil and gas producing, drilling, and field processing facilities are not activities, subject to the application and permit procedures of this act but the owner or operator thereof shall furnish the following information to the Office: (1) Specific description of the nature and location of the facility; (2) Estimated time of commencement of construction and construction time; (3) Estimated number and job classification, or employees of the applicant, or subcontractor of the applicant, during the construction phase, and during the operating life of the facility; (4) A copy of any studies which may have been made of the environmental impact of the facility.

House Bill No. 204 - This act provides for a special coal severance tax to provide assistance to communities impacted by coal development. The tax is based on a percentage of the gross value of coal produced in the preceding calendar year with the following structure: 1974 coal production at 0.4 percent; 1975 at 0.8 percent; 1976 at 1.2 percent; 1977 at 1.6 percent; and 1978 and subsequent years at 2 percent. This tax will be assessed and placed in the coal severance tax account until a total of 120
million dollars has been collected at which time it will be terminated. Approximately 50 years will be required to accumulate $120 million dollars at the present production rate of about 12 MTPY and assuming two percent severance tax and a coal price of $10 per ton f.o.b. the mine. At the production level of 100 MTPY as estimated by the Wyoming Geologic Survey and with the same price and tax, about six years will be required. This tax is in addition to the severance tax on coal providing funds for the Wyoming mineral trust fund mentioned below in House Bill No. 346.

House Bill No. 321 - This is the Wyoming State Land Use Planning Act. This act creates the Wyoming State Land Use Commission and provides that the Commission shall guide and coordinate land use planning activities at the local and state levels and assemble, within a year, a state land use plan. The plan will include state land use goals, policies, and regulations to guide the use of land for such purposes as agriculture, residential, commercial, industrial, open space, transportation, utilities, recreation, historic, scenic, and water storage. The commission will act under the guidance of an advisory committee and promulgate rules and regulation through the Office of Land Use Administration. The Commission is to receive for review and approval a county-wide land use program from each county within a year after the commission establishes statewide guidelines and goals. Land uses and use conflicts will be continuously monitored by the commission to provide a state-wide land-use inventory to be used as a planning by the Commission, state agencies, local governments, and persons wishing to develop the resources of the state. See page 4-22 of the March 1975 issue of Synthetic Fuels for more information about this act.

House Bill No. 346 - Metaliferous and non-metaliferous severance tax increases providing funds for the Wyoming Mineral Trust Fund. For coal and oil shale the severance tax is set at four percent up from three percent. Non-fossil deposits are taxes at two percent, up from one percent.

Senate Bill No. 12 - This measure creates the Wyoming Community Development Authority and empowers that board to issue revenue bonds up to $100 million to offset impacts on towns and counties. Among other things it dedicates one-half of one percent of the severance tax to secure the purchase of bonds, mortgages, etc.

Senate Bill No. 68 - This bill provides numerous amendments to the Wyoming Environmental Quality Act, most of which are administrative in nature. Several amendments of specific interest include: (1) The filing of a mining and reclamation plan in application for a mining permit; and (2) surface owner consent to surface mine where the surface owner is distinct from the mineral owner.

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ONE MILLION BARREL A DAY SYNFUELS INDUSTRY BY 1985 IS FORD GOAL

The foundations on which to build a million barrel a day commercial synthetic fuels industry are being laid by President Gerald Ford's Administration in what appears to be a solid breakthrough on a much clearer government energy policy.

Both the people in the Administration and many of the influential leaders in Congress are beginning to get a sharper picture of the energy situation and are in general agreement on getting started on commercial scale technology for synthetic fuels from conversion of
coal and oil shale. There remains considerable confusion in Washington on the best way to do it. Several combinations of incentives are being considered.

Since Ford announced the goal in his State of the Union address, nine task forces have compiled basic data which are expected to lead to comprehensive federal proposals early in 1976.

In his State of the Union remarks, the President said 20 new synthetic fuels plants are part of his program. He did not specify what combinations of synthetic fuels plants would be recommended. (See Ford's energy message in the March issue of Synthetic Fuels.)

Frank Zarb, FEA administrator, has assigned John Hill responsibility for the program. Hill's deputy is William McCormick, of the Office of Management and Budget (OMB). The question of who ultimately will run the program still has not been resolved. FEA, ERDA, and the Department of the Interior are candidates.

Special government corporations also are being considered. The options include a TVA type organization; a government/industry proposition; and a Comsat type group. An entirely new government agency along the lines of the Synthetic Rubber Office of World War II also is being evaluated.

The nine task force being coordinated by the OMB are:

1. National Science Foundation examination of impacts, if no commercial synthetic fuels industry is developed and the effects of alternative programs on commercial scale synfuels plants.
2. ERDA is updating cost estimates.
3. FEA is compiling a review of current synfuels plans and problems.
4. The Department of the Interior is drafting a review of forseeable environmental impacts.
5. FEA is producing a compendium of existing legislation and regulations pertinent to the commercial scale program and citing possible changes.
6. FEA also is assessing various incentives and is to select eight or nine as the most promising. (See related incentives articles in this issue.)
7. Interior is reviewing leasing of federal lands.
8. The Department of State is preparing a report on international aspects of such a program.
9. ERDA is examining the factors involved in procurement of equipment, manpower, materials, and related matters.

Besides these studies, technical reviews of oil shale, high-BTU gas, low-BTU gas, and liquids for utilities, refinery feedstocks from coal and municipal wastes as a power source are also being updated and correlated in "cross-cut" studies into the nine task force efforts.

The schedule for review and evaluation has slipped about a month from the June 30 deadline, when the endeavor was to have been on the president's desk. It is also possible Ford may take longer than originally anticipated to make the studies public. The original target for publication was July 15 with an administration backed plan to be presented to Congress in the autumn.

Program Size

Although the President called for a MMBPD oil equivalent program, for reasons best known to the bureaucracy, a larger program, a smaller program, and no program at all are being analyzed. The production levels being considered are:

- **High** - 1,700,000 B/D
- **Middle** - 1,000,000 B/D
- **Low** - 350,000 B/D

Under these production levels shale oil would be expected to be:

- **High** - 800,000 B/D
- **Middle** - 280,000 B/D
- **Low** - 150,000 B/D

The low level of production is called an information program. Under it, seven plants would be built as follows:
Under the MMBPD program, there would be six high-BTU gas plants, four shale mining plants, and two shale in situ operations.

The entire study may well run to four or five books, including a summary. In addition, an analysis of possible future scenarios for synthetic fuels supply and demand is being readied using the SRI-Gulf computer model.

Although an Oil Daily article suggested the MMBPD program has been scrapped and replaced by one plant for each synfuel, the report has been denied by high-level program participants. The story apparently stemmed from the low production option review.

While the President has recognized the necessity for pioneering a synfuels industry, Congress is yet to be convinced. Coming events will weigh significantly on its reaction to a specific proposal expected to emerge late this summer from the task force effort.

Already there is strong Congressional sentiment in favor of giving Ford more power to force energy conservation measures than he has asked.

This ties neatly into the Administration's announcement in May that estimates of undiscovered reserves of gas and oil in the United States are much less than previously believed.

The liquid petroleum estimate now ranges from 61 to 149 billion barrels compared with 200 to 400 billion barrels calculated in March 1974. Natural gas reserves reflect even more pessimism with a revision down from 1,000 to 2,000 trillion scb to 322 to 655 trillion scf.

Some observers are predicting increased Congressional concern and a building sense of energy urgency in view of continuing turmoil in the Middle East and unwillingness of OPEC to roll over and die.

Already segments of business and industry are showing alarm at the unreliability of future fuel supplies, particularly natural gas. Congress will get the message, although some members are still talking about windfall profits.

The word "government subsidy" associated with a synfuels program will cause some lawmakers to balk and will provide yet another test of the president's influence on the hill.

The prospect of government ownership of a synfuels industry operated by private companies, in the manner firms have run AEC installations, is one of the considerations which could get a thorough airing, although Ford now sees government ownership as the least desirable alternative and favors the incentives route.

If Ford can't get the needed legislation, he could proceed under the Defense Production Act of 1950 by declaring synthetic fuels to be strategic materials.

Meanwhile ERDA is probing the feasibility of joint industry-government corporations as yet another alternative.

All of these measures indicate a recognition that synthetic fuels and other products from oil shale, oil sands, and coal are politically possible and desirable in light of the balance of payments, the domestic employment and energy vulnerability pictures. It remains for the general public to realize their choice is going to be expensive energy or periodic of no energy at all.

# # #

12 FEDERAL PROCUREMENT NOTICES PUBLISHED AND TWO CONTRACT AWARDS ANNOUNCED

The Commerce Business Daily listed 12 energy-related federal procurement notices and two contract awards during this second quarter of 1975. While the published items cover a broad range of subjects, the list marks a significant drop in the number of such items in marked contrast to similar items published in the last issue of Synthetic Fuels.
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.)

Assessment of Cumulative Sociocultural Impacts of Proposed Plans for Development of Coal and Water Resources in the Northern New Mexico Region, Bureau of Reclamation, Box 11568, 125 South State Street, Salt Lake City, Utah 82111, February 26, 1975, page 3.

Study Evaluation of Bituminous and Sub-Bituminous Coal Reserves in Northwest Colorado, Sole Source RFP 44-75 issued to Colorado School of Mines Research Institute, USGS Central Region, Bldg 25, Denver Federal Center, Denver, Colorado 80225, March 4, 1975, page 3.

Development of Control Technology for Products and By Products of Fuel Conversion/Fuel Utilization Systems, RFP's on request, EPA Contracts Management Division, Office of Administration, Research Triangle Park, N.C. 27711.

Design and Evaluate New Methods and Techniques of Coal Extraction and Overburden Handling in Surface Coal Mines, synopsis #76, USBM Contracts Section, Bldg. 20, Denver Federal Center, Denver, Colorado 80225, March 5, 1975, page 15.

Study the Structural Behavior of an Oil Shale Mine, synopsis #77, USBM Contracts Section, Bldg 20, Denver Federal Center, Denver, Colorado 80225, March 6, 1975, page 21.

Development of Iron-Aluminum Alloys with a Combination of Good Oxidation and Corrosion Resistance and Strength for Coal Gasifiers and Other Applications, USBM negotiating with Solar Division of International Harvester, San Diego, California, March 7, 1975, page 1.


Environmental Assessment of Solid and Liquid Wastes from the Fluidized Bed Combustion of Coal and the Gasification of High Sulfur Oils, RFP CI-75-0190, Negotiated Contracts Branch, Contracts Management Division, NERC-EPA, Cincinnati, Ohio 45268, March 27, 1975, page 25.


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.)


Conversion of Coal to Low-Sulfur Fuel, contract issued under RFP DU-75-A195 by EPA to increase scope of work on existing contract with Institute of Gas Technology, Chicago, Illinois, April 4, 1975, page 2.
TOSCO PROPOSES A GOVERNMENT/INDUSTRY PROGRAM TO REACTIVATE COLONY DOW WEST OIL SHALE PROJECT

The Oil Shale Corporation (TOSCO) submitted a detailed proposal wherein the federal government and the Colony partners would reactivate the presently-suspended Colony Dow West Oil Shale Project. A copy of the TOSCO proposal is reproduced in the appendix of this issue on page A-48.

Government Commitment To Purchase The Products of the Plant Is Sought

TOSCO believes that the Colony Dow West Project can be reactivated by private industry if the federal government would lessen some of the uncertainties which are now deterring private investment in oil shale plants. TOSCO proposes a federal government commitment to purchase the products of the plant at contract prices that would vary depending upon the project financing arrangements. Three contract price cases are suggested:

Case A.
If the project is financed by 75 percent government-guaranteed loans at an interest rate of 8 1/2 percent and by 25 percent equity participation, the contract price would be $11.15 per barrel, in March 1975 dollars, based on March 1975 costs.

Case B.
If the project is financed by 60 percent government-guaranteed loans at an interest rate of 8 1/2 percent and by 40 percent equity participation, the contract price would be $12.80 per barrel, in March 1975 dollars, based on March 1975 costs.

Case C.
If the project could be financed totally by equity participation, the contract price would be $16.75 per barrel, in March 1975 dollars, based on March 1975 costs.

Detailed Estimate of Oil Shale Plant Cost Publicly Available for First Time

One thing which has been accomplished by the presentation of this proposal is to make public some reliable figures concerning the cost of a 48,000 BBL/day commercial plant. By reliable, we mean the figures are based on an intensive program of engineering plant design, on many years of study of special costs relating to oil shale development, on experience with acquisition of environmental background data, on knowledge of spent shale reclamation practices, and on every conceivable facet of the cost problem up to the point of commitment of funds to commence construction. All previous cost estimates are based mainly on assumptions. TOSCO’s capital cost estimate, according to the proposal, was prepared at a cost of more than $12 million. It should be sound. It is based on mid-1974 costs and includes adjustment for inflation since components were bid.

The December 1974 issue of Synthetic Fuels (pages 2-15 through 2-22) contains our review of USBM TPR-81, by Sid Katell, which estimated costs of a 50,000 BBL/day and a 100,000 BBL/day oil shale plant. We tried to show that the USBM cost estimate and the unofficial cost estimate by TOSCO for a comparable sized plant were not much different, being about $500 million for Katell vs. about $600 million for TOSCO, when costs were broken down in a manner that allowed like items to be compared.

Costs have escalated. ERDA, for example, is now using $568 million as the capital cost for a 50,000 BBL/day plant. TOSCO’s costs have escalated to those shown in Table 1.

Colony’s cost estimate has grown now to the $902.8 million shown in the recent proposal.

CAMERON ENGINEERS, INC.
A listing of the capital cost components of the proposed Colony plant is presented in Table 1, the "Case A" table, which is presented on this page. As shown, the total plant cost would be $902.8 million. This includes the cost of acquisition of oil shale reserves, which is said to be $79.1 million.

The $79.1 million for reserves acquisition for the Colony plant is analogous to the $210.3 million or the $117.8 million bonus bids which were made on the C-a and C-b federal tracts.

Some $128.2 million are cited in the proposal as being capital costs which have already been expended. These are costs for rail sidings, resource acquisition access roads, etc., and they are summarized in the Case A table.

**Project Financing Would Be Aided By Government-Guaranteed Loans**

Two of the proposed financing arrangements, Cases A and B, would involve government-guaranteed loans. In cases A and B, the project would be financed by equity contributions and by issuance of debentures guaranteed by the U.S. government. The equity contributions would be in the form of cash, land and reserves, and expenditures already incurred.

According to the proposal, equity capital would be paid in and government-guaranteed debentures would be issued on a schedule to match outlays. During construction, the equity contribution would consist of capital costs already incurred.

**Colony Partners Would Operate the Project**

It is proposed that the Colony Venture participants (ARCO, TOSCO, Ashland, Shell) would have responsibility for project operation, subject to supervision by the federal government.

The principal marketable product would be hydrotreated shale oil of the following specification:

| API Gravity | 40.0 |
| Sulfur, weight percent | Nil |
| Nitrogen, weight percent | 0.06 |
| Product yields, volume percent: | |
| Gasoline and Naphtha | 43.0 |
| Gas oil | 57.0 |
| Residuum | None |

**TABLE 1**

**CASE "A"**

<table>
<thead>
<tr>
<th>Capital Cost Components</th>
<th>$ Millions</th>
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<tbody>
<tr>
<td>Acquisition of Oil Shale Reserves</td>
<td>79.1</td>
</tr>
<tr>
<td>TOSCO II Technology License</td>
<td>no charge</td>
</tr>
<tr>
<td>Plant Design and Construction</td>
<td></td>
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<tr>
<td>Mining, Crushing and Processed Shale Disposal</td>
<td>86.2</td>
</tr>
<tr>
<td>Pyrolysis Unit</td>
<td>122.3</td>
</tr>
<tr>
<td>Fractionation &amp; Gas Recovery</td>
<td>15.0</td>
</tr>
<tr>
<td>Oil Upgrading, By-Product Recovery &amp; Waste Water Treatment</td>
<td>86.4</td>
</tr>
<tr>
<td>Site Development, Roads &amp; Dams</td>
<td>23.3</td>
</tr>
<tr>
<td>Utilities &amp; General Facilities</td>
<td>70.4</td>
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<tr>
<td>Field Costs</td>
<td>43.8</td>
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<td>Taxes &amp; Insurance</td>
<td>7.1</td>
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<tr>
<td>Engineering Services &amp; Fee</td>
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<td>Sub Total</td>
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<tr>
<td>Contingency</td>
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<tr>
<td>Escalation Allowance (Mid 1974 to March 1975)</td>
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<tr>
<td>TOTAL</td>
<td>580.3</td>
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</table>

<table>
<thead>
<tr>
<th>Capital Costs Already Expended or Committed**</th>
<th>$ Millions</th>
</tr>
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<tbody>
<tr>
<td>Acquisition of Oil Shale Reserves</td>
<td>79.1</td>
</tr>
<tr>
<td>Managing Contractor Services</td>
<td>18.3</td>
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<tr>
<td>Plant Access Road</td>
<td>3.4</td>
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<td>Railroad Siding</td>
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<tr>
<td>Land Acquisition</td>
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<td>Environmental Analysis</td>
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<tr>
<td>Mining &amp; Semi-Works Tests</td>
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<td>Project Management Staff</td>
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<tr>
<td>Community Planning &amp; Development</td>
<td>6.0</td>
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<tr>
<td>Mining Pre-Development</td>
<td>7.9</td>
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<tr>
<td>Mobile Equipment</td>
<td>15.8</td>
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<tr>
<td>Ceramics, Chemicals &amp; Catalysts</td>
<td>8.7</td>
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<tr>
<td>Prepaid Licenses</td>
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<tr>
<td>Employee Recruitment &amp; Training</td>
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<tr>
<td>Accrued Interest</td>
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<tr>
<td>Misc. Other Expenditures</td>
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<tr>
<td>Sub Total</td>
<td>108.7</td>
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<tr>
<td>Interest During Construction</td>
<td>84.7</td>
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<tr>
<td>Start-up &amp; Fixits</td>
<td>30.0</td>
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<tr>
<td>Working Capital</td>
<td>20.0</td>
</tr>
<tr>
<td>GRAND TOTAL</td>
<td>902.8</td>
</tr>
</tbody>
</table>

* Included in Grand Total of $902.8 million.
** As of proposed start of field construction, April 1, 1976.
Production rates projected are 8,726,700 barrels in the first year after start up, 15,090,000 barrels in the second year, and 15,708,000 barrels annually for the ensuing 18 years.

Each of the Colony partners would retain the right to purchase from the U.S. its equity percentage of marketable products acquired by the U.S. under its contract. The purchase price would be the average U.S. market price for the most comparable crude petroleum in the preceding quarter. If the contract price is higher than the market price, the government would pay the difference to the project. If the contract price is lower than the market price, the difference would be paid into a fund established for this project. If the fund accumulates a positive balance, the balance would be shared by government and the project in proportion to the amount of capital costs financed by government-guaranteed debt.

The proposed contract price for the oil would be firm for the life of the project subject to adjustment for inflation or deflation of capital outlay and of other costs. In Case A (75 percent government-guaranteed loans and 25 percent equity) the effect of cost increases attributable to changing economic conditions would be:

- Five percent per year inflation from March 1975 to start up would increase the price per barrel $1.71 including $0.91 per barrel additional operating costs.
- A $50 million increase in capital costs attributable to inflation would increase the contract price $0.75 per barrel. A $50 million increase in capital costs not attributable to inflation would increase the contract price $0.13 per barrel.
- A debt interest rate of 10 1/2 percent instead of 8 1/2 percent would increase the contract price $0.67 per barrel.

TOSCO Suggests Program Schedule

If the government's decision is affirmative, TOSCO suggests the following action program:

March-July, 1975
- Preliminary understanding reached on terms
- BLM and other agencies proceed on impact statement
- TOSCO interests industry in re-activating the project
- Government seeks any needed authority from Congress

July-September, 1975
- Definitive contacts executed
- EIS concluded

October, 1975
- Project released for construction

April, 1976
- Construction field start

June, 1979
- Operations begin at project competition

The Proposal is a Discussion Paper

TOSCO's proposal is addressed to no one. Apparently it is a discussion paper which is to be circulated within the government and elsewhere as a basis for discussions if anyone in government is interested.

Obviously, the U.S. government would examine the proposal's cost estimates, prices, terms, etc., before agreeing to guarantee loans, purchase the plant product, or invest in an equity position in the project. In addition, specific authority may have to be obtained from Congress for a government agency to participate. Then there is the matter of appropriation of money.

If the federal government were to develop an interest in this venture, one can visualize time consuming events. One of these includes bargaining. For example, if the market price of oil is lower than the agreed-upon contract
purchase price, government pays the difference according to the proposal. No question there. However, if the market price is higher than the agreed-upon contract purchase price, then, according to the proposal, government and the project share the difference. One can visualize disagreement there.

The proposal is a discussion paper, not a final agreement. The idea for the proposal probably stems from present government investigations into the types of incentives that might be employed to stimulate domestic production of energy. This is TOSCO's idea of an incentive.

In view of the many dis-incentives which government has dealt to the energy industries recently, it would represent a significant turn-around on the part of Congress for government to ensure an oil industry venture against risks associated with unremunerative future prices of oil, high interest rates, price fluctuations, etc. In a sense, it is a turn-around for private enterprise to seek such government interference.

The proposed time schedule seems overly optimistic. Involved are such necessities as the preparation by the government of environmental impact statements, public hearings, policy formation, Congressional actions, etc. Until the nations' lights, heating furnaces, and industry grows colder than they are now, Congress will see little urgency in acting on subsidies to the oil industries. For government and venture participants to execute definitive contracts and for the government EIS procedures to be concluded by July-September, 1975 are difficult to visualize.

# # # #
TOSCO SEEKS UNITIZATION OF UTAH LEASES

The Utah Division of Lands scheduled public hearings during the third week in June in Vernal, Utah, on a proposal by The Oil Shale Corporation to unitize 29 oil shale leases it has on option from Shell Oil Company.

TOSCO proposes to spend at least $8 million to develop a room and pillar mining plan by December 31, 1983, for the 14,688 acres about 35 miles south of Vernal in the Sand Wash area, if the leases can be brought under one written agreement.

The leases are in four blocks of about 7,087, 3,614, 2,505, and 1,480 acres. The blocks are separated from each other by federal and private lands. (See article and map in the December 1974 issue of Synthetic Fuels.)

TOSCO's unitization plan would give all 29 leases a common expiration date. It would permit a 35,000 to 100,000 barrel per day shale oil plant to operate on the largest block using shale from all blocks.

Utah law specifies that nonproducing leases expire and become available for competitive leasing. The TOSCO plan would enable some of the present blocks to be considered part of the main, producing block although they would not be producing. After 1983 TOSCO, could retain leases on nonproducing leases by paying the minimum royalty of $404,000 a year.

TOSCO also appears to want to acquire leases on federal intervening lands by speculating that a federal shale leasing policy will develop similar to the Department of Interior coal leasing practice.

Under the coal leasing policy, exceptions to the present leasing moratorium are possible if federal reserves are needed to continue present mining operations on adjacent nonfederal land. There are several thousand acres of federal shale lands adjacent to the state leases. There is no federal oil shale leasing policy now.

The TOSCO blocks are about seven to 12 miles west of federal oil shale prototype tracts U-a and U-b.

In addition to the Utah leases, sought for unitization, TOSCO has about 5,229 acres under other state leases in the vicinity.

Charles Hansen, Utah State Lands director, said that a major concern before the land panel is the impact of a precedent if unitization is granted. The issue is being evaluated by their staff and will be a major topic of debate at the Vernal hearings.

The agreement TOSCO has tendered calls for payment of a collective minimum royalty of $4 million through 1993, if the mine is developed, and specifies a payment of $734,400 annually thereafter, according to agency records.

Through the plan, TOSCO offered to develop mining on all the blocks within 20 years after the start of a commercial scale operation. The board has been advised that the Sand Wash Plan includes the first, third, fourth, and fifth largest tracts of Utah-owned land with significant oil shale deposits. If they can not be developed commercially under a unit plan, TOSCO considers that the prospects for development of any state leases to be poor.

The agreement provides that with unitization TOSCO will pay royalties of more than three times those in the existing leases. The agreement does not guarantee development and no time table is set for completion of additional exploration, environmental studies, and other work leading to a decision to produce shale oil.

TOSCO has already moved to acquire about 50 cubic-second-feet of water for the development from the White and Green Rivers.
TOSCO officials also indicate other mining methods besides room and pillar may be evaluated.

The Utah State Board of Oil, Gas, and Mining Conservation has already approved the TOSCO proposed resource evaluation plan.

OSEAP MEETING QUIET

Colorado Gov. Dick Lamm has designated Gerald D. Sjaastad, Colorado Deputy Director of Natural Resources, and State Representative Nancy Dick, D-Aspen, as the state's members of the U.S. Department of Interior Oil Shale Environmental Advisory Panel.

The new members were present at OSEAP's meeting May 15-16 at Meeker, Colorado.

In one of its least controversial meetings, the panel placidly endorsed changes in environmental data collection procedures by approving changes in lease stipulations for developers of federal prototype oil shale tracts in Colorado and Utah.

The thrust of the modifications is to get away from collecting data for data's sake and begin seeking data that would appear to be meaningful.

"It's pointless to try and take water samples in a dry stream or try and count snakes under two feet of snow just to comply with a predetermined schedule that requires samples to be taken at specific intervals," the panel was told.

Under new guidelines data will be collected when it is believed they will contribute to environmental knowledge pertinent to the tracts.

Pete Rutledge, USGS mining supervisor for the four tracts, said detailed information is being readied for a data retrieval system.

Rutledge said the policy change makes it possible to tailor environmental procedures to the specific tracts instead of giving identical treatment to all four. Since the tracts are different, the work will be more meaningful.

The panel also submitted a draft of its first annual report. The report highlights the year's activities and notes the special requests for panel input into matters not specifically related to the prototype leases.

The first request was for an Interior study and environmental impact statement on proposed water development on the White, Yampa, Green, Upper Colorado, and Duchesne Rivers.

The second request was for panel input into proposed federally sponsored in situ oil shale acceleration program.

The panel toured Tract C-b and scheduled tours of tracts U-a and U-b for June 17 and 18; and C-a for mid August.

William L. Rogers, western regional assistant to the Secretary of the Interior, is panel chairman.

The preliminary development and exploration plans and summary data reports for the prototype oil shale leases (January 19, 1974-April 15, 1975) are given in Table 1.
<table>
<thead>
<tr>
<th>Oil Shale Lease Tract</th>
<th>Document</th>
<th>Date</th>
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<tr>
<td>Colorado C-a</td>
<td>Preliminary Development Plan</td>
<td>January 1974</td>
</tr>
<tr>
<td></td>
<td>Exploratory Plan</td>
<td>May 1974</td>
</tr>
<tr>
<td></td>
<td>Statement of Work and Organization for Meteorological Systems, Air</td>
<td>July 15, 1974</td>
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<td></td>
<td>Quality Systems, and Studies (EG&amp;G, Contractor)</td>
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<td></td>
<td>Terrestrial Baseline Data Accumulation Program</td>
<td>October 1, 1974</td>
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<tr>
<td></td>
<td>(Ecology Consultants, Inc., Contractor)</td>
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<td></td>
<td>Scope of Work for Aquatic Baseline Data Accumulation Program</td>
<td>October 3, 1974</td>
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<td>(NUS Corporation, Contractor)</td>
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<td></td>
<td>Rio Blanco Oil Shale Project Progress Report 1</td>
<td>January 8, 1975</td>
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<tr>
<td></td>
<td>(submitted to OSEAP)</td>
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<tr>
<td>Colorado C-b</td>
<td>Preliminary Development Plan</td>
<td>March 6, 1974</td>
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<td></td>
<td>Exploration Plan for Tract C-b</td>
<td>April 10, 1974</td>
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<td></td>
<td>Core drilling and Associated Ground Water Program</td>
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<td></td>
<td>Supplemental Exploration Plan</td>
<td>May 6, 1974</td>
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<tr>
<td></td>
<td>Exploration Plan for Colorado Tract C-b (includes the April 10 and May 16 material in one bound document)</td>
<td>May 15, 1974</td>
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<td></td>
<td>Monitoring and Support Facilities</td>
<td>May 1974</td>
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<tr>
<td></td>
<td>Site Locations and Requirements</td>
<td></td>
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<tr>
<td></td>
<td>Pre-exploration Environmental Reconnaissance Tract C-b Core Drilling and Associated Ground Water Program (Woodward-Envicon, Inc., contractor)</td>
<td>July 15, 1975</td>
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<tr>
<td><strong>Utah U-a</strong></td>
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<td></td>
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<td>---</td>
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<tr>
<td>Sun Oil Co. and Phillips Petroleum Co.</td>
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<td><strong>Utah U-b</strong></td>
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<tr>
<td>White River Shale Oil Corp.</td>
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<td></td>
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<tr>
<td><strong>Utah U-a and U-b</strong></td>
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<td>(Combined Plans and Reports) as White River Shale Project</td>
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<tr>
<th>Environment and Exploration Program</th>
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<td>Preliminary Development Plan</td>
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<td>Preliminary Development Plan</td>
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<td>Partial Exploration Plan Environmental Baseline Data Collection and Monitoring Element</td>
<td>July 1, 1974</td>
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<td>Environmental Assessment of Proposed Monitoring Sites (VTN, Contractor)</td>
<td>August, 1974</td>
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<tr>
<td>Geological Exploration Program Supplement to Partial Exploration Plan</td>
<td>August, 1974</td>
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<tr>
<td>Quarterly Report No. 1 prepared for White River Shale Project (VTN, Contractor)</td>
<td>February, 1975</td>
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GULF-AMOCO VENTURE OPTIONS "CONDITIONAL" WATER RIGHTS FROM ROCKY MOUNTAIN POWER

Rocky Mountain Power Company (Rompoco) owns certain water rights, conditionally decreed, on the South Fork of the White River and on various other tributary streams to the Colorado River upstream from Colorado's oil shale area. It has been the intent of Rompoco to use the water in a future development designed to generate electric power.

Gulf Oil Corporation and Standard Oil Company (Ind.), acting as "Gulf-Standard," the venture engaged in developing the federal C-a oil shale tract in Colorado, signed an option agreement on April 15, 1975, with Rompoco for purchase of certain of Rompoco's conditional water rights.

This action, the agreement to purchase conditional water rights, is not common, but may well become more common as energy project developments progress in the area.

Gulf-Standard will require an assured and dependable supply of water for its planned developments on Tract C-a and, in 1974, filed for conditional water rights in connection with the Yellow Creek Reservoir (Water Right Application W-2220) and, as an alternative, the Duck Creek Reservoir (Water Right Application W-2221). For a map of the area and a discussion of the above applications, see the June 1974 issue of Synthetic Fuels, page 2-20.

Gulf-Standard apparently wants to obtain additional rights to supply its requirements and the option agreement with Rompoco is for this purpose.

"Conditional" water rights, as granted by the courts in Colorado, are not firm. They are conditional, as the name implies, and a firm right to the water is not obtained until the necessary diversion and storage facilities are built and the water is put to beneficial use. Until water is put to beneficial use, the courts may grant the available supply to someone else who does put it to beneficial use. Such is the system in Colorado.

Terms of the Option Agreement Listed

Subject to various terms, rights, waivers, etc., the general terms for the sale and purchase of the conditional water rights are:
Upon the execution of the agreement, Gulf-Standard paid Rompoco $10,000.

Gulf-Standard will pay Rompoco $10,000/month for 15 succeeding calendar months.

At the closing of the transaction in January 1977, Gulf-Standard will pay Rompoco $4.33 million.

In the event the transaction is closed as noted in the agreement, the purchase price may be adjusted. The price would be computed as being the difference between $4.5 million dollars and the yield in acre feet up to a maximum of 85,000 acre feet, of the "Category A and B" decrees at the changed point of diversion multiplied by one hundred dollars per acre foot. The maximum total purchase price including all initial monthly payments and the closing payment which, in any event, Gulf-Standard would be required to pay for all of the subject water rights would be $8.5 million dollars.

Quantities of Water Involved

Approval would have to be obtained from the courts for Gulf-Standard to change the points of diversion of the various Rompoco rights. If all constraints on this are such that Gulf-Standard can obtain 45,000 acre feet, the price would be $4.5 million. It may be possible for Gulf-Standard to divert as much as 85,000 acre feet/year, but this would be dependent on many things, a few of which are listed below.

- The availability of water at the original points of diversion.
- The availability of water at the new point of diversion upstream on the White River from its confluence with Yellow Creek.
- Court interpretations concerning limitations upon use imposed by terms of existing decrees.
- Hydrological, climatological, and watershed conditions.

Demands of other appropriators.

Present and future demands of the U.S. government, including Indian tribes.

Constraints imposed by interstate compacts.

Constraints imposed by legislation relating to salinity control, water quality control, protection of fish and wildlife, scenic or esthetic values.

# # # #
TOSCO RESEARCHERS DESCRIBE LEACHING METHOD FOR EXTRACTING ALUMINA FROM DAWSONITE OIL SHALE

F.C. Haas and M.R. Atwood studied the thermal decomposition and leaching characteristics of dawsonite (mineral formula = Na$_3$Al(CO$_3$)$_3$.2A1(OH)$_3$) and developed an improved method for recovering alumina from spent dawsonitic oil shale. Their alumina recovery process and a recommended assay procedure for determining recoverable alumina were presented before the Eighth Oil Shale Symposium at the Colorado School of Mines in Golden, Colorado, in a paper entitled, "Recovery of Alumina From Dawsonitic Oil Shales."

Assay Procedure for "Recoverable" Alumina Presented

TOSCO found that the most reliable results were obtained analyzing spent shale for recoverable alumina by leaching samples with 0.5 normal NaOH solution and subjecting the filtrate to analysis for alumina by atomic absorption techniques. The procedure is both simple and fast, requiring a one-gram sample of Fischer assay residue, ground to minus 65 mesh, which is leached at room temperature for ten minutes with 50 ml of 0.5 N NaOH solution.

Alumina Extraction Process Differs Slightly From the Assay Method

Alumina can be recovered from dawsonitic oil shales by first retorting the shale at about 500°C to decompose the kerogen. The spent shale is then rapidly leached at ambient temperatures and about 40 percent solids. After a liquid-solids separation, the pregnant leach liquor is heated to about 65°C and seeded with previously precipitated alumina trihydrate to precipitate the alumina. The precipitated alumina is then dried and calcined. One of the major problems associated with producing cell-grade alumina from shales has been silica contamination. By leaching cold and precipitating hot, this problem has been overcome.

Various parameters have been studied in the leaching step, such as, time, temperature, percent solids and caustic concentration. It was found that conditions of 40 percent solids, 25°C, 20 g/1 NaOH leach solution and one minute or less of leach time gave good alumina extractions with minimum silica dissolution.

Concerning precipitation of alumina, the sodium aluminate leach liquor is almost supersaturated with respect to sodium aluminate. If given enough time, the leach liquor will begin to decompose on its own according to the following reaction:

$$2 \text{NaAlO}_2 + 4 \text{H}_2\text{O} \rightarrow \text{Al}_2\text{O}_3 \cdot 3\text{H}_2\text{O} + 2\text{NaOH}$$

This reaction can be speeded up by adding an alumina trihydrate seed. The best temperature range for precipitation is from 60-80°C with the optimum being at 65°C. Fifty percent of the alumina is precipitated in one to two hours, whereas, only seven percent of the silica is precipitated.

Optimum results are obtained by recycle leaching and precipitation. Caustic is generated from the decomposition of sodium aluminate leach liquors. Thus, once the leaching and precipitation cycle has been started, the process is self-sufficient in caustic requirements. In fact, the process is a net producer of caustic and soda ash. Instead of starting the cycle with 20 g/1 NaOH solution, one could start with water. Alumina extraction, in the first cycle, would drop to about 60 percent from an expected 95+ percent, but sufficient caustic would be generated in the first and second precipitation cycles so that alumina extraction would increase rapidly to 95+ percent after about seven cycles.

The presence of nahcolite presents no adverse effects on the alumina recovery process.

# # #
NEW INFORMATION PRESENTED CONCERNING "EXTRACTABLE:" ALUMINA IN COLORADO OIL SHALE

The mode of occurrence, the reserves, and the possibilities for extracting alumina as well as oil and gas from Colorado oil shale, is discussed in a recent report entitled, "Dawsonite: Its Geochemistry, Thermal Behavior and Extraction From Green River Oil Shale," by J. W. Smith and N. B. Young of the Laramie Energy Research Center (ERDA). The report was presented at the Eighth Oil Shale Symposium sponsored by the Colorado School of Mines.

Dawsonite and Companion Mineral Nordstrandite Constitute the Sources of "Extractable" Alumina

It has been known for several years that after mild heat treatment, such as retorting of oil shale at 900°F, the alumina content of the mineral dawsonite in the shale is easily and quickly extracted by leaching with mild acid or basic solutions.

Until this report was issued, the dawsonite (Na₃Al(CO₂)₃⋅2Al(OH)₃ or NaAl(OH)₂CO₂) was believed to be the source of the easily extractable alumina. The persistent presence of nordstrandite with dawsonite has been confirmed, and nordstrandite (Al(OH)₃) has also been shown to be a source of easily extractable alumina.

The persistent presence of nordstrandite with dawsonite in the Colorado portions of the Green River Formation can be explained by the geochemistry of the mode of formation of several minerals, including dawsonite and nordstrandite. Two interrelated events accompanied dawsonite mineral formation, both being generated by a supply of CO₂ derived from organic matter present. As the pH of the lake water decreased, sodium bicarbonate (nahcolite) formed from sodium carbonate solution, as indicated by the equation:

\[ \text{Na}_2\text{CO}_3 + \text{CO}_2 + \text{H}_2\text{O} \rightarrow 2\text{NaHCO}_3 \]

As the pH decreased, aluminate ion precipitated as aluminum trihydroxide as indicated by the equation:

\[ \text{AlO}_2^- + \text{H}^+ + \text{H}_2\text{O} \rightarrow \text{Al(OH)}_3 + \text{NaHCO}_3 \]

Thus, nordstrandite is ever-present with dawsonite.

Differential thermal analysis (DTA) of dawsonite samples always gives curves which display an extra DTA peak, extra that is, when compared with DTA curves obtained from pure synthetic dawsonite. The cause of the extra peak had never been explained. Studies on the cause of this extra peak led to the discovery that about 20 percent excess alumina over that theoretically available could be extracted from dawsonite samples by leaching with weak NaOH solution. After further studies, the authors concluded that nordstrandite was the mineral associated with dawsonite and that the aluminum content of nordstrandite is extractable by leaching, after mild calcination.

Reserves of "Extractable" Aluminum Are Large

As nordstrandite occurs everywhere with dawsonite, its distribution is similar to that of dawsonite. A source of easily extractable alumina is represented in the minerals dawsonite and nordstrandite. The geographic location and thickness of the dawsonite-bearing occurrences are shown in Figure 1, reproduced from Smith's paper. An estimate of the dawsonite reserves, based on earlier and obviously incomplete data is given as Figure 2, also reproduced from Smith's paper. Together, the minerals dawsonite and nordstrandite from this area represent a domestic resource of extractable alumina of over 6.5 billion tons, enough to supply the United States for hundreds of years.

Preferred Methods For Extracting Alumina From Spent Shale Is Examined

Extraction of alumina from spent shale, the residue remaining after a
Figure 1. Geographic Location and Thickness of Colorado's Dawsonite Deposits.

Figure 2. Dawsonite Isoreserves in the Piceance Creek Basin.
The shale retorting operation, has been found to be quite economical. The base used, however, should be a weak base leaching solution, not a strong base as is used in the Bayer process. The Bayer process is expensive, unnecessarily violent, and is otherwise unsuited for extracting alumina from shale.

Table 1, reproduced from the Smith report, illustrates the Al₂O₃ extracted by 0.5 M Na₂CO₃ from samples of nahcolite-free oil shale heated under nitrogen at temperatures of 450° and 600° for 30, 60, 90, and 120 minutes. The -100 mesh residue was extracted hot with stirring. Extraction time was three minutes, and longer times recovered no significant additional amounts of alumina. Shorter extraction times were not tested. Before heating, the specimen yielded 6.49 weight percent acid-extractable Al₂O₃, 5.15 percent in dawsonite and 1.34 percent in nordstrandite. About 94 percent of the acid-extractable Al₂O₃ was recovered at 450°C (840°F) with heating times of 30 and 60 minutes. The high-carbon coke remaining on the shale did not interfere with the extraction.

Two factors which decrease alumina extractability are indicated in Table 1. Significantly less alumina was available from the shale heated to 600°C, and longer heating residence times appear to decrease the amount of extractable alumina.

These solubility reductions stemmed from glass formation and the loss of water from the Al(OH)₃. Heating to higher temperatures under nitrogen gradually reduced the amount of available alumina, indicating the gradual loss of water. Oil evolution from the raw shale can be completed quickly at about 450°C, the most suitable temperature neighborhood for heating oil shale for both oil and alumina production.

The amount of aluminate ion which can be retained in solution depends on the amount of hydroxyl ion (or the equivalent pH) in the solution. If the available base is consumed, the pH drops and solution of alumina will stop. This explains why water-leaching the retorted shale will not extract all of the available alumina. When dawsonite decomposes only one mole of carbonate is produced for two moles of aluminum in alumina. This is only half the base required to dissolve the alumina. Enough base must be present in excess to maintain the aluminate ion in solution.

Analcime occurs peripheral to the major dawsonite deposits. Production of alumina from areas where analcime occurs should be avoided, because analcime yields silica readily dissolved by base extraction.

The base extraction of spent shale seems the most probable route to alumina production from oil shale. This procedure is the basis of several workable patents for such alumina production which use both sodium carbonate and sodium hydroxide in their extraction processes. These are equivalent in aluminum extraction, but sodium hydroxide is more useful than soda ash for pH control. Soda ash can be readily obtained as a by-product, and sodium hydroxide can be readily manufactured from it by adding burned lime to a solution of Na₂CO₃.

To summarize the optimum procedures for extracting alumina from oil shale, the raw shale should first be heated to drive out the organic matter and decompose the nordstrandite and dawsonite. Atmosphere over the shale should be inert or at least not oxidizing to achieve temperature control of the retorting step. The shale should be heated between 450°C to no more than 550°C for only as long as is necessary to evolve the organic matter as oil. Burning the residual carbon coke is neither necessary nor desirable. The resulting spent shale is porous, permeable, wettable, and easily crushed. Crushing should be limited to that necessary to facilitate fast and efficient extraction but permit easy separation of the spent shale residue. The extraction should be rapid and
TABLE 1

ALUMINA EXTRACTED BY 0.5 M Na₂CO₃ FROM OIL SHALE HEATED AT 450°C or 600°C IN A NITROGEN ATMOSPHERE
(Extraction time = 3 minutes)

<table>
<thead>
<tr>
<th>Shale heating time, min.</th>
<th>Alumina recovered wt. pct. raw shale</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>450°C</td>
</tr>
<tr>
<td></td>
<td>600°C</td>
</tr>
<tr>
<td>30</td>
<td>6.12</td>
</tr>
<tr>
<td>60</td>
<td>6.12</td>
</tr>
<tr>
<td>90</td>
<td>6.08</td>
</tr>
<tr>
<td>120</td>
<td>5.73</td>
</tr>
</tbody>
</table>

continuous, and it should minimize shale exposure to strong base. Control of the amount of nahcolite entering the retorting process will help prevent glass formation and will also help the solvent recovery processes. The recovery of alumina from sodium aluminate solutions will probably involve precipitation of Al(OH)₃ with CO₂. This works well, and the procedures are known. Sodium concentration in the aluminum-bearing liquor must be kept low enough to prevent dawsonite formation during Al(OH)₃ precipitation.

Comparison With the Bayer Process

To compete with the long established Bayer process, still in use more than 80 years after the primary patent was issued, a new process applied to the ore must have technologic and economic advantages. Extracting alumina from oil shale seems to have such advantages.

The Bayer process requires ores high in alumina (~50 percent Al₂O₃) and low in silica (usually less than 4 percent SiO₂). Bauxite is the ore mineral treated by the Bayer process. The extractable alumina content of spent oil shale is much lower than the alumina content of bauxite. A plant processing about 30,000 tons of raw shale per day of dawsonitic oil shale could yield about 1,000 tons of alumina per day at 90 percent recovery. Preparing the shale for alumina extraction would produce 23,000 barrels of oil, and associated nahcolite plus dawsonite will produce soda ash. The required development of coproducts with the alumina is a significant asset to alumina production from oil shale.

Technologies of the Bayer process and the oil shale alumina extraction process contrast sharply, and several processing advantages to the oil shale extraction may compensate for the relatively small amount of alumina available per ton of spent shale. For equal alumina production, processing spent oil shale requires handling ten times as much five weight percent Al₂O₃ material as does 50 weight percent bauxite. To point out advantages in spent shale extraction this process must be compared with the Bayer process.

The major contrasts between the two processes lie in the pressure digestion, clarification, and precipitation steps. Specific differences between the two processes will be itemized and evaluated.

Pressure Digestion

Bayer: Ore ground to -20 mesh is digested at high pressure (commonly 200+ psig) and high temperature (to 400°F) in strong base (4 to 12 N) for periods of time ranging from 30 minutes to overnight.

Oil Shale: After inert atmosphere retorting to produce oil, alumina is dissolved from spent shale quickly and continuously in light base (~1N).

Comparison: The Bayer process is actually a batch process while oil shale retorting and extraction is a continuous process. The Bayer process is violent and requires expensive specialized equipment for the extraction, including pressure and temperature control apparatus. It dissolves silica which precipitates with sodium and aluminum from the concentrated extract. Oil shale can be extracted under mild conditions using standard
extraction equipment. Little silica will dissolve from the oil shale, eliminating the loss of caustic and alumina to the scale-forming sodium aluminum silicate precipitate which plagues the Bayer process. The moderate temperature and pressure conditions inherent in oil-shale processing will minimize water requirements which are large in the Bayer process.

Clarification

Bayer: Separation of the undissolved residue from pressure digestion, called "red mud," is a complex procedure made difficult by the fine-particle product resulting from digestion. Many of the recently published improvements on the Bayer process center on speeding the settling rate of the red mud from the aluminum-bearing solution. Washing the red mud, now accomplished with large series multistage counter-current mud washers, is also a difficult procedure.

Oil Shale: The soluble alumina can be extracted efficiently from much larger spent shale particles. Particle size control to retorting and extraction can optimize both the extraction and the separation rate. Particles as small as those generated in the Bayer process (less than 1 μm for some ores) need never appear in the spent shale.

Comparison: The spent shale settling equipment will have to handle many times the solids volume that the red mud from the Bayer process represents. However, the spent oil shale's easy extractability, washability, and filterability, the possibility of using and maintaining larger particles, and the lower density of the liquor carrying the particles being separated all tend to make spent shale separation much easier than red mud separation.

Precipitation

Bayer: Aluminum trihydroxide is precipitated from the supersaturated "green liquor" by cooling, then seeding the liquor with as much additional aluminum trihydrate as is in the "green liquor." The precipitation is rapid at first, then slows. Total precipitation time is 65 hours, and only 50 percent of the alumina in the liquor is recovered. After the Al(OH)_3 precipitate is removed, the spent liquor is reconditioned and recycled.

Oil Shale: Extracting alumina from spent shale requires only enough excess base to keep the low concentration of aluminate ion in solution. This limited base will neutralize readily on injecting CO₂, and the solution will shortly begin to precipitate Al(OH)_3. Seeding with about 25 percent of the liquor's Al(OH)_3 may be useful to provide particle size control. The resulting sodium bicarbonate solution containing only a limited amount of alumina is reprocessed for soda ash recovery and recycling.

Comparison: Aluminum trihydroxide precipitation in the Bayer process is an art. The required temperature control, the long storage time necessary for precipitation, and the density of the residual solution (making Al(OH)_3 separation difficult) indicates that it is also an expensive art. Chemical precipitation of Al(OH)_3 from the spent shale extract is much more likely to be a science.

Additional factors which may provide alumina extraction from oil shale some economic advantage include the availability of process materials from the processed ore. Soda ash will be produced routinely from dawsonite even in the absence of nahcolite. Co-occurring nahcolite can provide soda ash, if necessary. If not, the nahcolite may be mechanically separated. The CO₂ required for the precipitation may be obtained from flue gas or might be recovered from processing the co-occurring nahcolite. Lime for generating the NaOH required could be obtained locally by firing some of the washed spent shale discard, which is high in calcium carbonate content.

Author's Conclusions

Production of alumina from oil shale bearing dawsonite and nordstrandite with simultaneous production of shale
oil and sodium carbonates is technically feasible. Advantages in the extraction properties of spent shale may adequately compensate the disadvantage imposed by handling comparatively large quantities of spent shale. Production techniques should be designed around the character of the oil shale, and should not be applied directly from the Bayer process.

The energy available, as oil and gas, from retorting dawsonitic oil shale would be sufficient to process the extracted alumina to metallic aluminum. The facility which would mine 30,000 tons of raw oil shale/day would produce 23,000 barrels of shale oil/day plus 1000 tons of alumina/day and could conceivably use its oil as fuel to produce 529 tons of metallic aluminum/day.

IN SITU OIL SHALE INCENTIVES PROPOSED BY SENATOR

Senator Floyd Haskell, D-Colo., offered two amendments to S. 598 to speed in situ oil shale development by ERDA. One hiked funding for oil shale from $8.1 million to $24 million and the other permits ERDA to invite proposals from non-federal participants to cooperate with the agency for a 30,000 BPD in situ demonstration project on public land. The amendment authorizes the ERDA administrator in consultation with the Secretary of Interior to select the tract and allow the use of the land in a lease "without royalties or other consideration."

Haskell's proposal provides for environmental protection, timely and orderly development, and operation for at least one year after which the administrator can transfer the lease to the non-federal participant for continued commercial production. Terms for the transfer are not specified but left to negotiation between the administrator and the non-federal entity. Haskell said the purpose of the measure is to cut red tape and speed up research. Both amendments were accepted by the Senate Interior Committee Subcommittee on
TECHNOLOGY

LAWRENCE LIVERMORE LAB PROPOSES $80 MILLION PROGRAM FOR DEVELOPMENT OF AN IN SITU PROCESS TO EXTRACT OIL FROM SHALE

Lawrence Livermore Laboratory has published report No. UCRL-51768 entitled, "Rubble In Situ Extraction (RISE): A Proposed Program for Recovery of Oil From Oil Shale."

The conceptual rubble in situ extraction process described comprises a modified sublevel-caving method of mining to produce oil shale rubble suitable for retorting underground.

The program proposed by Lawrence Livermore Laboratory for developing this process and demonstrating it on a commercial scale would cost $80 million and require approximately six years time.

The project proposal assumes that the government would pay for the total program and would provide the necessary site. However, it is stated that an attempt would be made to obtain industry cooperation, advice, and participation at any time after the beginning of the program.

Rubble In Situ Extraction (RISE) Concept Examined

Figure 1, reproduced from the report, presents descriptions of the sequential operations needed for development of the RISE concept. Approximately 20 percent of the oil shale must be removed from the retort area by mining to create the necessary void space within the rubble. Large retorts are proposed by LLL, the commercial scale size being generally 100 x 100 x 300 feet high, with one retort of 250 x 250 x 1000 feet. For retorting of the rubble, LLL merely states that "hot gas is used as the heat transfer medium and that the hot gas is continuously generated from combustion of a portion of the oil shale, using an air stream."

The Experimental Approach of the $80 Million Project, as Outlined by LLL

LLL contends in its proposal that key problems can be resolved only on a significant scale in field tests. Its approach generally follows that assumption.

Concerning retorting, LLL would conduct laboratory retorting tests at various heating rates and in various atmospheres. The effect on permeability of rubble during heating under confining pressures would be determined. LLL is apparently conducting such tests in a column one foot in diameter by five feet high and is constructing a column retort three feet in diameter by 20 feet high. For retort scaleup, a non-commercial field experiment would be conducted. LLL notes, however, that industry (Occidental Oil Shale Company) has constructed and is operating retorts of this size and concludes that the cost of constructing and operating the optional retorts can be avoided if "cooperation" can be obtained between industry and government. If these data can be made available, the LLL non-commercial retorts might be unnecessary and the field experiments then could commence with the large commercial-scale retorts (100 x 100 x 300 feet).

Concerning rubblization, the problems would be addressed during the field program when three retorts with dimensions of 100 x 100 x 300 feet plus one retort with dimensions of 250 x 250 x 1000 feet would be constructed.

A site with minimum water problems would be selected that is suitable for both the development program and for commercial development. The performance of the experimental mine (if such a mine is needed) will forecast how much oil can be recovered, and will also establish the nature of support required in the underground development, the structural strength of the pillar separating one retort from another,
the nature of the caving mechanism in the roof of the retort and upward to the surface, and the quantity and quality of water inflow which would be experienced during the operation.

Program Schedule and Cost Estimates

Figures 2 and 3 and Table 1 reproduced from UCRL-51768, present what LLL terms the most optimistic time and cost schedules that can realistically be fielded.

- Starting slot
- Drift
- Shale
- Development
- Level A
- Level B

1. Development begins at top of block. Drifts spaced perhaps 45 ft on center horizontally are driven the width of the block. A vertical starting slot is driven to provide a free blasting surface for subsequent drilling and blasting.

2. Shale is loaded after each blasting operation. Approximately 20% of the broken shale is extracted. The remainder is left behind to form the rubblized retort block.

3. Development proceeds simultaneously on multiple sublevels. Drawn shale provides a continuous sample of the resultant particle-size distribution, a key variable in the retort operation. Blasting parameters can be adjusted to accommodate varying shale properties in order to achieve the desired fragment size.

Comments

The RISE concept is not too much different than Occidental Oil Shale Company's concept of modified in situ retorting.

One cannot fault LLL at this critical time for a nice try at obtaining an $80 million project to be supported by government with "funds which are made available promptly when needed and are dependable to allow efficient progression of the work."

Figure 1. Modified sublevel-caving mining method proposed for use in RISE process.
Year | 0 | 1 | 2 | 3 | 4 | 5 | 6
--- | --- | --- | --- | --- | --- | --- | ---
Rubble creation and rubble properties: Lab experiments and models Block studies with ret Flow and pressure-drop analysis and experiments Retorting technology: Lab and aboveground retorting studies Modeling of retort process: Code development Testing and refinement Chemistry of oil shale and shale oil: Structure, analysis, and decomposition Upgrading Thermomechanical properties Process economics Instrumentation development Environmental-related studies: Leaching and gas clean-up Modeling and process studies

Figure 2. Proposed schedule for technology studies recommended for in situ oil shale program.

Year | 1 | 2 | 3 | 4 | 5 | 6
--- | --- | --- | --- | --- | --- | ---
Commercial-scale development program: Site selection Environmental impact statement Mine design: A.E. management Mine construction: Access Main shafts Auxiliary shafts Drifts Surface drilling Rubblization: a b (optional) a
Waste management Instrumentation Draining Surface facility Retort: a b c (optional)
Process analysis and evaluation Noncommercial-scale program (optional) Rubblization Pressure drop and permeability studies Retort cove

Figure 3. Proposed schedules for commercial-scale development program and optional non-commercial-scale program.

However, we have some problems. Consider the statement in the LLL proposal that industry has shown little interest to date in in situ methods to develop oil shale. This simply is not true. We happen to remember Sinclair, Equity, Shell, Occidental, etc. Occidental's current efforts, technology, and successes are termed "too modest--too small to develop a technological base."

LLL suggests that if industry (Occidental) would "cooperate" with government by furnishing its in situ field test knowledge, then LLL could proceed more quickly with meaningful commerical scale investigations.

Consider these assumptions by LLL: (1) Even if government funding were available to industry, the corporate decision process would cause years of delay with in situ development; and (2) Additional time delays in developing in situ technology will be caused by the time needed for government decision and policy-making processes.

The naive conclusion to be derived from the above has to be that all of this would be circumvented merely by making available (promptly) to LLL sufficient funds and resources.

We have to note also that the proposal minimizes or ignores technical and environmental problems. Not recognized, for example, are the expensive consequences of not understanding the terrific problems in controlling a firefronts' uniform passage through a 250 x 250 x 1000-foot pile of coarse rubble shale. All available evidence shows this control is difficult even in small-diameter aboveground sealed retorts where gas flows, compositions, temperatures, fragment particle size, gas and "overburden" pressures, etc., can be maintained with some precision.

An in situ program proposal involving about one-fifth the cost of the LLL program is reviewed elsewhere in this issue.

# # # #
<table>
<thead>
<tr>
<th>Year Of Program</th>
<th>1</th>
<th>2</th>
<th>3</th>
<th>4</th>
<th>5</th>
<th>6</th>
<th>Totals</th>
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<td>Technology program costs ($1000's)</td>
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<td>4,910</td>
<td>4,880</td>
<td>3,870</td>
<td>2,750</td>
<td>1,700</td>
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<td>Commercial scale development field cost ($1000's)</td>
<td>4,300</td>
<td>11,550</td>
<td>7,900</td>
<td>13,300</td>
<td>8,200</td>
<td>1,350</td>
<td>45,600</td>
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<tr>
<td>Noncommercial-scale option, field costs ($1000's)</td>
<td>230</td>
<td>2,480</td>
<td>1,430</td>
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<td>Total operating costs ($1000's)</td>
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<td>18,940</td>
<td>14,210</td>
<td>17,170</td>
<td>10,950</td>
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<td>Capital costs ($1000's)</td>
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<td>1,300</td>
<td>1,080</td>
<td>220</td>
<td>150</td>
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OXY SPOKESMEN DISCUSS STATUS OF IN SITU PROJECT

According to recent announcements by Occidental Petroleum representatives, construction is well underway on a commercial sized underground retort. The completed retort will be in operation by this summer and based on the results obtained from this test, a decision will be made later this year either to begin commercial operations or continue research activities. Oxy is optimistic that the choice will be made for commercialization as they will have invested approximately $25 million by year's end. Occidental's annual report states that "a commercial retort complex could be started by early 1977."

The most recent update of Occidental's modified in situ project was provided by Dr. Don Garrett and Dr. Richard Ridley at the Colorado School of Mines Oil Shale Symposium held April 17 and 18. They also elaborated on some of the technical details of the project. A commercial retort will be 120 x 120 x 310 feet, in a 300-foot seam of shale averaging about 15 GPT. The speakers emphasized that by current standards this material is not even considered a reserve, and yet they feel their process makes its recovery economical. In fact, it was claimed that any grade down to 5 GPT could be processed before the "net energy" produced from the facility was zero.

There is still some question regarding the wall thickness which will be required between adjacent retorts. Oxy feels that the rubblized chimney will be a "totally load supporting mass by itself" and, therefore, the walls would be necessary only to serve as "curtain membranes" between chimneys. The Bureau of Mines, however, may disagree with this analysis and require that the walls serve as actual pillar supports. As membranes, the walls would probably be less than 20 feet thick, but as pillars their dimensions will have to be significantly greater. A preliminary diagram of the mining scheme is shown on page 2-34 of the June 1974 Synthetic Fuels. Oxy hopes that the 20-foot "membrane" walls will be allowed, as they could probably be completely retorted by the heat generated in the adjacent chimneys.

Proposed Production Will Require Many Retorts

The size of one commercial retort is impressive, but the magnitude of the
30,000 BPD facility envisioned by Oxy is even more staggering. A 120 x 120 x 310-foot rubble chimney containing approximately 15 percent void space theoretically could yield 100,550 barrels of oil, assuming 15 GPT shale. Occidental representatives claim a recovery factor of 70 percent. One may now assume two cases: first, that this recovery figure is based on just the volume of the rubble chimney, and second, that the value is based on a volume which includes the retorted walls. In the first case, each retort should yield approximately 70,390 barrels of oil. Using the second case, each retort should produce 100,290 barrels. The time period over which this oil will be produced is still uncertain; however, one can assume several numbers in a range from six to 18 months. As shown in Table 1, if one year is required to recover all of the oil product from a retort, no less than 110 retorts would have to be operating simultaneously at average production levels to generate the 30,000 BPD production goal.

Further consideration is the areal extent of the operation. Each retort would occupy an area of approximately 140 feet by 140 feet, assuming 20 foot wall thicknesses. This converts to about 0.45 acres per retort or at least 50 acres of producing retort area for a burn time of one year. Monitoring and controlling such a network will certainly be an awesome chore. Ridley noted that Occidental's 2,000 net acres of holdings, poor as they are, contain sufficient reserves to maintain the 30,000 BPD production level for 15 years.

Commercial Retorts to Have Second Mining Level

When discussing the construction of the commercial-size retort, Dr. Ridley mentioned that there will be two mining levels involved rather than just one, as in the research retorts. The second level will be a complete heading at or near the top of the proposed retort. Figure 1 illustrates the plan described by Ridley. The

| TABLE 1 |
| OCCIDENTAL IN SITU RETORTING STATISTICS |

<table>
<thead>
<tr>
<th>Basis:</th>
<th>Retort Size ................. 120x120x310'</th>
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<tbody>
<tr>
<td></td>
<td>Mined void volume ................ 120x120x46.5'</td>
</tr>
<tr>
<td></td>
<td>Average shale assay .............. 15 GPT</td>
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<tr>
<td></td>
<td>Total commercial production ...... 30,000 BPD</td>
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</table>

<table>
<thead>
<tr>
<th>Assumed Retort Burn Time</th>
<th>6</th>
<th>9</th>
<th>12</th>
<th>15</th>
<th>18</th>
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<tbody>
<tr>
<td>Production Per Retort (BPD)</td>
<td>386</td>
<td>257</td>
<td>193</td>
<td>155</td>
<td>129</td>
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<tr>
<td>Case 1*</td>
<td>550</td>
<td>366</td>
<td>275</td>
<td>220</td>
<td>183</td>
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<tr>
<td>Case 2*</td>
<td>78</td>
<td>117</td>
<td>156</td>
<td>194</td>
<td>233</td>
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<tr>
<td>Retorts Required</td>
<td>55</td>
<td>82</td>
<td>110</td>
<td>137</td>
<td>164</td>
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<tr>
<td>Area Under Production</td>
<td>35</td>
<td>53</td>
<td>70</td>
<td>88</td>
<td>105</td>
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<tr>
<td>Case 1</td>
<td>25</td>
<td>37</td>
<td>50</td>
<td>62</td>
<td>74</td>
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</tbody>
</table>

*Case 1: 70% recovery based on volume of rubble chimney.
Case 2: 70% recovery based on volume of entire retorted area (including 10 feet of surrounding walls).
Scheme No. 1: No vertical separation

Scheme No. 2: 30' vertical separation

Figure 1. Occidental Commercial-Sized Retort.
upper level will serve as a base from which drilling will proceed prior to placing the explosive charges in the retort zone. After the chimney is rubblized and the combustion front is initiated, combustion air will be supplied through the heading.

Oil production in the underground retort precedes the advancing combustion front by 30 to 40 feet. Thus, when the combustion front is this distance from the bottom of the retort, total oil production will have been achieved. Yet, there will remain a large amount of carbon residue to be burned. So that the heat from this combustion may be fully used, Oxy intends to inject water into the hot (1200 to 1500°F) retort to produce H₂ and CO by the water gas reaction. Ridley and Garrett explained that this "secondary recovery" will significantly increase the overall efficiency of the operation.

Product Properties Described

The gaseous product of the process has a BTU content of approximately 75 BTU/SCF. Speakers at the oil shale symposium indicated that this is currently the minimum level which may be economically used for power generation. The gas contains approximately 0.6 percent sulfur, but it has not yet been determined in what form this sulfur appears. Dr. Garrett stated that although it should appear as H₂S, it has no odor. Also unusual is the fact that no heavy ends or aerosols are contained in the product until very near the end of the production period. Garrett advanced the theory that they may adsorb on the surface of the rock as they pass through the lower portions of the chimney.

The synthetic crude produced is reportedly free of solids and, therefore, may be usable directly as a boiler fuel. Tests indicate that such direct use would also meet current NOₓ standards. The oil has an API gravity of about 25 to 26 degrees and has a pour point of approximately 70°F. Sulfur content is 0.6 to 0.7 percent and nitrogen content is between 1.5 and 1.8 percent. Some degree of secondary cracking occurs in the retort.

Oxy Seeking New Outlets for Technology

Occidental’s annual report states that "oil shale offers a promising means of bringing our country toward its goal of becoming more self-sufficient in energy if an economic process for the extraction of oil can be developed." It is obvious that Oxy feels their modified in situ technique meets these requirements. Not only are they maintaining their current level of activity with 200 employees at the Colorado site, but they are also seeking to enlarge their holdings in the state. They have stated that, "our ultimate goal will be to obtain a position in the richer U.S. government shale lands and also to operate through joint ventures or by licensing the process to others."

Before expertise may be sold or processes licensed, however, the firm must protect its proprietary position through patent filings. One patent has been issued and 33 others currently are pending. Furthermore, the Stanford Research Institute "has prepared an economic analysis which favorably compares the Occidental lower capital investment and lower operating cost process with conventional mining and aboveground retorting."

# # # #

SANDIA LABORATORIES REPORTS RESULTS OBTAINED FROM ITS INSTRUMENTATION OF A USBM IN SITU FRACTURIZATION EXPERIMENT IN OIL SHALE

Sandia Laboratories recently published No. SAND 74-0372 entitled, "Rock Springs Oil Shale Fracturization Experiment: Experimental Results and Concept Evaluation." Working in conjunction with the Bureau of Mines, Sandia was applying its expertise in instrumentation to an in situ oil shale fracturization experiment conducted at Site 9 of the
Bureau's Rock Springs, Wyoming, field test area.

A review of the USBM in situ field test program in the Rock Springs area was presented on page 2-9 of the March 1975 issue of Synthetic Fuels.

Before Sandia's participation, the USBM had drilled a nine-spot pattern of wells some 160 feet into the oil shale formation and had hydraulically fractured and propped three horizontal cracks in the formation. For air injection, oil production, monitoring, etc., eight additional wells had been drilled within the original nine-spot pattern.

In concept, the middle hydraulic fracture was to be filled with approximately 7,000 pounds of liquid explosive and the upper and lower fractures would contribute void space. Shock waves from the detonation, reflecting from the void zones, would cause multiple fractures, and thereby increase the permeability of the formation.

Before the detonation on May 31, 1974, Sandia put stress gages and geophones on and in the oil shale formation to measure the spatial and temporal variation of the shock wave. From the data furnished by the instrumentation, Sandia hoped to be able to correlate observed and predicted fracturization.

The observed stress pulse amplitudes were about an order of magnitude less than expected. This discrepancy could have been caused by an absence of explosive or a detonation failure in the middle hydraulic fracture in the region just below the stress gages. Alternatively, lenses of porous material (tuff) were found in post-test coring, which could have seriously degraded the stress pulse. In any event, the stress pulses did not induce a significant number of fractures into the formation, and post-test coring verified that the induced fracturization was low.

While the Rock Springs event was not as successful as one might have hoped from a fracturization standpoint, Sandia claims they learned much about the details of the concept and that computer simulations outlined in this report indicate that experiments like the one at Rock Springs can induce significant fractures into nonporous rocks like oil shale.

# # # #

BUREN NOTES COMPOSITIONAL VARIATIONS IN UTAH SHALE

The U.S. Bureau of Mines has, for several years, been studying the soluble and insoluble organic compounds in the Green River Formation. They used three coreholes: one from the Green River Basin of Wyoming, the second from the Piceance Creek Basin of Colorado, and the third from the Uinta Basin in Utah. The most recent publication dealing with the results of this study is Report of Investigations No. 8017 entitled, "Compositional Variations of Organic Material From Green River Oil Shale - WOSCO EX-1 Core (Utah)." The analysis of the Colorado corehole was discussed on page 1-19 of the June 1971 issue of Synthetic Fuels and the Wyoming results were summarized on page 2-28 of the June 1974 issue.

The analysis of the Utah core showed that the amount of extract per unit of organic carbon did not increase with depth of burial. This finding agrees with those related to the Colorado and Wyoming studies, and thus, enhances the contention that the soluble extract did not come from the kerogen as a result of depth-related factors. It also reinforces the theory that the soluble and insoluble organic materials represent products of different degrees of source material polymerization.

The soluble material extracted from the Utah sample per unit of organic carbon was 2.1 times greater than that recovered from the Colorado core and 3.3 times greater than that from the Wyoming core. Though the authors did
not advance any ideas of why this occurred, they did note because of this feature, approximately one-fourth of the organic material in the Utah shale could be commercially produced by solvent extraction techniques.

The results of the Utah shale analysis also differed from the Colorado and Wyoming shales in that no linear relationship existed between the weight percent extract and the carbon content. The authors suggest that this reinforces the supposition that the organic material in the Utah core may have migrated from its original source. This concept is also supported by the low extraction ratios for the lower portions of the core and the high concentrations of soluble material in certain sections of the core. However, other analytical data suggest that the material had not migrated vertically to any significant extent.

### MOBIL RESEARCH MODELS OIL SHALE RETORT

A paper entitled, "Development and Utilization of a Model for Evaluating Aboveground and In Situ Retorting of Oil Shale" was presented by D. W. Lewis at the National Meeting of the American Institute of Chemical Engineers held in Houston in March. The report was prepared by Lewis, E. F. Kondis, N. T. Siuta, and P. W. Schneider, all of the Mobil Research and Development Corporation in Paulsborough, New Jersey.

During their investigations, they attempted to model mathematically the individual processes which occur simultaneously in an actual oil shale retorting operation. These models were then mathematically combined in such a way as to predict the behavior of an oil shale retort. The individual processes studied were:

- Kerogen decomposition as a function of time, temperature, and particle size
- Carbonate decomposition
- Coke combustion, both intrinsic and diffusion limited
- Retort-gas combustion
- Retort gas-to-shale heat transfer including transfer to the particle surface and thermal diffusivity within the particle

Each mathematical model was tested against actual data taken from a laboratory model which simulated the individual process being studied.

**Models Coupled to Predict Retort Behavior**

The individual models were then coupled into a combined model for predicting the effects of various process variables, e.g., gas rate, oxygen concentration, etc. The predictions from the combined model were next compared to actual data taken from the gas combustion retort operated by Mobil at the Anvil Points facility between 1964 and 1967. Figure 1 illustrates how well the model predicted the actual retort behavior.

The model was also applied to in situ retorting processes. Figure 2 shows the reactions which the authors postulated would occur in a rubblized bed of shale. Based on the results of this analysis and data taken from Mobil's in situ field experiments, the authors outlined three major problem areas:

- Achieving uniform permeability and uniform particle size distribution so that problems of gas channeling, high pressure drop through the shale bed, and slow retorting of large shale particles are reduced.
- Obtaining high oil yields to achieve maximum resource utilization, minimum mining, and minimum amount of raw shale to be retorted for a given oil production rate.
- Producing a product gas with sufficient burning quality to compete as an economic energy source.
Furthermore, they stated that "these potential problems need to be resolved by laboratory and field demonstrations before commercialization of in situ retorting can proceed." Considering the claims of commercialization by Occidental Petroleum, as discussed elsewhere in this section of Synthetic Fuels, Oxy evidently has resolved these problems.

The authors of the paper foresee their model being useful in many areas of retorting technology. These include:

- Studies of kerogen decomposition rates and optimization of yield to useful oil and gas products.
- Development of process understanding to improve operability and throughput rates for aboveground retorts.
- Development of engineering designs to improve shale oil yield from both aboveground and in situ retorting.
- Modification of retorting parameters to optimize processing of oil shales having significantly different mineral compositions.

SYNCRUDE PATENTS WATER-SAVING TAILINGS DISPOSAL SYSTEM

The Syncrude Group recently obtained U.S. Patent No. 3,869,384 which deals with the treatment of the tailings stream from an oil sands extraction facility which uses the hot water process. The tailings stream is fed into two separate settling zones rather than just one, as is now the practice. In the first settling zone, which could be a mined-out area near the plant, coarse solids settle out and form a deposit of "beach" sands. Some of the tailings water, along with fines solids becomes trapped in the void spaces in the sand grains. In this way, some fines
are removed from the system. Part of the remaining tailings water is pumped to a second settling basin for settling of fines by conventional means.

A major portion of the tailings water from the second settling basin, including a relatively high quantity of suspended fines, is recycled to the extraction plant where it is added to the sand tailings to make them pumpable. Thus, the only clarified water needed by the extraction plant is in the pulping of mined oil sands and for other additions to the bitumen/sand separation process. Recycled water is used entirely for tailings disposal.

BUREAU OF MINES DESCRIBES A PROPOSED ACCELERATED OIL SHALE IN SITU PROGRAM

A proposed program of accelerated oil shale in situ research has been prepared by a Federal Government Interagency Oil Shale Panel. The program is directed specifically toward research needed to overcome the technical obstacles that have retarded the development of in situ processes.

The program goal is to develop, by 1980, several commercially viable technologies for the in situ production of shale oil.

National in scope, the program is expected to be undertaken with private funds in part with joint federal/private financing and, where neither is feasible, wholly with federal funds. The federal government would provide overall program management to ensure that all parts of this highly interrelated program move forward harmoniously.

Although emphasis is directed toward the oil shales of Colorado, Utah, and Wyoming, research would also be initiated on the oil shale deposits that underlie much of the Eastern United States. A number of feasible in situ technologies would be tested in various oil shale resource types.

The Interagency Oil Shale Panel which formulated the program consisted of oil shale experts from ERDA, DOI, and EPA. Details of the program are contained in an unnumbered report entitled, "Accelerated Oil Shale In Situ Research: A National Program." Copies of the report may be obtained from the Laramie Energy Research Center, ERDA, P. O. Box 5395, University Station, Laramie, Wyoming 82070.

The conceptual framework for this in situ program was presented in a previous report entitled, "A Strategy to Stimulate Oil Shale Development By In Situ Processing." That report was reviewed in the September 1974 issue of Synthetic Fuels, page 2-25. The present report concerns the research to be conducted.

Objective and Administration of the Program

The objective of the research program is to advance to the point of commercial application by 1980 alternative methods for in situ recovery of shale oil and, in so doing, extend the data base needed to form future policies for oil shale development on public lands.

The in situ research program, to be administered by two federal agencies, involves two concurrent actions:

1. By the Interior: Initiate those steps that could lead to lease sale(s) one or two prototype oil shale tracts for in situ development by private industry.
2. By ERDA: Initiate an accelerated program of in situ research designed to complement the Interior action.

The two actions are interrelated; information developed under the first action will be used to program the second. To determine industry interest, Interior will offer two oil shale tracts for in situ development. Industry will signal their interest (or lack thereof) by nominating tracts for development using a technology to be specified. This will then allow ERDA to program research to support—but not duplicate—what industry or through in-house efforts. This accelerated program can be initiated by July 1975.
In Situ Technologies and Resource Targets Relating to the Proposed Program

In situ processing may be accomplished by two principal means: (1) a borehole technique where oil shale is first fractured underground and heat is applied, or (2) a process in which some mining is followed by the application of heat. These two types of in situ processing are referred to as in situ (no mining) and modified in situ (some mining), respectively.

Methods of fracturing will vary, depending on the amount of surface area needed underground and the method used to raise the broken oil shale to the pyrolysis temperature of about 900°F.

Heat may be applied in several ways, by hot fluids, by hot gases, or by direct combustion.

All of these technical approaches, and combinations thereof, ultimately may be required for optimum development of the various types of deposits found in Colorado, Utah, and Wyoming. There is not one type, but several types which have been classified by the Bureau of Mines as follows:

Type I - Deep
This target is deeply buried (up to 2,000 feet), grade 15-25 gallons per ton; beds to several hundred feet thickness; generally impermeable; may contain dawsonite and nahcolite--typical of the Lower Zone shale in the Piceance Creek Basin; almost entirely federally owned.

Type II - Shallow
These shales are under 100 feet or more of overburden; grade 15-25 gallons per ton; thickness to 250 feet; generally impermeable--typical of Utah and Upper Zone Piceance Creek Basin; federal, state, and privately owned land.

Type III - Deep Leached
These shales are deeply buried (1,200 feet); grade 15-25 gallons per ton; thickness to 1,000 feet; permeable; saline aquifer over most of the area but some waterfree permeable areas--typical of Leached Zone in Piceance Creek Basin; almost entirely federally owned. By considering five distinct in situ technologies and four major resource types, a minimum of 20 separate projects would be required to test all combinations of technology and resource target. However, seven of the ten possible combinations may be of potential commercial interest.

The Current Program

The current program consists of a number of sequential tests at one type site in Wyoming. This is a small test (under ten acres) at a depth of about 150 feet. This research will be continued as an in-house project. Additionally, four other field tests covering one to ten acres will be initiated in Type IV deposits. These will be performed on a contract basis, starting with design and procurement in fiscal year 1976.

Overview of Accelerated Program

Systematically planning a research program to test the feasibility of in situ technologies requires matching the projected potentials of the technologies with known
needs or uses. Technical tradeoffs must be made to bring new technologies to fruition and benefits versus detrimental effects must be determined. The accelerated program will develop this information. A generalized diagram of the major areas to be evaluated or considered for the proposed program is presented in Figure 1, reproduced from the report.

The accelerated in situ oil shale program is designed to evaluate both true in situ as well as modified in situ techniques. All these phases will be drawn together as shown in the overview PERT chart in Figure 2, which is also reproduced from the report.

The PERT diagram shows that the accelerated oil shale in situ research needs to be conducted in three major areas. These areas are: (1) in situ production of liquids and in particular, the development of adequate fracturing techniques; (2) modified in situ production of liquids; and (3) in situ production of gases.

Both liquid and gaseous products will be made from oil shale in situ (Figure 2). Improvement in fracturing techniques is critical to employment of in situ methods as shown in the top part of the figure. The completion of the fracturing research, along with the supporting activities could lead to the construction of a process demonstration unit (PDU) two years after the research starts. After PDU operates for about one year, the decision for true in situ commercialization could come four years after starting the fracturing program.

## ## ##

INDUSTRY COUNTERS NET ENERGY ARGUMENT

Ever since the Pandora's box of net energy ratios was opened last year by several oil shale critics, industry has been trying to counter the claims that oil shale processing uses more energy than it produces. A comprehensive review of the events that have led to

Figure 2. Overview of Accelerated Oil Shale In Situ Research PERT Network.
the current industry studies is provided on page 1-1 of the December 1974 issue of Synthetic Fuels.

The claims of negative net energy have come from a variety of sources, have been based on totally different calculations, and in some cases have appeared as merely a single number without any apparent calculations to back it up. Unfortunately, most of the industry's initial arguments against the claims were also fragmentary and lacked the engineering calculations necessary to support their counter-claims adequately. Within the past few months, however, several oil companies and research organizations have begun to develop a united front against the net energy critics.

The Colorado School of Mines Oil Shale Symposium (April 17, 18) and the National AIChE Meeting in Houston (March 17-21) served as forums in which companies such as Atlantic Richfield, Paraho, TOSCO, and Occidental presented the results of their independently-derived net energy calculations. A USCD/NSF (RANN) Workshop held at the University of California Energy Center in La Jolla, California, on January 21, also allowed spokesmen from industry to compare notes on their calculations. Present at this meeting were representatives from Atlantic Richfield, TOSCO, Union, Shell, Standard Oil (Indiana), Conoco, University of California, Denver Research Institute, Colorado School of Mines Research Institute, Colorado Energy Research Institute, National Science Foundation, and Cameron Engineers.

ARCO Takes Simplified Approach

A paper entitled "Net Energy and Oil Shale," was written by C.E. Clark and D.C. Varisco of Atlantic Richfield. Based on this report, Varisco made presentations at both the University of California meeting in La Jolla and the oil shale symposium at the Colorado School of Mines. The authors managed to develop a simplified flow diagram of a

![Figure 1. ARCO Net Energy Balance - Total Consumption Boundary](file)

( all values in 10^9 BTU/SD )

CAMERON ENGINEERS, INC. 2-31
typical 100,000 BPD oil shale facility and then analyze the "net energy ratio" based on two different boundary systems. The plant model and the idealized boundaries are shown in Figures 1 and 2. This type of analysis clearly shows the importance of boundary location on the resultant net energy ratio.

ARCO essentially had three goals in developing this net energy model. First, they wanted to find some rationale for the energy ratios being quoted by many opponents of oil shale development; in particular the 2.5:1 ratio stated by Carolyn Johnson at the FEA hearings on Project Independence in August of last year. Secondly, they wished to analyze the whole concept of net energy ratios and determine where they had value, if at all. Finally, using accepted engineering techniques, they hoped to generate a worthwhile and generally accepted net energy value for an oil shale complex.

Using the boundary as shown in Figure 1, the authors calculated a net energy ratio called the "total consumption" ratio. This was defined as the energy contained in saleable products divided by the total amount of energy consumed. As shown in Table 1, the net energy ratio for this system was 2.6. It may be noted that the fuel produced by the complex and recycled for internal use is accounted for as a consumption but not as output.

According to Varisco, this was done because that fuel was not considered a "saleable" product even though it was valuable to the plant operator. In addition, the 2.6 figure closely approximates the 2.5 value quoted by Carolyn Johnson. The point of saleability can be argued, as Varisco will agree, by simply stating that the plant operator is actually buying the fuel from himself at cost. For plant use, therefore, it is a saleable product. Following this reasoning, and including the internally-used fuel product as an output, the net energy ratio increases to 3.3.

Figure 2. ARCO Net Energy Balance - External Consumption Boundary
Another net energy calculation was then made using the boundary shown in Figure 2. In this calculation, since the internal consumption of fuel is totally within the boundary, the 148 x 10^6 BTU is not counted either as consumption or output. The only energy consumed is that provided by society. In this case, as is shown in Table 2, the net energy ratio, called the "external consumption" ratio is 8.8; yet the functional system has not changed at all. Therefore, slight changes in the boundaries of the problem make tremendous differences in the net energy ratio. Furthermore, this point is made whether one considers the internally-used fuel as "saleable" or not.

Varisco and Clark took their analysis one step further and included an electrical power plant within the boundary, thereby eliminating a consumption of 50 x 10^6 BTU of energy. They did not, however, subtract the same amount of energy from output, but this should be included as the energy required for the power plant must be obtained from "saleable" products. In this case, the net energy ratio is 38.8. As the authors point out, "carrying this process to the extreme, it would be possible to increase the net energy ratio without bound for any system that had a net energy ratio greater than one.

The authors, having established two different definitions, stated that both have merit but should be carefully used and be applied only to certain areas. The total consumption definition should be used to evaluate reserves and various methods of producing a product from a given resource. The external consumption

### TABLE 1

**ARCO NET ENERGY BALANCE - TOTAL CONSUMPTION BOUNDARY**

<table>
<thead>
<tr>
<th>Consumption (10^9 BTU/SD)</th>
<th>Output (10^9 BTU/SD)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Internally Used Fuel</td>
<td>148</td>
</tr>
<tr>
<td>Electric Power</td>
<td>50</td>
</tr>
<tr>
<td>Other</td>
<td>13</td>
</tr>
<tr>
<td></td>
<td>211</td>
</tr>
<tr>
<td>Internally Used Fuel*</td>
<td>148</td>
</tr>
<tr>
<td>Oil</td>
<td>480</td>
</tr>
<tr>
<td>Coke</td>
<td>42</td>
</tr>
<tr>
<td>Other</td>
<td>32</td>
</tr>
</tbody>
</table>

Net Energy Ratio = \(\frac{702}{211} = 3.3\)

*Not included in original ARCO analysis. This calculation yielded a value of \(\frac{554}{211} = 2.6\)

### TABLE 2

**ARCO NET ENERGY BALANCE - EXTERNAL CONSUMPTION BOUNDARY**

<table>
<thead>
<tr>
<th>Consumption (10^9 BTU/SD)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Electric Power</td>
</tr>
<tr>
<td>Other</td>
</tr>
<tr>
<td></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Output (10^9 BTU/SD)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Oil</td>
</tr>
<tr>
<td>Coke</td>
</tr>
<tr>
<td>Other</td>
</tr>
</tbody>
</table>

Net Energy Ratio = \(\frac{554}{63} = 8.8\)
figure, however, may be helpful in evaluating the "attractiveness of different resources" and in social planning, as it "indicates the energy returned to society for each unit of energy invested."

Paraho Uses Thermal Efficiencies

Another company which has recently made attempts to counter the net energy claims of critics, while at the same time clarifying the situation, is Paraho Oil Shale Demonstration, Inc. A Paraho representative, Kumar Kunchal, presented Paraho's net energy data in talks at both the CSM symposium and the national AIChE meeting in Houston.

Knowing the thermal efficiencies of each component process, an overall thermal efficiency was calculated for the entire process. The overall thermal efficiency approach used by Paraho assumes that all power requirements, including electricity, can be generated on site, and are therefore within the plant boundary. An overall thermal efficiency of 60 percent would indicate that for every 100 units of energy produced by the facility, 60 units would be available for society's use and 40 units would have to be recycled for internal energy use.

If one applies ARCO's boundary concept to this case it could be visualized as in Figures 3 and 4. The "total consumption" energy ratio would thus be \((60 + 40) : 40 = 2.5\) and the "external consumption" ratio would be \(60 : 0 = \infty\).

The point of the Paraho analysis was not, however, to rationalize the values quoted by others, or even to establish a new calculational formula. Rather, they wished to find an analysis which could be applied to several alternative energy sources; i.e. coal, oil shale, and crude oil. Since intermediate hydrocarbon products from different sources are not exactly comparable, each was assumed to be refined to similar useful end products (liquid transportation fuels, synthetic natural gas, and electricity). The overall thermal efficiencies resulting
from this type of analysis are shown in Tables 3, 4, and 5. As the table values indicate, the thermal efficiencies of oil shale conversion are roughly the same as those for coal conversion and on the average are only 23 percent (relative) less than those for crude oil processing.

Amoco Sees Need for Economic Model

At the La Jolla meeting, Manoj K. Sanghvi of Standard Oil Company (Indiana) presented some interesting remarks aimed at countering the net energy argument without detailed engineering calculations. His first point concerned the basic concept of energy:

"Unlike money which has been created by common consensus as a standard of value and is by definition additive, energy (expressed for example as BTU) has variable characteristics and may represent different social and economic values depending on its form, location, and timing; in general, energy units should not be added without modification to correct for energy "quality" that recognizes the value of that energy from the standpoint of the user.

"Most of the published net energy work either fails to recognize the non-additive nature of raw energy units or applies approximate conversion factors for energy quality derived in one context to another where they would not be appropriate. Thus, the divergence of policy conclusions reached through energy analysis and economic analysis is largely attributable to illogical addition of energy quantities that are essentially non-additive."

Sanghvi went on to question the validity of maximizing energy output-input ratios. Not only do currently defined ratios ignore the "quality" of energy, but as shown by the ARCO analysis, the value of the ratio may be driven to zero or infinity simply by altering the system boundaries. Therefore, the Amoco spokesman felt "the comparative significance of values such as 5 or 15....cannot be
### TABLE 3

**PARAHO THERMAL EFFICIENCY ANALYSIS**
**FOSSIL FUEL TO TRANSPORTATION LIQUID FUELS**
PERCENT ENERGY REQUIRED FOR EACH OF THE FOLLOWING STEPS

<table>
<thead>
<tr>
<th></th>
<th>Oil Shale*</th>
<th></th>
<th>Coal</th>
<th></th>
<th>Crude Oil</th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Case A</td>
<td>Case B</td>
<td>Eastern</td>
<td>Western</td>
<td>Sour</td>
<td>Sweet</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>(Sub-Bitu)</td>
<td>(Lignite)</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Mining Or Pumping</td>
<td>1.5</td>
<td>1.1</td>
<td>0.5</td>
<td>0.1</td>
<td>0.1</td>
<td>0.1</td>
<td></td>
</tr>
<tr>
<td>Crushing and/or</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Transportation</td>
<td>10.5</td>
<td>6.5</td>
<td>2.5</td>
<td>3.0</td>
<td>1</td>
<td>1</td>
<td></td>
</tr>
<tr>
<td>Liquefaction</td>
<td>16</td>
<td>8</td>
<td>30</td>
<td>33</td>
<td>---</td>
<td>---</td>
<td></td>
</tr>
<tr>
<td>Pre-Refining to</td>
<td>9</td>
<td>9</td>
<td>30</td>
<td>33</td>
<td>---</td>
<td>---</td>
<td></td>
</tr>
<tr>
<td>Get Syncrude</td>
<td>5</td>
<td>5</td>
<td>5</td>
<td>5</td>
<td>12</td>
<td>7</td>
<td></td>
</tr>
<tr>
<td>Overall Thermal</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Efficiency</td>
<td>64%</td>
<td>74%</td>
<td>65%</td>
<td>62%</td>
<td>87%</td>
<td>92%</td>
<td></td>
</tr>
</tbody>
</table>

*See Note on Table 5.

### TABLE 4

**PARAHO THERMAL EFFICIENCY ANALYSIS**
**FOSSIL FUEL TO SYNTHETIC NATURAL GAS (S.N.G.)**
PERCENT ENERGY REQUIRED FOR EACH OF THE FOLLOWING STEPS

<table>
<thead>
<tr>
<th></th>
<th>Oil Shale*</th>
<th></th>
<th>Coal</th>
<th></th>
<th>Crude Oil</th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td></td>
<td>Sub-Bitu</td>
<td>Lignite</td>
<td>Sour</td>
<td>Sweet</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Case A</td>
<td>Case B</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Mining or Pumping</td>
<td>1.5</td>
<td>1.1</td>
<td>0.5</td>
<td>0.1</td>
<td>0.1</td>
<td>0.1</td>
<td></td>
</tr>
<tr>
<td>Crushing and/or</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Transportation</td>
<td>10.5</td>
<td>6.5</td>
<td>2.5</td>
<td>3.0</td>
<td>1</td>
<td>1</td>
<td></td>
</tr>
<tr>
<td>Retorting</td>
<td>16</td>
<td>8</td>
<td>45</td>
<td>35</td>
<td>17</td>
<td>15</td>
<td></td>
</tr>
<tr>
<td>Gasification</td>
<td>18</td>
<td>18</td>
<td>45</td>
<td>35</td>
<td>17</td>
<td>15</td>
<td></td>
</tr>
<tr>
<td>Overall Thermal</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Efficiency</td>
<td>61%</td>
<td>70%</td>
<td>53%</td>
<td>63%</td>
<td>82%</td>
<td>84%</td>
<td></td>
</tr>
</tbody>
</table>

*See Note on Table 5.
### TABLE 5
PARAHO THERMAL EFFICIENCY ANALYSIS
FOSSIL FUEL TO ELECTRIC POWER
PERCENT ENERGY REQUIRED FOR EACH OF THE FOLLOWING STEPS

<table>
<thead>
<tr>
<th></th>
<th>Oil Shale*</th>
<th>Coal</th>
<th>Crude Oil</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Case A</td>
<td>Case B</td>
<td>High Sulfur Coal</td>
</tr>
<tr>
<td>Mining or Pumping</td>
<td>1.5</td>
<td>1.1</td>
<td>0.5</td>
</tr>
<tr>
<td>Crushing and/or</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Transportation</td>
<td>10.5</td>
<td>6.5</td>
<td>2.5</td>
</tr>
<tr>
<td>Retorting</td>
<td>16</td>
<td>8</td>
<td>22</td>
</tr>
<tr>
<td>Clean Boiler Fuel</td>
<td>8</td>
<td>8</td>
<td>22</td>
</tr>
<tr>
<td>Production</td>
<td>65</td>
<td>65</td>
<td>65</td>
</tr>
<tr>
<td>Fuel to Electric Power</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Overall Thermal Efficiency</td>
<td></td>
<td>24%</td>
<td>27%</td>
</tr>
</tbody>
</table>

*100,000 BPD Plant: (A) 28 GPT Shale
10% Fines
90% Fischer Assay Yield

(B) 35 GPT Shale
6% Fines
100% Fischer Assay Yield

ascertained without introducing other data and judgements into the analysis." Sanghvi proposed that the only real "objective function" which should be maximized is a complex economic input-output model, which accounts for all relevant input, both energy and non-energy. Should some input become more valued by society, its "economic coefficient" would then be explicitly modified to reflect the new value. Sanghvi did not, however, state when Amoco would have such a comprehensive economic model available, if at all.

**CERI Study Well Underway**

The net energy study being performed by the Colorado Energy Research Institute (CERI) is well underway. To date, most of the time spent has been in collecting data and establishing individual system boundaries. In addition, the ratios and accounting systems used by other investigators have been studied. The latest word from CERI is that they will try to restrict themselves to input-output balances rather than ratios. The sentiment is that because ratios are extremely sensitive to small changes in the absolute values of inputs and outputs, they are of little if any value to the technical persons who must make energy decisions.

Fifteen sectors of energy production are to be studied by CERI and these have been divided into ones having hard data available (e.g., conventional oil production) or soft data (e.g., coal liquefaction, oil shale, etc.). Furthermore, indications are that much time will be spent trying to obtain hard data rather than relying on dollar/ BTU conversions. This of course is consistent with the statement by the Amoco spokesman regarding the "quality" of energy.

**Summary**

Because of the general anti-oil company sentiment which currently seems to pervade the thinking of the U.S. population, a handful of vocal critics has
managed to raise an issue which has become a thorn in the side of the synthetic fuels industry. Initially, the corporations involved tended to shrug off the net energy debate as just another minor criticism which their public relations departments could handle. Now that the issue has gained a foothold and has received attention by the media, most companies involved in synthetic fuels development have found it necessary to take a stand regarding the debate.

Atlantic Richfield, TOSCO, and Paraho have all attempted to counter the claims with data and engineering calculations, while Amoco and Union have argued against the claims using logic rather than data. Moreover, several independent research organizations have begun comprehensive net energy studies.

Based on the arguments presented in the "logical" analyses, one is left with the distinct impression that by itself, a net energy ratio cannot be a useful decision making tool. However, if one rejects these arguments and clings to the value of the ratio, the data presented by ARCO, TOSCO, and Paraho show that oil shale development, as well as that of other synthetic fuels, will definitely produce more energy than it consumes.
WESTCO PROPOSES EXPERIMENTAL IN SITU OIL SHALE PROJECT

Western Oil Shale Corporation (WESTCO) sponsored discussion meetings in Las Vegas and Denver in October and December 1974 and January 1975, with regard to the planning of an in situ oil shale experiment.

The primary objective of the experiment to be planned will be to determine the recovery efficiency of in situ retorting of oil shale rubbleized by using conventional underground mining and blasting techniques.

Subject to the commitment of at least eight companies to share the planning costs, WESTCO will (on a cost basis) undertake the "design project" portion of the program. The work which WESTCO would perform during this phase would include:

- Core drill through the oil shale at the selected site (SW 1/4 SW 1/4, Section 16, Township 9S, Range 25E, Uintah County, Utah)
- Prepare operating agreements for the later experimental project
- Prepare specifications for mining and oil recovery system
- Design surface facilities and equipment for in situ retorting
- Design instrumentation for data recovery
- Prepare detailed time and manpower schedule for the experimental project
- Prepare detailed cost estimates for the experiment project

Project Costs Would Total $400,000

The total cost to eight participants for this initial phase of the project would be $400,000. If eight participants have not signed commitments by May 31, 1975, those who have signed will be released from their commitments.

A breakdown of the proposed project's cost follows:

<table>
<thead>
<tr>
<th>Description</th>
<th>Cost</th>
</tr>
</thead>
<tbody>
<tr>
<td>Confirmatory well</td>
<td>$50,000</td>
</tr>
<tr>
<td>Operating agreement</td>
<td>85,000</td>
</tr>
<tr>
<td>Mine development</td>
<td>75,000</td>
</tr>
<tr>
<td>Process development</td>
<td>50,000</td>
</tr>
<tr>
<td>Instrumentation</td>
<td>40,000</td>
</tr>
<tr>
<td>Time, manpower, environmental, etc.</td>
<td>50,000</td>
</tr>
<tr>
<td>Contingency</td>
<td>50,000</td>
</tr>
</tbody>
</table>

TOTAL $400,000

Project Would be Conducted on Westco Properties in Utah

WESTCO proposes to reserve for use by the participants its state of Utah oil shale lease covering the SW/4 of the SW/4 of Section 16, Township 9 south, Range 25 East, Uintah County, Utah. WESTCO will also make available to the participants, if desired, its oil shale lease in Section 32 of Township 9 South, Range 24 East (400 acres) for an expanded experiment.

Other Details of Proposed Project Reviewed

WESTCO would serve, on a cost basis, as project manager unless a different project manager is selected by a 2/3 vote of the project's advisory committee.

Opportunity to become a participant will be available to any financially responsible person, with the provision that late joiners pay a late entry fee of ten percent.

Participants will have no obligation to contribute personnel, but will have the right to assign one person as a member of the project advisory committee. Participants gain royalty-free license to use any product, art, or information developed. Participants will receive periodic (not less than monthly) reports of the work progress.

# # # #
DOW REQUESTS $42 MILLION GRANT FROM ERDA

The Dow Chemical Company, which for many years has been investigating the feasibility of recovering oil and gas from eastern oil shales by in situ techniques, recently submitted a proposal to the Federal Energy Research and Development Administration (ERDA) for a seven-year, $42 million project. The field test would be conducted near Midland, Michigan, in Antrim shale which underlies almost two-thirds of the state. The shale formation outcrops in the northern part of Michigan along a line from Traverse City to Alpena and also near the Ohio-Michigan border. Between these two extremes however, near Midland, the formation dips to a depth in excess of 3,000 feet. While the formation varies in thickness it is generally about 200 feet thick.

Dow estimates that the 40,000 square miles of Michigan Antrim shale contains in excess of 2.5 trillion barrels of oil. They also point out that Michigan has the markets, manpower, water resources, and the infrastructure necessary to support an oil shale industry. In addition, representatives of Dow feel that people in Michigan would be much more likely to accept such an industry than the populace of the western oil shale regions. Dow senses that a Michigan resident will become concerned about environmental damage only if it will occur in the immediate vicinity of his property, whereas citizens from all over Colorado are opposed to operations in Rio Blanco county even though they have never been there and probably will never go.

More Shale But Less Oil In Eastern Shales

A Dow representative, John P. Humphrey, testified before a house government operations subcommittee on May 8. During his presentation, he stated that eastern shales underlie approximately 400,000 square miles of the United States, while the Green River shale underlies only 17,000 square miles. Some reporters, who were obviously unaware of the significance of these figures, released articles indicating that reserves 23 times larger than those in Colorado had just been discovered! Of course, the existence of these eastern deposits was known long before the Green River shale was discovered, and furthermore, the areal extent of the deposit has no real bearing on the quantity of oil contained in the deposit, let alone its recoverability.

Not only do eastern shales contain less organics per ton than Green River shale, but the organics they do contain yield a lower percentage of oil than the western shale. In fact, the Antrim shale which Dow proposes to investigate contains only about 10 GPT. Thus, considerably greater quantities of eastern shale would have to be retorted to yield the same amount of liquid product as is produced by a given quantity of Green River shale.

The gasification properties of eastern shales is often cited as their strong point, and this is true to a limited extent. In fact, Dow's interest in the shale originated with their desire to use the low-BTU gas products rather than the liquid products. Now that crude oil has become a politically valuable commodity, the company has begun to emphasize those products as well. The organic constituents of eastern oil shales typically yield about the same amount of gaseous products per pound as Green River shale, and in some cases slightly more. Therefore, a shale grade as determined by the modified Fischer Assay method, which accounts only for liquid products, tends to be somewhat misleading regarding the amount of gaseous products recoverable. As mentioned before, however, eastern shales contain considerably less organics per ton of rock, and thus even with an equivalent gasification value of organics, eastern oil shales are not as productive as western shales. Nevertheless, large quantities of liquid and gaseous products are available from eastern shales and should Dow develop a viable recovery technique, which would make large scale retorting possible, the eastern shales could be of significant value in minimizing the nation's future energy shortages.

Forward Combustion To Be Used

Dow's current in situ field test as well as those proposed under the ERDA
Figure 1. Dow In Situ Recovery Scheme in Michigan Antrim Shale.
grant, involve horizontal, forward combustion through fractured shale beds. The firm has not yet disclosed the type of process which will be used to fracture the shale. Figure 1 illustrates the recovery technique as well as the geology of the region in which the tests will occur.

Compared to open pit mining or above ground retorting, in situ recovery is generally acknowledged to being more environmentally acceptable. The major problems which still remain regarding this type of recovery in the Green River Formation is subsidence and the eventual leaching of soluble salts from the retorted chambers. Both of these problems are minimized or alleviated when the techniques are applied to eastern shales. Because the eastern shales are true shales rather than marlstones, they do not lose strength on retorting, and in fact may get stronger as they are "fired." Due to the absence of saline minerals, no soluble salts remain after retorting and thus the leaching problem is eliminated.

Contrary to popular opinion, getting money from the government is not always an easy task, especially when values like $42 million are involved. Recognizing this, Dow Chemical managed to back up their request to ERDA with some political clout. Prior to submitting the ERDA proposal, Dow organized their information into a study entitled "Michigan Resource Development" and submitted this to the Michigan Energy and Resource Research Association (MERRA). This group is composed of government, university, and industrial representatives and was set up by the governor's office in the early part of 1974 to find programs to reduce Michigan's dependence on out-of-state energy sources. Following a favorable response from MERRA, Dow proceeded to apply for the ERDA grant, having behind it the support of the state of Michigan.

Comment

The fact that Dow Chemical has requested a grant from ERDA indicates that much work is yet to be done before a viable commercial process is developed. If such a technological breakthrough was right around the corner, Dow, with a 1974 net income of $557 million and total assets in excess of $5 billion, would certainly have financed the project from in-house and avoided any association with a government agency at all. Yet the fact that they are continuing the project indicates that results to date have at least been encouraging. Dow Chemical is certainly one of the most knowledgeable and capable companies currently investigating oil shale recovery techniques, and as low grade as it is, there is a lot of oil shale in the eastern United States. The development of a viable in situ processing scheme would be of value to the entire oil shale industry, both in the east and west.

# # # #

SHELL OIL ASSUMES MANAGEMENT OF C-b OIL SHALE LEASE

Shell Oil Company took over the operational reins of Federal Oil Shale Prototype Tract C-b from Atlantic Richfield on June 1. The decision to switch operating managers was made May 20. Shell vice president for mining ventures Keith Doig and R.E. Meeker, manager of development and technology, were to oversee the changeover.

An ARCO spokesman said ARCO felt its private oil shale program on Parachute Creek in northwest Colorado about ten miles south of C-b combined with the federal program spread its shale expertise too thin. He said preparation of a preliminary detailed development plan and environmental studies on C-b would continue under Shell.

A Shell official said his firm was moving to replace ARCO personnel as fast as possible. It is expected Shell would retain several ARCO personnel at C-b. Shell and ARCO are equal partners in C-b with The Oil Shale Corporation and Ashland Oil Company. They have spent about $24 million in bonus payments and $8 million in development costs since bidding $117.8 million for the tract in February 1974.
The management changeover did not affect the four-way partnership, and will give Shell an opportunity to develop more first-hand oil shale expertise. Shell has more than 10,000 acres of oil shale lands in northwest Colorado in addition to holdings in Utah.

Tentative plans for C-b development are for a 50,000 BPD plant supplied by shale from an underground mine to be operational in 1981. A decision to proceed with development must be made by early 1977.

# # # #

PARAHO REVEALS PLANS FOR PROJECT EXPANSION

The Paraho Development Corporation, Inc. has released a prospectus outlining its plans to construct a full-size oil shale retorting module capable of producing 7300 BPD of synthetic crude. The basic information regarding the project was first publicly discussed by Harry Pforzheimer and John Jones at a meeting with the U.S. Bureau of Mines at the Denver Federal Center on May 13, but the 50-page prospectus did not become available until May 28.

The overall plan calls for 12,500 tons of shale to be mined per day, with approximately 1,000 TPD ending up as fines and the remaining 11,500 TPD going to the retort. The shale will be mined from an eastern extension of the existing mine on the Naval Oil Shale Reserve. The mining plan will involve conventional room and pillar methods with a 40-foot upper level and a 30-foot lower bench. The haulage entries in the rooms will be 55 to 60 feet wide and the pillars will be 60 x 60 to 80 feet. The mined shale will be stockpiled in the mine for use during high production periods.

Primary crushing will take place in the mine by a single or double toothed roll crusher. The prospectus states that a 30,000-ton surge pile of crushed shale will be maintained. Ore from the primary crusher will be conveyed on a belt through an orepass to a secondary crusher near the retorting facility.

So that a commercial facility can be approximated as closely as possible, the proposed retort site will be at an elevation of about 7,000 feet, along the existing mine road. The bench which is to be prepared for the crushing, screening, and retorting facilities will cover about five acres.

The proposed retort will be 42 feet in diameter (outside) and 72 feet high, including the feed bin. The internal structure will essentially be scaled up from the existing 10-1/2 foot semi-works retort, but will probably contain more gas jets. The retort will operate slightly above atmospheric pressure. The processing of 11,500 TPD of shale will require 7.7 MMSCFH of recycle gas and 2.3 MMSCFH of process air. In addition to the 7300 BPD of synthetic crude, the unit will also produce 11.17 MMSCFH of low-BTU product gas and 9,200 TPD of retorted shale.

The liquid product will be pipelined through heat traced transfer lines down to the existing storage facilities currently being used in the Paraho project. Because of the limited capacity of these tanks, it is anticipated that the product will be trucked from the site daily. Spent shale from the retort will be trucked down the mine road to the existing disposal site.

Water required for the project will be obtained from the Colorado River. There is already a storage facility at the 6,100 foot level, but the six-inch transfer line will have to be replaced. It is anticipated that approximately 9,000 KV of electric power will have to be supplied from outside sources. The Paraho report states that mine requirements of 69 KV would be supplied by upgrading existing lines, but the remainder will have to be provided through a new transmission line.
TABLE 1
COST ESTIMATES FOR PARAHO FULL-SIZE MODULE
(IN THOUSANDS OF DOLLARS)

I. Direct Design & Construction
   A. Materials, Equipment, Labor, Subcontracts, and Indirects
      1. Mining $7,080
      2. Primary Crushing 1,770
      3. Raw Shale Handling 2,720
      4. Secondary Crushing & Screening 3,410
      5. Retorting 21,900
      6. Dust Collection 590
      7. Oil Storage & Shipping 470
      8. Spent Shale Handling 4,010
      9. Utilities 2,690
     10. Offsites 4,980
         49,620

   B. Insurance and Taxes 1,240

   Total Direct Costs 50,860

II. Other Design & Construction Costs
   A. Sohio 255
   B. Development Engineering, Inc. 1,065
   C. Paraho 400

   Total Other Costs 1,720

TOTAL DESIGN AND CONSTRUCTION 52,580

III. Operating Costs
   A. Utilities
      1. Water 180
      2. Electricity 1,230
      3. Diesel Fuel 3,620
      4. Other 30
         Subtotal 5,060

   B. Operating Staff
      1. Salaries & Wages 7,190
      2. Supplies, Travel, Misc. 3,030
         Subtotal 10,220

   C. Maintenance
      1. Salaries & Wages 2,750
      2. Material 2,960
         Subtotal 5,710

   D. Insurance & Taxes 2,650

   TOTAL OPERATING COST 23,640

   TOTAL PROGRAM COST $76,220
The proposed project will cover a four-year period and terminate when the facility is turned over to the U.S. government. The disposition of the plant at that time will then be determined by the Congress. Unless that body decides to continue operation, the facility will be shut down and put into a standby status. At this time, there are no plans to continue the project past the demonstration stage. A comprehensive project schedule is shown in Figure 1. Engineering, purchasing, and construction are expected to require about 18 months. Five months are allocated for shakedown operations and 25 months of full scale operations are planned.

The Paraho prospectus reported a project cost estimate of $76,220,000 based on first quarter 1975 dollars. An itemized breakdown of these costs is shown in Table 1.

**Preliminary Test Results Discussed**

Back in 1972 when Development Engineering, Inc. signed a lease agreement with the Department of the Interior, they described the goals and studies to be made during the Paraho demonstration project. These goals and objectives were listed on page 2-17 of the June 1973 issue of Synthetic Fuels. Contained in this list are proposed runs using both direct and indirect heating modes of operation. To date, the only mode examined has been the direct-heated type, which makes the Paraho retort closely resemble the U.S. Bureau of Mines gas combustion retort. The results of the tests were briefly described by Pforzheimer and Jones at the May 13 meeting and in the Paraho prospectus. According to the reports, "the results obtained during the originally planned 10-day demonstration were so favorable that the operating period was extended to 56 days."

During the 56-day run, Paraho experienced an operating factor of about 88 percent and it was claimed that 95 percent of the potential liquid product (as determined by Fischer assay) eventually wound up in tankage. This recovery efficiency was considerably higher than had been expected. Furthermore, the spent shale reportedly contained a lower organic carbon content than was anticipated.

It was stated at the May 13 meeting that internal temperatures were so low (less than 1,000 to 1,200°F) that the thermocouples were thoroughly checked after the run to make sure that they had been working properly. Due to these unusually low temperatures, little carbonate decomposition was noted. Due to some screening problems, a larger fraction of fines than desired was fed to the retort. It was found, however, that the equipment was capable of handling a much higher fraction of minus half-inch particles than the design calculations had indicated.

Approximately 800,000 BTU of low-BTU gas were produced from each ton of shale retorted. This gas averaged about 95 BTU/SCF and, therefore, the generation rate was about 8420 SCF/ton. It was reported that gas turbine manufacturers consider 125 BTU/SCF to be the minimum heat value which can be used efficiently, and thus some degree of CO2 removal may be necessary before Paraho's product gas can be sent to turbine units.

Little information was provided at the May 13 meeting regarding the properties of the synthetic crude product; however, since the configuration of the Paraho unit is similar to that of the BuMines gas combustion retort, one would expect crude properties similar to those produced by the BuMines unit. These properties are shown in Table 2. Information given in the prospectus regarding design parameters for a commercial facility also gives some insight into the operating parameters used in the semi-works facility. These criteria are:
Figure 1. Paraho Full-Size Module Development Schedule.
Maximum throughput rate, lb/hr/ft² 700
Liquid recovery, % of modified Fischer assay 95%
Oil shale size +1/4 to 3-1/2”
Gas production, BTU per ton of shale 800,000
Shale quality, gallons per ton 30
Air rate, standard cubic feet per ton 4,800
Recycle gas rate, standard cubic feet per ton 16,000
Seal gas rate, standard cubic feet per ton 840

Approximately 10,000 barrels of Paraho's crude product was refined at the Gary Western Refinery in Gilsonite, Colorado. The seven different fuels which were manufactured are to be tested in various government facilities throughout the United States. The fuels produced were:

- Gasoline (92.6 octane)
- Marine diesel fuel
- "Special" diesel fuel
- Jet-A jet fuel
- JP-4 jet fuel
- JP-5 jet fuel
- #6 Bunker C fuel oil

These fuels were transported to the following government facilities for testing:

- Wright-Patterson AFB (Dayton, Ohio)
- Lewis Research Center (Cleveland, Ohio)
- Naval Air Propulsion Test Center (Trenton, New Jersey)
- Mobility Equipment Research and Development Center (Ft. Belvoir, Virginia)
- Energy Research Laboratory (Bartlesville, Oklahoma)

Reportedly, some of the lead-free gasoline has already been tested in Paraho company vehicles and some employee automobiles. Some of the diesel fuel was used in an ore carrier operated by the Cleveland Cliffs Iron Company. The results of the government's tests will be valuable in determining the disposition of additional products produced at the Anvil Points facility. As was noted previously, the Paraho retort is designed to operate both in a direct and indirect heated mode and to date only the direct heated configuration has been investigated. Therefore, it is likely that future tests on the semi-works retort will include some operation in the indirect heated mode (thus making the retort resemble a Petrosix type).

Economics of Commercial Plant Analyzed

Since Paraho's goal is eventually to sell their retorting process to firms involved in commercial oil shale ventures, the firm provided some "preliminary commercial economics" in the prospectus. The analysis was based on a 100,000 BPD plant using 16 retorts the size of the module which Paraho proposes to construct in the expansion program. It was assumed that two separate mines, each producing 30 MMTPY, would be necessary to support the operation. It was further assumed that the fines would be discarded rather than be processed in another type of retort such as the TOSCO II.

Since few data are available on the operating characteristics of the indirect heated mode, the economic analysis was made assuming a direct heated mode. It was also presumed that
### TABLE 2

**PROPERTIES OF SYNTHETIC CRUDE FROM USBM GAS COMBUSTION RETORT**

<table>
<thead>
<tr>
<th>Property</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Gravity, °API</td>
<td>19.8 ± 0.2</td>
</tr>
<tr>
<td>Pour Point, °F</td>
<td>83.5</td>
</tr>
<tr>
<td>Nitrogen, wt. %</td>
<td>2.14 ± 0.15</td>
</tr>
<tr>
<td>Sulfur, wt. %</td>
<td>0.699 ± 0.025</td>
</tr>
<tr>
<td>Oxygen, wt. %</td>
<td>1.67</td>
</tr>
<tr>
<td>Carbon, wt. %</td>
<td>83.93</td>
</tr>
<tr>
<td>Hydrogen, wt. %</td>
<td>11.36</td>
</tr>
<tr>
<td>Conradson Carbon, wt. %</td>
<td>4.71</td>
</tr>
<tr>
<td>Viscosity, SUS @ 100°F</td>
<td>270</td>
</tr>
<tr>
<td>Viscosity, SUS @ 212°F</td>
<td>47.6</td>
</tr>
<tr>
<td>Sediment, wt. %</td>
<td>0.042</td>
</tr>
<tr>
<td>Molecular weight</td>
<td>328</td>
</tr>
</tbody>
</table>

### TABLE 3

**COST ESTIMATES FOR COMMERCIAL FACILITY COST CENTERS**

<table>
<thead>
<tr>
<th>Cost Center</th>
<th>Initial Capital, $MM</th>
<th>Deferred Capital, $MM</th>
<th>Operating Cost, $MM/yr.</th>
<th>Operating Cost, $/BBL</th>
<th>Royalty Cost, $/BBL</th>
</tr>
</thead>
<tbody>
<tr>
<td>Mining, Crushing, Screening, Disposal</td>
<td>185</td>
<td>90</td>
<td>59.3</td>
<td>1.80</td>
<td>---</td>
</tr>
<tr>
<td>Retorting</td>
<td>165</td>
<td>---</td>
<td>22</td>
<td>0.67</td>
<td>0.10</td>
</tr>
<tr>
<td>Upgrading</td>
<td>400</td>
<td>---</td>
<td>47</td>
<td>1.43</td>
<td>---</td>
</tr>
<tr>
<td>Total</td>
<td>750</td>
<td>90</td>
<td>128.3</td>
<td>3.9</td>
<td>0.10</td>
</tr>
</tbody>
</table>

### TABLE 4

**ECONOMIC ANALYSIS RESULTS FOR BASE CASE (IN 1975 DOLLARS)**

<table>
<thead>
<tr>
<th>Synthetic Crude Value ($/BBL)</th>
<th>Discounted Cash Flow (% Return)</th>
</tr>
</thead>
<tbody>
<tr>
<td>8.00</td>
<td>12.7</td>
</tr>
<tr>
<td>8.50</td>
<td>13.6</td>
</tr>
<tr>
<td>9.00</td>
<td>14.6</td>
</tr>
<tr>
<td>9.50</td>
<td>15.5</td>
</tr>
<tr>
<td>10.00</td>
<td>16.4</td>
</tr>
<tr>
<td>10.50</td>
<td>17.2</td>
</tr>
<tr>
<td>11.00</td>
<td>18.1</td>
</tr>
<tr>
<td>11.50</td>
<td>18.9</td>
</tr>
<tr>
<td>12.00</td>
<td>19.7</td>
</tr>
</tbody>
</table>
the low-BTU product gas could be sold to nearby utility plants.

It was recognized that some degree of upgrading would be required to convert the raw synthetic crude into usable products. A raw shale oil with the following properties was assumed:

<table>
<thead>
<tr>
<th>Property</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Gravity, °API</td>
<td>20.0</td>
</tr>
<tr>
<td>Pour Point, °F</td>
<td>+85</td>
</tr>
<tr>
<td>Nitrogen, wt. %</td>
<td>2.2</td>
</tr>
<tr>
<td>Sulfur, wt. %</td>
<td>0.7</td>
</tr>
<tr>
<td>Oxygen, wt. %</td>
<td>1.4</td>
</tr>
<tr>
<td>C:H Ratio</td>
<td>7.4</td>
</tr>
<tr>
<td>Distillation EP, °F</td>
<td>&lt;1000</td>
</tr>
<tr>
<td>BS &amp; W, Vol. %</td>
<td>0-1.0</td>
</tr>
</tbody>
</table>

The first upgrading step recommended was coking, followed by severe hydro-treating to reduce the N₂, O₂, and S contents. According to a recent engineering study, the resulting liquid product would have the following characteristics:

<table>
<thead>
<tr>
<th>Property</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Gravity, °API</td>
<td>47.0</td>
</tr>
<tr>
<td>Pour point, °F</td>
<td>0</td>
</tr>
<tr>
<td>Nitrogen, wt.%</td>
<td>&lt;0.1</td>
</tr>
<tr>
<td>Sulfur, wt.%</td>
<td>&lt;0.03</td>
</tr>
<tr>
<td>Oxygen, wt.%</td>
<td>=0.1</td>
</tr>
<tr>
<td>C:H Ratio</td>
<td>6.3</td>
</tr>
<tr>
<td>Distillation EP, °F</td>
<td>700</td>
</tr>
</tbody>
</table>

This product could then be transported to a conventional refinery for further processing.

The first step in the economic analysis was the division of the entire processing facility into three cost centers:

- Mining, crushing, screening, and spent shale disposal
- Retorting
- Shale oil upgrading

Cost estimates were then made for each of these centers. Those estimates (in 1975 dollars) were as shown in Table 3.

The products from the processing facility were assumed to be:
- 80,500 BPSD of premium quality, low pour syncrude
- 2900 BPSD of LPG
- 290 T/SD of ammonia
- 2600 T/SD of coke
- 118 billion BTU/SD of export gas

An economic analysis was first made on a "base case" and then some of the assumptions were changed, one at a time, to show the effect of each variable on the value of the synthetic crude product. The results of the sensitivity analysis are shown in Tables 4 and 5. The base case assumptions are as follows:

1. 1975 dollars
2. Three-year construction period
3. Three-month start-up
4. 90 percent overall service factor
5. 20-year operating period
6. Investors rate of return on total capital
7. 15 percent depletion allowance on value of crude shale oil
8. 15-year depreciation on retorting and refining, 10-year on mining, and 20-year on the water supply
9. 7 percent investment credit on all capital other than deferred capital
10. 51 percent tax rate which covers federal and state burden
11. 12¢ per ton extraction royalty
12. 10¢ per barrel retort oil royalty on crude shale oil
13. Plant gate basis for project analysis
14. Product demand for treated shale oil, coke @ $30/ton, export gas @ $1.00/MMBTU LHV, ammonia @ $100/ton, LPG @ $8.00/EBL and Sulfur @ zero value
15. Water is available in required quantity
TABLE 5
PARAMETER SENSITIVITY ANALYSIS

<table>
<thead>
<tr>
<th>Case No.</th>
<th>Description</th>
<th>Synthetic Crude Value ($/BBL)</th>
<th>Rate of Return (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Base Case</td>
<td>9.22</td>
<td>15</td>
</tr>
<tr>
<td>2</td>
<td>Depletion Allowance @ 0%</td>
<td>10.30</td>
<td>15</td>
</tr>
<tr>
<td>3</td>
<td>$1.70/MM BTU Export Gas</td>
<td>8.20</td>
<td>15</td>
</tr>
<tr>
<td>4</td>
<td>$75/Ton Coke</td>
<td>7.80</td>
<td>15</td>
</tr>
<tr>
<td>5</td>
<td>Investment Credit 0%</td>
<td>9.70</td>
<td>15</td>
</tr>
<tr>
<td>6</td>
<td>10% Fines</td>
<td>9.30</td>
<td>15</td>
</tr>
<tr>
<td>7</td>
<td>Capital Requirements @ 110%</td>
<td>9.95</td>
<td>15</td>
</tr>
<tr>
<td>8</td>
<td>All Byproduct Values @ 0%</td>
<td>12.35</td>
<td>15</td>
</tr>
<tr>
<td>9</td>
<td>Operating Costs at 110%</td>
<td>9.73</td>
<td>15</td>
</tr>
<tr>
<td>10</td>
<td>Four year Construction Period</td>
<td>10.20</td>
<td>15</td>
</tr>
</tbody>
</table>

16. No change in current Colorado-Utah environmental requirements

17. Insurance and taxes - 2.5 percent of capital costs

18. Electric power costs based on $1.70/MMBTU

19. Fines used to cover retorted shale area equals eight percent of mined shale

EIS May Slow Project

Indications are that Paraho is anxious to get started on the full-size module as soon as possible even though tests are probably not complete on the semi-works retort. One major obstacle to rapid development is the possibility that a full-scale environmental impact statement (EIS) will be required. The Bureau of Mines has already prepared an environmental impact assessment for the project and this has been submitted to the Department of the Interior. Based on the assessment, Interior may well decide that an EIS is required, and if so will authorize the tedious, time-consuming tasks to begin. Even if a full EIS is not required, it is likely that at least an addendum to the EIS for the current project will be necessary. Either way, much valuable time will be lost.

Recent announcements by Harry Pforzheimer indicate that "verbal assurances" of continued financial support have been received from all 17 of the current Paraho participants. This is of course encouraging, but verbal commitments are a long way from a signed contract and Pforzheimer will no doubt sleep much better when these contracts are in hand. There really is no reason to doubt that industry will faithfully support the expanded project, as some in industry felt that a full-size module should have been constructed during the first phase, rather than the 10-1/2 foot retort.

The construction of the full-size module is definitely a necessary and important step toward a commercial oil shale industry. Total funding by industry is likely, as is government approval for the project. The requirement of an EIS is possible, and while it may not kill the program, it might well delay it by as much as one year. We can only hope that if an EIS is required, Interior will consider it a top priority item and expedite the process as much as possible.

# # # #
LAND

ALBERTA LEASING DATA SUMMARIZED IN MINES AND MINERALS REPORT

The Alberta Mines and Minerals Department has published an outstanding statistical report entitled, "Alberta Oil Sands-Facts and Figures." The publication contains a wealth of information regarding the ownership and leasing status of land in the four major oil sands deposits of Alberta. Furthermore, the information is presented in a logical and understandable manner. Detailed tabulations are held to a minimum and full use is made of bar charts, 'pie' diagrams, and maps.

Prior to discussing the disposition of land, however, the report defines certain terms which are used throughout the text. This list of concise definitions is as follows:

**Bituminous Sands**
The oil sands being within townships 84 to 104 inclusive in ranges 4 to 18 inclusive, west of the 4th meridian and occurring in the McMurray Formation, being the stratigraphic formation lying above the upper Devonian carbonate sediments and below the Clearwater formation. (The Mines and Minerals Act 2.(1)2.)

**Bituminous Sands Lease**
A long-term agreement whereby the owner of the oil sands that occur in the McMurray Formation within the Bituminous Sands Area accords the lessee the right to win, work, and obtain these oil sands.

**Convertible Petroleum and Natural Gas Disposition**
An exploration agreement (reservation or permit) granting the right to explore for conventional petroleum and natural gas, including oil sands. The holder of such an agreement may apply for oil sands right where drilling has established the presence of oil sands to the satisfaction of the Minister.

Crown Mineral Rights
Those owned by the Crown in the right of Alberta. For the purposes of the report, Crown minerals in the right of Canada (Indian Reserves, etc.), are included in the freehold mineral rights category.

**Crude Bitumen**
A naturally occurring viscous mixture composed mainly of hydrocarbons heavier than pentane which, in its naturally occurring state, is not recoverable at a commercial rate through a well.

**Freehold Mineral Rights**
Those mineral rights owned by a party other than the Crown in right of Alberta. These include mineral rights granted to private citizens, companies, and the federal government.

**In Place Reserves**
Defined as the total raw bitumen in a deposit.

**In Situ Areas**
Those portions of the bituminous and oil sands deposits overlain by more than 500 feet of overburden. Such deposits are too deep to mine by surface mining methods and, therefore, require production by special drilling and "flushing" methods designed to reduce the viscosity of the heavy oil.

**Oil Sands**
Sand and other rock materials which contain crude bitumen and includes all other mineral substances in association therewith. (The Mines and Minerals Act 2.(1)20.)

The highly viscous crude hydrocarbon material in oil sands is not recoverable in its natural state through a well by ordinary production methods.

**Oil Sands Lease**
A long-term agreement whereby the owner of the oil sands accords the lessee the
right to win, work, and obtain oil sands that are known to exist in designated zones within the location.

Oil Sands Prospecting Permit
A short-term agreement granting the holder the right to explore for oil sands.

Surface Mineable Area
That part of the bituminous sands area overlain by less than 150 feet of overburden. The depth of overburden limiting surface mining operations today is based on recovery economics and technology that may reasonably be anticipated in the near future.

Synthetic Crude Oil
The upgraded product obtained from crude bitumen. It is defined as a mixture, mainly of pentanes and heavier hydrocarbons, that may contain sulfur compounds, that is derived from crude bitumen and that is liquid at the conditions under which its volume is measured or estimated, and includes all other hydrocarbon mixtures so derived. (The Oil and Gas Conservation Act 2.141.)

Undisposed Crown
Crown mineral rights that are not held under a petroleum and natural gas, oil sands, or bituminous sands agreement.

Distribution of Land and Reserves Shown
Over 90 percent of all leased land in the oil sands areas is controlled by 17 large oil companies. The distribution of this ownership is shown in Figure 1. The in place reserves contained in the deposit areas are estimated at 895 billion barrels but only eight percent are overlain by 150 feet or less of overburden, thus making them amenable to recovery by surface mining. On the other hand, roughly 76 percent of the reserves are under at least 500 feet of overburden and are, therefore, deemed recoverable by in situ techniques. The recovery of the remaining 16 percent is considered "uncertain." The distribution of these reserves and their probable methods of development are graphically shown in Figures 2 through 4.

Figures 6 through 10 summarize the disposition of land in all four deposit areas. By the report's definition, oil sand dispositions are in the form of leases or prospecting permits and other Crown dispositions are petroleum and natural gas agreements. Areas classed as undisposed Crown is land held by Alberta which can be posted for sale in the future. As shown in Figures 6 and 8, the Cold Lake deposit includes an inordinately large amount of freehold land. This is primarily due to the fact that the deposit area extends into the agricultural region of Alberta.

The distribution of ownership within the individual deposit areas is shown graphically in Figures 11 through 14. Accompanying each of these figures in the report is a tabulation showing lease numbers, acreages, and lease issue/expiration dates.

The Athabasca area is worthy of particular interest due to its large amount of strip mineable reserves. Thus, the report discusses these reserves in detail. Figure 15 is a map of the Athabasca region showing the boundaries of the surface mineable reserves and Figure 16 illustrates the distribution of the land.

A copy of the publication may be obtained for $5 by writing to the Department of Mines and Minerals, Petroleum Plaza, South Tower, 9915-108 Street, Edmonton, Alberta, T5K 2C9.

# # # #
Figure 1. Oil Sands Held by Individual Companies

Figure 2. In Place Reserves Recoverable by Various Techniques

Figure 3. In Place Reserves by Deposit Area
Figure 4. Area of Land in Each Deposit Showing Probable Method of Development

Figure 5. Provincial Revenues From Oil Sands
Figure 6. Distribution of Land in Oil Deposits
Figure 7. Athabasca Ownership

Figure 8. Cold Lake Ownership

Figure 9. Wabasca Ownership

Figure 10. Peace River Ownership
Figure 11. Athabasca Acreage Leased by Individual Companies

Figure 12. Cold Lake Acreage Leased by Individual Companies
Figure 13. Wabasca Acreage Leased by Individual Companies

Figure 14. Peace River Acreage Leased by Individual Companies

Figure 15. Bituminous Sand Leases in the Surface Mineable Area of the Athabasca Deposit
Figure 16. Surface Mineable Acreage in Athabasca Deposit Leased by Individual Companies
P.R. SPRING COREHOLES ANALYZED BY BUMINES

During a 1973 coring program, the U.S. Bureau of Mines drilled 17 coreholes in the P.R. Spring oil sand deposit area. Three cores from the Seep Ridge area are discussed in Report of Investigations 8003 and three others from the Asphalt Wash area are discussed in RI 8030. In addition to these core data, the analyses of four coreholes in the Threemile Canyon area were discussed in RI 7923. A summary of these results was presented on page 3-15 of the September 1974 issue of Synthetic Fuels.

The coreholes analyzed in RI 8003 were located about 2.5 miles apart along a NNW-SSE line across the southern end of Seep Ridge, which in turn is located in the south-central portion of the P.R. Spring deposit. The coreholes in the Asphalt Wash area were about 3.5 to four miles apart along the section line between T12S and T13S.

Based on the results of the Seep Ridge cores, the authors divided the area into four major zones (see Figure 1). The analysis of these zones in each of the coreholes is detailed in Table 1. The average oil saturation in the upper zone is 42.6 percent of pore volume but decreases with depth to only 29.5 percent in the lower zone. Other trends noted were that tar sand thickness, bulk density, and water saturation all decreased with depth but porosity and permeability tended to increase. The only measured characteristic which exhibited a trend with direction was the specific gravity of the oil, which increased to the north.

### Table 1: Analysis of Seep Ridge Cores

<table>
<thead>
<tr>
<th>Corehole (PRS)</th>
<th>Zone 1</th>
<th>Zone 2</th>
</tr>
</thead>
<tbody>
<tr>
<td>Net tar sand thickness</td>
<td>ft</td>
<td></td>
</tr>
<tr>
<td>Porosity, saturated</td>
<td></td>
<td></td>
</tr>
<tr>
<td>por of bulk vol</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Porosity, extracted</td>
<td></td>
<td></td>
</tr>
<tr>
<td>por of bulk vol</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Permeability, saturated</td>
<td>md</td>
<td></td>
</tr>
<tr>
<td>Permeability, extracted</td>
<td>md</td>
<td></td>
</tr>
<tr>
<td>Oil saturation</td>
<td></td>
<td></td>
</tr>
<tr>
<td>pet of pore vol</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Water saturation</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Bulk density, saturated</td>
<td>g/cm$^3$</td>
<td></td>
</tr>
<tr>
<td>Sand grain density</td>
<td>g/cm$^3$</td>
<td></td>
</tr>
<tr>
<td>Specific gravity of oil</td>
<td></td>
<td></td>
</tr>
<tr>
<td>API</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

**Note:** The table data is not transcribed due to its extensive nature, but it shows the trend and details of the analysis for each zone.
Figure 1. Columnar Sections of Seep Ridge Area.

### TABLE 2

ANALYSES OF ASPHALT WASH CORES

<table>
<thead>
<tr>
<th>Well</th>
<th>Zone</th>
<th>PR-1</th>
<th>PR-5</th>
<th>PR-4</th>
<th>PR-1</th>
<th>PR-5</th>
<th>PR-4</th>
<th>All 3</th>
<th>All 3</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>1</td>
<td>1</td>
<td>1</td>
<td>2</td>
<td>2</td>
<td>2</td>
<td>1</td>
<td>1</td>
</tr>
<tr>
<td>Net thickness of tar sand...ft.</td>
<td>16</td>
<td>12</td>
<td>23</td>
<td>23</td>
<td>12</td>
<td>0</td>
<td>17</td>
<td>18</td>
<td></td>
</tr>
<tr>
<td>Porosity, saturated...pct.</td>
<td>8.9</td>
<td>9.1</td>
<td>9.0</td>
<td>10.6</td>
<td>12.5</td>
<td>9.0</td>
<td>11.3</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Porosity, extracted...pct.</td>
<td>23.2</td>
<td>25.0</td>
<td>25.5</td>
<td>25.1</td>
<td>23.9</td>
<td>24.7</td>
<td>24.7</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Permeability, saturated...md.</td>
<td>120</td>
<td>47.2</td>
<td>64.6</td>
<td>62.9</td>
<td>199</td>
<td>71.5</td>
<td>110</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Permeability, extracted...md.</td>
<td>401</td>
<td>532</td>
<td>795</td>
<td>627</td>
<td>683</td>
<td>609</td>
<td>577</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Oil saturation...pct of pore vol.</td>
<td>57.1</td>
<td>61.0</td>
<td>63.5</td>
<td>52.2</td>
<td>57.3</td>
<td>60.9</td>
<td>53.9</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Water saturation...pct of pore vol.</td>
<td>2.6</td>
<td>1.9</td>
<td>1.4</td>
<td>1.7</td>
<td>1.3</td>
<td>1.7</td>
<td>1.6</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Bulk density, saturated...g/cm³</td>
<td>2.183</td>
<td>2.167</td>
<td>2.128</td>
<td>2.130</td>
<td>2.107</td>
<td>2.150</td>
<td>2.122</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Sand grain density...g/cm³</td>
<td>2.664</td>
<td>2.633</td>
<td>2.632</td>
<td>2.661</td>
<td>2.696</td>
<td>2.642</td>
<td>2.673</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Compressive strength, saturated...psi</td>
<td>4.812</td>
<td>2.915</td>
<td>4.099</td>
<td>3.852</td>
<td>5.637</td>
<td>3.023</td>
<td>4.268</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Compressive strength, extracted...psi</td>
<td>3.893</td>
<td>2.594</td>
<td>4.049</td>
<td>4.858</td>
<td>4.269</td>
<td>3.538</td>
<td>4.710</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Oil specific gravity at 60° F....</td>
<td>0.979</td>
<td>0.989</td>
<td>1.001</td>
<td>0.996</td>
<td>0.989</td>
<td>0.993</td>
<td>0.995</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Oil gravity...° API</td>
<td>13.0</td>
<td>11.6</td>
<td>5.9</td>
<td>10.6</td>
<td>13.6</td>
<td>11.0</td>
<td>10.7</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
The authors of the Asphalt Wash report divided that area into two separate zones (see Figure 2). Table 2 describes the properties of the oil sands in each of these zones. Both zones are of about the same thickness but oil saturation in the lower zone is less. In zone 1, the saturated porosity remained fairly constant with depth, while extracted porosity, extracted permeability, and oil saturation decreased with depth. All other properties increased with depth. In zone 2, saturated porosity and permeability, as well as sand grain density, decreased with depth. The compressive strength exhibited no trend with depth in either zone.

# # # #

TEXACO PATENTS HYDRAULIC MINING TECHNIQUE APPLICABLE TO TAR SANDS

U.S. Patent 3,858,654 assigned to Texaco describes a method for recovering bituminous petroleum from tar sands deposits by hydraulic mining. The system features an injection string of pipe which has horizontally-oriented nozzles on the lower end. A means is provided for rotating the pipe while simultaneously injecting fluids down the injection string. Also provided is a separate flow path for recovering the injected fluid with bitumen at the surface.

The fluid used in this mining method is an aqueous solution of polyphosphate wetting agent plus an alkalinity agent, heated to a temperature greater than that of the tar sand formation. At the surface, the bituminous petroleum is separated from the alkaline phosphate solution by contacting the fluid with a hydrocarbon fluid such as diesel oil.

# # # #

TREATMENT OF MIDDINGLS STREAM FROM HOT WATER PROCESS DESCRIBED BY SYNCRUDE PATENT


The middlings stream from the primary separation cell is diluted with hot water, aerated, and allowed to settle in a quiescent zone. In the quiescent and dilute environment within the settler vessel, the buoyant bitumen forms a froth product which is reduced in solids and water content in comparison to the prior art secondary recovery froth obtained by sub-aeration flotation machines. The froth product from the settler vessel is preferably combined with the froth from the primary separation cell and forwarded to the froth treatment circuit.

# # # #
AMOCO'S IN SITU PROJECTS IN ALBERTA OIL SANDS DESCRIBED AT NINTH WORLD PETROLEUM CONGRESS

For several years, Amoco Production Company has been conducting a series of in situ tests at various sites in the Athabasca oil sands and in the Cold Lake oil sands of Alberta province. Richard Mungen of Amoco described these tests in a paper presented at the Ninth World Petroleum Congress held in May in Tokyo, Japan.

Mungen noted first that the Athabasca bitumen and the Cold Lake heavy oil are similar chemically, but have different viscosities. At formation temperature of 50°F, the bitumen has a viscosity of two to five million cps and is essentially solid. The heavy oil has some mobility and displays a viscosity of about 100,000 cps at 55°F.

Considering first the tests in Athabasca oil sands, Amoco conducted several 2-well tests in 100-foot pay zones overlain by 800 to 1000 feet of overburden. The objectives were to reduce the viscosity of the bitumen by heating with steam and/or in situ combustion and then produce oil in a conventional manner at 150°F, or higher. To achieve practical recovery rates, air had to be injected at fracturing pressures. It was noted in the 2-well tests that injected fluids tended to move upward in the formation.

Subsequent testing on a half-acre site using a central injection well and four producing wells involved fracturing at the injection well followed by formation ignition and air injection. Mungen reported that 50 percent of the formation volume in the test area was heated to 150°F or higher, with 100°F temperatures at the injection well. Of the 90,000 barrels originally in place, 53,000 were heated to 150°F or higher, 6300 barrels were burned, and 29,000 barrels were produced during the 2-year test period. The product oil had a viscosity of 10 cps at 300°F.

The in situ procedures which were developed consisted of a heating phase which required about eight months while steam and air were being injected at formation fracturing pressures. This was followed by a blow down or production phase when injection was suspended. During this period, formation pressures decrease, connate water flashes to steam, and the steam drives bitumen into flow channels and to the production wells. Then a forward drive production phase follows when air injection is re-established, combustion is initiated, and water is injected. This phase is known as the COFCAW process; COFCAW is an acronym derived from the words Combined Forward Combustion And Water (injection).

Larger-scale tests are underway on a ten-acre tract and plans are formulated for testing a 32-well pattern on a 35.5-acre tract. Should a decision be made to proceed to a commercial project, it would require eight to ten years before achieving full production.

Amoco is also testing in situ methods for recovering heavy oil in the Cold Lake deposits, where the pay zone is about 100 feet thick. Three progressively larger pilot tests are involved, the Ethel, May, and Leming pilots. Current tests at the May pilot utilize 23 wells drilled on a ten-acre five-spot pattern. At this site, water in an underlying formation was in communication with the oil sands and interfered with operations. The proposed Leming pilot will use 56 wells arranged in seven-spot patterns with wells 600 feet apart, and will be in an area which does not have the underlying water problem. If successful, pilot operations here could lead to large-scale commercial development by the early 1980's, Munger stated.
The Chairman of the Alberta Energy Resources Conservation Board (ERCB), Dr. G. W. Govier, spoke at the annual meeting of the American Institute of Mining, Metallurgical and Petroleum Engineers (AIME) held in New York in February. The first part of his presentation, dealing with Alberta and Canada's crude oil supply situation, stressed that "since 1968 the proved remaining recoverable reserves have been declining in the face of a low rate of reserve additions and high levels of production." Furthermore, in 1974 Canada exported approximately 900,000 BPD to the U.S. while at the same time importing roughly the same amount from Venezuela and the Middle East. For this reason, Canada must sell its exports at world prices, so it can afford to import the foreign crude at world prices.

Govier noted that the Canadian National Energy Board (NEB) has become increasingly concerned about the levels of exports relative to the existing reserves. Therefore, it announced a policy late last year restricting Canadian exports "as necessary to protect Canadian needs." The policy provides that "all surplus in indigenous supply may be exported when productive capacity is forecast to be adequate for Canadian needs over a ten year period; when productive capacity is estimated to be adequate for a period less than ten years, say x years, it provides that x/10 of the surplus of the indigenous supply may be exported." Dr. Govier stated that as of February, productive capacity was estimated to be 7.3 years. Thus, 73 percent of Canada's excess capacity may be exported. According to recent NEB estimates, however, the surplus indigenous supply will dwindle to zero by 1982 unless new fields are discovered and developed.

Oil Sands Could Produce 13 MMBPD

Dr. Govier next presented a summary of the oil sands reserves and a brief review of proposed surface mining operations. During this discussion, he referred to the new criterion used by the ERCB in determining the reserves practically recoverable by surface mining. This criterion was discussed on page 3-16 of the March 1975 issue of Synthetic Fuels.

It was noted that while the Clark hot water extraction process currently used in the Great Canadian Oil Sands operation, is a viable process, it results in a 10 percent bitumen loss, consumes large amounts of energy, and creates huge tailings disposal areas. The ERCB "takes the position that for plants to come on stream after the mid-1980's new or improved technology must be developed to lessen the tailings disposal problem."

Govier then discussed the various in situ projects currently in operation. It was his stated belief that "it will not be long before there is at least one in situ process ready for full scale commercial development."

The limiting factors for future growth, as Govier sees it, are availability of capital, equipment manufacturing facilities, design and professional services, construction labor, and operating personnel. In no way can reserves be considered limiting, as the surface mineable deposits alone could support up to 30 plants, each having a 100,000 to 150,000 BPD capacity producing in excess of 3 MMBPD. Furthermore, Govier sees the reserves amenable to in situ recovery as being large enough to support at least a 10 MMBPD industry. Assuming logistical and economic problems are overcome, Govier optimistically stated that a 600,000 BPD industry could be expected by 1985.

# # # #

HOUSE COMMITTEE REPORT ANALYZES OIL SANDS DEVELOPMENT

The future of oil sands development in the United States is largely in the hands of the federal government, as roughly 70 percent of the nation's reserves are on federally owned lands. Congress will play a major role in determining the

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SYNTHETIC FUELS, JUNE, 1975
course which this development will take and therefore must have at its disposal accurate and comprehensive data on which to base its decisions. This data input may indeed come from lobbyists and special interest groups, but much unbiased information may be generated by internal investigative agencies. Such an agency is the Congressional Research Service, a division of the Library of Congress. This group recently prepared a report for the Subcommittee on Energy of the Committee on Science and Astronautics, a functional group within the U.S. House of Representatives. The report was entitled, "Energy from U.S. and Canadian Tar Sands: Technical, Environmental, Economic, Legislative, and Policy Aspects."

The 90-page report clearly and concisely reviews the history of oil sands development in Canada and the United States, and includes sketches of all five current projects in the Athabasca region. The publication also discusses at some length the magnitude of the reserves and the impact they could have on both Canadian and U.S. energy supplies. Most importantly, the report analyzes each of the problem areas which currently prohibits, or will eventually inhibit, the growth of the U.S. oil sands industry.

National Policy Necessary

The report cites the following as the primary factors which currently limit the growth of the U.S. oil sands industry:

- Lack of a clearly defined national oil sands policy as part of a broader national energy policy
- Lack of a clearly defined and workable oil sands leasing policy
- State of the technology for oil sands processing
- Availability of water in the Uinta Basin and in other parts of Utah for tar sands processing
- Uncertainty associated with the oil exporting and pricing policies of OPEC
- Lack of a firm and definite policy regarding a subsidy or guaranteed price for the development of the synthetic fuels industry in the U.S.
- Lack of information on the exact nature and the extent of domestic oil sands deposits
- Limited resource base and scattered geographical location of domestic resources
- Scarcity of construction materials, manpower, and rapidly increasing construction and operating costs

Since Utah is the state in which the first commercial projects would probably be sited, the report singled out some problems which could cause significant delays in any proposed venture:

- The Tar Sand Triangle and Circle Cliffs giant deposits are largely on federal lands. Leasing of federal lands for "asphaltic minerals" or oil sands has been delayed pending legislation.
- Proposals for national parks, national monuments, desert wilderness areas, and recreation areas cover most of the Circle Cliffs and Tar Sands Triangle giant deposits and could result in surface uses incompatible with mineral resource development.
- Water supply may constitute a serious handicap to exploitation of Utah deposits.
- Oil sands and oil shale are superimposed in the P.R. Spring giant deposit, which may present legal difficulties.

The establishment of a national oil sands policy, or at least a clear understanding of the priority of oil sands in the national energy development plan, is definitely the most pressing of the above-mentioned problem areas. This is especially important because much of the funding for large resource and development projects will undoubtedly come from government sources. Several of the questions which the authors of the reports cite as critical considerations are:

- What priorities should development of the U.S. oil sands resources receive?
- In the realm of international diplomacy, what level of influence, if any, should the U.S. exert on
foreign countries to develop their oil sands resources?

- What role or strategy should the Department of the Interior assume in the development of oil sands processing technologies?
- What should be the distribution of costs and benefits with respect to development of the federally-owned oil sands deposits?
- Should private industry or should an agency of the federal government develop the federally-owned oil sands?

**Federal Leasing Policy Inhibits Development**

Following the establishment of a national policy, the next logical step would be to make available to industry the oil sands reserves located on federal land. For any other resource, this would simply mean leasing more land; however, the present mechanism for granting bituminous sands leases has some serious drawbacks. The Secretary of the Interior is currently authorized to grant conventional oil and gas leases as well as bituminous sands leases. Herein lies the problem: both types of leases may be issued on the same tract of land, but the leases may be to different individuals. Most of the available oil sands are amenable only to in situ recovery—fireflood, steam injection, etc. Similarly, a conventional oil and gas lessee may well use this type of technique as a "secondary recovery." If such methods are used by either operator, who is to say whether the source of the recovered oil was the bituminous sands deposit or the conventional oil reservoir. Prospective oil sands lessees see this type of leasing arrangement as having a "built in lawsuit."

The state of Utah has circumvented this difficulty by granting state hydrocarbon leases on minerals including oil, gas, and bituminous sands, but excluding oil shale, gilsonite, and coal. Thus, if thermal stimulation techniques are used by the lessee it does not matter where the oil comes from.

However, the solution to the federal leasing dilemma is not nearly so simple as converting existing oil and gas leases to hydrocarbon leases similar to those in Utah. The report states that, "if tar sands leases were to be exchanged for present oil and gas leases, give away charges may result - if not, some tar sands deposits may be locked up until present oil and gas leases terminate. Alternatively, there is the possibility that the Department of the Interior could issue new regulations which specifically addressed the problems of in situ processing of tar sands. These regulations would provide that if a developer uses in situ means to extract oil from the ground, he is entitled to legal ownership of any hydrocarbon material except coal or oil shale regardless of whether it is tar sands oil or conventional oil. Whether or not it is possible for the Department of the Interior to remove all legal problems associated with leasing of federally-owned tar sands would have to be explored."

**Research Will Make Canadian Crude Available to U.S.**

One of the conclusions drawn by the authors of the report was that, "decision-makers in the United States should not consider U.S. tar sands a major energy source. For the Uinta basin in Utah and surrounding regions, tar sands may prove to be a valuable source of synthetic oil; however their contribution will be limited by environmental, economic, technical, and policy constraints." This does not mean, however, that continued research in the area of oil sands processing will not eventually pay off by providing significant amounts of energy to the U.S. Rather, it implies that the U.S. must consider the future development of non-domestic oil sands deposits, such as those in Alberta, Canada. Contrary to popular opinion, this concept does not run counter to the recent announcements that Canada will be eliminating crude oil exports to the United States by 1982.

Late last year, the Canadian National Energy Board (NEB) instituted a policy which would control the amount of crude
oil exported from that country. This policy provides that all surplus in indigenous supply may be exported when the productive capacity is forecast to be adequate for Canadian needs over a 10-year period. If the productive capacity is estimated to be adequate for less than 10-years, call it x years, the policy states that only \( \frac{x}{10} \) of the surplus in indigenous supply may be exported.

If the Canadian productive capacity does not keep pace with the increasing demand for oil, the surplus available for export will continue to decrease until the productive capacity is the same as the consumptive rate. The current productive capacity is adequate for about 7.3 years, and thus 73 percent of the crude which can be produced in excess of Canada's needs may be exported. The NEB predicts that by 1982 the productive capacity will just satisfy Canada's requirements, and thus exports will cease.

Another situation which directly affects Canada's export policy is that country's lack of an east-west crude oil transportation system. Even though the western provinces produce adequate quantities of oil to supply all of Canada, the lack of a transportation system requires that western oil be exported at world prices to pay for oil imported to the eastern provinces from Venezuela and the Middle East. By 1976, a pipeline between Sarnia and Montreal is to be completed. This pipeline will be capable of transporting 250,000 BPD to eastern Canada, and will eliminate the need to import a similar amount of crude.

There are two means by which the 1982 deadline could be averted. First, by a massive conservation effort on the part of the Canadian population; not a likely possibility. Secondly, productive capacity could be increased substantially, and thus create an exportable surplus. Turning the vast oil sands deposits of Alberta into oil production centers would certainly create such a surplus. Therefore, it is in the best interest of the U.S. and Canada to develop a viable in situ oil sands recovery technique.

The subcommittee report states that "an opportunity exists to establish a U.S.-Canadian joint effort to further the technology of extracting oil from tar sands by in situ means. Some experts question the political acceptability of the joint U.S.-Canadian effort on tar sands processing. Any joint program would raise several questions, for example: (1) Would the Canadians agree to U.S. involvement in a research and development project on Canadian tar sands? (2) What level of funding would be required to participate effectively in cooperative efforts to further tar sands processing technology? (3) Would the United States be assured of a fair return for their efforts if an acceptable in situ technology is worked out? (4) Would U.S. involvement in a successful joint R&D program result in an increased supply of oil to the United States?"

While the subcommittee report makes no recommendations per se, it clearly defines what decisions must be made and what questions must be addressed in arriving at those decisions. Hopefully, Congress will make full use of the data contained in this report and establish a national oil sands policy or priority, develop a workable oil sands leasing program, and investigate the acceptability of a joint Canadian-U.S. in situ research program.

# # # #
Corporations

GCOS President Reports First Quarter Profit of $2 Million

Kenneth F. Heddon, president of Great Canadian Oil Sands Limited (GCOS), summarized the recent activities of the company at the annual meeting of shareholders, held in Edmonton on April 18, 1975. He emphasized the role which GCOS has played in the Alberta economy but also referred to the many mechanical and economic problems which continue to plague the operation. However, in spite of these difficulties, the firm earned $1,955,000 during the first three months of 1975. Production during this period averaged 45,300 BPD.

GCOS spent approximately $50 million for goods and services in 1974, roughly 80 percent of which went to purchases in the province of Alberta. In addition, they paid about $26 million in wages to the 1,700 GCOS employees. Of course, the majority of this money also found its way into the mainstream of the Alberta economy. GCOS paid $13 million directly to the province through royalties.

New Corporate Positions Created

There was also a management reorganization at GCOS last year. This change was aimed at accomplishing three corporate goals:

1. Increase productivity and place the maximum amount of control and responsibility with the primary operating groups at the Ft. McMurray plant
2. Increase sales revenue by searching out applications of higher value for synthetic crude and sulfur and by marketing GCOS expertise in oil sands technology
3. Strengthen forward planning

To accomplish these goals, three new posts were filled as follows:

- Earl J. Rea, Director of plant Operations
- William L. Oliver, Director of Marketing
- W. C. Tostevin, Director of Finance and Planning

These men report directly to the Vice President and General Manager, Reginald D. Humphreys.

Sulfur to be Sold to Italy

Due to higher international prices for sulfur, GCOS began a test program to sell some of its product sulfur to Italy. Reports indicate that the initial contract calls for the sale of roughly 100,000 tons per year. Current sulfur stockpiles at the plant are estimated to be about 400,000 tons, with the extraction process adding another 100,000 tons per year.

An interesting statistic quoted by Heddon was that for each additional one percent increase in overall bitumen recovery (now about 90 percent) yearly sales revenues would increase by about $1 million, assuming $7/barrel product price. This, Heddon feels, is adequate incentive to debottleneck and improve plant efficiency rather than invest the estimated $75 to $100 million to expand the capacity to 65,000 BPCD in one step.

Ever since the major accident which occurred in the spring of 1974 (see page 3-15 of the December 1974 issue of Synthetic Fuels), mechanical problems have plagued the operation. Hopefully, modifications and repairs made during a three-week plant shutdown which began on April 19 will alleviate many of these difficulties. Another major expense was a $10 million bucketwheel excavator purchased from Orenstein and Koppel. This unit will be used primarily for overburden removal, but will also be used part time for oil sands mining.

Heddon Disappointed With Ministers Conference

Near the end of his presentation, Heddon referred to the recent Ministers Conference on Energy held in Ottawa. Heddon observed that failure of the ministers to agree on a higher price for Canadian oil, while expected, was very disappointing. "With drilling rigs leaving Canada and plans for new oil
sands plants going back on the shelf, we can only hope that the differences of opinion on this issue will be reconciled quickly and such reconciliation will be on a basis that recognizes the direction in which the long-term interests of Canada lie."

# # #

USERS OF GCOS SYNTHETIC CRUDE LISTED

Table 1 shows the actual nominations of companies and refineries which purchased synthetic crude from the Great Canadian Oil Sands (GCOS) plant during the three-month period from February to April. Also shown are the estimated requirements for May and June. The source of this information is the monthly listing of nominations for Alberta crude oil and pentanes plus published by the Alberta Energy Resources Conservation Board.

# # #

TABLE 1

TABULATION OF NOMINATIONS FOR SYNTHETIC CRUDE OIL PRODUCED FROM ATHABASCA BITUMINOUS SANDS

<table>
<thead>
<tr>
<th>Purchaser/Destination</th>
<th>Nominations, B/D</th>
<th>Estimated Requirements, B/D</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>February</td>
<td>March</td>
</tr>
<tr>
<td>Northwestern Refining Company/St. Paul Park, Minnesota</td>
<td>8,000</td>
<td>4,500</td>
</tr>
<tr>
<td>Imperial Oil Enterprises Ltd./Edmonton, Alberta</td>
<td>5,500</td>
<td>1,600</td>
</tr>
<tr>
<td>Shell Canada Limited/St. Boniface, Manitoba</td>
<td>10,000</td>
<td>7,300</td>
</tr>
<tr>
<td>Corunna, Ontario</td>
<td>2,900</td>
<td>2,800</td>
</tr>
<tr>
<td>Sun Oil Company Ltd./Sarnia, Ontario</td>
<td>10,000</td>
<td>10,000</td>
</tr>
<tr>
<td>Toledo, Ohio</td>
<td>11,657</td>
<td>11,430</td>
</tr>
<tr>
<td>TOTAL</td>
<td>48,057</td>
<td>37,630</td>
</tr>
</tbody>
</table>
SYNCRUDE RELEASES STUDY OF PREHISTORIC BEAVER CREEK QUARRY

A report entitled, "The Beaver Creek Site: A Prehistoric Stone Quarry on Syncrude Lease No. 22," has been released by Syncrude Canada Limited as part of its continuing environmental research series and listed as Environmental Research Monograph 1974-2.

The report explains that the stone quarry or "artifactory" is particularly useful in determining not only the technological advancement of prehistoric people, but in establishing their social structure as well. The type and degree of sophistication of the products manufactured at the site provide insight into the technological adaptability of the culture. Likewise, a knowledge of the quarry products, along with information regarding their occurrence throughout the region, can lead the investigator to an understanding of the prehistoric populations' territorial boundaries. The regional distribution of some products may also indicate that these products were used extensively for trading.

The archeological site on Syncrude Lease No. 22 was originally discovered during an archeological survey conducted in 1973. The results of that survey, contained in Syncrude Report 1973-d, were briefly reviewed on page 3-32 of the March 1974 issue of Synthetic Fuels. The actual excavation of the site required approximately 1,500 man-hours and was conducted between May 4 and July 13, 1974. Because the areal extent of the Beaver Creek quarry is roughly 100,000 square feet, and thus cannot be thoroughly excavated and studied in detail, randomly located, five foot square areas were excavated. The findings at each of the sites were then statistically analyzed to determine the extent and composition of the complete quarry.

Based on the findings at the quarry site, conclusions were drawn, and these in turn led to implications regarding the nature of the occupation of the archeological site. The authors of the report surmised that the Beaver Creek quarry served as "a rudimentary industrial center for groups living in surrounding areas." They also suggested that although the site was used during several periods of time, the major occupation was between 300 and 400 A.D. Furthermore, "the intermittent use of the quarry and the small camp sites upstream from the quarry reflect a 'restricted wandering' pattern characteristic of small historic hunting, fishing, and gathering groups of the Boreal Forest."
The Alberta Provincial government was informed on December 13, 1974, that the Syncrude Project was going to cost at least $2 billion, an increase of $1.2 billion over the previous estimate. Immediately thereafter, the government ordered a probe of Syncrude's past activities and their rationale for the $2 billion estimate. Foster Research Limited of Calgary was contracted to double-check the viability of the Syncrude project. Loram International Ltd., also of Calgary, was assigned to study the cost estimates and determine their accuracy. Price, Waterhouse and Company was to review the accounting and auditing procedures used to date of the project, including the projections which led to the current cost estimates. Finally, Hu Harries & Associates, of Edmonton, was commissioned to study the impact which possible project delays would have on the economy.

All of the reports prepared by the above firms were received by the Alberta government only days before the final decision was made to invest in the project. This led many critics to accuse the government of making a hasty decision without having fully analyzed the information contained in the reports. While certainly a thorough review of all the figures and charts was not possible, just a brief review of the conclusions presented by the reports shows overwhelmingly that all financial statements and projections made by Syncrude Canada Ltd. were accurate, including the projected $2 billion estimate.

Auditors Find Accounting Procedures Legitimate

The results of the Price, Waterhouse and Company study were contained in a 45-page report which detailed all of Syncrude Canada's assets, liabilities, and future commitments. The conclusions which were drawn from the data included the following:

"Subject to receipt of approved financial statements and an auditors' report thereon signed by Peat, Marwick, Mitchell & Co. we report that during the course of our review nothing came to our attention which would indicate that the assets and liabilities of Syncrude Canada Ltd. December 31, 1974 and the receipts and expenditures for the years 1972 through 1974 were not presented fairly except no reference is made to possible additional liabilities which would result if the Syncrude Project were abandoned.

"The total costs of the Syncrude Project to December 31, 1974 are:

<table>
<thead>
<tr>
<th>Description</th>
<th>Amount</th>
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<tbody>
<tr>
<td>Expenditures from inception in 1959 to completion of Phase I on August 31, 1973</td>
<td>$52,941,000</td>
</tr>
<tr>
<td>Phase II-Mildred Lake Plant</td>
<td>$157,575,000</td>
</tr>
<tr>
<td>Utility Plant</td>
<td>$6,907,000</td>
</tr>
<tr>
<td>Housing</td>
<td>$7,547,000</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>$224,970,000</strong></td>
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</table>

"Interest during construction has not been included as a cost of construction. At an interest rate of ten percent, interest on the total investment through 1978 would exceed $500,000,000.

"The Syncrude estimate of $79,600,000 for direct owners costs is not unreasonable, except that no provision has been included for saline water disposal, the cost of which could amount to $30,000,000.

"The working capital allowance included in the Syncrude estimate of $64,400,000 has been calculated in accordance with the provisions of the draft accounting manual which will form part of the definitive agreement between the Syncrude participants and the Province of Alberta.

"The net housing costs provided by Syncrude Canada Ltd. of $16,700,000 for the Mildred Lake Plant and $900,000 for the Utility Plant appear reasonable. However, the project cost estimates do
not include mortgage financing of approximately $100,000,000 through 1978, which will be raised by Northward Developments Ltd.

"Commitments recorded by Syncrude Canada Ltd. at December 31, 1974 of $420,000,000 appear reasonably stated."

The basic conclusions reached by Loram International, Ltd. regarding the cost estimates were contained in a report entitled "Executive Summary of Conclusions and Findings." Some of the conclusions were:

"During the month of January 1975, Loram International Ltd. reviewed the total Syncrude Canada Ltd. estimate for the Mildred Lake Project including Utility Plant and the $2,282,000,000 estimate found to be within acceptable limits.

"The Canadian Bechtel Ltd. estimate for that phase of the work designated as the Mildred Lake Project was submitted by Canadian Bechtel Ltd. and Syncrude Canada Ltd. on November 18, 1974. This estimate totalled $1,559,775,000, including subsequent Syncrude Canada Ltd. adjustments. On the basis of the reviews conducted by Loram and its consultant, Fluor, this estimate can be regarded as a reliable assessment of the capital cost of the Mildred Lake Project as estimated in November 1974.

"The July 1973 Appropriation of $960,000,000 has been reviewed in light of the Syncrude Canada Ltd. estimate of $2,048,000,000. Although it is not possible to completely reconcile the two estimates, it can be shown there are justifiable reasons for the increase in cost. It is primarily attributable to three factors:

(i) severe and unanticipated escalation
(ii) additional preproduction costs due to increases in duration of the project and manpower requirements, and
(iii) estimate growth as the engineering definition of the project advanced.

"No evidence has been found to suggest the July 1973 appropriation estimate was improperly understated or, likewise, the December 1974 estimate has been unduly inflated.

"The escalation used to develop the capital cost of this project was found to be within acceptable limits. Loram has examined the projected rates and the manner they were applied, and have concluded that the allowances applied were reasonable at the time."

Firm Establishes Economic Viability

The results of the study performed by Foster Research Limited are contained in a six-page summary submitted to the Alberta government and subsequently tabled (made public) in the legislature. The economic viability of the Syncrude project was examined using an economic model based on a variety of assumptions. Crude oil price at the plant gate was assumed to be $15.45 per barrel in 1978 increasing to $35 per barrel by 2003. It was also assumed that initial production in 1978 would be approximately 13,000 BPD but would increase to 129,000 by 1985. The report stated that the production rates, operating costs, and capital costs using the analysis were from the January 1975 Syncrude Task Force evaluation conducted by Alberta. Furthermore, all calculations were based on conditions established by the 1973 Letter of Agreement (see Synthetic Fuels, December 1973, page 3-22) by which Alberta was to receive 50 percent of all profits after initial capital costs were recouped. The various options which Alberta could exercise according to the Letter of Agreement were not considered to be active.

Table 1 summarizes the financial status projected for the Syncrude project by Foster Research. According to these estimates, the province of Alberta would begin earning profits as early as 1981. By 2003 their share would amount to about $345 million per year. Throughout the 25-year lifetime of the project, Alberta would earn a total of over $4 billion.

3-22
TABLE 1
PROJECTED FINANCIAL STATUS OF SYNCRUDE PROJECT

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<tr>
<td>Crude Price @ Plant Gate ($/bbl.)</td>
<td>13.70</td>
<td>13.70</td>
<td>13.70</td>
<td>14.00</td>
<td>15.00</td>
<td>16.10</td>
<td>17.30</td>
<td>18.65</td>
<td>20.60</td>
<td>22.70</td>
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<tr>
<td>Estimated Production (Mbbls./d.)</td>
<td>51.5</td>
<td>92.8</td>
<td>108.3</td>
<td>108.3</td>
<td>123.7</td>
<td>128.9</td>
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<tr>
<td>Revenue</td>
<td>257.5</td>
<td>546.0</td>
<td>553.4</td>
<td>553.4</td>
<td>577.3</td>
<td>577.3</td>
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<td>Operating Costs</td>
<td>233.4</td>
<td>265.7</td>
<td>272.2</td>
<td>272.2</td>
<td>310.1</td>
<td>341.8</td>
<td>373.5</td>
<td>410.7</td>
<td>455.3</td>
<td>496.3</td>
<td>545.5</td>
<td>596.6</td>
<td>651.7</td>
<td>718.3</td>
<td>757.2</td>
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<td>Amortization of Capital Costs</td>
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<tr>
<td>Capital Costs</td>
<td>121.1</td>
<td>118.5</td>
<td>115.6</td>
<td>112.8</td>
<td>110.0</td>
<td>104.4</td>
<td>97.6</td>
<td>85.3</td>
<td>71.5</td>
<td>61.3</td>
<td>52.3</td>
<td>41.2</td>
<td>29.3</td>
<td>21.7</td>
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<tr>
<td>Total Allowed Costs</td>
<td>353.5</td>
<td>371.2</td>
<td>387.8</td>
<td>400.1</td>
<td>434.2</td>
<td>563.5</td>
<td>593.1</td>
<td>624.4</td>
<td>665.0</td>
<td>706.6</td>
<td>742.6</td>
<td>780.2</td>
<td>827.5</td>
<td>876.6</td>
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<tr>
<td>Profit (Loss)</td>
<td>(96.0)</td>
<td>90.9</td>
<td>153.7</td>
<td>153.7</td>
<td>143.0</td>
<td>194.0</td>
<td>220.9</td>
<td>253.1</td>
<td>304.2</td>
<td>367.4</td>
<td>436.0</td>
<td>504.2</td>
<td>582.4</td>
<td>661.0</td>
<td>690.9</td>
<td></td>
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<td></td>
<td></td>
</tr>
<tr>
<td>Loss Carry Forward</td>
<td>(96.0)</td>
<td>51.1</td>
<td></td>
<td></td>
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<td></td>
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<td></td>
<td></td>
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<td></td>
<td></td>
</tr>
<tr>
<td>Profits to be shared</td>
<td>148.6</td>
<td>153.3</td>
<td>143.0</td>
<td>194.0</td>
<td>220.9</td>
<td>253.1</td>
<td>304.2</td>
<td>367.4</td>
<td>436.0</td>
<td>504.2</td>
<td>582.4</td>
<td>651.0</td>
<td>690.9</td>
<td></td>
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<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Alberta’s share (50%)</td>
<td>74.3</td>
<td>76.7</td>
<td>71.5</td>
<td>97.0</td>
<td>110.4</td>
<td>126.5</td>
<td>151.2</td>
<td>180.6</td>
<td>231.2</td>
<td>291.2</td>
<td>325.5</td>
<td>345.4</td>
<td></td>
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<td></td>
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<td></td>
</tr>
</tbody>
</table>

NOTES
1. Capital costs included all Syncrude capital costs incurred after February 23, 1972. The first production of synthetic crude oil is expected in 1978, with capacity production of 128,900 barrels per calendar day projected to be achieved in 1985.
2. The interest allowance is at the rate of 8% on 75% of capital employed. Capital employed does not include any interest cost during construction.
3. Capital costs to be amortized, include all pre-production costs (net after deduction of pre-production revenue) and capital expenditures plus $90 million allowed for interest costs during construction (working capital is excluded).

Alberta Will Make More Profit Than Industry

The above estimates do not take into account the recent investments by the federal and provincial governments. Therefore, the Foster Report considered that the Syncrude partners would earn a profit equal to that of Alberta. Considering that other government partners are now involved and Alberta still holds the options guaranteed by the 1973 Letter of Agreement the Syncrude partners share of the profits will be decreased substantially. In fact, if the Alberta options are exercised, the industrial participants will be left with only 15.3 percent of the pre-tax profits. Thus, instead of earning $345 million per year in 2003, the Syncrude partners will be left with only $108 million. An analysis of the Syncrude profit distribution may be found on page 3-23 of the March 1975 issue of Synthetic Fuels.

Another analysis conducted by Foster Research dealt with the price which must be received for the synthetic crude oil product in order for the project to "break even" over the life of the plant. That is, "by the year 2003 Syncrude should have received total revenues such that deducting all cash costs (inclusive

TABLE 2
PROJECTED "BREAK-EVEN" VALUE OF SYNCRUDE PRODUCT

|------|------|------|------|------|------|------|------|------|------|------|------|------|------|------|------|------|------|------|------|------|------|------|------|------|------|

CAMERON ENGINEERS, INC. 3-23
of capital costs) the resultant total net cash flow would be zero." The necessary market prices are shown in Table 2.

The Foster Report certainly makes the Syncrude project appear to be a highly profitable operation. This must certainly have been how the province of Alberta interpreted it also, because less than one week after receiving this report, they contributed $400 million to the project ($200 in the form of a loan to the individual industrial participants). Some of the assumptions made in the analyses are no longer valid and others are questionable. However, now that the project is proceeding, time will tell whether Foster's predictions of economic viability were accurate.

# # # #
INDIAN WATER RIGHTS IN THE TONGUE RIVER BASIN MONTANA

Two complaints have been filed in the United States District court for the District of Montana seeking an adjudication of the rights of the Northern Cheyenne Indian Tribe, the Crow Indian Tribe, and the United States to water in the Tongue River and Rosebud Creek. This litigation arose as several corporations, water users associations, and numerous individuals are seeking rights to water from these sources, primarily for stock watering and industrial purposes; also, the Crow and Northern Cheyenne Indian Tribes and the United States claim priority rights to the water through treaties, executive orders, and acts of Congress. The following summaries describe the complaints.

Plaintiff: Northern Cheyenne Tribe

The defendants named in this complaint, No. 75-6-BLG, dated January 30, 1975, are the Tongue River Water Users Association and various individuals. The plaintiff is asking the court to declare title to the Northern Cheyenne Tribe to the use of all water from the Tongue River and Rosebud Creek that is and will be needed for the development of the reservation with a priority date of May 10, 1868. The claim to this water arises under the Treaty of the United States with the Northern Cheyenne and Northern Arapahoe Tribes of May 10, 1868, and under Executive Orders of November 26, 1884, and of March 19, 1900.

Plaintiff: United States of America

The defendants named in this complaint, No. 75-20-BLG, dated March 7, 1975, are the Tongue River Water Users Association, Montana Water Storage Company, Water Reserve Company of Montana, Gulf Oil Corporation and various individuals. The plaintiff, in this case, is asking the court to require that all defendants appear before the court and explain their individual claims to water in the Tongue River and Rosebud Creek within the state of Montana.

The plaintiff is requesting that the court declare that the United States as a fiduciary holds for the benefit of the Northern Cheyenne and Crow Indian Tribes rights to all water in the Tongue River and Rosebud Creek that will be reasonably needed for the development of the reservations. The Crow Tribe claims water only from Rosebud Creek with a priority date of May 7, 1868, the date of the treaty setting aside the Crow Reservation. The Northern Cheyenne Tribe claims water from Rosebud Creek with a priority date of November 26, 1884, the date of the Executive Order setting aside that portion of the Northern Cheyenne Reservation surrounding the drainage of Rosebud Creek. The Northern Cheyenne Tribe also claims water from the Tongue River with a priority date of March 19, 1900, the date of the Executive Order setting aside an additional portion of the Northern Cheyenne Reservation whose eastern boundary extends to the middle of the Tongue River. The United States also claims water from the Tongue River for use in Custer National Forest and on the Livestock Experiment Station, both adjacent to the Tongue River.

The language of the various treaties and executive orders surrounding these two complaints is rather clear in its intention to provide adequate water from these sources for the needs and development of the reservations. No final decision from the court has been forthcoming.

WATER FOR ENERGY IN THE UPPER MISSOURI RIVER BASIN

Water from the Upper Missouri River Basin is needed in the development of the economic potential of the 63 counties of Wyoming, Montana and North and South Dakota that make up the basin drainage area. Figure 1 describes the boundary of the Upper Missouri River Basin. Within the UM basin lies potential coal and agricultural development alternatives that must be integrated with an orderly and deliberate use of the available resources.
Missouri main stem and tributary waters. The acquisition of water from the main stem or existing and proposed impoundments in the UM basin is a function of basin flow allotments to the various states by UM basin river compacts, and the availability within the states. The disposition of water has long been a point of contention between the states, the federal government, industrial and agricultural sectors, private individuals, and foreign governments. In an attempt to define the allocation of water, several water compacts between states in this region have been signed. Litigation surrounding the compacts and various state and federal water laws has slowed the development of available water for both public and private uses.

The identification of water quantity and quality is an ongoing task for state, federal, and private study groups. One of the more comprehensive studies of water in the UM basin is being done by the Northern Great Plains Resources Program (see Figure 1). More recently, the Department of the Interior under the direction of the Assistant Secretary for Land and Water, established the Water for Energy Management Team to compile all available information concerning the disposition of water in selected river basins. The team's effort in the UM basin is reported in "Water for Energy in the Northern Great Plains Area With Emphasis on the Yellowstone River Basin," dated January 1975.

**Water Compacts, Laws, and Pending Litigation**

Wyoming, Montana, and North Dakota formed the Yellowstone River Compact under the Act of October 30, 1951. The compact confirms existing water rights as of January 1, 1950, and provides for the allocation of unappropriated water, as of the same date, from the interstate tributaries of the Yellowstone River according to the following schedule:
North Dakota, though not apportioned water from the Yellowstone River, is assured existing rights at the time of signature. The compact also provides for the development of water in one state to be used in another; the importing of water into the Yellowstone Basin; the exporting of water from the basin with unanimous consent of the compacting states; and that the compact will not adversely affect Indian water rights.

The Belle Forche Compact between the states of Wyoming and South Dakota apportions 90 percent of the Belle Forche River flow to South Dakota and ten percent to Wyoming. The compact was signed on February 26, 1944, and establishes rights similar to those covered by the Yellowstone Compact. These are the only two water compacts at this time.

The Flood Control Act of 1944, among other things, established the Pick-Sloan Missouri Basin Program (P-SMBP), under which is authorized Missouri main stem impoundments, diversion, and hydroelectric generation projects. The P-SMBP gives the federal government the right to control non-program diversions by states on the grounds that they will limit "federal" main stem water as needed for the P-SMBP. The Flood Control Act of 1944 allows federal main stem impoundment of three times the average annual Missouri River flow at Sioux City, Iowa. The states argue that water rights may only accrue to the federal government after the water has been impounded and put to a beneficial use. The language of the Flood Control Act of 1944 is far reaching and is under heavy debate.

The state of Wyoming allocates water by issuing a permit upon approval of an application submitted to the state engineer. The date of priority is established by the State Engineer when the application is deemed complete and the water use is established to be beneficial. Upon approval of the permit, times are established by the State Engineer for starting and completing diversion facility construction. Once the water has been appropriated and put to beneficial use, the State Board of Control will adjudicate the water right and issue a Certificate of Appropriation. Wyoming has provided for the change of use of water under certain conditions and for the use of groundwater under a permit system.

Montana is also under a permit system of water use rights since the passage of the Montana Water Use Act of 1973. Application is made to the Montana Department of Natural Resources and Conservation and, upon approval, a permit is granted. After the water has been appropriated and put to beneficial use, the Department issues a certificate of water use rights. Certificates are not issued in areas where existing water rights have not been adjudicated. This is a significant point because prior to the 1973 act (mentioned above), no set policy of water right determination was in force. As a result in many areas the Department is attempting to determine existing rights. As in Wyoming, change of use of water is possible upon approval. Groundwater may be acquired under a similar system. Since 1974, a 3-year moratorium has been in effect on diversions greater than 20 cubic feet per second or 14,000 AFY from the Yellowstone River basin due to pending adjudication of prior rights.

North Dakota appropriates water in much the same way as Wyoming and Montana with a permit system recognizing priority rights, with distribution of water handled by the North Dakota State Water Commission, and adjudication of water rights by the State Engineer.

Two cases pending in the Montana Federal District Court have a direct bearing on the use of water for energy development: Environmental Defense Fund vs. United States, Civil #1220, and Intake Water Company vs. Yellowstone River Compact Commission, Civil #1184. No. 1220 challenges the authority of the Bureau of Reclamation to sell water for industrial uses from Boysen and Bighorn...
Reservoirs on environmental and statutory grounds. No. 1184 challenges the constitutionality of the restrictions placed by the Yellowstone River Compact on the interbasin transfer of water.

In nearly all cases, Indian water rights came into being when a reservation was created whether by treaty, by act of Congress, or by Executive Order and are geographically related to lands within the reservation. Presently the rights of the Crow and Northern Cheyenne nations to water in the Bighorn River is being litigated to determine the extent of Indian apportionment.

Surface Water Supply

The supply of water in the UM basin may be defined in terms of the following four subbasins.

<table>
<thead>
<tr>
<th>SUBBASIN OR TRIBUTARY</th>
<th>Drainage Area Sq. Mi.</th>
<th>Instantaneous</th>
<th>Annual</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Maximum ft³/s</td>
<td>Minimum ft³/s</td>
<td>Average ft³/s</td>
</tr>
<tr>
<td>Upper Missouri River</td>
<td>314,600</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>(At Sioux City, Iowa)</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Upper Missouri River</td>
<td>243,500</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>(At Oahe Dam)</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Eastern Dakota Tributaries</td>
<td>58,300</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Western Dakota Tributaries:</td>
<td>77,100</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Cheyenne River</td>
<td>12,800</td>
<td>46,300</td>
<td>1</td>
</tr>
<tr>
<td>Belle Fourche River</td>
<td>5,870</td>
<td>17,900</td>
<td>0</td>
</tr>
<tr>
<td>Moreau River</td>
<td>5,700</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Grand River</td>
<td>2,390</td>
<td>15,000</td>
<td>0</td>
</tr>
<tr>
<td>Cannonball River</td>
<td>4,310</td>
<td>94,800</td>
<td>0</td>
</tr>
<tr>
<td>Heart River</td>
<td>3,310</td>
<td>30,500</td>
<td>0</td>
</tr>
<tr>
<td>Knife River</td>
<td>2,507</td>
<td>35,300</td>
<td>0</td>
</tr>
<tr>
<td>Little Missouri River</td>
<td>8,500</td>
<td>65,000</td>
<td>0</td>
</tr>
</tbody>
</table>

Flow data, withstanding total UM basin consumptive depletions of about 6.5 AFY (1970), within the UM basin in terms of these subbasins is presented in Table 1. Maximum and minimum
annual flows for the main stem of the Missouri River and the Bighorn River as well as instantaneous flows are irrelevant due to flow control through storage facilities. Annual maximum and minimum flows for some Western Dakota Tributaries are not available. The Missouri River flows at Sioux City, Iowa, are considered to be a good approximation of the total UM basin flow. All flows in the Missouri River originating above the Oahe Dam are considered possible sources of water for use in energy development. The Yellowstone River subbasin accounts for about one half of these flows. Therefore, emphasis is placed on the Yellowstone River Subbasin. A rough estimate of 5.2 million AFY is needed as flow through in the Yellowstone River Subbasin to maintain the existing ecosystem. This quantity of water is approximately 60 percent of the total Yellowstone River average annual flow of 8.8 million AFY, withstanding consumptive depletions at 1970 water development levels. This indicates about 3.6 million AFY yet available at maximum water use in the Yellowstone Subbasin. Table 2 delineates the allocation of flows by interstate water compacts. Table 3 summarizes existing major storage facilities in the Northern Great Plains Area. The Missouri River Basin Comprehensive Framework Study contributed data found in Tables 1 through 3.

Groundwater Supply

Two aquifer systems of significance exist within the UM basin. The two systems individually consist of a grouping of formations which vary in thickness, porosity, and depth below ground surface. The water bearing systems are known as the "Shallow Aquifers" and the "Madison Aquifer" with the following geologic formations within each system:

Shallow Aquifers: Fort Union Formation (includes coalbeds and sandstone); Hell Creek Formation; Fox Hills Sandstone Formation; Wasatch Formation; and alluvium along major rivers and their principal tributaries and in buried preglacial valleys.

Madison Aquifer: Madison Limestone Formation; Minnelusa Formation; Tensleep Sandstone Formation; and associated underlying carbonate formations.

The Shallow Aquifers have an aggregate thickness between 4,000-6,000 feet and

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Yellowstone River</td>
<td>Powder River</td>
<td>416,000</td>
<td>287,300</td>
<td>120,700</td>
</tr>
<tr>
<td></td>
<td>Tongue River</td>
<td>304,000</td>
<td>241,100</td>
<td>96,400</td>
</tr>
<tr>
<td></td>
<td>Big Horn River</td>
<td>2,500,000</td>
<td>2,100,000</td>
<td>1,800,000</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td>to (2,300,000)</td>
</tr>
<tr>
<td></td>
<td>Clarks Fork</td>
<td>767,000</td>
<td>714,000</td>
<td>429,000</td>
</tr>
<tr>
<td></td>
<td>Belle Fourche River</td>
<td>184,000</td>
<td>87,000</td>
<td>7,300</td>
</tr>
</tbody>
</table>

¹ Historic Average Annual Flow Adjusted to the 1970 level of Development - Table 1
TABLE 3
EXISTING MAJOR RESERVOIRS AFFECTING STREAMFLOWS
IN THE NORTHERN GREAT PLAINS AREA

<table>
<thead>
<tr>
<th>Stream</th>
<th>Reservoir</th>
<th>Storage in Thousand Acre-Feet</th>
<th>Uses</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>Inactive and Dead</td>
<td>Active</td>
</tr>
<tr>
<td>Missouri</td>
<td></td>
<td>4,300</td>
<td>10,900</td>
</tr>
<tr>
<td></td>
<td>Fort Peck</td>
<td>5,000</td>
<td>13,400</td>
</tr>
<tr>
<td></td>
<td>Lake Sakakawea</td>
<td>5,500</td>
<td>13,700</td>
</tr>
<tr>
<td>Milk</td>
<td>Nelson</td>
<td>18.7</td>
<td>66.8</td>
</tr>
<tr>
<td>Clarks Fork</td>
<td>Cooney</td>
<td>0</td>
<td>24.4</td>
</tr>
<tr>
<td>Wind-Bighorn</td>
<td>Bull Lake</td>
<td>0.7</td>
<td>151.8</td>
</tr>
<tr>
<td></td>
<td>Pilot Butte</td>
<td>5.4</td>
<td>31.5</td>
</tr>
<tr>
<td></td>
<td>Boyesen</td>
<td>252.1</td>
<td>549.9</td>
</tr>
<tr>
<td></td>
<td>Buffalo Bill</td>
<td>48.2</td>
<td>373.1</td>
</tr>
<tr>
<td></td>
<td>Bighorn</td>
<td>502.3</td>
<td>613.7</td>
</tr>
<tr>
<td></td>
<td>Upper Sunshine</td>
<td>1.0</td>
<td>52.0</td>
</tr>
<tr>
<td></td>
<td>Lower Sunshine</td>
<td>1.9</td>
<td>54.9</td>
</tr>
<tr>
<td>Powder</td>
<td>Lake DeSmet</td>
<td>0</td>
<td>239.0</td>
</tr>
<tr>
<td>Tongue</td>
<td>Tongue</td>
<td>5.9</td>
<td>68.0</td>
</tr>
<tr>
<td>Heart</td>
<td>Dickinson</td>
<td>1.2</td>
<td>5.5</td>
</tr>
<tr>
<td></td>
<td>Heart Butte</td>
<td>6.8</td>
<td>69.0</td>
</tr>
<tr>
<td>Grand</td>
<td>Bowman-Haley</td>
<td>4.3</td>
<td>15.8</td>
</tr>
<tr>
<td></td>
<td>Shadehill</td>
<td>58.2</td>
<td>30.0</td>
</tr>
</tbody>
</table>

R - Recreation (includes Fish & Wildlife), FC - Flood Control, Irr. - Irrigation, N - Navigation, P - Power, M - Municipal, I - Industrial, S - Stockwater, D - Domestic

are found at depths ranging from surface outcrops to 8,000 feet below land surface. That portion of this system capable of yielding substantial quantities of water ranges in thickness between several hundred to several thousand feet. A deep well (1,000 to 5,000 feet) open to all sandstone and coalbed formations, to well depth, in the system may yield up to 500 gpm as indicated by USGS data. Some existing wells less than 100 feet in alluvium yield up to 50 gpm for irrigation purposes. Most existing wells tap the Shallow Aquifers at depths less than 300 feet and draw up to 50 gpm for stock watering. This system is found primarily within the Northern Great Plains Study Area with the exception of the Bighorn Mountain and Black Hills areas where older geologic formations outcrop.

The Madison Aquifer underlies the Shallow Aquifer at depths of 4,000-6,000 feet below sea level in much of southeastern Montana and up to 10,000 feet below sea level in the southern portion of the Powder River Basin. This system may have the potential of producing up to 2,000 gpm from wells ranging in depth from 5,000 to 15,000 feet below ground surface. This system is found throughout the Northern Great Plains Study Area with the same exceptions as the Shallow Aquifer system. This system must be considered only potential as much investigation is yet required to prove it's production capacity. Of geologic and hydrologic importance is the presence of a low porosity shale bed between the Shallow and Madison Aquifer systems.

Surface mining of coal with pit depths up to 200 feet may intercept local portions of the Shallow Aquifer system and cause lower yields from surrounding irrigation and stock.
watering wells up to four miles away. There is no indication that these wells would be permanently destroyed; however, an increase in well depth may be required to maintain their yields.

Major Contracts for Industrial Water

Option contracts for industrial water, primarily from existing and proposed federal impoundments but also including state waters, have been executed for 712,000 AFY in the UM basin as shown by the company and impoundment in Table 4. An option contract reserves a quantity of water for a certain period of time but does not establish or transfer use rights. Though no options have been converted to an active status, a potential for use is certainly indicated. Of the total 712,000 AFY, 450,000 AFY may be designated for use in Wyoming with the remaining 232,000 AFY for Montana. Application for an additional 3,083,000 AFY has been filed as shown in Table 5 by supply source and area of use. The availability of water in many areas of the UM basin can not meet the quantity applied for. Of major concern in the appropriation of water are the instream needs which ultimately establish the limit to consumptive water use.

Projected energy development and corresponding water requirements in the UM basin were published in the Draft Northern Great Plains Resources Program Report and reviewed in the December, 1974 issue of Synthetic Fuels on page 4-27.

Water Distribution Potentials

The distribution of water between subbasins within the UM basin remains a potential solution to inadequate water availability in areas of expanded coal production. The cost of construction and operation of interbasin aqueducts is certainly a constraint to the development of such distribution systems but other constraints exist; not the least of which is the Yellowstone River Compact. The Compact is clear on the subject of interbasin transfers. One specific case is the transfer of

### Table 4

<table>
<thead>
<tr>
<th>Contractor</th>
<th>Expected Area of Use</th>
<th>Contractor</th>
<th>Expected Area of Use</th>
</tr>
</thead>
<tbody>
<tr>
<td>Yellowtail Unit</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>(Bighorn Lake)</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Kerr-McGee Corp.</td>
<td>50</td>
<td>50</td>
<td></td>
</tr>
<tr>
<td>Shell Oil Company</td>
<td>28</td>
<td>28</td>
<td></td>
</tr>
<tr>
<td>Exxon Corporation</td>
<td>50</td>
<td>50</td>
<td></td>
</tr>
<tr>
<td>Peabody Coal Co.</td>
<td>40</td>
<td>40</td>
<td></td>
</tr>
<tr>
<td>Reynolds Mining Co.</td>
<td>50</td>
<td>50</td>
<td></td>
</tr>
<tr>
<td>John S. Wahl</td>
<td>50</td>
<td>50</td>
<td></td>
</tr>
<tr>
<td>Gulf Oil Corporation</td>
<td>25</td>
<td>25</td>
<td></td>
</tr>
<tr>
<td>Shell Oil Corporation</td>
<td>50</td>
<td>50</td>
<td></td>
</tr>
<tr>
<td>Colorado Interstate Gas Co.</td>
<td>40</td>
<td>40</td>
<td></td>
</tr>
<tr>
<td>Ayrshire Coal Co.</td>
<td>30</td>
<td>30</td>
<td></td>
</tr>
<tr>
<td>Panhandle Eastern Pipeline Co.</td>
<td>30</td>
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<td></td>
</tr>
<tr>
<td>Shell Oil Company</td>
<td>20</td>
<td>20</td>
<td></td>
</tr>
<tr>
<td>Norwesury and Rege, Inc.</td>
<td>50</td>
<td>50</td>
<td></td>
</tr>
<tr>
<td>Phillips Petroleum Co.</td>
<td>50</td>
<td>50</td>
<td></td>
</tr>
<tr>
<td>Contracted for use on Ceded Lands</td>
<td>30</td>
<td>30</td>
<td></td>
</tr>
<tr>
<td>Subtotal</td>
<td>365</td>
<td>118</td>
<td>110</td>
</tr>
<tr>
<td>Boysen Basin</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>(Boysen Reservoir)</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Sun Oil Company</td>
<td>35</td>
<td>35</td>
<td></td>
</tr>
<tr>
<td>Mobil Oil Corporation</td>
<td>50</td>
<td>50</td>
<td></td>
</tr>
<tr>
<td>Subtotal</td>
<td>85</td>
<td>85</td>
<td></td>
</tr>
<tr>
<td>State of Montana</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Tongue River Reservoir</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>(Montana Power Co.)</td>
<td>4</td>
<td>4</td>
<td>4</td>
</tr>
<tr>
<td>TOTAL</td>
<td>450</td>
<td>122</td>
<td>110</td>
</tr>
</tbody>
</table>

1 Contracts written by the Bureau of Reclamation.
2 The 30,000 acre-feet annually available under this contract was heretofore reserved for irrigation on the Crow Indian Reservation. It is to be used exclusively for coal resource development on ceded lands adjacent to the Crow Indian Reservation in Montana.
3 Final execution pending questions relating to Indian water rights.
Displacement of water from the Bighorn River downstream from Bighorn Lake. Waters to be transferred would be released from Bighorn Lake but left in the river system as long as possible.

Displacement of water from the Yellowstone River between the points of confluence of the Yellowstone with the Tongue and Powder Rivers.

Displacement of water directly from Boysen Reservoir on the Wind River.

Case No. 2 is the most environmentally sound, in that it allows the flows in the UM basin and subbasins to remain in their respective river courses throughout the entire UM system prior to diversion. Case No. 3 assumes a trans-divide displacement of a portion of Wyoming's Upper Colorado River allotment. The point to be made is that there are potential solutions to the allocation of water for energy development.
### TABLE 5
#### OCTOBER 1974
#### UPPER MISSOURI RIVER BASIN
#### ADDITIONAL APPLICATIONS FOR WATER
(In 1,000's of Acre-feet)

<table>
<thead>
<tr>
<th>Unit or river supply system</th>
<th>Wyoming</th>
<th>Montana Non-Indian</th>
<th>Montana Indian</th>
<th>North Dakota</th>
<th>Unknown</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>Yellowstone Unit (Bighorn Lake)</td>
<td>80</td>
<td>352</td>
<td>70</td>
<td></td>
<td></td>
<td>502</td>
</tr>
<tr>
<td>Boysen Unit (Boysen Reservoir)</td>
<td>9</td>
<td>9</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Wind Bighorn-Yellowstone River system</td>
<td>330</td>
<td>670</td>
<td>20</td>
<td>1,020</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Fort Peck</td>
<td>749</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>799</td>
</tr>
<tr>
<td>Garrison Reservoir (Lake Sakakawea)</td>
<td></td>
<td>251</td>
<td></td>
<td></td>
<td></td>
<td>310</td>
</tr>
<tr>
<td>Oahe Reservoir</td>
<td></td>
<td></td>
<td>125</td>
<td>125</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Heart Butte Unit (Lake Tschida ND)</td>
<td></td>
<td>18</td>
<td></td>
<td></td>
<td>18</td>
<td></td>
</tr>
<tr>
<td>Moorhead Reservoir (potential)</td>
<td>50</td>
<td>75</td>
<td>95</td>
<td>220</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Beaver Creek (Little Missouri River, MT)</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>36</td>
<td>36</td>
</tr>
<tr>
<td>Shadehill Reservoir (SD)</td>
<td>19</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>19</td>
</tr>
<tr>
<td>Square Butte Creek (ND)</td>
<td>2</td>
<td></td>
<td></td>
<td></td>
<td>2</td>
<td></td>
</tr>
<tr>
<td>Knife River (ND)</td>
<td></td>
<td></td>
<td>23</td>
<td></td>
<td></td>
<td>23</td>
</tr>
<tr>
<td><strong>TOTAL</strong></td>
<td>488</td>
<td>1,846</td>
<td>70</td>
<td>353</td>
<td>326</td>
<td>3,083</td>
</tr>
</tbody>
</table>

#### TENNECO AFFILIATE SUES UTAH INTERNATIONAL

District Judge Jack Shanstrom, Livingston, Montana, has been designated to preside over a lawsuit filed by Intake Water Company over water rights in the Powder River in Wyoming and Montana. In the state court suit filed March 6 in Helena, Intake, a subsidiary of Tenneco, Inc., named the Montana Board of Natural Resources and Conservation, its individual members; the Montana Department of Natural Resources and Conservation, department director Gary J. Wicks and Utah International, Inc. (UII), defendants.

Intake claims the state agencies improperly assigned UII a water use permit for 139,410 acre feet of water in the Powder River. Intake claims it has prior right to the water in Montana although UII filed first in Wyoming. Intake filed for water in the river under the Yellowstone River Compact with the state of Montana on September 27, 1974.

UII filed for the water in Wyoming on December 4, 1973, but did not file in Montana until January 14, 1975. The Montana authorities accepted UII's Wyoming filing date as prior in time, thus putting Intake's claims behind those of UII. Under the compact the two states share water in the stream. Intake claims the Montana action was illegal and administrative efforts to correct the situation have been futile. The board replied it is not entitled by law to set priority dates and hasn't done so. The department asserts Intake has yet to properly protest the matter administratively. They both ask the case be dismissed. Judge Shanstrom was assigned the litigation after disqualification of two earlier judges.

UII plans to use the water in its Fence Creek, Wyoming, Project. Fence Creek is tributary to the Powder River. Intake desires 318,700 acre feet of water for a reservoir near Moorhead, Montana, which would back water up in the Powder River into Wyoming.

Tenneco and UII both have coal holdings in the area and consider water vital for their developments, including possible coal gasification plants.

#### WATER DEVELOPMENT FOR NORTH DAKOTA'S WEST AREA LIGNITE REGION DESCRIBED

The significance of water from the Missouri River for coal conversion is graphically illustrated in the North Dakota State Water Commission's West River Area Diversion study. The comprehensive report was completed at a cost of $298,818 in state funds and is the subject of a series of public meetings in May and June called by the commission in the 14,349 square mile
area south and west of the Missouri River. Lignite reserves in the area in seams five feet or more thick and with 1,000 feet or less overburden total more than 11 billion tons.

The report tabulates the possible available water for municipal, industrial, agricultural and electric power generating purposes along with their benefit-cost ratios and the possible fiscal impact on population and business volume.

Maximum water development without diversion would yield 732,903 acre feet of water in support of seven coal conversion plants, in the Knife, Heart, and Little Missouri River basins. The Missouri itself could supply three more coal conversion facilities with water from Lake Sakakawea.

The study assigns synfuels production of 250 million cubic feet of gas daily to the plants. It also concludes that the arbitrary allocation of water solely for a dominant use--industry--is unlikely. Water development will be for a combination of industrial, recreational, municipal and agricultural purposes. Diversion of water only for agriculture is not economically feasible, according to the report.

Nineteen possible water developments without diversion from Lake Sakakawea were analyzed. Five of them are now in existence. Of the 732,903 acre feet developable, 346,114 acre feet could be allocated for coal conversion at a cost of about $41.8 million (1973 dollars).

The commission concluded that three coal conversion plants could be built on the lake shore without water being diverted to other uses. Descriptions of each of the selected water developments cites flood control benefits, power generation potential and computes benefit-cost ratios using interest rates ranging from four percent to 8.5 percent.

The report investigators examining water development with diversion analyzed a total of 75 existing and potential dam sites and selected 19 as feasible for study. Combinations of individual water development sites resulted in 120 different potential water diversion plans, each of which became the basis for a multi-level development analysis.

Diversion plans could lead to from three to ten coal conversion plants in the Knife River basin; two to six plants in the Heart River area; two to seven in the Cannonball River basin; two to eight in the Little Missouri River basin, and one or none in the Grand River, depending on which combination of projects was selected.

In addition, up to ten coal conversion plants could be sited for direct use of Missouri River water. The maximum diversion analyzed brought 1.2 million acre feet of water annually from the lake by pipeline or 1.5 million acre feet for the more water consumptive, but cheaper, canal system.

The water would irrigate 284,498 acres, supply 28 conversion plants, and generate 31,000 megawatts of electric power as well as allocate 38,093 acre feet of water for municipal use. Development costs would top $800 million.

The projects examined were those yielding the highest benefit-cost ratios.

Coal conversion projects could bring 92,720 persons to the West River area, without diversion and up to 398,427 with maximum diversion, the study predicted. The lengthy report of some 600 pages including socio-economic and communications studies, does not provide a timetable for development in the 14-county area.

The report concludes a combination of agricultural-industrial development is most likely. Imminent water development should be as flexible as possible for eventual inclusion in more comprehensive projects.
Without diversion, gross business volume could increase by $636 million a year; employment could leap by 37,840 jobs, and overall population increase by 102,500 persons.

The upper level of development with diversion could mean an additional 309,000 irrigated acres, 42,600 acre feet of water for municipal use, and industrial water capable of supplying 32 coal conversion plants. Business volume could leap to $3 billion annually with comparable increases in employment of 165,000 persons and overall population by 447,000. The report recommends the North Dakota Legislature authorize the 14-county area jurisdiction to create a legal entity with powers of taxation, development proposal control, and authority to operate and maintain a comprehensive water diversion system. It warns that several development plans are now on file and, if developed piecemeal without regard for possible future events, could result in unnecessary expense.

Environmental impacts, other than on land and wildlife, are generally omitted. But it is noted there is great local concern on changes in lifestyle resulting from water and development, lignite mining, and possible coal conversion plants.

The study, considered with the 1973 report on lignite utilization in the West River area by Dean Alan G. Fletcher, director of the Engineering Experiment Station at the University of North Dakota, Grand Forks, provides a baseline of data on what the future may hold for the now essentially rural area.

Fletcher estimates ten million tons of lignite are required for a 250 SCFD gasification plant. A plant would employ 300 to 800 persons depending upon the process used, about eight times as many people as an electric power generating station using the same amount of lignite.

Each plant, by Fletcher's estimate, would increase the population by 3,000 to 6,000 persons. The lignite is characterized as having 31 to 45 percent moisture; 23 to 33 percent volatile matter; 24 to 34 percent fixed carbon; four to ten percent ash; 0.7 to 1.8 percent sulfur and a heating range of from 5,600 to 7,700 BTU.

The report estimates 1,000 square miles of the area would be disturbed by surface mining operations if the most easily reached lignites were mined.

EL PASO WITHDRAWS NORTH DAKOTA WATER APPLICATION

El Paso Natural Gas Company withdrew an application filed with the North Dakota Water Commission for 72,000 AFY from Lake Sakakawea in March 1975, after being requested by the Commission to present project details and plans for the use of the water. The water is being requested for a proposed four-plant lignite gasification project in Stark, Bowman, and Dunn Counties, North Dakota.

El Paso indicated that the information required by the Commission to allow a proper and detailed evaluation of the water use and overall environmental compatibility of the project has not been assembled and a definite time schedule for completion of the studies has not been set. The Commission stated that the application is incomplete because of lack of project information and, therefore, unacceptable. The Commission rejected El Paso's request for additional time to prepare a presentation to the Commission. El Paso has not abandoned the project and will refile for the water at a later date.

El Paso is currently entangled in problems concerning water acquisition from the Navajo Reservoir in northwest New Mexico and is trying to negotiate with the Bureau of Reclamation to obtain the needed water for the Burnham Gasification Project. The delays encountered in the New Mexico Project must certainly be retarding development in North Dakota.
TWO AMERICAN NATURAL GAS SUBSIDIARIES FILE WITH FPC FOR SNG CERTIFICATION

Michigan Wisconsin Pipe Line Company and ANG Coal Gasification Company filed a joint application with the Federal Power Commission on March 26, 1975, as the initial step in gaining government approval for construction of a coal gasification facility in Mercer County, North Dakota. The joint application specifically requested certificate authorization for:

1. Interstate sales of synthetic natural gas (coal) commingled with natural gas by ANG Coal Gasification Company to Michigan-Wisconsin.
2. Construction and operation by Michigan-Wisconsin of a 28-mile pipeline to transmit commingled gas from Crystal Falls, Michigan, to their customers in Wisconsin.

ANG Coal Gasification Company, a newly created subsidiary of American Natural Gas Company, has assumed from Michigan-Wisconsin the responsibility of implementing the plans for the Mercer County coal gasification project. The gas to be produced by ANG will be put into the transmission system of Great Lakes Transmission Company at Thief River Falls, Minnesota and withdrawn by Michigan-Wisconsin at Crystal Falls, Michigan. Great Lakes will construct a new line connecting the ANG gasification plant with Great Lakes' system at Thief River Falls at which point SNG will be commingled with natural gas. Great Lakes will apply for jurisdictional transportation services.

Specifically requested by the applicants is the authorization to exclude any allowances for funds used during construction (AFUDC) from the product gas price. It is proposed that the AFUDC - to include financing charges, commitment fees paid on debt and an after-tax return of 12 percent on equity - be recovered during construction by an upward adjustment of $0.07 per Mcf of Michigan-Wisconsin's present resale rates as opposed to the less desirable treatment of capitalizing these funds and recovering them after construction. If the proposed treatment is authorized, the application estimates a product gas cost of $2.50 per Mcf plus costs associated with transmission. The capitalization of the AFUDC, it is estimated, would result in a gas cost of $3.20 per Mcf. According to ANG, the proposed cost treatment is essential to project financing. Project cost is presently estimated to be $900 million - coal gasification plant at $778.3 million and the associated mine at $125.8 million. The design capacity of the plant being considered is 275 Mcf per stream day or 250 Mcf per average calendar day with an assumed on stream factor of 91 percent.

A review of the proposed facility and the acquisition of necessary water rights may be found on page 4-42 of the March 1975 issue of Synthetic Fuels.

The application filed by Michigan-Wisconsin and ANG Coal Gasification Company sheds some light on the supply situation facing American Natural Gas Company in the near future. Reductions in delivery are expected by Michigan-Wisconsin to start in 1976 with a supply deficit of 60 Bcf in 1976 and increasing to 300 Bcf by 1984; this notwithstanding additions to their system of SNG by 1981 and expected supplies of Arctic gas by 1980. Michigan-Wisconsin faces a contract renewal with Canada for 158 Mcf per day in 1981. The curtailment by Canada of this gas is considered a good possibility and would require, for make-up alone, 65 percent of the new gas supply expected from the Mercer County SNG plant. A significant shift from natural gas to other energy sources is not expected, according to ANG, in Michigan-Wisconsin's major service areas before at least 1985.

The FPC is not expected to make a final decision on this project until March 1976. However, since the FPC has made a final decision (Opinion No.728) on a similar project proposed by Western Gasification Company in New Mexico, a decision on the ANG filing may be expected. The FPC has ruled (Opinion No. 663) that it only has jurisdiction over interstate...
sales of SNG after it is commingled with natural gas. Discussion of the final FPC decision on the WESCO filing may be found on this page in the following article.

American Natural Gas Company is attempting a corporate level reorganization, contingent on approval by the Securities and Exchange Commission, to allow a more flexible policy regarding the financing of major long-term projects under the Public Utilities Holding Company Act. The regrouping proposal has met with stockholder approval and would allow the company to diversify its holdings.

# # # #

FPC GIVES FINAL DECISION ON WESCO PROJECT

The Federal Power Commission rendered a final decision on the joint application filed on February 7, 1973, by Transwestern Coal Gasification Company (subsidiary of Transwestern Pipeline Company) and Pacific Coal Gasification Company (subsidiary of Pacific Lighting Corporation) for authorization to transport and sell ANG from the proposed WESCO (a joint venture of TransCoal and Pacific Coal) coal gasification complex in San Juan County, New Mexico. FPC Opinion No. 728, dated April 21, 1975, authorizes the issuance of certificates to TransCoal and Pacific Coal for transfers, sales and deliveries of SNG and the construction and operation of facilities required for the transfer, sale, and delivery. Opinion No. 728 is published in entirety on page A-31 in the Appendix of this issue of Synthetic Fuels.

The point at issue throughout the proceedings leading up to the final decision has been the initial SNG unit rate and the establishment of a mechanism to adjust the rate to assure an adequate rate of return. The FPC authorized in the same action an initial rate of $1.38 per MCF with subsequent rate adjustments to be made under Section 4 of the Natural Gas Act. The initial rate as authorized is to be in effect through the first six months of plant testing and start up, at which time the parties involved will file under Section 4 for a rate adjustment based on actual operating costs and data. The adjustments to be authorized at that time will ostensibly allow for a 15 percent rate of return; a rate determined by the FPC and stated in Opinion No. 728 to be reasonable and necessary. The costs incurred during the initial six-month period not covered by the initial rate of $1.38 per MCF are to be amortized over the life of the contracts. The initial gas price set forth in Opinion No. 728 is based on a price of $1.32 per MCF which was estimated to be adequate at the time of the original filing in February 1973. The $1.38 per MCF figure however, reflects a recent adjustment in the contract price of coal from 24.52 to 30.94 cents per million BTU as negotiated with Utah International, Inc.

On March 13 and 14, 1975, Transwestern Pipeline Company and Pacific Lighting Corporation at oral argument proceedings before the FPC emphasized the need for cost of service tariffs on produced SNG to assure full cost recovery. This treatment, they stated, is necessary to attract adequate financial support. The total project investment, based on January 1975 costs, is estimated to be $852 million to be born equally by TransCoal and Pacific Coal. This capital outlay of $426 million for each company represents three times Transwestern's present worth ($142 million) and two thirds of Pacific's present worth ($640 million). The companies argue that because of current cost figures, an initial unit cost for SNG should be adjusted to $2.40 per MCF from $1.32 per MCF which was based on an initial mid-1973 capital cost of $447 million. The commission refused to take into account at this time the higher capital costs involved in setting the initial rate stating that under the specified rate adjustment procedures the recovery of investment is assured. FPC staff argued that an open-ended cost of service tariff would be tantamount to deregulation and not in the best interest of the consumer.
The final decision authorizes the sale of three-fourths of the total plant output (250 MMCFD) or 188 MMCFD to Pacific Lighting Service Company at the California border and the remaining 62 MMCFD to Cities Service Company by displacement for distribution in Oklahoma and Texas.

The text of Opinion No.728 provides a detailed explanation of project background, FPC jurisdiction, the need for SNG by these companies, and arguments pro and con for the decision rendered.

This is the first final decision handed down by the FPC on jurisdictional matters regarding the production of SNG a cost of service tariff reflects the inability of the FPC to allow rate treatment conducive to the establishment of an SNG industry. The tight regulation of price has halted further development in the WESCO project and has set a precedent for future SNG rate treatment.

The artificially held low price of gas can only forestall the construction of SNG capacity and remove the incentive to invest the billions of dollars required.

# # # #

EL PASO REQUESTS DEFERRAL OF FPC FINAL DECISION OF BURNHAM PROJECT

El Paso Natural Gas Company requested the Federal Power Commission on March 27, 1975, to defer a final decision on jurisdictional matters regarding its' proposed Burnham, New Mexico, coal gasification plant due to uncertainties surrounding coal and water supply for the project. El Paso has requested water from the Navajo Reservoir under contract with the Bureau of Reclamation, however, to date that contract has not been submitted by Interior for congressional approval. The consumption of this water contract is essential to further planning and financial commitments by El Paso. The lack of a firm water supply has forced El Paso to drop an option to purchase the remaining half of a coal lease at Burnham for $30 million now held equally by El Paso and Consolidation Coal. The 40,287-acre coal lease was purchased from the Navajo Nation in 1968. The terms of the option were to be completed at the end of 1975 with a final payment of $25 million that El Paso has chosen not to make. The $5 million that has already been outlayed will probably provide a basis for a future renegotiation of the option.

El Paso feels that a final decision now on the project SNG rate structure by the FPC would be untimely and would not reflect the unresolved problems of water and coal availability and cost. The commercial phase of the Burnham project has not been cancelled by El Paso, however, it has been indefinitely delayed.

In oral argument proceedings before the FPC on March 13 and 14, 1974, El Paso and Transwestern Pipeline Company/Pacific Lighting Corporation (equal owners of the WESCO Project) presented current capital estimates for their respective projects and desired SNG rate treatment. At that time El Paso testified that it's capital outlay will be $1.2 billion based on January 1, 1975, costs. The plant is estimated to cost one billion dollars and the mine at $225 million. This investment is substantially higher than the $605 million estimate in 1973 (plant - $491 million, mine - $114 million). Current first-year unit cost of SNG is estimated to be $3 per MCF compared to $1.51 per MCF in 1973. El Paso stressed the need for a 15 percent rate of return on equity coupled with a cost of service tariff to assure financing. FPC decisions and comments relating to the WESCO project are discussed in the preceding article.

The effect that a deferred rate decision on El Paso's proposed experimental gasifier module to be placed on site near Burnham at a cost of about $22.5 million is not clear. El Paso has petitioned the FPC for advanced approval to include the development R&D expenditures in their cost of service.

A discussion of the proposed El Paso project may be found on pages 4-16 and
Panhandle Eastern Pipe Line Company has announced a delay of up to a year in the construction schedule of a coal gasification plant being planned in the Powder River Basin of Wyoming about 60 miles north of Douglas. Under the revised schedule, construction may start in the summer of 1976 provided the project can meet new and amended state and federal regulations pertaining to such factors as plant siting, surface mine reclamation, and environmental quality. In addition to the constraints of state and federal regulations, inflating project costs coupled with a lack of unified federal policy covering the varied aspects of energy resource development have caused the project delay. Other synthetic fuels projects are suffering the same problems and delays at a time when domestic energy development should be expanding.

The project currently is estimated to be one billion dollars which presumably includes both plant and mine facilities. In 1973, this project was estimated at about $500 million. The critical issue surrounding the financing of a project of this type is that the FPC refuses to allow a cost of service tariff on the SNG produced for interstate sale. The reluctance by the FPC to give this necessary rate treatment is hampering and even bringing to a halt the development of financial support. A recent FPC decision on this subject was discussed in a preceding article in this section of this issue of Synthetic Fuels. The plant will produce 250 MMCFD of SNG assuming an online factor of 93 percent, consuming 9.2 MMTPY. Similar projects in New Mexico proposed by WESCO and El Paso are estimated to cost $852 million and $1.2 billion, respectively.

The appropriation of water for this project is continuing with only one firm commitment of 26,500 AFY of excess flow (flooding conditions) from the North Platte River. A discussion of this water permit is on page 4-14 of the March 1975 issue of Synthetic Fuels.
GOVERNMENT

SRI REPORTS ON USE OF H-COAL SYNCRUDE FOR DEPARTMENT OF DEFENSE USE

Stanford Research Institute (SRI) has completed a study for the Defense Advanced Research Project Agency concerning the potential for meeting part of the Department of Defense (DOD) energy requirements by synthetic petroleum from coal. SRI's final report is entitled, "Synthetic Petroleum for Department of Defense Use."

Copies are available from the Air Force Aero Propulsion Laboratory, Wright-Patterson Air Force Base, Ohio, as Technical Report AFAPL-TR-74-115.

Consumption of petroleum by the DOD was shown to be 571,000 barrels per day during FY 1974, with 66 percent of this being jet fuel, six percent being gasoline, and 28 percent being distillates, residuals, and heating fuel.

H-Coal Process Selected For Study

The two principal basic coal liquefaction processes are the pyrolysis process and the solvent refining, or hydrogenation process. Leading coal liquefaction processes include the COED process in the first category, and the H-Coal, Synthoil, and SRC processes in the second category. The H-Coal process was selected by SRI as the most suitable for meeting DOD's petroleum needs. The H-Coal process produces approximately three barrels of syncrude, suitable for a refinery feedstock, per ton of coal. The Synthoil and SRC processes are designed for production of heavy fuel oil or utility fuel. The COED process also produces a syncrude suitable as a refinery feedstock but yields only about one barrel of syncrude per ton of coal, with the remaining yield in the form of char.

Cost of H-Coal Syncrude Determined

The conversion of coal to syncrude by the H-Coal process was analyzed for Illinois No. 6 coal, representing a typical high-sulfur eastern bituminous coal produced by underground mining, and Wyoming Powder River coal, representing a low-sulfur western subbituminous coal produced by surface mining. The total capital investment for a syncrude plant with a capacity of 100,000 barrels per day, according to SRI, is (in millions of dollars):

- Eastern Coal $685
- Western Coal $668

The elements of the total syncrude costs in terms of dollars per barrel are given in Table 1, with the total cost set to yield either a ten percent or a 15 percent discounted cash flow (DCF) after-tax return on investment. It should be possible to obtain financing with a lower rate of return on investment if the risk is reduced, such as by a price guarantee. The federal income tax part of the cost is returned to the U.S. Treasury. Hence, for comparison with the cost of foreign crude, the income tax portion of the syncrude cost should be excluded. The net costs are then substantially below the present delivered price of foreign crude of about $12 per barrel.

Syncrude Refining Methods and Costs Surveyed by SRI

Compared with natural crudes, the H-Coal syncrude has more of the lighter fractions. The syncrude is high in aromatics, which makes it valuable for gasoline but requires additional processing for jet fuel.

Several alternative approaches to refining the syncrude were considered. These include:

- A new refinery without conversion (cracking) facilities to produce a minimum cost product slate.
- A new refinery with conversion facilities to produce the maximum yield of jet fuel.
- An existing refinery processing a combination of natural crude and syncrude.
The jet fuel yields for these cases are:

- New refinery, minimum cost slate: 28%
- New refinery, maximum jet fuel: 45%
- Existing refinery, crude and syncrude: 20%

Thus, the jet fuel yields are substantially below the DOD jet fuel proportion, and the gasoline yield is several times as great as the DOD gasoline proportion.

The capital investment, excluding working capital for syncrude, for the new syncrude refineries of 100,000 barrels per day capacity are (in millions of dollars):

- Minimum cost slate: $95
- Maximum jet fuel: $167

The total costs of refining the syncrude for the minimum cost slate are less than the costs of refining natural crude in typical modern refineries which are designed to produce gasoline as the major portion of the output.

Maximizing the jet fuel yield increases the refining costs by $0.36 to $0.52 per barrel with a ten or a 15 percent, respectively, DCF return on investment, making the costs more comparable with existing crude refineries.

The syncrude could be processed in existing refineries along with natural crude for an additional investment in hydrotreating facilities of approximately ten percent of the existing refinery investment. The cost of this additional investment is partly compensated by the higher quality of the syncrude. The refining costs for the syncrude are $0.52 per barrel of product greater than those for refining crude only, with a 15 percent DCF return on investment.

SRI Study Conclusions Listed

- The production of Syncrude from coal to supply DOD liquid fuel needs is feasible. Whether the conversion of coal to a refinery feedstock is a desirable part of an overall national

TABLE 1
H-COAL SYNCRUDE COST ELEMENTS
(Dollars per Barrel)

<table>
<thead>
<tr>
<th>Cost Element</th>
<th>Eastern</th>
<th>Western</th>
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</thead>
<tbody>
<tr>
<td></td>
<td>15% DCF</td>
<td>10% DCF</td>
</tr>
<tr>
<td>Coal</td>
<td>$3.43</td>
<td>$3.43</td>
</tr>
<tr>
<td>Other operating costs less credit for by-products</td>
<td>1.63</td>
<td>1.63</td>
</tr>
<tr>
<td>Investment costs, less taxes</td>
<td>3.81</td>
<td>2.79</td>
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<tr>
<td>Subtotal</td>
<td>$8.87</td>
<td>$7.85</td>
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<tr>
<td>Federal income taxes</td>
<td>2.51</td>
<td>1.49</td>
</tr>
<tr>
<td>Total</td>
<td>$11.38</td>
<td>$9.34</td>
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</tbody>
</table>
strategy for synthetic fuels development is beyond the scope of the study.

Because a reduction in crude prices poses a risk to the syncrude plant investment, some means of reducing the risk, such as a price guarantee, may be necessary to implement syncrude production. Furthermore, reducing the risk would reduce the required return on investment and hence the cost of syncrude.

The estimated syncrude costs are below the current delivered price of foreign crude of about $12 a barrel. Furthermore, a substantial component of the cost of the syncrude is federal income tax which is returned to the U.S. Treasury.

The H-Coal process produces a syncrude suitable for refinery feedstock. This syncrude may be refined to conventional fuel products using processes that exist in most modern refineries. However, the jet fuel yield is lower and the gasoline yield is much higher than the proportions of these products in the DOD fuel mix.

The H-Coal syncrude can be refined in a new refinery or along with natural crude in a modified existing refinery at a cost comparable with the cost of refining natural crude.

The distribution of syncrude products directly from DOD dedicated plants to DOD installations would entail substantially higher transportation charges than use of locally procured products.

A likely approach to utilization of syncrude for DOD fuel needs would be to provide a price guarantee for DOD dedicated syncrude plants, to refine the syncrude along with natural crude in existing refineries, and to trade the output for local products in the area of use.

---

ESTIMATED CAPITAL INVESTMENT FOR THREE COAL SURFACE MINES

Initial capital investment and annual operating costs for coal strip mines have been estimated by the Bureau of Mines (Information Circular 8661) under three sets of mine siting criteria. The hypothetical mine sites are located in the Eastern, Interior, and Northern Great Plains Coal Provinces with the general mining plans for each site assumed to be as similar as possible to allow comparison. The mines are sized to supply sufficient coal to one 250 MMcf per day high BTU coal gasification facility. The annual production from the mines is assumed to be 4.8 MM tons for the Eastern Province, 6.7 MM tons for the Interior Province, and 9.2 for the Northern Great Plains Province. Higher annual coal production corresponds to a lower heating value of the coal with the assumption that the plant BTU input remains constant at approximately 125 X 10^{12} BTU/year. By using an estimate of 13,000 BTU/lb for bituminous coal in the Eastern Province, the heating values of the coals being mined in the Interior and Northern Great Plains Provinces are 9,300 BTU/lb and 6,800 BTU/lb, respectively. The acreage requirement for each of the three mines over a 20-year life at the assumed production rates is shown in Table 1 with average coal seam and overburden thicknesses used in the economic analysis and general mine plans.

Summary of Capital Investment and Costs

A summary of the total estimated capital investments and operating costs for each of the three mines is shown in Table 2; these figures are also represented in terms of expected annual production. A further definition of initial capital investment in terms of direct investment (mining equipment and buildings, site preparation, and exploration) field indirect costs, engineering, overhead, contingencies, fees, interest during construction and working capital is
TABLE 1

Acreage Necessary to Provide Coal Requirements to Sustain a 20-year Operation

<table>
<thead>
<tr>
<th>Province</th>
<th>Production, MM tpy</th>
<th>Coal Seam Ft.</th>
<th>Overburden Ft.</th>
<th>Annual Acres Required, 90-percent recovery</th>
</tr>
</thead>
<tbody>
<tr>
<td>Eastern</td>
<td>4.8</td>
<td>6</td>
<td>0-100</td>
<td>493</td>
</tr>
<tr>
<td>Interior</td>
<td>6.72</td>
<td>6</td>
<td>70</td>
<td>691</td>
</tr>
<tr>
<td>Northern Great Plains</td>
<td>9.2</td>
<td>25</td>
<td>70</td>
<td>231</td>
</tr>
</tbody>
</table>

shown in Tables 3, 4, and 5 for the Eastern, Interior, and Northern Great Plains mines, respectively.

The personnel requirements for each of the three mines as estimated by the BoM study are summarized in Table 6 according to job type and mine location.

General Mining Plans

A general mine plan was established for each coal province as a basis for the investment and cost analysis. No attempt was made to describe the mine layout but all major pieces of equipment were considered in the initial investment based on a set of regional criteria. The criteria used for each analysis are:

TABLE 2

SUMMARY OF CAPITAL INVESTMENT, OPERATING COSTS, AND SELLING PRICE BY ANNUAL OUTPUT CAPACITY

<table>
<thead>
<tr>
<th>MM tons per year and province</th>
<th>4.8, Eastern</th>
<th>6.72, Interior</th>
<th>9.2, Northern Great Plains</th>
</tr>
</thead>
<tbody>
<tr>
<td>Estimated initial capital investment</td>
<td>$45,358,600</td>
<td>$54,603,000</td>
<td>$29,871,000</td>
</tr>
<tr>
<td>Estimated deferred capital investment</td>
<td>15,711,400</td>
<td>22,150,000</td>
<td>26,415,000</td>
</tr>
<tr>
<td>Total</td>
<td>61,070,000</td>
<td>76,753,000</td>
<td>56,286,000</td>
</tr>
<tr>
<td>Capital investment per ton of production</td>
<td>12.72</td>
<td>11.42</td>
<td>6.12</td>
</tr>
<tr>
<td>Operating cost per year</td>
<td>17,527,900</td>
<td>21,870,800</td>
<td>20,914,400</td>
</tr>
<tr>
<td>Operating cost per ton of production</td>
<td>3.65</td>
<td>3.25</td>
<td>2.27</td>
</tr>
<tr>
<td>Selling price per ton, 12 percent DCF ( ^1 )</td>
<td>4.79</td>
<td>4.23</td>
<td>2.66</td>
</tr>
</tbody>
</table>

\( ^1 \) Discounted cash flow.
### TABLE 3
ESTIMATED WORKING CAPITAL AND TOTAL CAPITAL INVESTMENT,
4.8 MM TPY STRIP MINE LOCATED IN THE EASTERN COAL PROVINCE

**Estimated Working Capital**

<table>
<thead>
<tr>
<th>Item</th>
<th>Cost</th>
</tr>
</thead>
<tbody>
<tr>
<td>Direct labor</td>
<td>$537,300</td>
</tr>
<tr>
<td>Operating supplies</td>
<td>$709,300</td>
</tr>
<tr>
<td>Payroll overhead</td>
<td>$188,100</td>
</tr>
<tr>
<td>Indirect cost</td>
<td>$249,300</td>
</tr>
<tr>
<td>Fixed cost</td>
<td>$210,200</td>
</tr>
<tr>
<td>Spare parts</td>
<td>$103,400</td>
</tr>
<tr>
<td>Miscellaneous</td>
<td>$50,000</td>
</tr>
</tbody>
</table>

Total working capital = $2,047,600

**Total Estimated Capital Investment**

<table>
<thead>
<tr>
<th>Item</th>
<th>Cost</th>
</tr>
</thead>
<tbody>
<tr>
<td>Direct Investment</td>
<td>32,815,100</td>
</tr>
<tr>
<td>Field Indirect</td>
<td>656,300</td>
</tr>
<tr>
<td>Engineering</td>
<td>669,400</td>
</tr>
<tr>
<td>Overhead and Administration</td>
<td>1,707,000</td>
</tr>
<tr>
<td>Contingencies</td>
<td>5,377,200</td>
</tr>
<tr>
<td>Fees</td>
<td>824,500</td>
</tr>
</tbody>
</table>

Total plant (insurance, tax base) = 42,049,500

Interest during construction = 1,261,500

**Subtotal** = 43,311,000

Working capital = 2,047,600

Estimated initial capital investment = 45,358,600

Estimated deferred capital investment = 15,711,400

Total capital and deferred investment = 61,070,000

---

1 This is an average cost of $12.72 per ton of annual production.

**Eastern**

- Hilly terrain
  - 6-foot coal bed with overburden ranging from zero feet at the outcrop to a maximum of 100 feet at the highwall
  - Overburden will be drilled, blasted, and removed with 100-cubic-yard electric shovels
  - Coal not blasted will be removed with 15-cubic-yard electric shovels and hauled in 120-ton trucks

**Interior**

- Flat terrain
  - 6-foot coal bed with 70 feet of overburden
  - Overburden will be drilled, blasted, and removed with 120-cubic-yard electric shovels
  - Coal not blasted will be removed with 20-cubic-yard electric shovels and hauled in 120-ton trucks
### TABLE 4

**ESTIMATED WORKING CAPITAL AND TOTAL CAPITAL INVESTMENT, 6.72 MM TPY STRIP MINE LOCATED IN THE INTERIOR COAL PROVINCE**

#### Estimated Working Capital

<table>
<thead>
<tr>
<th>Item</th>
<th>Cost (in $)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Direct labor</td>
<td>3 months</td>
</tr>
<tr>
<td>Operating supplies</td>
<td>3 months</td>
</tr>
<tr>
<td>Payroll overhead</td>
<td>3 months</td>
</tr>
<tr>
<td>Indirect cost</td>
<td>4 months</td>
</tr>
<tr>
<td>Fixed cost</td>
<td>0.5 percent of insurance base.</td>
</tr>
<tr>
<td>Spare parts</td>
<td></td>
</tr>
<tr>
<td>Miscellaneous</td>
<td></td>
</tr>
<tr>
<td><strong>Total working capital</strong></td>
<td></td>
</tr>
</tbody>
</table>

#### Total Estimated Capital Investment

<table>
<thead>
<tr>
<th>Item</th>
<th>Cost (in $)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Direct Investment</td>
<td></td>
</tr>
<tr>
<td>Field Indirect</td>
<td></td>
</tr>
<tr>
<td>Engineering</td>
<td></td>
</tr>
<tr>
<td>Overhead and Administration</td>
<td></td>
</tr>
<tr>
<td>Contingencies</td>
<td></td>
</tr>
<tr>
<td>Fees</td>
<td></td>
</tr>
<tr>
<td><strong>Total plant (insurance, tax base)</strong></td>
<td></td>
</tr>
<tr>
<td>Interest during construction</td>
<td></td>
</tr>
<tr>
<td><strong>Subtotal</strong></td>
<td></td>
</tr>
<tr>
<td>Working capital</td>
<td></td>
</tr>
<tr>
<td>Estimated initial capital investment</td>
<td></td>
</tr>
<tr>
<td>Estimated deferred capital investment</td>
<td></td>
</tr>
<tr>
<td><strong>Total capital and deferred investment</strong></td>
<td></td>
</tr>
</tbody>
</table>

---

1. This is an average cost of $11.42 per ton of annual production.

---

**Northern Great Plains**

- Rolling terrain
- 25-foot coal bed with 70 feet of overburden
- Overburden will be drilled, blasted, and removed with 45-cubic-yard electric draglines
- Coal not blasted will be removed with 15-cubic-yard electric shovels and hauled in 120-ton trucks.

All blasting is to be done with an ammonium nitrate-fuel oil mixture. Incoming voltage to the mine is assumed to be 7,200 volts for operation of overburden drills, stripping equipment, and coal loading shovels. Reclamation equipment will be done with conventional bulldozers and wheel tractor scrapers and will be the same at each site. The mines in each case are assumed to have two operating pits and a common crushing and storage facility.

---

**CAMERON ENGINEERS, INC.**

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### TABLE 5
ESTIMATED WORKING CAPITAL AND TOTAL CAPITAL INVESTMENT, 9.2 MM TPY STRIP MINE LOCATED IN THE NGP COAL PROVINCE

**Estimated Working Capital**

<table>
<thead>
<tr>
<th>Item</th>
<th>Cost</th>
</tr>
</thead>
<tbody>
<tr>
<td>Direct labor</td>
<td>$613,700</td>
</tr>
<tr>
<td>Operating supplies</td>
<td>$805,000</td>
</tr>
<tr>
<td>Payroll overhead</td>
<td>$214,800</td>
</tr>
<tr>
<td>Indirect cost</td>
<td>$283,700</td>
</tr>
<tr>
<td>Fixed cost</td>
<td>$133,700</td>
</tr>
<tr>
<td>Spare parts</td>
<td>$188,900</td>
</tr>
<tr>
<td>Miscellaneous</td>
<td>$90,000</td>
</tr>
<tr>
<td><strong>Total working capital</strong></td>
<td><strong>$2,329,800</strong></td>
</tr>
</tbody>
</table>

**Total Estimated Capital Investment**

<table>
<thead>
<tr>
<th>Item</th>
<th>Cost</th>
</tr>
</thead>
<tbody>
<tr>
<td>Direct Investment</td>
<td>$20,866,900</td>
</tr>
<tr>
<td>Field Indirect</td>
<td>$417,300</td>
</tr>
<tr>
<td>Engineering</td>
<td>$425,700</td>
</tr>
<tr>
<td>Overhead and Administration</td>
<td>$1,085,500</td>
</tr>
<tr>
<td>Contingencies</td>
<td>$3,419,300</td>
</tr>
<tr>
<td>Fees</td>
<td>$524,300</td>
</tr>
<tr>
<td><strong>Total plant (insurance, tax base)</strong></td>
<td><strong>$26,739,000</strong></td>
</tr>
<tr>
<td>Interest during construction</td>
<td>$802,200</td>
</tr>
<tr>
<td><strong>Subtotal</strong></td>
<td><strong>$27,541,200</strong></td>
</tr>
<tr>
<td>Working capital</td>
<td>$2,329,800</td>
</tr>
<tr>
<td>Estimated initial capital investment</td>
<td>$29,871,000</td>
</tr>
<tr>
<td>Estimated deferred capital investment</td>
<td>$26,415,000</td>
</tr>
<tr>
<td><strong>Total capital and deferred investment</strong></td>
<td><strong>$56,286,000</strong></td>
</tr>
</tbody>
</table>

1 This is an average cost of $6.12 per ton of annual production.

### TABLE 6
PERSONNEL REQUIREMENTS FOR THREE COAL STRIP MINES ACCORDING TO JOB TYPE AND MINE LOCATION

<table>
<thead>
<tr>
<th>Job Type</th>
<th>Eastern Province 4.8 TPY</th>
<th>Interior Province 6.72 TPY</th>
<th>N.G.P. Province 9.2 TPY</th>
</tr>
</thead>
<tbody>
<tr>
<td>Production</td>
<td>72</td>
<td>70</td>
<td>90</td>
</tr>
<tr>
<td>Maintenance</td>
<td>54</td>
<td>54</td>
<td>63</td>
</tr>
<tr>
<td>Reclamation &amp; Road Building</td>
<td>16</td>
<td>24</td>
<td>24</td>
</tr>
<tr>
<td>Utility</td>
<td>12</td>
<td>12</td>
<td>12</td>
</tr>
<tr>
<td>Salary</td>
<td>24</td>
<td>24</td>
<td>24</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td>178</td>
<td>184</td>
<td>213</td>
</tr>
</tbody>
</table>
ECONOMIC SYSTEM ANALYSIS OF LARGE SCALE COAL SURFACE MINING OPERATIONS

Fluor Utah, Inc. is performing a comprehensive economic system analysis of coal preconversion technology under contract 14-32-0001-1520 with OCR. The objective of the study is to assemble sufficient data on coal resource development in the form of a system model to "...identify and define the physical, technical, social, economic, legal and environmental problems of producing 75,000 TPD or more of coal from individual surface mines in the United States..." Progress made during the first eleven months, the first phase of the two-phase program, is presented in R&D Report No. 99 - Interim Report No. 1 entitled "Economic System Analysis of Coal Preconversion Technology," dated June 1974. The study, initiated in August 1973, is scheduled for 42 months. Phase one will last 24 months and entails the development of a mathematical model of the siting, design, operation, and evaluation of surface coal mines and related coal preparation and transportation facilities. The model terminates at the point of use, i.e., electrical generating, gasification, or liquefaction plants. Phase two will be the comparative analysis of up to twenty distinct mining operations to form a basis for evaluation of future developments within the constraints of cost, safety, continuity, and conservation of coal reserves, and minimum environmental damage.

The two major tasks under phase one are the collection of data and the construction of the model. Data are presently being gathered on coal deposit characterization, mine equipment, preparation and process equipment, transportation systems, socio-economic and physioeconomic factors, coal industry financial statistics, and existing mining operations. The intent is to code and place all pertinent data in files from which the model may draw as it progresses through the logical steps of the economic system analysis.

Coal Deposit Characterization and Mine Site Selection

The characterization of coal deposits is the compilation of resource-reserve, geologic, geographic, physiographic, stratigraphic, and socioeconomic data to be used in the identification of areas suitable for large scale surface mining. Those areas capable of supporting the equivalent production of 75,000 TPD of 13,000 BTU per pound coal, based on resource data, are termed "Geology Target Regions." The overlay of favorable socioeconomic constraints on the geology target regions further identifies those areas acceptable as mine sites and are termed "Base Case Areas." It is the base case areas that are of particular interest to the study by Fluor and it is the characterizing data of these areas that are being prepared for use in the economic analysis.

Resource-reserve data have been compiled from two major sources, with some current updating where necessary:


Excerpts from these two publications, Tables 1 and 2, give updated values for the coal resource and reserve base. As defined by USGS/USBM: resource is the total amount of coal in place within certain depth and thickness criteria; and reserve is that portion of the resource which is economically and technologically mineable at some stated time. Table 1, resource data, is supplemented by the following notes according to the numbers in parentheses on the table.

NOTES ON TABLE 1

1. Small resources of lignite included in subbituminous coal.
2. Contain some subbituminous coal from the Black Mesa field.
3. Small resources of lignite in beds less than 30 inches thick.
### TABLE 1

**ESTIMATED REMAINING COAL RESOURCES**

**OF THE UNITED STATES, JANUARY 1, 1972**

(Millions of Short Tons)

<table>
<thead>
<tr>
<th>State</th>
<th>Identified* 0-3,000 ft</th>
<th>Hypothetical** 0-3,000 ft</th>
<th>Total Resources 0-3,000 ft</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Bituminous</td>
<td>Sub-bituminous</td>
<td>Lignite</td>
</tr>
<tr>
<td>Alabama</td>
<td>13,342</td>
<td>0</td>
<td>2,000</td>
</tr>
<tr>
<td>Alaska</td>
<td>19,413</td>
<td>110,668</td>
<td>(1)</td>
</tr>
<tr>
<td>Arizona</td>
<td>21,246(2)</td>
<td>0</td>
<td>21,246</td>
</tr>
<tr>
<td>Arkansas</td>
<td>1,638</td>
<td>0</td>
<td>350</td>
</tr>
<tr>
<td>Colorado</td>
<td>62,339</td>
<td>18,242</td>
<td>0</td>
</tr>
<tr>
<td>Georgia</td>
<td>24</td>
<td>0</td>
<td>24</td>
</tr>
<tr>
<td>Illinois</td>
<td>139,124</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>Indiana</td>
<td>34,573</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>Iowa</td>
<td>6,509</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>Kansas</td>
<td>18,674</td>
<td>0</td>
<td>(3)</td>
</tr>
<tr>
<td>Kentucky</td>
<td>64,842</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>Maryland</td>
<td>1,158</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>Michigan</td>
<td>205</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>Missouri</td>
<td>31,014</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>Montana</td>
<td>2,299</td>
<td>131,855</td>
<td>87,521</td>
</tr>
<tr>
<td>New Mexico</td>
<td>10,752</td>
<td>50,671</td>
<td>0</td>
</tr>
<tr>
<td>North Carolina</td>
<td>110</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>North Dakota</td>
<td>41,358</td>
<td>0</td>
<td>350,630</td>
</tr>
<tr>
<td>Ohio</td>
<td>3,281</td>
<td>0</td>
<td>(3)</td>
</tr>
<tr>
<td>Oregon</td>
<td>50</td>
<td>284</td>
<td>0</td>
</tr>
<tr>
<td>Pennsylvania</td>
<td>56,759</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>South Dakota</td>
<td>2,572</td>
<td>0</td>
<td>2,031</td>
</tr>
<tr>
<td>Tennessee</td>
<td>6,048</td>
<td>0</td>
<td>6,824</td>
</tr>
<tr>
<td>Texas</td>
<td>23,541(4)</td>
<td>180(4)</td>
<td>0</td>
</tr>
<tr>
<td>Utah</td>
<td>9,352</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>Washington</td>
<td>1,867</td>
<td>4,190</td>
<td>117</td>
</tr>
<tr>
<td>West Virginia</td>
<td>100,628</td>
<td>0</td>
<td>100,628</td>
</tr>
<tr>
<td>Wyoming</td>
<td>12,705</td>
<td>107,951</td>
<td>0</td>
</tr>
<tr>
<td>Other States</td>
<td>610(6)</td>
<td>32(7)</td>
<td>46(8)</td>
</tr>
</tbody>
</table>

TOTAL 686,033 424,073 449,519 1,586,625 1,314,280 2,900,405

*Specific bodies of coal whose location, quality, and quantity are known from geologic evidence supported by engineering measurements with respect to the demonstrated category.

**Undiscovered coal that may reasonably be expected to exist in a known coal province under known geologic conditions.
TABLE 2
ESTIMATED REMAINING STRIPPABLE COAL RESOURCES OF THE UNITED STATES, JANUARY 1, 1973
(Millions of Short Tons)

<table>
<thead>
<tr>
<th>State</th>
<th>Bituminous</th>
<th>Sub-Bituminous</th>
<th>Lignite</th>
<th>Total</th>
<th>Strippable Reserve</th>
</tr>
</thead>
<tbody>
<tr>
<td>Alabama</td>
<td>616</td>
<td>0</td>
<td>(1)</td>
<td>616</td>
<td>83</td>
</tr>
<tr>
<td>Alaska</td>
<td>1,201</td>
<td>6,187</td>
<td>8</td>
<td>7,396</td>
<td>4,408(2)</td>
</tr>
<tr>
<td>Arizona</td>
<td>0</td>
<td>396</td>
<td>0</td>
<td>396</td>
<td>383</td>
</tr>
<tr>
<td>Arkansas</td>
<td>199</td>
<td>0</td>
<td>32</td>
<td>231</td>
<td>173</td>
</tr>
<tr>
<td>California</td>
<td>0</td>
<td>100</td>
<td>0</td>
<td>100</td>
<td>25</td>
</tr>
<tr>
<td>Colorado</td>
<td>860</td>
<td>(4)</td>
<td>0</td>
<td>860</td>
<td>490</td>
</tr>
<tr>
<td>Illinois</td>
<td>18,679</td>
<td>0</td>
<td>0</td>
<td>18,679</td>
<td>3,081</td>
</tr>
<tr>
<td>Indiana</td>
<td>2,642</td>
<td>0</td>
<td>0</td>
<td>2,642</td>
<td>997</td>
</tr>
<tr>
<td>Iowa</td>
<td>997</td>
<td>0</td>
<td>0</td>
<td>997</td>
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<td>67,246</td>
<td>15,976</td>
<td>144,924</td>
<td>43,765</td>
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</table>
TABLE 3

SUMMARY OF U.S. BUREAU OF MINES PARAMETERS FOR DETERMINING STRIPPABLE RESOURCES AND RESERVES

<table>
<thead>
<tr>
<th>State</th>
<th>Minimum Bed Thickness (inches)</th>
<th>Maximum Overburden (feet)</th>
<th>Economic Stripping Ratio (feet/feet)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Arizona</td>
<td>60</td>
<td>130</td>
<td>8:1</td>
</tr>
<tr>
<td>Colorado</td>
<td>60</td>
<td>50-120</td>
<td>4:1-10:1</td>
</tr>
<tr>
<td>Illinois</td>
<td>18</td>
<td>150</td>
<td>18:1</td>
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<tr>
<td>Indiana</td>
<td>14</td>
<td>90</td>
<td>20:1</td>
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<tr>
<td>Kentucky - east</td>
<td>28</td>
<td>120</td>
<td>14:1</td>
</tr>
<tr>
<td>Kentucky - west</td>
<td>24</td>
<td>150</td>
<td>18:1</td>
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<tr>
<td>Montana</td>
<td>60</td>
<td>60-125</td>
<td>2:1-18:1</td>
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<td>New Mexico</td>
<td>60</td>
<td>60-90</td>
<td>8:1-12:1</td>
</tr>
<tr>
<td>North Dakota (Lignite)</td>
<td>60</td>
<td>50-75</td>
<td>3:1-12:1</td>
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<td>28</td>
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<td>15:1</td>
</tr>
<tr>
<td>Utah</td>
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<td>39-150</td>
<td>3:1-8:1</td>
</tr>
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<td>28</td>
<td>120</td>
<td>15:1</td>
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<tr>
<td>Wyoming</td>
<td>60</td>
<td>60-200</td>
<td>1:5-10:1</td>
</tr>
</tbody>
</table>

4. Excludes coal in beds less than 48 inches thick.
5. Includes coal in beds 14 inches or more thick, of which 14,000 million tons are in beds 48 inches or more thick.
6. California, Idaho, Nebraska, and Nevada.
7. California and Idaho.
9. Includes beds of bituminous coal 14 inches or more thick and beds of subbituminous coal and lignite 30 inches or more thick.
11. Total figure only includes 27 billion tons of subbituminous coal and lignite strippable reserves reported by the Montana Bureau of Mines and Geology.
12. Includes eight tons estimated hypothetical strippable coal reserves reported by Montana Bureau of Mines and Geology.

Table 2, strippable reserve data, is supplemented by the following notes according to the numbers in parentheses on the table.

NOTES ON TABLE 2

1. Lignite resources not estimated for Kansas, Mississippi, Louisiana, and Alabama.
2. Coal reserves of 3,865 million tons of bituminous and subbituminous coal in the Northern Alaska field is included, even though an economic export market does not exist.
4. Subbituminous coal resources and reserves not estimated for Oregon and Colorado.
7. Total figure only includes 27 billion tons of subbituminous coal and lignite strippable reserves reported by the Montana Bureau of Mines and Geology.

The data in Table 1 reflect updating since they were published on page 3-2 of the September 1971 issue of Synthetic Fuels. Table 3 describes coal bed thickness, overburden depth, and coal thickness-to-overburden ratio criteria for selected states used by the USBM in determining economically strippable resources and reserves.

The report (R&D Report No. 99, Interim Report No.1) goes into some detail on the techniques of data coding, filing, and retrieval for model use as well as model construction.

# # # #

LAWSUIT AIMS AT FEDERAL PREFERENTIAL COAL RIGHT LEASES COMPLYING WITH ENVIRONMENTAL LAWS

A lawsuit to determine the bearing of the National Environmental Policy Act on federal preferential coal rights leasing applications was filed March 10 in U.S. District Court for the District of Columbia. Bringing the action are the Natural Resources Defense Council and the Environmental Defense Fund. The defendants are the Secretary of Interior and top officers of the Bureau of Land Management and the U.S. Geological Survey.

The suit contends preferential coal right leases should not be issued without Interior first determining the environmental impacts or at least ascertaining environmental costs relative to development of publicly owned coal. It is aimed at lease applications pending after issuance of coal prospecting permits to federal lands from which the permit holder claims discovery of commercially developable coal. Under a long-standing Interior policy now being re-evaluated, the prospector has been assured a lease if he finds commercial quantities of coal.

NRDC estimates more than 750,000 acres of federal mineral rights containing some seven billion tons of coal are at issue in the suit. Additional deposits could be involved depending upon Interior's new coal leasing regulation.

Another thrust of the suit could result in determination of environmental factors that would rule out development of some lease applications because of adverse impact on the environment, such as negative effect on underground water or low potential for disturbed land revegetation. NRDC feels application of NEPA could result in consolidation of some coal leases and possibly the cumulative effects of several leases in an area being evaluated collectively instead of individually.

# # # #

NEW RULING EXPECTED ON COAL PROSPECTING PERMIT LAWSUIT

A new U.S. District Court ruling is expected momentarily in Wyoming on the legality of the Secretary of the Interior rejecting coal prospecting permit applications. District Judge Ewing T. Kerr stirred Interior into action last February in ruling a series of 1971 coal prospecting permit applications to Interior's Bureau of Land Management be reinstated and directing the Secretary to grant hearings to unsuccessful permit applicants under the National Environmental Policy Act.

The judge acted on a petition filed by American Nuclear Corp., Elizabeth W. and Page T. Jenkins, and Jane P. and John S. Wold. He ruled after government lawyers failed to file briefs countering the applicants' claims. The plaintiffs contended applications for coal prospecting permits in the Powder River Basin were filed before the Secretary issued an order on February 13, 1973, rejecting pending and future applications for prospecting permits. They maintained the Secretary's ruling was arbitrary and under NEPA was illegal because no findings were made to support a coal prospecting moratorium.
The judge's ruling, in effect, set up a priority system for once pending coal prospecting permit applications on the basis of filing time. Also it asserted applications could not be rejected without environmental findings and granting a hearing to unsuccessful applicants. Kerr later stayed his order after government attorneys belatedly asked he hear their side of the case which had not been filed in accordance with court rules of procedure.

Interior asserted the mere filing of a permit application gives the permit seeker no rights other than to have his application considered. Also, the matter does not come under NEPA while Interior is considering coal leasing and prospecting policy. Interior prepared an environmental impact statement on coal leasing policy.

American Nuclear was assigned the permits in exchange for royalty agreements with the plaintiffs.

While the matter pertains only to the applications before the court, a ruling reinstating the rejected applications could have profound precedential effects on petitions for federal coal prospecting permits and assigning of coal leases under the 1920 Mineral Leasing Act.

FATE OF COAL STRIP MINE BILL UNCERTAIN AFTER PRESIDENTIAL VETO

The fate of the highly controversial Surface Mining Control and Reclamation Act of 1975 (HR 25) was uncertain as this issue of Synthetic Fuels went to press. Early Congressional confidence a veto could be overridden vanished in the wake of President Ford's rising leadership stock on the hill and with the public. The May 20 veto was being viewed in light of the president's positive actions in sending Marines to recapture a pirated merchant ship in Southeast Asia, hiking the oil import tariff from $1 to $2, scolding Congress for its inaction on a national energy program, and flying a goodwill visit to Western Europe.

In vetoing the bill "with a deep sense of regret," Ford said 36,000 jobs could be lost if the bill became law; it would result in higher energy costs to consumers; it would render the nation more vulnerable to imported oil, and would unnecessarily reduce domestic coal production. He said it would invoke cumbersome and unwieldy federal-state regulations, excessive tax provisions, and result in higher coal prices and limit development of public coal resources.

Representative Morris Udall, D-Arizona and a Democratic candidate for President, promptly called for hearings to ascertain where Ford got the data leading to the conclusions Udall called "erroneous."

The President's reasoning closely followed National Coal Association and American Mining Congress objections to the measure, some of which were highly conjectural and devoid of new employment opportunities which could result from the act. A Conference Committee report resolving conflicts between Senate and House versions of a law incorporated eight changes and modified language to meet six other objections among 27 major faults cited by the Administration.

Key provisions of the final bill were:

- Establishment under the Secretary of Interior an Office of Surface Mining Reclamation and Enforcement with a director to be appointed by the President. The director would report to the Secretary.
- Authorization of $2.5 million over seven years to each state to help establish mining and minerals research institutes. The states would match the federal money on a 50/50 basis.
- Authorization of $15 million for fiscal 1975 for research and planning which could include coal gasification and liquefaction projects, provided the research results become public. The stipend would be increased $2 million annually for six years.

The Abandoned Mine Reclamation Fund levy was set at 35 cents a ton of surface mining.
mined coal or ten percent of the value of the coal at the mine, whichever is less; 15 cents per ton on underground coal and a fee of five percent of the value for lignite or 35 cents a ton, whichever is greater. The tax is to be paid quarterly. Half of the revenues would be paid to the states from which the funds were collected.

The money would go to projects recommended by state governors and grants of up to 80 percent of project costs can be paid from the fund. State and local governments can acquire orphan mined lands, reclaim them and sell or use the property for public benefit, including coal conversion plant sites.

The bill calls for publication of administrative regulations within 180 days. The regulations would be subject of a public hearing before being adopted in final form. State regulations equal to or more stringent than the federal rules can supercede the Interior regulations. Coal miners have six months after establishment of the regulations for a surface land control and reclamation program to obtain a five-year renewable permit for existing operations.

Enforcement provisions based on inspections call for imposition of fines of up to $5,000 per day per civil offense for not having a permit or not following prescribed mining/reclamation practices. Jail terms and up to $10,000 fines are imposed for criminal violations.

A broad range of environmental and related technical data is necessary to obtain a permit. The permit can be terminated if mining isn't begun within three years, although a permit issued for a mine in support of a coal conversion plant remains valid if the plant construction is begun prior to mine development. Data submitted for a permit becomes public, except for coal analysis, although potentially toxic elements in the coal must be noted publicly. Applications for coal permits and coal exploration permits may become the subject of public hearing if there is opposition to them. The bill also sets performance standards which require the operator to maximize coal recovery, use native plants to restore vegetation, and reclaim the land to a condition at least as good as it was prior to mining. Measures for protecting water quality and integrity of hydrologic patterns are repeatedly emphasized in the bill.

Exemptions to reclamation are possible if the mined out land is to be put to a use different than that which existed prior to mining. Surface effects of underground coal mines on urban and other developed areas are also included in the bill and authority to close underground mines is provided the Secretary of the Interior if a public hazard exists.

Controversial lawsuit provisions in the final bill permit citizen lawsuits against the government and protects miners from lawsuits if they are following approved plans. Miners may sue the government if administrative remedies to regulations are not satisfactory.

The bill maintains prohibitions on new mining in national forests, and systems of wilderness, national parks, scenic areas, wild rivers and near national historic sites, even if they are only proposed in legislation still before Congress.

The bill contains provisions for obtaining data on non-coal minerals subject to surface mine development. Coal mines west of the 100th meridian are allowed limited exemptions to some regulations concerning land reclamation. The area involved includes the coal rich Northern Great Plains.

Lands not suited for surface mining may be designated by state governors, federal agencies, and individuals whose interests may be affected. Provisions for public hearings are included on controversies over unsuitable lands.

The controversy over mining alluvial valley floors suitable for farming is resolved in the bill by protecting the hydrologic balance of the valley and banning mining where farming comprises a significant part of a ranching operation.
The conference committee noted range land in alluvial valley floors does not constitute farming land and it believes only five percent and probably less of the coal lands in the West come under the alluvial valley floor provision.

Authorization for appropriations for modifications of the bill for Alaskan coal deposits and for applicability of the law to similar provisions for oil shale and oil sands development are $250,000 and $500,000, respectively.

Indian Tribes could be given surface mine and reclamation regulatory powers under the bill provided additional legislation authorizes it. A study report on the matter is due January 1, 1976, if the measure becomes law. In the meantime, surface coal mining operations on Indian reservations are to comply with the act and provisions of the act are to be incorporated in existing leases.

Surface owner protection -- one of the "critical" objections Ford has with the measure -- requires surface property owners to give written consent to mining of federal coal beneath their land. Bidders on federal coal leases are to include payment of the appraised value of surface property in a separate portion of their bid.

Compensatable surface ownership includes loss of income during mining and reclamation efforts; cost of re-location or dislocation; cost for loss of livestock, crops, water, or other improvements and miscellaneous other damage. Surface owners' interest is to be determined by three appraisers. Congress is to receive a report on the impact of this provision of the law, which does not apply to Indian lands. Penalties are prescribed for bribing and being bribed to get surface owners consent.

An Interior spokesman said the regulations called for by the bill have already been drafted and if the veto is over-ridden a few modifications will be made and they will be promptly published. The content of the regulations closely parallels the guidelines outlined in the bill itself (Title V). Department of Interior surface coal mine regulations published in the December 11, 1974, Federal Register (and Synthetic Fuels, March 1975) are in bureaucratic limbo.

If the President's veto is over-ridden, the regulations will be scrapped. They follow the strip mine bill reclamation standards almost work for word. If the veto is sustained, the regulations could go into effect almost immediately or wait until the environmental impact statement on federal coal leasing is completed and federal coal leasing policy determined.

Interior has decided to issue a revised draft of the leasing program instead of going to a final EIS. The revised draft is expected to be published shortly, but may await the installation of former Wyoming Governor Stan Hathaway as Secretary of the Interior.

The regulations are described by an industry spokesman as "harsh," and it is anticipated new regulations would be less severe and, of course, would be limited to coal lands in which there is a federal interest. Nor would they be retroactive to rehabilitate abandoned workings. The strip mine bill is applicable to all lands including those where both surface and mineral rights are in private ownership.

UTILITY COAL CONVERSION MONTHS AWAY AS FEA ISSUES NOTICE OF INTENT TO PROHIBIT BURNING OIL AND NATURAL GAS FOR ELECTRIC POWER GENERATION

The validity of the idea to reconvert scores of electric power generating stations back to coal from oil and natural gas is months, if not years away from determination. That was about the only clear picture emerging from FEA's environmental impact statement and subsequent public hearings with utilities targeted for conversion because of their existing but mostly unused coal burning capability.

As of June 1, FEA had sent 20 utility companies notices of intent to force
the use of coal at 31 generating stations with 70 generating units. Nearly 80 are being considered for conversion. Of the 70 units, 40 are burning oil, 28 use natural gas and two use both. Most had been converted from coal in recent years to meet air pollution standards. FEA Administrator Frank G. Zarb issued the notices of intent in May under the Energy Supply and Environmental Coordination Act of 1974. Under the act, FEA must order conversions before its authority to do so expires on June 30. Legislation is pending before Congress to perpetuate the life of the Act. FEA scheduled public hearings in the Midwest and along the Atlantic seaboard to get the utility industry reaction to the notices. The environmental study lucidly shows degradation of the environment resulting from the conversion concept, even while meeting present and proposed air and water quality and other environmental standards. The hearings focused on the utility industry's sorry financial situation and other fundamental factors not included in the EIS such as:

- Is the long term supply of coal available?
- Is available coal suited to a unit's boilers?
- Are transportation facilities available to move the coal?
- Do coal mining companies need capital from utilities to expand existing or start new operations?
- What is the labor picture for mining and transportation?

The financial issues are as complex as the logistic and technical ones. Some firms have disposed of coal loading and storing sites and facilities; others no longer have the sludge disposal sites or facilities for moving wastes and other facilities that were terminated during the switchover from coal. Many plants are in urban areas where land use is restricted and pollution controls are firm. The conversions will cost millions of dollars the utilities can only get from customers or Congressional action such as tax breaks.

Many, if not most, utilities report their air pollution control equipment inadequate to meet air quality standards. Some have boilers designed for coals which are no longer available on a dependable, long term basis.

FEA acknowledged that not all the factors involved in conversion have been examined and that in many cases "the values used (in computations) are rough estimates of factors which are very difficult to characterize or quantify." FEA clearly recognizes a situation-by-situation approach is required and a blanket order on conversion is unworkable. It is expected that some of the utilities will be put under orders before the end of June to convert. They would have six months to prepare plans on the conversion and it would be many, many months in most cases before the conversions themselves are put into effect. Whether or not the 1978 deadline for conversion can be met with environmental standards being satisfied is far from certain.

A summary of conclusions from the EIS includes:

- Increased air pollution from nitrogen and sulfur oxides, particulates and trace elements as well as fugitive dust.
- Diversion of water for sludge handling and coal mining and processing operations and increased water pollution from mining operations and waste disposal.
- Higher noise levels in vicinity of coal mining, processing, transporting, and handling operations.

The EIS briefly examines alternatives to coal and concludes there are major uncertainties in nuclear, synthetic fuels, geo-thermal steam, solar, and other energy sources that prevent them from having much impact on the short term goal to promptly reduce dependence upon oil imports. The report notes also that many of the power plants proposed for conversion will be within ten years of the end of their normal useful life by 1980. FEA observes that under present law it can order power plants now on the drawing boards to include
coal burning facilities, but not require the utilities to burn coal.

The plan to convert from oil and gas to coal includes major non-utility energy users in industry. Furnaces using 100 million BTU's per hour or more are required to examine conversion potential.

EPA and FEA can determine the cost of switchover to be too expensive. If so, no conversion order will be issued. The installations being reviewed are those originally designed to burn coal, but which were later converted to oil and gas. Power units specifically designed for oil and gas are not part of the program.

On the basis of fuel costs alone, it is conceded coal is the cheaper energy. But cost of transportation, pollution controls, and other capital outlays can result in continued burning of oil or gas since one of the provisions of the program is to maintain electric service.

In many instances, the utilities realize that supplies of natural gas and oil are limited and uncertain, so environment and costs aside, coal is going to be the fuel.

About 400 million tons of the nation's 600 million ton annual coal production goes to steam power generation, FEA said. If the target of a 595,000 barrel per day reduction in oil imports can be achieved by 1980, more than $2 billion annually based on $10 per barrel oil could be kept out of foreign pockets. FEA estimates the coal conversion program would need 60 million tons of coal annually.

The effect on natural gas is far from certain, since natural gas systems will be at peak capacity -- if the gas is available -- no matter who the customer is.

FEA studies show the utilities and the major oil-gas industrial users are the places where the most gas and imported oil can be saved soonest. What the studies have yet to reveal is if the conversion is feasible in the present fiscal climate and what incentives may be needed to reduce the balance of payments drain as well as foreign fuel dependency. Nor is it certain environmental standards can be attained within the prescribed deadlines. The possibility of off-shore oil supplies becoming available to the eastern utilities is also being evaluated. Even with off-shore oil, the coal burning capability would appear feasible on a backup basis if a particular situation warrants it. On the eve of the public hearings, the utilities had been surprisingly quiet on the conversion concept.

# # # #
ENVIRONMENT

COLSTRIP RECLAMATION STUDY CONTINUES

The most recent report on high plains coal strip mine land revegetation from Montana Agricultural Experiment Station shows considerable progress is being made in disturbed land reclamation. The study in cooperation with Montana State University and Western Energy Company is continuing at the Rosebud Mine, Colstrip, Montana.

The work at an elevation of 3,200 feet is directed at complying with Montana's landmark surface mine land reclamation law which requires restoration of disturbed lands to provide a suitable permanent vegetative cover capable of:

- Feeding wildlife and livestock as well as it had before mining
- Regenerating itself under natural conditions
- Preventing soil erosion

The latest report (No. 69) is from the research of Brian W. Sindelar, Richard Atkinson, Mark Majerus, and Ken Proctor under the direction of R.L. Hodder. It describes the work and concludes that of a variety of methods to increase soil moisture retention gouging disturbed lands is best, overall. Gouging entails using specially designed equipment to scoop six to eight inch deep basins about 15 inches wide and three to four feet long in the land to be reclaimed.

The results of revegetative work using a variety of plants, fertilization, mulching, and other techniques is reported. The work reveals compaction from heavy machinery used in earth moving is a significant negative factor, along with soil moisture, in obtaining satisfactory revegetation.

Another factor was rodents which devoured seed and roots on some experimental plots. Methods used to encourage predators which successfully controlled the pests are also cited.

In raising several questions needing more study, the report records the deterioration of stockpiled topsoil. Living organisms in the soil perish during the interval between overburden removal and replacement of the soil for reclamation. How to "recharge" the replaced top soils is a major area for research.

The researchers also concluded a minimum of four inches of topsoil is desirable at the site and that greater amounts of topsoil did not show significant benefits to plants during the study period.

The report is weakened by the total absence of economic data and even preliminary conclusions on the potential significance of the findings. Also, the directional exposure of the test plots and the apparent differences between them would be helpful, even if tersely summarized and taken from earlier research.

During the summer of 1975 soil mulching trials are in progress using different methods of site preparation. The mulches being used are manure, sawdust and straw. It is the fourth consecutive year of reclamation studies at the southeast Montana mine.

PLANT MATERIALS CENTER FOR COAL-OIL SHALE DEVELOPMENT PROPOSED NEAR MEEKER, COLORADO

An Upper Colorado River Regional Plant Materials Center to develop and grow seed for reведения of oil shale and coal mined lands in northwest Colorado, southwest Wyoming, and northeast Utah has tentatively been selected near Meeker, Colorado. U.S. Soil Conservation Service (SCS) hopes to get 80 to 100 acres of the Grant Nielsen ranch. Negotiations were proceeding smoothly until Nielsen died. The matter is now being pursued with his estate.
The estate prefers to sell no less than 180 acres at a cost of $239,400. Representatives of the Douglas Creek Soil Conservation District, Rangely, and the White River Soil Conservation District, Meeker, are trying to raise state and industry cooperative funds to acquire the property.

The site was deemed the best of more than 20 inspected by SCS, district and revegetation experts at Colorado State University. SCS has $400,000 to get the center started, Ellis Sedgley, Colorado resources conservationist, said. The land price is higher than anticipated.

The Rocky Mountain Oil and Gas Association (RMOGA) Environmental Subcommittee of the Oil Shale Committee, has endorsed industry support for a center including $96,000 for land and $130,000 for buildings. It observed SCS, the U.S. Fish and Wildlife Service and the U.S. Forest Service Surface Environment Mining Project expect to contribute $50,000, $50,000 and $30,000 respectively for annual operations. Federal funds are not available for building or land acquisition, it said.

The committee preferred the Rangely area for the center, as more typical of regional environment. SCS favored the Meeker site for availability of water, developed land, and other improvements which will expedite research. While it endorsed the concept, the subcommittee believes additional inquiry should have been made for oil company owned land or even BLM property for the center, a move which could substantially reduce costs. The RMOGA group recommended formation of an advisory panel for the center that would include representatives of industry donors.

The purpose of the center is to provide seeds and plants for revegetating mine spoils, spent shale tailings, rights of way, and other disturbed lands in a manner to provide food for wildlife and livestock and prevent wind and water erosion. Of 50 varieties of plants proposed for revegetation, only three are now classified as being highly adaptive to the Upper Colorado region, SCS reports.

In a study of reclamation needs, SCS found "diversity in vegetation to satisfy the many environmental needs cannot be accomplished with the plant materials now available." Sedgley believes it is an urgent matter to get the project underway since thousands of acres are destined for disturbance from coal, oil shale, and associated development.

It can take ten years or more to produce plant varieties particularly adapted to the 6,500-foot elevation, 100-day growing season, limited rainfall, and other factors. Sedgley said SCS is working on a new variety of sagebrush which is palatable to cattle and could help revegetate the land and contribute to the agricultural economy.

The cooperative plant materials center could keep mining companies from duplicating each other's revegetation research efforts, he said. SCS has published an analysis of the need and feasibility of the center.

# # # #

RESEARCH ON TOXIC EFFECTS OF COAL PROPOSED

A program to identify and evaluate toxic effects of synthetic fuels processing is being prepared by a joint government-industry committee under the auspices of the National Academy of Sciences. An informational meeting in Washington on May 15 was called by Ralph C. Wands, director of National Research Council Advisory Center on Toxicology, resulted in a steering committee being formed to prepare a proposal for funding a toxicology research effort.

The NAS group selected Lt. Cmdr. Leigh E. Doptis, Branch of Medicine and Surgery, U. S. Navy, steering committee chairman. Vice chairmen are Dave Coffin, Environmental Protection Agency, and James M. McNerney, American Petroleum Institute. Ralph Wands was named secretary.

Consideration of health aspects of converted hydrocarbon fuels came in the wake of a publication on the carcinogenic potential of coal and coal conversion products by Battelle Memorial Institute.
The Battelle study by R. I. Freudenthal, G. A. Butz, and R. I. Mitchell summarized known data of cancer linked to coal mining, coking, gasification, liquefaction/hydrogenation, and solvent refining. The report notes the paucity of information on hydrocarbon compounds associated with coal processing and the even greater lack of data on toxic effects of most of the known coal originated organic chemicals.

The study found the actual carcinogenic risk associated with coal mining is either low or non-existent. A far different picture is developed however for coking/carbonization of coal and processes yielding coal tars and other compounds. Coal tar contains about 10,000 chemical compounds, of which only about 1,000 have been identified. The Battelle report cites data from several studies linking coal tars with cancer of the larynx, lungs, nasal sinuses, kidneys, bladder, urinary organs, stomach, intestines, pancreas, and other physiologic centers. High yield phenol processes, a substantial economic factor, also correlate to compound health hazards in some studies.

New coking furnaces incorporate designs which can lessen hazards to workers directly involved in coking coal operations. In the U.S., there are about 10,000 persons directly involved in coking coal operations.

The Battelle report cautions research results should not lead to premature conclusions that carbonization is the most hazardous of coal conversion processes. "Equally serious hazards may exist with some other coal processing operations," the authors advised.

The early stages of coal gasification are the most suspect as being detrimental to health. Yet, even considering a number of different processes, few specific data are available. The report points a respectful finger at tars of high-boiling oils, and warns of potential cocarcinogenic and synergistic effects. Cocarcinogen is defined as an agent which increases the potency of a carcinogen by direct, concurrent, local effect on tissue.

Liquefaction and solvent refining offer a variety of potentials for carcinogenic hazards and non-hydrocarbon fractions must not be discounted for possible cocarcinogenic effects.

The presence of crude gas of tar, oil, naptha vapors, and other hydrocarbons and sulfur compounds may generate a carcinogenic potential which can be eliminated by engineering design which minimizes exposure to skin and inhalation.

The report notes that the gas from coal is not known to cause cancer. The report falters in not putting the matter into perspective for industry workers and the general public. The relative significance of the cancerous potential needs to be compared with other known health hazards from the outset, even if such comparisons are prepared on limited information. This aspect of the synthetic fuels picture also needs consideration by the new NAS steering committee.

# # # #
COAL LEASING ACTIVITY REPORTED

Several federal competitive lease applications have been filed for coal in the Raton Mesa area of Colorado. This area has a potential for the development of bituminous coal at the time of a reinstated federal coal leasing policy. CF and I Steel Corporation of Pueblo, Colorado, has applied for 44,836 acres in Las Animas County and Tipperary Corporation of Midland, Texas, has applied for 69,044 acres in Las Animas and Huerfano Counties, Colorado. In Montana Dryer Brothers, Inc. (subsidiary of Burlington Northern) has filed for a federal competitive Lease in McCone County for 15,109 acres. McCone County is the area of the proposed Burlington Northern Circle West coal conversion and water diversion projects. Interior expects to have the final draft of the federal coal leasing program publicly available this summer.

A state lease of note was issued to Utah Resources International in Garfield County, Utah for 25,873 acres.

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Catalytic Production of Hydrocarbons from Coal-Steam Systems

Researchers at the University of Wyoming at Laramie have been developing coal gasification technology since 1968 under contract with Interior's former Office of Coal Research and presently under contract with ERDA. The initial portion of research, which ended in 1973, was directed at the development of a single stage multicatalyst system to convert coal directly to high-BTU SNG. The coal gasification work at Laramie has been strictly bench scale on a semi-continuous basis with some catalyst performance data obtained with a bench, steady-state system using prepared synthesis gas mixtures. The catalysts employed are several alkili and alkiline carbonates, and Group VIII transition metals to include nickle and iron. Research efforts and results are summarized for the period 1968 to 1973 and recently released in OCR R&D Report No. 80 Final Report. The title of the report is "The Direct Production of Hydrocarbons from Coal-Stream Systems."

Various combinations of the catalysts mentioned above were used to investigate the carbon-steam gasification reactions over a range of temperature and pressure. These experiments showed the production gas ranged between 500 and 900 BTU per SCF (CO₂ free) at a rate of about 10 MSCF per ton of coal (5 SCF per lb). The optimum conditions of the system appear to be approximately 650°C (1200°F), 30 psig and a ratio of coal to alkil-carbonate of about five to produce gas after methanation with a heating value of about 900 BTU per SCF at 70 percent carbon conversion. Scaling the optimum preliminary bench data to a commercial operation; about 25 MTPD or 9.13 MMTPY would be required for a 250 MMSCFD SNG plant. This operation would require about 2.5 MTPD of carbonate salt or 0.91 MMTPY at a recovery factor of 50 percent.

The carbonates shown to be useful are sodium carbonate (Na₂CO₃), trona (Na₂CO₃·NaHCO₃·2H₂O) and potassium carbonate (K₂CO₃). The recovery of up to 90 percent of these carbonate catalysts has been shown to be possible via a single wash of the recovered ash, according to the report; however, the economy of this washing operation is not indicated. The Group VIII metals behave in different ways, catalyzing distinct product distributions. Nickle is known to catalyze reactions producing methane while iron favors the production of liquid products. The alkil-carbonates tend to promote the carbon-steam reaction. The overall reaction of the multicatalyst system, as supported by the Wyoming research, appears to be:

\[ C + H₂O = \frac{1}{2} CH₄ + \frac{1}{2} CO₂ \]

Conclusions that may be drawn about the system are: (1) steam rate must be judiciously controlled since high steam rates, particularly in the presence of iron, yield effluent rich in hydrogen; (2) coal-steam reactivity seems to decrease with pressure but may be offset by increasing the temperature; (3) carbon monoxide introduction into the system enhances the coal-steam reaction; and (4) hydrocarbon production falls off with catalyst temperatures greater than 600°C (1125°F).

The process has been studied with a fixed methanation catalyst bed. The degree of methanation of course was proportional to the residence time of the synthesis gas in the nickel catalyst bed. The effect a fluid bed reactor will have on the overall system kinetics and product distribution are yet to be studied. A fluid bed system would include in one stage the reactions between the steam and carbon, catalyzed with both carbonate and nickle, in a homogenous reaction zone. The thermodynamics of these various reactions indicate the potential of the system being auto thermal. The balancing of the endothermic carbon-steam reactions against the exothermic methanation reactions appear to be possible. Thermo-dynamically the kinetics of the methanation reactions are favored at about 400°C (752°F) but an increase in pressure will compensate.
HYGAS PILOT PLANT OPERATES ON SELF SUSTAINED BASIS

During May 1975, the HYGAS pilot plant at IGT's research facility in Chicago, Illinois, operated for 203 hours with no supplemental heat input for a total of 20 hours other than what was available within the system. The test run consumed 350 tons of lignite. The product gas composition was 96.5 percent methane and 3.5 percent hydrogen with a heating value of approximately 970 BTU/ cu ft.

Dr. S. William Gouse, Jr., Deputy Assistant Administrator for Fossil Energy, said, "This successful operation culminates the intensive effort of the HYGAS group in the last few years during which many modifications and improvements have been incorporated into the plant."

In the course of the run, the hydrogen flow to the start-up heater was cut back gradually until all hydrogen and oxygen were shut off from the start-up heater, and the system sustained itself in this mode of operation for almost 20 hours. All auxiliary units operated satisfactorily. Tests are underway to lengthen the time of sustained thermal operation.

Crushed coal is slurried with a process derived light oil, pumped to 1000 to 1500 psi and introduced at the top of the reaction column at about 1800°F. The oil is vaporized and recovered. The coal falls counter current to a hydrogen stream where about one-half of the coal is reacted. The gas is recovered at the top of the column with char removed at the bottom. The subsequent steam-oxygen gasification of the char renders the process hydrogen. The system has these advantages:

1. It works at pipeline pressure and eliminates the need for compressors.
2. The raw gas from the reactor contains a high percentage of methane, and thus minimizes the size and cost of the methanation section.
3. Energy requirements are minimized by transfer of char and gases between the various vessels at equally high temperatures and pressures.

IN SITU COAL GASIFICATION - TEXAS UTILITIES SERVICES INC.

Texas Utilities Services Inc., an affiliate of Dallas Power and Light Company, Texas Electric Service Company, and Texas Power and Light Company, will use underground gasification technology developed in the Soviet Union to determine the feasibility of gasifying deep lignite deposits in east Texas. Soviet research into the underground production of combustible gas from deep coal deposits began in 1933; the Soviets are now operating two underground gasification plants. Although the heating value of the gas is expected to be relatively low, it represents a potentially economical method for extracting energy from lignite deposits which lie more than 150 feet below the surface. A pilot plant is scheduled for operation in 1976.
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A National Program

ACCELERATED OIL SHALE IN-SITU RESEARCH

ERRATA

1. Add footnote to bottom of page 8 following the last line of the first full paragraph. This line should read: "These 7 combinations are marked with a + in Table 1. 5a/"

Footnote 5a/ is as follows: External review of this report indicated that + symbol in Table 1 should be given to the technical options listed under "in situ" and "Type I" Resource Targets. Although data is not publicly available to support this conclusion, it is considered likely that technologies developed under an accelerated program would result in several promising options in addition to those listed in Table 1.

2. Figure 5, Page 14. The correct Figure number and title for this Figure is: Figure 6. - True In Situ Research Projects, PERT Network. The proper location of the Figure is Page 17.

3. Figure 6, Page 17. The correct Figure number and title for this Figure is: Figure 5. - Overview of Accelerated Oil Shale In Situ Research and Development Program, PERT Network. The proper location of the Figure is Page 14.

Coordinated by
Interagency Oil Shale Planning Panel
March 1975
The information contained in this report was coordinated by a Government interagency panel. It is being presented to provide interested parties an opportunity to comment before a decision is reached to implement or modify this major national effort. Your comments are solicited by May 1, 1975 and should be directed to:

Director
Laramie Energy Research Center
Energy Research and Development Administration
P.O. Box 3395, University Station
Laramie, Wyoming 82070

PREFACE

The accelerated oil shale in situ research and development included in this report was coordinated by a U.S. Government Interagency Oil Shale Panel in February 1975. The Panel was composed of oil shale experts in several disciplines and drawn from: (1) The newly created U.S. Energy Research and Development Administration (ERDA); (2) the Department of the Interior (as represented by several agencies of that Department); and (3) the Environmental Protection Agency. A listing of the personnel from these agencies and their respective titles appears below:

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ACCELERATED OIL SHALE IN SITU RESEARCH

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Laramie

1/ Laramie Energy Research Center
2/ Office of Research and Development
3/ Bartlesville Energy Research Center
4/ Morgantown Energy Research Center
5/ Mine Enforcement and Safety Administration
6/ Fish and Wildlife Service
7/ New titles under ERDA unknown. Old titles with previous agency given.
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ACCELERATED OIL SHALE IN-SITU RESEARCH
A National Program

I. SUMMARY

Efforts to develop the Nation's vast oil shale resources have largely focused on mining the oil shale and heating it in surface vessels called retorts. An alternative technical approach, called in situ (or in-place) retorting, has not been actively pursued. Yet, development of a viable in-situ technology offers the potential of both significant environmental advantages and an increase in the amount of recoverable resources.

The program described in this report is directed specifically toward research needed to overcome the technical obstacles that have retarded the development of in-situ processes.

The program goal is to develop, by 1980, several commercially viable technologies for the in-situ production of shale oil.

National in scope, the program is expected to be undertaken with private funds in part with joint Federal/private financing and, where neither is feasible, wholly with Federal funds. The Federal Government would provide overall program management to ensure that all parts of this highly interrelated program move forward harmoniously.

Although emphasis is directed toward the oil shales of Colorado, Utah, and Wyoming, research would also be initiated on the oil shale deposits that underlie much of the Eastern United States. A number of feasible in-situ technologies would be tested in various oil shale resource types.

<table>
<thead>
<tr>
<th>Page</th>
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<tbody>
<tr>
<td>15. Horizontal Modified In Situ Research Projects, PERT Network</td>
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<tr>
<td>16. Horizontal Modified In-Situ Research Projects, Milestones</td>
</tr>
<tr>
<td>17. In-Situ Gasification Research Projects, PERT Network</td>
</tr>
<tr>
<td>18. In-Situ Gasification Research Projects, Milestones</td>
</tr>
<tr>
<td>19. Environmental and Support Studies, PERT Network</td>
</tr>
<tr>
<td>20. Environmental and Support Studies, Milestones</td>
</tr>
</tbody>
</table>
II. INTRODUCTION

The Department of the Interior, in cooperation with the Energy Research and Development Administration (ERDA) and other government agencies, has developed a program designed to accelerate the development and application of in-situ processes to recover shale oil from oil shale. Specifically, the objective of this program is:

To advance to the point of commercial application by 1980, alternative methods for in-situ recovery of shale oil and, in so doing, extend the data base needed to form future policies for oil shale development on public lands.

The in-situ program, to be administered by two federal agencies, involves two concurrent actions:

1. By Interior: Initiate those steps that could lead to lease sale(s) of one or two prototype oil shale tracts for in-situ development by private industry, and

2. By ERDA: Initiate an accelerated program of in-situ research designed to complement the Interior action.

The two actions are interrelated, with information developed under the first action used to plan the second. That is, to determine industry interest, Interior will offer one oil shale tract for in-situ development. Industry will signal their interest (or lack thereof) by nominating tracts for development using a technology to be specified. This will then allow ERDA to plan research to support -- but not duplicate -- what industry is willing to do. Also, technologies not of immediate interest will be pursued by cooperative ventures with industry or through in-house efforts. This accelerated program can be initiated by July 1975.

The conceptual framework for this in-situ program has been presented 1, extensively reviewed, and approved for implementation. An updated schedule for the program is presented in Figure 1. The upper line represents in-situ research while the bottom two lines represent continuation of Interior's prototype oil shale leasing program. Note in this Figure how information is expected to be developed and exchanged; the results of the leasing action provide the primary criterion to select the research to be conducted under government sponsorship.

The present report is concerned with the research to be conducted. Since the initial results of the call for tract nominations with technology

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1 Office of Research and Development, Department of the Interior, A Strategy to Stimulate Oil Shale Development by In Situ Processing, August 1973, 30 pp.
specified is not now available, the report presents the research necessary to achieve the in-situ program objective. None of this research is expected to be undertaken by private industry on public lands or in conjunction with the development of leases on these tracts on public lands. These efforts will not be duplicated under federally sponsored program. The reader should therefore understand that some of the research activities described below will probably be undertaken with public funds.

The total research program is presented for completeness and is based on current information. The plan will be modified as additional information becomes available.

III. NEED FOR IN-SITU PROGRAM

In situ, or underground processing, of oil shale offers many potential advantages over the technologies that will be employed on the public lands leased under the Department of Interior's Prototype Oil Shale Leasing Program. As compared to mining and surface processing of oil shale, for example, it is estimated that in-situ production of shale oil would require:

- Two-thirds fewer people to operate the process,
- One-half the amount of water, and
- One-third to essentially no disposal of waste oil shale.

In-situ processing also offers the possibility of application to low-grade oil shales. This advantage is important in that some 1.2 trillion of the total resource of 1.8 trillion barrels of shale oil is in low-grade deposits that may never be recovered by conventional mining techniques. Additionally, this low-grade resource is largely found on public lands and must be considered in conjunction with any future leasing of such lands. Sound planning therefore dictates that in-situ technology be advanced to the point of commercial application prior to the time such leasing decisions are made.

It is not now known when future decisions will be made concerning oil shale development on public lands. However, the analysis conducted for Project Independence 2/ indicated that public oil shale land will need to be leased beginning in the 1979-80 period if a decision is reached to accelerate shale oil production over that contemplated under the prototype program. Thus, information concerning the commercial application of in-situ technology needs to be available by 1980 for the government to discharge its responsibility to manage oil shale development on public lands.

Specifically, the type of information to be developed includes:

- Recovery efficiency (hydrocarbons and minerals),
- Types of shale deposits to which process is applicable,
- Compatibility of process with other processes which may ultimately be required to maximize recovery of total resource,
- Guidelines to protect health and safety of workers,
- Delineation of environmental effects,
- Process demands on other resource bases (energy, water, equipment and materials and manpower), and
- Ability of process to contribute to national energy objectives considering cost and rate of application.

Such information on surface and underground mine development followed by surface retorting will be available from development of a prototype tracts under Interior's 1974 leasing program. 3/ The in-situ program would complement this action as shown in Figure 2.

Specifically, the in-situ program is to develop, through leasing plus research, the ability by 1980 to:

1. Determine the technical and economic feasibility and environmental costs of shale oil recovery by the true in situ or the modified in-situ retorting method.
2. Determine the best fracturing or explosive rubblizing technique for the resource.
3. Determine the operating conditions necessary to obtain the desired retorting results, whether these results be maximum gas production, maximum oil production, or maximum resource recovery.


IV. IN-SITU RESEARCH PROGRAM

A. In-Situ Technologies and Resource Targets

In-situ processing may be accomplished by two principal means: (1) a borehole technique where oil shale is first fractured underground and heat is applied, or (2) a process in which some mining is followed by fragmenting the remaining oil shale into the voids created by mining followed by the application of heat. The first method has been or is being researched by Shell Oil, Equity Oil, the Energy Research and Development Administration (work previously done by the Bureau of Mines and transferred to ERDA), and others. The second is currently being developed by Garrett Research and Development Corp., a subsidiary of Occidental Petroleum. These two types of in-situ processing are referred to as in situ (no mining) and modified in situ (some mining), respectively.

Methods of fracturing will vary, depending on the amount of surface area needed underground and the method used to raise the broken oil shale to the pyrolysis temperature of about 900°F.

Heat may be applied in several ways, by hot fluids, by hot gases, or by direct combustion.

All of these technical approaches, and combinations thereof, may be ultimately required for optimum development of the oil shale resource. This follows from consideration of the various types of deposits found in Colorado, Utah, and Wyoming. There is not one type, but several types which have been classified by the Bureau of Mines 4/ as follows:

Type I. Deep

This target is deeply buried (up to 2,000 feet), grade 15-25 gallons per ton; beds to several hundred feet in thickness; generally impermeable; may contain dawsonite and nahcolite—typical of the Lower Zone shale in the Piceance Creek Basin; almost entirely Federally owned.

Type II. Shallow

These shales are under 100 feet or more of overburden; grade 15-25 gallons per ton; thickness to 250 feet; generally impermeable—typical of Utah and Upper Zone Piceance Creek Basin; Federal, State, and privately owned lands.

Type III. Deep Leached

These shales are deeply buried (1,200 feet); grade 15-25 gallons per ton; thickness to 1,000 feet; permeable; saline aquifer over most of area but some waterfree permeable areas—typical of Leached Zone in Piceance Creek Basin; almost entirely Federally owned.

Type IV. Thin Beds

Type IV shales are characterized by variable depths (100 to over 3,000 feet), grade 15-25 gallons (4,000 to 50,000 cubic feet) in sequence of beds up to 50 feet thick interspersed with barren rock; oil shale beds generally not permeable — typical of Wyoming basins and some Utah deposits; Federal, State and privately owned lands.

The complexity of the research required to obtain the objective of this in-situ program has been described by the Bureau of Mines. By considering five distinct in-situ technologies and four major resource types, a minimum of 20 separate projects would be required to test all combinations of technology and resource target. However, as shown in Table 1, present information indicates that only 7 of the 20 possible combinations are of potential commercial interest. These 7 combinations are marked with a + in Table 1.

The modified in-situ processing method is more widely applicable than the in-situ approach as shown in Table 1. The in-situ approach is more likely to be applied to thin beds such as those found in Wyoming. Based on present information, one technology option may be amenable to the deeply leached oil shale found only in the Piceance Creek Basin, i.e., hot fluids injected through boreholes. The lack of applicability to Type III deposits represents an important opportunity for the development of new approaches that may evolve from the proposed program with emphasis on the approach(s) that can recover the minerals (nabcolloid and Dawsonite) as well as the shale oil associated with this resource target.

The variability of the oil shale deposits and the varying demands for hydrocarbon products (gasoline, fuel oil, or fuel gases) indicates that no one processing technique can be universally applicable to all types of oil shale resource targets. It follows that there is a need to develop several techniques to the point of commercial application to assure that efficient resource recovery is achieved at acceptable environmental costs.

B. Current Program

The current program consists of a number of sequential tests at one Type IV site in Wyoming. This is a small test (under 10 acres) at a depth of about 150 feet. This research will be continued as an in-house project. Additionally, four other field tests covering 1 to 10 acres will be initiated in Type IV deposits. These will lead to a final demonstration of a true in-situ process on a 20-acre site. These latter four tests will be performed on a contract basis, starting with design and procurement in fiscal year 1976.

Table 1. Potential for Application of In Situ Technology by Resource Target and Technologic Option.

<table>
<thead>
<tr>
<th>Technologic Options</th>
<th>Resource Targets</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Type I</td>
</tr>
<tr>
<td></td>
<td>Deep 2,000 feet</td>
</tr>
<tr>
<td>Modified In Situ</td>
<td>N.A.</td>
</tr>
<tr>
<td>Horizontal Retort</td>
<td>+</td>
</tr>
<tr>
<td>Vertical Retort</td>
<td>+</td>
</tr>
<tr>
<td>In Situ</td>
<td>N.A.</td>
</tr>
<tr>
<td>Inject Hot Fluids</td>
<td>N.A.</td>
</tr>
<tr>
<td>Inject Hot Gases</td>
<td>?</td>
</tr>
<tr>
<td>Direct Combustion</td>
<td>N.A.</td>
</tr>
</tbody>
</table>

NOTE: + indicates promising application of a specific technology to a specific resource target.

N.A. - is not applicable.
?

- is of questionable application.


5/ Ibid.
ACCELERATED OIL SHALE IN SITU RESEARCH

Table 2: Current In-Situ Oil Shale Research, Energy Research
And Development Administration: (Dollars in Millions, Budget Authority)

<table>
<thead>
<tr>
<th>Program: Oil Shale</th>
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<tr>
<td><strong>Fiscal Year</strong></td>
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<tr>
<td><strong>1974</strong></td>
</tr>
<tr>
<td><strong>Trans. Quarter</strong></td>
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<tr>
<td><strong>In-Situ Program: ERDA</strong></td>
</tr>
<tr>
<td>a. Oil Production</td>
</tr>
<tr>
<td>b. Gas Production</td>
</tr>
<tr>
<td>c. Environmental Studies</td>
</tr>
<tr>
<td><strong>2. Composition and Characterization</strong></td>
</tr>
<tr>
<td>0.9</td>
</tr>
<tr>
<td><strong>TOTAL OIL SHALE</strong></td>
</tr>
<tr>
<td>3.7</td>
</tr>
</tbody>
</table>

C. Exercise of Accelerated In-Situ Program

Systematically moving research programs to the feasibility of the in-situ processing of oil shale is currently proposed to Congress for Fiscal Year 1976. This program, as currently proposed in Table 2, is an in-situ processing program, but would need to be accelerated in concert with the accelerated in-situ program.
ACCELERATED OIL SHALE IN SITU RESEARCH

Figure 4. - Major Areas of Research for Accelerated Oil Shale Research
Modified in-situ programs address the research problems associated with both horizontal and vertical retorting systems. Since industry is already actively engaged in the vertical retorting research, a cooperative program could rapidly advance the technology. For example, a cooperative program could lead to a decision for commercialization 2 years after such a program is initiated.

A horizontal retorting system will require a more gradual scale up since little information is available from past accomplishments. Starting with a site capable of retorting 6,000 tons and scaling up to a site capable of retorting 24,000 tons will take at least 2 years after starting the program. Evaluation, construction and operation of a PDU will require at least another 2 years. Therefore a decision for commercialization will be at least 4 or perhaps 5 years from the start of the program.

Gasification of oil shale in situ (actually maximizing gas production in situ because both liquids and gases are produced) will offer yet another option for development. This research is proposed to maximize the gas heating value as well as the gas produced from an underground oil shale operation. The construction of a 25-40 ton gasifier could lead to a decision to construct a PDU 2 to 3 years after initiation of the program. Results from the PDU would not be obtainable for at least another 2 years.

The overall program is designed to assess many relevant in-situ technologies as soon as possible. The accelerated research program concerns itself with a procedure for the measurement of the impacts of in-situ oil shale development and the trade-off among these relevant technologies. This will be done in arriving at a final assessment of the technology for demonstrating the practicality of advancing the in-situ oil shale research to the commercial phase.

Thus, a most important aspect of the accelerated research program is to extend the options available for process design. The results of this multiple approach research program will also allow decision-makers to clearly assess the technology's relevance throughout the design program and not after the design has been completed.

Although some assessments cannot be made until designs are formalized and pilot plants are built, the results will provide a range of conditions within which the technology should operate.

V. IN SITU RESEARCH PROJECTS

As detailed above in Chapters IV, Section B, the Government is currently conducting in-situ research in a plan to carry out four sequential tests at one site. A decision to scale up to demonstration may be made by 1980. The site represents resource Type IV (Wyoming). However, applicability of techniques developed in situ to other resource types identified as suitable for in-situ methods remain in question.
The accelerated program includes an expansion to six test sites and the concurrent conduct of 12 or more experiments over a 2-1/2-year period. The six sites address three of the four resource target areas, I, III, and IV, respectively in Western and I, II, and VI in Eastern oil shale as follows:

<table>
<thead>
<tr>
<th>Type Oil Shale</th>
<th>Site Location</th>
</tr>
</thead>
<tbody>
<tr>
<td>Western</td>
<td></td>
</tr>
<tr>
<td>IV</td>
<td>Site 1 - Lane member, Green River Formation, Wyo. Depth 400 ft.</td>
</tr>
<tr>
<td></td>
<td>Site 2 - Tipton member, Green River Formation, Wyo. Depth 1,500 ft.</td>
</tr>
<tr>
<td></td>
<td>Site 3 - Parachute Creek member, Green River Formation, Utah. Depth 1,000 ft.</td>
</tr>
<tr>
<td>III</td>
<td>Site 4 - Leached zone, Parachute Creek member (below Mahogany Zone), Piceance Basin, Colo. Depth about 1,000 ft.</td>
</tr>
<tr>
<td>I</td>
<td>Site 5 - Lower Zone, Parachute Creek member, Piceance Basin, Colo. Depth about 2,000 ft.</td>
</tr>
<tr>
<td>Eastern</td>
<td>Site 6 - Antrim shale, Mich. Depth about 1,000 ft.</td>
</tr>
</tbody>
</table>

The site locations and resource type is related to key events for the in-situ research projects in Figure 6. The milestone chart for these projects is presented in Figure 7. Each phase of the activities is discussed in more detail in the sections which follow.

Industry participation and cost sharing is expected on sites 4, 5, and 6, and is desired on sites 1, 2, and 3. At least one field test will be conducted at each of these sites.

At each of the first three sites the application of in-situ methods depends on developing fracturing technology to connect well patterns through the shale beds and provide adequate heat transfer surface to permit retorting. Consequently, an intensified fracturing research effort is required before the nine retorting tests planned for these sites can be initiated.
Acceleration is achieved by conducting the 12 field tests concurrently during the first 2-1/2 years of the program so that decisions for scale up or direct commercialization can be reached by 1978. The probability that viable in-situ processes will be achieved is greatly increased by the variety of site and retorting conditions included in the program. The cooperative programs, sites 4, 5, and 6, will most likely be done by private industry since they have expressed interest and are currently conducting research on in-situ processing. The cooperative programs phase is designed to gain rapid access to information which may now exist on in-situ processing or may be developed in the near future.

A. Fracturing Research

This section presents an accelerated research program for fracturing and retorting oil shale by Wyoming and Utah at depths of 400, 1,000 and 1,500 feet. This program will be accomplished by the acceleration of the in-house program and initiating industry-Government programs.

The accelerated program addresses itself to nine field tests for fracturing and retorting in Utah and Wyoming. Figure 8 shows the general areas proposed for the experiments as discussed below:

Utah (Figure 9) - Three sites would be concurrently developed to test various fracturing techniques at depths of about 1,000 feet. The fracturing designs will include high explosive hydraulic fracturing, hydraulic fracturing, hot fluid accompanied by retorting, and vertical hydraulic fracturing. Nuclear explosive fracturing is not included in this program.

Wyoming (Figure 10) - These sites would be located in two 1/4 sections with well patterns drilled to 400 and 1,500 feet. The tests on the three sites at 400-foot depth will be hydraulic fracturing-high explosive tests with well spacing of 50, 100, and 150 feet using an inverted nine-spot pattern. The tests at the 1,500-foot depth will be high explosive-hydraulic fracturing, hydraulic fracturing-hot fluid accompanied by retorting and vertical hydraulic fracturing.

The locations shown on Figures 9 and 10 were chosen to take advantage of the rich oil shale sections at the desired depth. For example, Figures 11 and 12 are included to show the variations in oil shale grade with depth and also that rich sections of oil shale are interbedded with lean oil shale in much of the Wyoming deposit. While these cores were taken in the general area of the proposed 400 and 1,500 foot fracturing experiment tests, they are not from the exact locations.

The different fracturing experiments will be evaluated using various instrumentation techniques, for example, microseismic methods, resistivity methods, active seismic methods and flow and tracer tests.

B. Preparation for Recovery Research

Well patterns and well spacing will be varied at each of the sites depending on the local geological conditions. Once the oil shale zone is fractured, new wells will be drilled in the fractured zone as a result of the evaluation work. The wells will be cased and cemented and used for the injection and production wells while the explosive fractured
ACCELERATED OIL SHALE IN SITU RESEARCH

Figure 9. - Proposed Utah Site Locations

Figure 8. - True In Situ Research, Overview of Proposed Sites
ACCELERATED OIL SHALE IN SITU RESEARCH

Figure 10. Proposed Wyoming Site Locations

Figure 11. Histogram of Wyoming Corehole No. 1, Sweetwater County, Wyoming

LEGEND

- OUTLINE OF GREEN RIVER FORMATION
- TOWN

SCALE: MILES
wells will be used for monitoring. Surface facilities, plant facilities, and instruments and monitoring equipment will be installed along with production equipment.

C. Retorting Research

Two types of retorting will be employed in this phase of the operation: underground combustion and hot fluid injection accompanying underground combustion. The latter method will be employed only at the 1,000- and 1,500-foot sites. The gases produced from retorting will be utilized in running steam generators and gas turbines on site. The site will be evaluated after in-situ retorting is terminated.

D. Supporting Program

To complete the true in-situ research program the following support activities would be carried out:

- Continue base operating research program. This includes refinement of computer models, lab work, technical supervision, and engineering which needs to continue over the life of the program at a steady rate in order to maintain a base technical and engineering capability.
- Conduct follow-on experiment(s) at one or more of the established sites in order to optimize the technique(s) which the earlier program has shown to be most promising.
- Start a demonstration scale up jointly with industry in which the industry sponsors provide a portion of the funds for field construction.

E. Government-Industry Cooperative Tests

Government-industry cost sharing cooperative programs are contemplated to complete the overall program. Three areas to be investigated are eastern oil shale deposits, hot gas injection, and leaching in oil shale deposits.

The proposed approach is for Government and industry to enter into a cooperative cost sharing venture in at least these three areas to complement the research discussed above.

VI. MODIFIED IN SITU RESEARCH PROJECTS

Accelerated research will address problems in processing shales in strata that range from a few feet to several hundred feet in thickness. Overburden may range from none in shale outcrops, to 1,200 feet in the center of the Piceance Creek Basin, or to more than 1,200 feet in parts of the Uinta Basin. The shales range in permeability from essentially zero to shales with large voids created by water leaching of salts so that interconnecting vugs an inch or more in diameter are present. Physical properties may be one of the parameters that determines the applicability of a process. Results of the research should allow the selection of appropriate processes to produce the maximum energy values at a variety of locations in the oil shale deposits and thereby achieve an efficient overall recovery of the resource.
The need for a recovery system that can be used to recovery oil from low-grade shales (15 gallons per ton) becomes more vital as new resource data becomes available. Such new data indicates that if the proposed modified in-situ research is successful and if the system can be used for low-grade shales lying above higher grade (30 gallons per ton) shales of the Mahogany Ledge, shales heretofore considered as non-economic may become extractable resources. A very preliminary assessment by the USGS of 15-gallon-per-ton shales that fall into this category indicates our resource base might be increased by over 60 billion barrels in Colorado alone. This does not increase the total oil-in-oil shale base of 1.8 trillion barrels, but indicates that more of the total base may become economic to recover.

The accelerated modified in-situ research program involves activity in three areas: (1) mining research; (2) vertical modified in-situ research; and (3) horizontal modified in-situ research. The following sections list those steps necessary to accelerate the research together with system diagrams and goals sought.

A. Mining

Most of the experimental, or prototype, operations carried out to date in the Green River oil shale have employed the surface retorting of shale mined by conventional methods; and it is expected that the initial attempts at commercial-scale production also will follow this standard practice. However, less than 10 percent of the tremendous energy resource in the Green River Formation occurs in the readily minable upper shale beds. In order to increase such reserves and to offer improved options for their extraction, research must be performed on methods of recovering the oil not only from the deeper beds, but also from the widespread leaner deposits.

Development of a modified in-situ research or commercial production area must start with mining and mining will be required throughout the major portion of the expected life of the project.

The initial mining phase will be that required to develop (obtain entry) to the areas that are to be in-situ retorted. The size and number of development openings will be controlled for the most part by the design of the in-situ retorts. The only mining research considered during this development stage is the comparison (actual or paper study) of the rate and costs of tunnel excavation by means versus rate and cost of excavation by conventional methods.

The major mining research effort will be required in the design and construction of the in-situ retorts and the pillars separating these retorts. Retort and pillars must be designed so as to provide for containment of combustible and toxic gases formed during retorting and thus permit simultaneous mining and retorting in the same general area. It is also necessary that the overall retort and pillar design provide necessary roof support to that retorting operations are not complicated by caving of the overlying formations.

B. Modified In-Situ Retorting

Early efforts in in-situ retorting of oil shales using hydraulic and explosive fracturing to produce permeability experienced plugging of fractures with fines produced by the explosive and poor control of frontal movement. These tests are indicative of the difficulty of obtaining good permeability without first introducing porosity, or void volume. Subsequent research indicates that good permeability is probably best obtained by extracting a portion of the shale by mining and rubbling the shales above and/or below the mined zone.

Application of the vertical retorting system requires a method for obtaining a cavity filled with broken shale. Two methods of preparing vertical retorts are considered promising: (1) Mine out sufficient shale from underground retort cavity to provide the desired permeability with the remainder of the shale fragmented by drilling and blasting, and (2) use a nuclear explosive to create an underground cavity into which the overlying shale subsequently collapses. The use of nuclear explosives is not considered in this discussion.

Major areas of research and development of modified in-situ processing should include the following parameter investigations:

1. Optimum chimney dimensions that would be economical for a commercial-sized unit.
2. Optimum shale grade that best utilizes the resource.
3. Optimum pillar dimensions and spacing separating underground retorts.
4. Optimum rubble permeability to utilize most of the resource.
5. Secondary oil recovery from the pillars.

1. Vertical Modified In-Situ Research

Preparation of broken oil shale underground in a vertical configuration and direct combustion of the oil shale so prepared has been under active field development by Occidental Petroleum Corporation since mid-1972. Additionally, a number of other private firms or combinations of firms are known to be interested in exploring the potential of this approach. It is generally agreed that of all the in-situ methods described in this report, the vertical modified in-situ approach is closest to commercial application if the remaining technical problems can be overcome. Due to this, a call for tract nominations under the prototype leasing program outlined above would most likely result in nominations that would seek to apply this technique.
To meet the objectives of the in-situ program, Government has several options:

1. Contract with a research firm or firms actively engaged in modified vertical in-situ research to acquire quickly the information needed for Government purposes.

2. Contract a research firm that has or can gain access to an area already mined and initiate experimental work.

3. Initiate mining to prepare several chimneys and initiate experimental work designed to obtain maximum data acquisition in a minimum time.

The planning sequence for option 3 is given in Figure 13, and the milestone schedule in Figure 14. Option 3 thus provides maximum Government involvement which will be less if adequate information can be developed under the other two options outlined above.

2. Horizontal Modified In-Situ Research

At the present time no field research on horizontal modified in-situ retorting is in progress. Beginning in July 1975, an accelerated Government in-house program would include this research. The systems diagram for projects under this heading is given in Figure 15, while Figure 16 provides the technical milestone details.

The first experiment would consist of a horizontal development using a tunnel 500 feet long in either the Laneu or the Tipton member of the Green River Formation on White Mountain about 5 miles southwest of Rusk Springs, Wyo. (See Figure 10). The shale thickness in this area is 30 to 40 feet and if the broken shale in the retort is 20 feet wide the total amount of shale to be incorporated in this first experiment will be from 12,000 to 16,000 tons. This experiment will be conducted stepwise from one end of the retort to the other increments of 10 to 20 feet. Variations in operating parameters can be tried on each increment so optimum operating conditions to maximize recovery can be established in the first tunnel.

When retorting in the first tunnel is completed a second tunnel will be developed as close to the first tunnel as practical. The width of this second tunnel will be determined from results obtained from processing the first tunnel.

During the course of this first experiment information on the following will be obtained:

1. Efficiency of "stepwise" horizontal retorting,

2. The recoverability of the resource,
Figure 15. Horizontal Modified In Situ Research Projects, PERT Network

ACCELERATED OIL SHALE IN SITU RESEARCH
To accelerate this program further, three parallel experiments should be started the second year. The first of these experiments would be an investigation of a system that might be termed a “covered pit retort.”

Some Utah shales about 20 miles southwest of tract U-a (See Figure 9) are nearly exposed and can be rubblized by emplacing explosive from the top, then creating a rectangular, horizontal bed. The required permeability and surface area would be made by “lifting the surface.” This experiment will involve design of: A recovery system, airfeed devices, explosive emplacement, and shale fracture patterns.

This is a resource that could also be recovered by strip mining, but strip mining systems are capital and equipment intensive. The covered pit system will not require extensive investment before production begins.

This experiment will yield rapidly available, horizontal-burn data that could be extrapolated to other horizontal in-situ processes.

It will also provide information about the type of seal required to conduct a stepwise horizontal burn in shale that outcrops or lies close to the surface.

A second parallel experiment would be similar to the one being conducted on White Mountain, but would utilize oil shale in a dipping bed near Kinney Rim. This area, near Wyoming tracts W-a and W-b (See Figure 10), is not as easily accessible as the White Mountain area but represents the shales in the Washakie Basin. Because it is more difficult to work in this remote area approximately one additional year and additional funding will be required to complete this phase of the project.

The third parallel experiment would be conducted in Colorado near the confluence of Piceance Creek and the White River. The site will be located north of Superior Oil Company’s lease land and will consist of three oil shale that dips approximately 15 degrees and is considered unminable. Development of this site will also require additional time and money.

3. Supporting Research (150-Ton Retort)

To supplement the modified in-situ retorting needs, the 150-ton retort at the Larimer Energy Research Center would be used to make the following investigations:
1. The void volume of the shale charge would be varied from about 30 to 50 volume-percent. Pressure drop tests and radioactive tracer measurements would be made in an attempt to determine surface area and free path volumes that could be applied to field experiments.

2. Shales with a range of assay would be retorted, i.e., 10 to 40 gpt material.

3. The 150-ton retort would be converted to an adiabatic vessel to demonstrate increased oil yields.

4. Shale sizes would be varied to simulate that in the vertical in-situ chimney.

5. Hot gas or steam injection would be tried to determine effects on oil recovery.

VII. IN-SITU GASIFICATION OF OIL SHALE PROJECTS

The objectives of the research on gasification of oil shale are as follows: (1) To produce sufficient energy in the off-gas stream to operate an in-situ recovery system, (2) to study the feasibility of producing a supply of 600-plus Btu/ft³ gas, (3) to define the operating parameters for operation of an in-situ system to insure maximum utilization of the resource. To reach these objectives will require several parts of the research to be conducted concurrently (Figures 17 and 18).

Laboratory experimentation to develop statistical models would be continued. Process variables that can be effectively studied include effects of pressure, oil shale grade, oxygen content of injected gases, water injection, recycle gas, reaction rates, varying gas flux, temperature, and others. Present work has been limited to the first four. At laboratory scale the experimentation can progress extremely rapidly and is limited primarily by available manpower. As this work is essential as input data to design of larger scale experimentation, it is planned to increase the number of persons assigned to this work by four, which will increase the number of experiments per week from two to seven.

The statistical models developed in the laboratory should be checked out on a larger scale (0.25 to 2.5 ton) in order to obtain more valid design input data. Unavailability of small-scale gasifiers require that one be built for this purpose. This work will start immediately and should be completed in FY 1976. The gasifier would then be operated in conjunction with a larger aboveground gasifier to allow rapid research in specific problem areas uncovered as work progresses.
In early 1976, bids will be requested for the design of an above-ground gasifier. This design will be for a 25- to 40-ton batch gasifier to be a "turnkey" operation. The request will be for some industrial group to build, instrument, and operate the pilot unit. Laramie Energy Research Center personnel will define the operating parameters, be actively involved in all phases of the construction and operation, will retain responsibility for research direction, and will be responsible for paperwork of all data. The plant will be physically located near the Laramie Energy Research Center to allow efficient use of existing facilities and personnel. It is planned to set up a research site where planned laboratory work, small-scale gasifier, and 25- to 40-ton aboveground pilot unit could share personnel, physical facilities, and control instrumentation. The purpose of this pilot unit will be to develop the operating parameters necessary for later field operation; so included as appendant research studies will be gas cleanup equipment and equipment to study efficient usage of the offgas.

Concurrent with the proposed aboveground work will be initiated on cleanup of the extremely large gas streams anticipated from commercial-sized in-situ recovery projects. A 50,000-barrel-per-day plant using 20,000 ft³/bbl (with no allowance for increase due to in-place generation of gases from organic material) will produce 1 billion ft³/day. A request for proposal to industry for study and design of equipment suitable for cleanup of this gas volume will be submitted.

Along with the laboratory and pilot plant work, a contract will be let for development of a mathematical model describing the entire system. This will be updated as information becomes available.

Cooperation with industry on any field project where gasification of oil shale will be investigated thoroughly. If the Government can gain useful information, the Laramie Center will negotiate to obtain data by purchase, by joint operation, or any other feasible means.

All work will be designed to provide input to a major PDU in-situ retorting as a separate study where maximum utilization of the resource is the criteria. This will involve selection of a field site, drilling, fracturing, evaluation, lease or purchase of compressors and other operating equipment, oxygen generation equipment, instrumentation, setup of gas cleanup equipment, leasing or purchase of turbine generator or similar equipment, and all other steps necessary to conduct a large-scale demonstration of the process.

VIII. SUPPORTING RESEARCH

Accelerating in-situ research will necessarily require expansion and acceleration of research designed to support that program. These support programs are outlined below. Detailed programs will be developed and implemented as specific sites are delineated.
A. Environmental Design Criteria

Identification and quantification of the environment impact of alternative in-situ processing options will be an integral and continuing support program. As shown in Figures 19 and 20, this expanded program would be focused on the impacts on air, water, land, and socio-economic factors. Composition and quantity of all effluents and products produced would be determined, such as dust, gases, process water, and formation water. Amounts of surface disturbance, waste rock quantities and character would be estimated. Noise and waste heat are factors to be considered. Of equal importance in field test design and operation will be instrumentation to monitor these parameters. The number and type of personnel required for construction and operations would be established as a guide to measure socio-economic impacts from commercial development of a particular process.

Measures to control adverse impacts and rehabilitate affected areas would also be evaluated using all available information from past and ongoing environmental programs such as those connected with the Prototype Leasing Program as well as institutional research such as the COSEP studies in Colorado. Of particular concern are the quantities and treatment of gases, effects on wildlife, and water quality.

In order for any in-situ retort process to reach commercialization, air and water quality standards of EPA, the State and local jurisdictions must be met. Therefore, research will be conducted on ways to "clean up" off gases and process water.

When ready for tentative selection of field test sites several alternative sites should be considered. Environmental assessments of the proposed field tests will be performed by competent contractors with overall supervision and coordination by in-house environmental staff. The assessment will help select the best site of the alternatives, any special problems, estimate impacts, and rehabilitation requirements.

Acceleration of in-situ oil shale research will create an increased need to have available the necessary data for basin-wide or regional planning. Environmental baseline data are currently being collected on and around Federal lease tracts and private developments and are to be included in the experimental design for proposed accelerated research. Additional regional data for regional planning is needed in air quality/meteorology, water quality, and biology. For example, a Federal program to develop basin or regional air quality models and collect additional data necessary for input to these models is needed. Data for regional planning is needed in the ground water field and particularly in the Uinta and Green River Basins. Acceleration of the USGS program of ground water modeling and data collection for the modeling is required. Estimates for regional biological programs will be determined by the location and scope of the specific projects.
Because of the nature of the environmental support programs, they would be best planned and carried out by an interagency group made up of parties with existing responsibilities in the particular field.

B. Mathematical Modeling

Under the accelerated in-situ oil shale program, various techniques are to be investigated as methods for recovering the hydrocarbons locked up in oil shale. These include true and modified in-situ retorting and oil shale gasification. Preparatory to these recovery techniques, two different methods of creating voids in the otherwise impermeable oil shale were proposed. Each of these proposed investigations uses modeling as a tool to help achieve successful resource recovery. Both of the retorting techniques, and the gasification of oil shale, convert kerogen to a different hydrocarbon form via pyrolysis. The only real difference involved in the physical method for recovering the resource. To take advantage of this common base an unified and coordinated modeling effort will be initiated which will utilize the information developed in each project to augment the development of all other projects.

A preliminary mathematical model was developed based on the 15-ton retort configuration which was used to determine the accuracy of the theoretical mechanisms assumed to occur during the retorting process. This model simulates linear, forward-combustion retorting. Presently, comparison of computed results shows good qualitative agreement with the experimental results obtained in the 15-ton retort; however, quantitative agreement between actual and computed results is not yet as good as desired.

During the development of the present model, data for several mechanisms of the retorting process were unavailable. Therefore, special projects were initiated to investigate these areas. As data from the special projects already initiated becomes available, it will be incorporated into the model. With the addition of this information, the retorting mechanisms should be adequately defined and the model should be capable of accurately simulating the 15-ton retort. When this is achieved, the model will be programmed to simulate modified in-situ retorting and the new accurate retorting mechanisms will be incorporated into a revised model which will be used to simulate true in-situ retorting. Alternately, the project to complete the models for modified and true in-situ could be contracted out once the ongoing projects are completed. Simultaneously with this work, a model will be initiated for the oil shale gasification project, and modeling for the fracturing work will be contracted out to one of several groups which have already developed expertise along these lines. When the gasification model achieves satisfactory simulation capability, it will be incorporated into the retorting models. Data acquired while retorting the first pilot fracturing project will be used to determine the accuracy of the true in-situ model.
This comprehensive in-situ oil shale program is designed to develop the following capability by 1980:

1. To decide whether it is best to recover the hydrocarbon from any given oil shale resource by the true in situ or the modified in-situ retorting method.
2. To determine the best fracturing or explosive rubbling technique for the resource.
3. To determine the operating conditions necessary to obtain the desired retorting results, whether these results be maximum gas production, maximum oil production, or maximum resource recovery.

C. Water Resources Investigation

Current programs or plans of the Geological Survey for water resources monitoring and water supply investigations as related to oil shale development are, with certain exceptions, considered adequate. Stream flows are being monitored in Wyoming, Colorado, and Utah with sufficient density of coverage to assess regional surface water supplies and to detect possible changes on an areal basis. Sediment records are also being obtained and samples of stream water collected for analyses of chemical quality, including trace metals. A few additional measuring and sampling sites may be desirable once the in-situ retorting sites have been selected.

Monitoring and assessing the ground water resources in the oil shale areas of Wyoming and Utah are not adequately covered. As a minimum, three wells, constructed and completed for pumping tests and subsequent sampling and water level observations are suggested for each in-situ site. Cores should be obtained, as needed for resource investigations as discussed below. The Geological Survey should obtain the water samples, provide the laboratory analyses and run the pumping tests for integration of these results with its other programs. Subsequent and continuous monitoring may be assigned to another group.

D. Resource Appraisal

Past work has established regional resource characteristics. However, additional coring and well logs would be required to delineate resource characteristics of a particular location. These could be obtained in conjunction with the water resources investigations discussed immediately above.

In addition, a wealth of corehole and surface geophysical data from oil and gas exploration have been obtained in the Green River and Great Divide Basins. Much of these data are available for purchase. Computer programs for analysis of the data are available for some types of evaluations.

For evaluations pertaining to hydrologic parameters, existing computer programs will be modified for use in this accelerated in-situ program.

E. Health and Safety

The need to evaluate health and safety hazards associated with the expected large scale conventional mining of oil shale is recognized in the Government's overall oil shale program. The modified in-situ processes will present additional hazards because men are working underground at the same time that retorting is being done. The development of means to control these hazards must be an integral part of the in-situ research program.

Health problems specific to oil shale mining include the possibility of carcinogenic properties in oil shale, dust, spent shale, or burnt shale and possible dermatological hazards from either dusts or shale oil itself. In addition, there is the possibility of pneumoconiosis-inducing dusts, requiring study.

Toxic gases produced by retorting (H2S, SO2, CO, CO2, etc.) present obvious hazards and reinforce the necessity of stringent controls over in-situ retorting operations.

Specific data on unusual health problems associated with oil shale mining are nonexistent, but there are some indications of possible hazards that may be encountered in oil shale mines that do not occur in other mines. In a survey conducted by the Bureau of Mines at the Rifle, Colorado operation in 1966, it was determined that the airborne dust contained 10-11% free silica. This is not unusual to mining, but there may be some problems in dust control in oil shale because of the difficulty of wetting the dust particles. Wetting agents or detergents will probably be necessary before water can successfully alloy to dust.
APPENDIX A

CURRENT GOVERNMENT RESEARCH - FY 1976

This appendix lists, in outline form, the research topics in oil shale currently programmed for FY 1976. The program listed in this appendix are those of the U.S. Department of the Interior and those programs transferred from Interior to the Energy Research and Development Administration. Table A-1 lists the subprogram, agency, and FY 1976 projected funding levels.

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<th>Subprogram</th>
<th>Agency</th>
<th>FY 1976 Funding $MM</th>
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<tr>
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<td>BLM 2/</td>
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<tr>
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<td>FWS 3/</td>
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<td><strong>TOTAL</strong></td>
<td><strong>ERDA</strong></td>
<td><strong>19.67</strong></td>
</tr>
</tbody>
</table>

2/ Bureau of Land Management
3/ Fish and Wildlife Service
4/ U.S. Geological Survey
5/ Bureau of Mines
The following outline lists the program by agency, program, and
sub-program.

A. Bureau of Land Management, FY 76, $1MM
   1. Energy Minerals Rehabilitation Inventory and
      Analysis (EMRIA)

B. Fish and Wildlife Service, FY 76, $0.6 MM
   1. Environmental Studies
      a. Biological Inventory
      b. Ecological Mapping
      c. Biological Monitoring
      d. Rehabilitation, Enhancement, and Mitigation
      e. Coordination and Management

C. Geological Survey, FY 76, $3.27 MM
   1. Oil Shale Resource Base
      a. Resource Assessment
      b. Environmental Geologic and Geochemical Research
   2. Hydrologic Research
      a. Collection of Basic Hydrogeologic Data
      b. Aquifer Tests to Determine Effect of Mining on
         Ground-Water System
      c. Environmental Impact of Mining on Quantity and
         Quality of Water
      d. Development of Management Models of the Hydrologic
         System which will simulate the response of Mining
         stresses
      e. Impact of the Disposal of Mine Water
      f. Synthesize and Analyze Data
   3. Microbial Stimulation

D. Bureau of Mines, FY 76, $5.6 MM
   1. Mining Technology
      a. Oil Shale Extraction
         (1) Extraction Technology
         (2) Waste Management

E. Energy Research and Development Administration FY 76, $7.7 MM
   1. In Situ Processing of Oil Shale
      a. In Situ Shale Oil Production
      b. In Situ Shale Gas Production
      c. Environmental Studies, In Situ Processing

F. Energy Research and Development Administration FY 76, $1.3 Million
   1. Clean Fuels From Oil Shale
      a. Composition and Conversion Studies
Office of the Secretary

COLORADO, UTAH, AND WYOMING

Call for Nominations of, and Request for Information Regarding Areas for Oil Shale Leasing

Notice is hereby given that nominations of lands for prospective oil shale leasing for in situ development in the States of Colorado, Utah, and Wyoming and comments on such lands may be submitted to the Secretary of the Interior not later than June 30, 1975.

Nominations shall include a description of the lands sought to be included in an oil shale lease, if the lands have been surveyed under the public land rectangular system, each nomination shall describe the lands by legal subdivision, section, township, and range. If the lands have not been surveyed, each nomination shall describe the lands by metes and bounds, giving courses and distances between the successive angle points on the boundary of the tract, and connected by courses and distances to a monument or to a prominent topographic feature. When projected surveys have been approved and the effective date thereof published in the Federal Register, each nomination for lands shown on such projected surveys, filed on or after such effective date, shall describe the lands according to the legal subdivision, section, township, and range shown on the approved projected surveys. Maximum size of single lease tracts is 5,120 acres. Smaller areas may be nominated and more than one area may be proposed for consideration.

A tract nomination shall be submitted together with a recommendation of the type of in situ technology that might be used to develop the tract using in situ means. Description of the recommended technology must be brief (approximately 5 to 10 pages) and include only such detail as is needed to provide the government with an accurate and unambiguous understanding of the recommended approach. It should indicate the general classification of the technology, "true in situ" (no mining), "modified in situ" (some mining), or variations thereof. It should indicate the mineral resources present on the nominated tract and preliminary plans with respect to maximum utilization of the resource, including associated minerals if present. If modified in situ is recommended, the probable proportion of the resource to be removed by mining and its disposition must be indicated. Also to be attached are preliminary plans to: (1) Mitigate environmental degradation, (2) minimize water and power requirements, and (3) provide maximum protection for the health and safety of the workmen. Submission of the recommendation will not obligate the nominator to apply that technology should he eventually win the right to develop the tract. The recommendation is expected to be made in good faith for the advice of the government in decision-making regarding future directions of government research programs and other such reasons as the government shall determine.

Nominations and comments should be submitted in triplicate not later than June 30, 1975, and addressed to: Director, Bureau of Land Management, Department of the Interior, Washington, D.C. 20240.

Envelopes should be marked "Nominations and Comments for Oil Shale Leasing in (State)."

A supplement, which shall cover the additional tracts offered, will be prepared to the final environmental statement for the prototype oil shale leasing program released on August 30, 1973. Public hearings will be held and a draft statement issued in the preparation of that supplement. A description of any tracts, which may be released for competitive bidding, will be published in the Federal Register and the published notice of such lease offerings will state the conditions and terms for leasing and the place, date, and hour at which bids will be received and opened.

JOHN C. WHITAKER,
Under Secretary of the Interior;

APRIL 17, 1975.
OIL SHALE LANPS IN STATES OF
COLORADO, UTAH, AND WYOMING
Applications for Permits To Conduct
Informational Core Drilling

Notice was published in the Federal
Register on Wednesday, June 30, 1971,
(36 FR 12319-12320) permitting the fil­
ing of applications for special land-use
permits to conduct informational core
drilling in order to allow the evaluation
of the environmental characteristics, hy­
drology, and the oil-shale resources of
specific sites in Colorado, Utah, and
Wyoming. That notice was extended for
an additional 2 years until June 30, 1975.
That notice is hereby extended for an
additional period of six months until
December 31, 1975.

JOHN C. WHITAKER,
Under Secretary of the Interior.
April 17, 1975.

[FR Doc.75-10585 Filed 4-22-75; 8:45 am]
OPINION NO. 728

Transwestern Coal Gasification
Company
Docket No. CP73-211

Pacific Coal Gasification
Company

Western Gasification Company

Issued: April 21, 1975

ERRATA NOTICE
(April 28, 1975)

OPINION NO. 728

OPINION AND ORDER GRANTING CERTIFICATION
OF TRANSPORTATION AND SALE OF GAS PRODUCED FROM COAL
(Issued April 21, 1975)

Page 14, line 5, change Section "4" to Section "5"

Kenneth F. Plumb,
Secretary.

DC-51
UNITED STATES OF AMERICA
FEDERAL POWER COMMISSION

Transwestern Coal Gasification  )  Docket No. CP73-211
Company  

Pacific Coal Gasification  )
Company  

Western Gasification Company  )

OPINION NO. 728

APPEARANCES

James W. McCartney, Jack D. Head and Joseph F. Weiler for
Transwestern Pipeline Company

K. R. Edsall and E. A. Tharpe for Southern California Gas
Company and Pacific Lighting Service Company

B.E. Potts, Alfred O. Hall, Daniel R. Hopkins, Dale A. Wright
and Harold L. Talisman for Cities Service Gas Company

C. Frank Reisnyder, Samuel Shephard Jones, G. Scott Cuming,
Richard S. Morris and Richard Owen Baish for El Paso Natural
Gas Company

John P. Mathis, J. Calvin Simpson and William H. Booth for
The People of the State of California and Public Utilities
Commission of the State of California

John F. Harrington, Thomas F. Brosnan, Lawrence Robertson, Jr.,
and Steven M. Beattie for Tucson Gas and Electric Company

William D. Braun for the Staff of the Federal Power Commission

UNITED STATES OF AMERICA
FEDERAL POWER COMMISSION

Before Commissioners: John N. Nassikas, Chairman;
William L. Springer, and Don S. Smith.

Transwestern Coal Gasification  )  Docket No. CP73-211
Company  

Pacific Coal Gasification  )
Company  

Western Gasification Company  )

OPINION NO. 728

OPINION AND ORDER GRANTING CERTIFICATION
OF TRANSPORTATION AND SALE OF GAS PRODUCED FROM COAL

(Issued April 21, 1973)

SPRINGER, Commissioner,

This is the first coal gasification case to come before us for decision. Coal gas is of major importance to the nation's
capacity to produce energy today and in the future. The case
itself poses a multitude of issues for our review and decision;
however, the central questions are jurisdiction, pricing,
the distribution of risk between the company and the consumers,
the need for the project and the natural gas and synthetic gas
supply alternatives.
I. PROCEDURAL HISTORY

On February 7, 1973, under Docket No. CP73-212, Transwestern Coal Gasification Company (Trans Coal), Pacific Coal Gasification Company (Pacific Coa) and Western Gasification Company (Wesco) applied for certificates of public convenience and necessity to authorize the construction and operation of coal gasification facilities in San Juan County, New Mexico, and the sale of approximately 250,000 Mcf per day of gas derived from a coal gasification process, hereinafter referred to as SNG, for deliveries to be made at the outlet of the plant facilities. Concurrently therewith, Transwestern Pipeline, a subsidiary of Texas Eastern Transmission Corporation, in Docket No. CP73-211, filed for authorization to construct and operate approximately 67 miles of 36 inch pipeline and appurtenances for the transportation of such SNG and for the resale thereof in a commingled stream in interstate commerce. Certificate authorization was also sought for tap and valve facilities at the point of interconnection between the 67-mile pipeline and Transwestern Pipeline's existing system near Gallup, New Mexico.

On September 4, 1973, we issued Opinion No. 663 /1 in which we concluded that the coal gasification facilities and the 67-mile pipeline were not within our jurisdiction and therefore dismissed the application in Docket No. CP73-212. We also dismissed Transwestern's application in Docket No. CP73-211 involving it related to the 67-mile pipeline facility. Our opinion did not affect that portion of the application which related to the connecting facilities or the transportation of SNG after the commingling with natural gas.

Thereafter on November 16, 1973, Trans Coal, Pacific Coal and Wesco (Applications) filed an amended application seeking authorization for the two coal companies to sell the SNG directly to customers of Transwestern Pipeline, Pacific Lighting Service Company (Pacific Lighting) and Cities Service Gas Company (Cities). Transwestern Pipeline sought authorization to provide the required transportation service.


Eight days of hearing were held in December 1973, and February 1974. On June 13, 1974, the Presiding Administrative Law Judge William J. Ellis issued the initial decision granting the certificate contingent on specific conditions. Briefs on exceptions were filed by Pacific Coal, the Public Utilities Commission of and for the State of California (CPUC), El Paso Natural Gas Company (El Paso), Cities, Transwestern Pipeline and Staff. The Pipeline Coal Gasification Committee filed an untimely petition to intervene in conjunction with a brief on exceptions. /2 Briefs opposing exceptions were filed by Transwestern, El Paso, CPUC, and Staff. Oral argument was held on March 14, 1975.

II. THE PROPOSED PROJECT

The proposed coal gasification plant is to be located on the Navajo Reservation in northwest New Mexico. It will be capable of converting approximately 25,000 tons of coal per day into 250,000 Mcf of SNG daily, having a Btu content of approximately 970 Btu per cubic foot. During the hearing, the plant, including the 67-mile connecting pipeline, was estimated to cost $447,000,000 based on mid-1973 estimates. Pacific Coal and Trans Coal have purchased from Utah International sufficient coal and water supplies to operate the plant for a period of 25 years.

Pacific Coal and Trans Coal each own 50% of the plant's output. Pacific Coal will sell its SNG to Pacific Lighting whereas Trans Coal will sell one-half of its volumes to Pacific Lighting and the remaining volumes to Cities. The sale to Pacific Lighting will be made at an existing delivery point on the Arizona-California border, near Needles, California and the sale to Cities will be made at existing delivery points in the Panhandle areas of Texas and Oklahoma. The rates charged by Trans Coal and Pacific Coal to their purchasers will include transportation charges paid by them to Transwestern Pipeline. Based on mid-1973 cost figures, the calculated price per Mcf of the SNG to be produced in the Wesco plant would be

/2 The Committee consists of ten natural gas pipeline systems which are actively studying or have announced plans to construct and operate coal gasification plants in the Western United States.
contracts with the United States covering the purchase of water from the Navajo Reservoir and the San Juan River. Trans Coal and Pacific Coal will pay Utah International $7.00 per acre-foot for all water they are entitled to use in the project. Applicants estimate that the water used yearly represents only 1% of all the water in the upper basin of the Colorado River system which has been allocated to consumptive use in New Mexico in accordance with the Colorado River Compact of 1922.

The requested action of the F.P.C. is not a major federal action warranting the preparation of an environmental impact statement under the National Environmental Policy Act. Nor have any parties or litigants raised environmental issues in this administrative proceeding. The Bureau of Reclamation of the Department of Interior however is preparing a Final Environmental Impact Statement (EIS) in order to assess the impact of the entire project upon the existing environment. We have received a copy of the Draft EIS and are preparing our comments thereon as to the need for supplemental supplies of pipeline gas. In addition to the filing of the Final EIS with the Council on Environmental Quality, there are several actions which must be completed by Federal and state agencies before the Wesco plan may be implemented.

The primary federal approvals which must be received from the Department of Interior are these:

(1) Bureau of Reclamation must approve Wesco’s plan as provided in the water service contract;

(2) U.S. Geological Survey must approve the mine development plan; and,

(3) Bureau of Indian Affairs must give written approval of all land leases, rights of way, and access roads negotiated with the Navajo Tribe for the plant and the associated facilities.

None of the parties have asserted that an environmental impact study is required prior to our certification of the construction and operation of the Wesco plant as has been

__/ On March 7, 1975, the parties amended the Western Gasification Agreement No. 1, dated 1973, whereby the base price of the coal was increased from 20.8 to 26.240 cents per million Btu.
used on peak days to reduce curtailment of priority one customers; however, the curtailment of this class will not thereby be eliminated. From the foregoing, we conclude that this project is an absolute necessity for the consumers in California and the Midwest, absent the availability of equivalent sources.

IV. JURISDICTION

A primary question that confronts us is whether the proposed sales by the Applicants is subject to the Commission's jurisdiction. Relying on Opinion No. 663 ./, Staff asserts that the Commission is without jurisdiction. Staff argues that the following statement in the opinion precludes us from regulating the sale. "...there can be no such thing as the sale of synthetic gas mixed with natural gas". ./ Staff admits that when the coal gas is introduced into the Transwestern Pipeline and mixed with natural gas the total supply becomes natural gas.

In its Brief opposing Exceptions, Transwestern asserts that the Commission settled this issue in Opinion No. 663 wherein the Commission stated:

We exercise certificate authority over the interconnection facilities necessary to permit mixing of the artificial gas with the natural gas, over the transportation facilities and any applicable transportation rate after mixing, and over the rate at which the artificial gas is sold for resale in interstate commerce after mixing with natural gas. ./

In Opinion No. 663, we stated the jurisdictional boundaries of our regulation of synthetic natural gas and intended to do so clearly. In the instant case, the sales to Pacific Lighting


./ Brief on Exceptions, p. 3.

./ 50 FPC 651, 664.

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and Cities will occur after the SNG and natural gas have been mixed within Transwestern's pipeline and are therefore clearly within the parameters of our jurisdictional boundaries. /

Staff attempts to buttress its argument by asserting that the sale is not subject to curtailment. It further argues that because Pacific Coal and Trans Coal do not own jurisdictional facilities, they cannot make jurisdictional sales. /

Neither argument is persuasive or relevant to the issue of whether the sales are jurisdictional. The Staff's argument with respect to curtailment is somewhat confusing. It is implicit that a supplemental supply source offsets curtailment and the Applicants herein have made this argument.

The second argument regarding jurisdictional facilities is also unclear. We have addressed this issue directly in Opinion No. 663 wherein we stated that we would exercise certificate authority "over the rate at which the artificial gas is sold for resale in interstate commerce after mixing with natural gas". The fact that we have not assumed jurisdiction over the project itself does not foreclose our asserting jurisdiction over the rate to be charged to the purchasers.

In conjunction with the jurisdictional issue, we are confronted with the problem that Cities will not receive the SNG which it purchases but rather will receive gas through displacement deliveries. Although Cities will purchase 62,500 Mcf per day from Trans Coal, it will actually receive displacement deliveries from the seller at two delivery points. The total output from the coal gasification plant will be delivered through a commingled stream to Pacific Lighting.

In the Initial Decision, the Presiding Judge issued a certificate allowing Transwestern Pipeline Company to transfer and deliver to Cities "at the existing points of delivery in Texas and Oklahoma, a quantity of natural gas equal in heating value to the quantity of coal gas" ./ referred to in their

"/ The jurisdical issue presented herein is distinguishable from that in Columbia LNG Corporation, Opinion No. 699, 50 FPC 1252, reh. den. Opinion No. 699-A 50 FPC 1943 (1973). In the latter case, the sale of the SNG occurred at the tailgate of the reforming plant unmixed with natural gas and was therefore clearly outside the Commission's jurisdiction.

./ The Saturn Oil and Gas Company v. F.P.C., 250 F. 2d 61 (10th Cir. 1957), cert. denied, 355 U.S. 956 (1958).

./ Mimeo, p. 47.
agreements. In its brief on exceptions, Cities asserts that the Judge erroneously concluded that Cities would not purchase SNG from Trans Coal. Cities maintains that the certificate prescribed by the Judge should be amended to expressly authorize the sale of SNG by Trans Coal directly to Cities.

Cities argues that the receipt of displacement gas will place it in the same position as the physical receipt of SNG volumes and further that the necessity of cross-hauling natural gas and SNG will be eliminated. That Cities will not physically receive the SNG, does not, in Cities' view, bar or preclude a sale-purchase transactions between Cities and Trans Coal.

The only other party to the proceeding to address this issue is Transwestern who supports Cities' position. Transwestern argues that as there is no legal difference between natural gas and a mixture of natural gas and coal gas; therefore, there should be no conceptual difference between Cities' and Pacific Lighting's transactions.

By order issued May 27, 1974, the Commission deferred consideration of a separate application filed by Cities in Docket No. CP74-185, to construct facilities to transport volumes of gas purchased from Trans Coal. Transwestern, Cities, and Pacific Lighting agreed that should such authorization not be issued by the Commission or should Cities not accept it, Pacific Lighting should be entitled to purchase Trans Coal's entire portion of the plant output. They argue that the certificate authorization should be conditioned accordingly and Cities' interest in the project would thereby be protected while any source of possible delay or uncertainty would be removed.

We find that the certificate should be amended as suggested by Cities. A denial of the certificate would endanger Cities receiving the additional supply of gas and would operate as a penalty to its customers whereas the allowance of the displacement deliveries will eliminate unneeded transportation expense.

Docket No. CP73-211

IV. PRICE

The central issue in this proceeding is the pricing of the SNG. Pacific Lighting and Cities have agreed to purchase the entire plant output on a cost of service basis. The proposed tariff provides that these buyers shall pay monthly the sellers' total cost of service, including a 15% return on equity, regardless of the amount of gas delivered. Non-delivery for any reason, including force majeure, does not relieve them of their obligation.

The Applicants have asserted that the foregoing pricing provision is a prerequisite to the method of financing this operation, which they have termed "project financing". Project financing guarantees the investors the recoupment of all monies invested in the project by the end of the initial 25 years of plant operation. Specifically, the plan for financing proposes the issuance of 25-year bonds worth $342 million at a hypothetical rate of 8-1/2% and the subscription to $114 million of stock by Pacific Coal and Trans Coal. The plan provides for the bonds being sold to institutional investors on a private placement basis. The capital structure will therefore consist of approximately 75% debt and 25% equity.

Fifty-seven per cent or $72,606,000 of the estimated annual cost of service is fixed costs which include depreciation, taxes, and return. The annual operation and maintenance expenses, $51,548,000 or 43% of the cost of service, are subject to inflation. It is noted that the coal contract is included as a variable item. The Judge, however, estimated that if the latter expenses increased 40% over the next 10 years, the total cost of service would increase only 17.2%.

The Applicants vigorously assert that the viability of the project depends on its financing and its financing depends on the Commission's approval of a full cost of service tariff. They argue that they are incapable of acquiring the requisite capital through conventional means so that the project must be economically self-sufficient in order to attract sufficient capital on terms favorable to the investors. They argue further that any additional conditions that this Commission may attach to their proposal to protect the consumers against future cost increases will in and of themselves increase the financing
costs by causing the interest cost to rise. A full cost of service tariff is the sole means by which the Applicants say that they can be assured of recovering all prudently incurred costs and expenses plus a reasonable return on equity in a prompt manner. Under a full cost of service tariff, they assert the Staff will have full access to all cost data on a continuing basis for review purposes.

In the Initial Decision, the Judge ordered that within 6 months of the proposed start-up date, the parties should submit a proposed price which would operate as the initial rate until a subsequent filing was made pursuant to Section 4. In deriving this pricing mechanism, the Judge reviewed prior Commission decisions on supplemental supply programs, which disallowed cost of service tariffs and established fixed initial rates.

The Judge prescribed the following conditions, stating:

(K)(1) While it would be premature now to pinpoint a specific price, by the time the works are nearing completion and within six months of the proposed start-up date, the parties may readily compute an initial price per Mcf or, preferably, per MMbtu, and submit it for immediate and final approval by the Commission, along with a memorandum detailing how it was computed and reciting also the final financing arrangements that have been made. That initial rate will control as the filed tariff until it shall be changed under the authority of the Natural Gas Act.

(2) If increases are later found to be required to recover the cost of service, the interest and the equity return contemplated, the new rate may be computed and filed as an increased tariff, subject to review and control here under Section 4...(emphasis added). __/

The Judge was unconvinced by the Applicants' argument that project financing was essential. Rather he compared the project to the building of toll roads, bridges or pipelines which have historically been financed by conventional means. He concluded that full cost of service treatment was inappropriate and a just and reasonable rate should be established. He was, however, unwilling to speculate about the level of the rate and directed the parties to make a filing which appears to allow the Applicants to charge initially whatever price they are able to justify.

Staff concurs in the Judge's rejection of the full cost of service tariff. Staff asserts that the Commission's continuing surveillance over the rates charged under a full cost of service tariff would be legally insufficient because if the Commission found the Applicant's rates to be excessive, its single course of action would be to institute a Section 5 proceeding which would grant only prospective relief. Citing Catco, Staff asserts further that the Supreme Court effectively expressed its disapproval of full cost of service tariffs in the following statement:

If unconditional certificates are issued where the rate is not clearly shown to be required by the public convenience and necessity, relief is limited to Section 5 proceedings, and ...full protection of the public interest is not afforded. __/

Staff foresees that if there were a severe and pronounced decrease in the load factor, an open-ended rate would thereby be created under a full cost of service tariff which would escalate automatically and indefinitely. This is a risk which we cannot ignore.

Staff maintains further that a finding of public convenience and necessity is impossible unless a rate condition is attached to the Applicants' certificates. Citing the Commission's decisions in other synthetic gas supply cases, the Staff maintains that a rate condition is "absolutely necessary to protect the public interest". Staff asserts that the Judge failed to comply with the court's requirement set forth in Catco as to giving "a most careful scrutiny and reasonable reaction

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Mimeo, p. 42.

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to the initial price proposals". Staff further objects to the
Judge's provision for an initial rate filing six months prior
to commencement of operation on the basis that the filing could
not be suspended and the initial rate would be reviewable only
in subsequent Section 4 proceedings.

CPUC took an active part in the proceeding and advoc-
cated a pricing mechanism which differed from that proposed
by the Applicants, Staff or the Judge. CPUC proposed that
the certificate should be conditioned upon an initial rate
of $1.32 for all sales occurring during the start-up period.
Those costs attributable to the start-up period, which are not
recovered by the sales, shall be amortized over the life of
the project and recovered through rates established in a sub-
sequent Section 4 proceeding.

CPUC joined Staff in its arguments against a full cost
of service tariff and took exception to the Judge's resolution
of the price issue due to its lack of clarity. The project
itself will require a period of testing before it is capable
of sustained full production, therefore CPUC asserts that it
is necessary to distinguish between the commencement of the
testing operations and the commencement of full scale pro-
duction. The Judge did not define the phrase "start-up date"
which he used in directing the Applicants to file an initial
rate.

CPUC maintains that if the Judge intended the "start-up
date" to be the beginning of the testing operations, the initial
price would have to be determined without information as to
the plant's performance and without provision for recovering
excess costs. On the other hand, if the Judge intended the
"start-up date" to mean full scale operation, he did not make
provided for the rate of gas produced during the testing
period. To eliminate this apparent ambiguity in the initial
decision, CPUC advocates that the Commission should establish
an initial price of $1.32 per Mcf for the testing period and
provide for a Section 4 rate hearing to be commenced during
the testing period.

CPUC objects to the Staff proposal on pricing on the basis
that the Staff proposal would require the Commission to make
an accurate determination of the cost of producing the SWG
three years before the sales commence. CPUC agrees that Catco

is applicable to the extent that the Commission must analyze
costs and make a determination as to whether the sale will
be in the public interest, however, CPUC maintains that the
Presiding Judge has done this. Although CPUC agrees with
Staff that initial price should be set out in the certificate,
it asserts that its proposal is a more effective pricing
mechanism which fully complies with Catco.

CPUC cites Judge Levant's Initial Decision in El Paso
Natural Gas Company, Docket No. CP70-138, as containing a
pricing provision essentially similar to their proposal in
this case. El Paso's contracts set an initial price of $1.40
per Mcf during the "start-up period" (or testing period)
which precedes the date of the First Regular Delivery. Judge
Levant directed El Paso to make a rate filing pursuant to
Section 4, no later than 30 days prior to the date of the
First Regular Delivery, setting forth the cost of gas to be
purchased and the actual costs incurred during the start-up
period. Based on these figures, the Judge found that the
initial full production price could then be realistically
determined.

This is the first major coal gasification project to
be constructed in the United States. Neither Pacific Lighting,
the corporate parent of Pacific Coal, nor Transwestern Pipe-
line can guarantee repayment of the sums involved. In order
to encourage investors to participate in a project of this
experimental nature, which is non-jurisdictional, we recognize
that they must receive some assurance of recovering their
investment.

Furthermore, we are acutely aware of the need for this
country to develop its own sources of energy. The coal
gasification process is a means by which the United States
may attain a greater measure of energy self-sufficiency and
reduce its vulnerability through dependence on foreign markets.
Coal gasification is one of the few potentially commercial means
of developing a supplemental supply of gas from domestic re-
sources.
In the preliminary draft of the Natural Gas Survey, the dimensions of the current gas shortage are graphically depicted. The report concludes that not only are significant deposits of gas becoming harder to find. We are mindful however that over the course of the past two years there have been extensive drilling efforts to find new natural gas supplies to meet economic demand. The report also sets forth the current levels of curtailment and their impact upon the nation's consumers, providing little encouragement that the supply outlook will brighten.

In December, 1974, the Staff issued a report in which it concluded that "conventional U.S. gas production has reached its peak and will be declining for the indefinite future... (which) means that from hereon we must make do with less gas in absolute terms." In conjunction with declining production, Staff foresew increased reliance on supplemental supplies. It is evident that only by encouraging both domestic exploration for natural gas and development of the commercial technology for producing synthetic gaseous fuel can the total gas supply be increased. Therefore in approaching the pricing issue, we feel compelled to review it from a new perspective and to consider our previously enunciated policies as relevant, but not controlling.

We have carefully reviewed our prior decisions on supplemental supply projects. Without exception, we have attached a fixed rate to each certificate authorizing the sale of supplemental supplies. We have reaffirmed this policy on numerous occasions. In all of these cases, we have refused to adopt the cost of service methodology due to our concern

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A Realistic View of U.S. Natural Gas Supply, Staff Report.

Ibid, p. 20.


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In establishing a rate of $1.38, we have assumed a Btu content of approximately 970 Btu per cubic foot.

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that the rates might escalate beyond the zone of reasonableness to the detriment of the consumers. Our concern has proven to be real because the costs of supplemental supplies have risen and the Applicants in the foregoing cases have subsequently filed under Section 4 of the Natural Gas Act for increased rates. As we have indicated, the same danger exists in this case.

We find that the proposed rate is the most viable method of pricing this new source of supplemental supply for it provides a means of ensuring the Applicants that they will receive a just and reasonable price for the SNG while providing adequate protection for the consumers against imprudent and improper expenses. We therefore find that our certification of this project should be conditioned to provide for an initial rate of $1.38 per Mcf which will apply to all SNG which is produced during the first six months of the testing operations. Although we are aware that this initial rate will not allow the Applicants to recover their full costs during the testing period, we further provide herein that all excess cost should be amortized over the life of the project and recovered through the rates subsequently established in a Section 4 proceeding. In so doing, we are providing a means by which the Applicant will recoup all reasonable and prudent costs that are incurred. In the event that the Applicants are unable or unwilling to make a Section 4 filing at the end of the initial six month testing period, they may elect to file for an extension of the $1.38 rate. In providing for the foregoing, our intention is to keep informed as to the progress of the plant and its operations during the testing period. We believe that this overall pricing mechanism will allow the Applicants to assure their investors that they will recover the costs incurred plus a reasonable rate of return on their investment in this project.
During oral argument, counsel for Transwestern Coal Gasification Company introduced the coal supply contract amendment as an exhibit. He asserted the necessity of having the contract amendment as part of the evidence in this proceeding; however, urged us to do so without reopening the record. It was suggested that a motion could be served on all parties and if there should be no answers within the period provided for response, the contract amendment would be accepted into evidence. The Commission approved the proposal. 

On March 21, 1975, the Applicants filed a motion to supplement the record with the amendment of March 7, 1975, Western Gasification Agreement No. 1 and a two page tabulation of revised cost estimates as of January, 1975. None of the parties objected to the aforesaid motion and we will therefore allow both exhibits to become part of the record.

The amendment to the coal contract is based on the same concepts as the original contract. It provides for a fixed base price for coal for the life of the contract which escalates in accordance with indices reflecting the cost experience in the coal mining operation. The contract amendment increases the base price from 20.8 cents per million Btu to 26.24 cents per million Btu in addition to modifying various components of the indices.

We have independently reviewed the terms of the contract amendment and conclude that the contractual arrangements are reasonable and in the public interest and that the SNPC price may properly reflect all changes in the price of coal which result from the application of the contract formula, with a single exception. Section 7.1 of the amended contract provides that the methods for adjusting the base price may be revised upon the request of either party in the event that "extreme or radical changes in economic factors and conditions from those existing on January 1, 1975," occur "by reason of events or circumstances beyond their reasonable control." It is apparent that this provision will become operative in only highly unusual situations. In approving the March 7, 1975 amendment, we herein reserve the right to review any future modifications to the present contractual provisions that may result from the operation of Section 7.1 and determine whether they are reasonable and in the public interest.

(1) Under the original contract, the components of the coal price were these:

<table>
<thead>
<tr>
<th>Original Contract</th>
<th>Adjusted Base Price</th>
<th>4% State Tax</th>
<th>5% Contingency</th>
</tr>
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<tr>
<td></td>
<td>22.457c</td>
<td>.898c</td>
<td>1.168c</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>24.523c</td>
</tr>
</tbody>
</table>

(2) The base price under the original contract is deducted from the adjusted base price to determine the impact of the escalation provisions. To approximate the impact of the escalation provisions upon the base price of the amended contract, we use the following equation:

\[
\frac{22.457c - 20.8c}{20.8} = \frac{1.657c}{20.8} = \frac{2.090c}{26.24}
\]

(3) Amended Contract

<table>
<thead>
<tr>
<th>Amended Contract</th>
<th>Base Price</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>26.240c</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Amended Contract</th>
<th>Adjusted Base Price</th>
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<tbody>
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We find that the cost of coal as established in the contract amendment should be a component of the initial rate. In determining the amount of the component, we have estimated what price of the coal would have been in mid-1973 under the amended contract. We have found that the original coal component of 24,523 cents per Mcf would have been approximately 30.936 cents per Mcf or 6.423 cents per Mcf more under the provision of the contract as amended. We therefore find that the initial rate should be $1.38 per Mcf.

Oral argument, Tr. 1672.
During oral argument the Applicants indicated that the cost estimates based on mid-1973 costs submitted during the administrative hearing were no longer realistic estimates of what the price level of SNG would be when full operation of the Wesco plant commences in 1979. Applicants submitted revised cost estimates as of January, 1975 which we have received into evidence in this proceeding. During oral argument counsel for the Applicants asserted that these costs were submitted for the primary purpose of illustrating the effect inflation has had on the original mid-1973 cost estimates submitted during the hearing. Based on this showing of a dramatic increase of the estimated costs over the 18 month period, counsel argued that the Commission should certificate the project without further delay so as to minimize any further increment in costs due to inflation. Counsel for the Applicants did not assert that the revised cost estimates represented a reliable base on which to establish the price level for the SNG, when plant operations commence. The ultimate just and reasonable rate will be prescribed by the Commission based upon evidence presented in a Section 4 proceeding under the Natural Gas Act when the full cost of service of this project is capable of being reduced to reasonable certainty.

In its answer to the Applicants' motion to admit these revised costs and the amended coal contract, Staff did not object to their receipt into evidence. Staff, however, cautioned the Commission that it was essential for the Commission to attach conditions to this certificate which would protect the consumers from excessive cost burdens. In adopting the aforementioned pricing mechanism, we have modified Staff's pricing proposal, as modified by CPUC, and thereby provided an appropriate means of assuring that the consumer will receive the supplemental supply at the lowest reasonable price.

We are cognizant that the present and future requirements of the Midwestern and California consumers require that we encourage the development of alternate energy supplies. We are also aware that the price level established for these supplies must be compensatory so as to elicit these supplies. However, we are unable to accurately determine at this time what level of pricing would allow the Applicants to recover their full costs plus a reasonable rate of return.

We are therefore unable to establish a fixed initial rate for "regular deliveries". By the same token, we are also unable to provide for a full cost of service tariff which would allow us to make only prospective adjustments to the price. Our regulatory responsibilities require us to review the proposed price of the SNG from the Wesco project.

We are concerned about the Applicants' argument that the regulatory lag which accompanies Section 4 filings will jeopardize the financing of the project. In view of the projected shortage for the markets herein involved, which will result from increased levels of firm service curtailments, we can only anticipate that any responsible future Commission would act in an expeditious manner so as to minimize unnecessary delay and thereby preserve the public health and safety and avoid economic hardship.

**Incremental Pricing**

Although the parties to the proceeding did not consider the issue of how the supplemental supply should be priced to a purchasing distributor, it is an issue which we believe should be addressed in future rate hearings involving both cities and jurisdictional suppliers of Pacific Lighting. Three-fourths of the project supply will be purchased directly by Pacific Lighting at its incremental price at the California border for delivery solely within the State of California at rates to be approved by CPUC. The question of incremental pricing is therefore not relevant to this portion of the supply which is in fact incrementally priced to the distributor.
On the other hand, Cities intends to use this additional supply of 62,500 MCF per day to offset projected curtailments for its entire system which provides service to various distributors in a five state area. We are foreclosed from considering the issue at this time because it is not part of the record in this case.

We are constrained to put the parties on notice that both the issues of incremental pricing and the protection of purchasers of SNG at the incremental price from the curtailment of supplies purchased will be considered in subsequent rate and curtailment proceedings, of Cities and the jurisdictional suppliers of Pacific Lighting. __/ We intend to provide sufficient flexibility for future Commissions to review the allocation of this supplement supply with respect to end use requirements of the customers.

V. Rate of Return

The appropriate rate of return is also an issue in this proceeding. The Applicants urge that a return of 15% on equity is both reasonable and necessary for the project's viability. CPUC and Staff argue that the rate is excessive and should be no higher than 13%. Transwestern's current rate of return on equity permitted by the Commission. They assert that the risk to equity investment does not approach the level of risk assumed by natural gas producers but is comparable to that of pipeline operations.

The rate of return on equity is a function of the relative riskiness of the proposed investment. By adopting the pricing mechanism we have herein with respect to this coal gasification project, we have injected an additional element of risk for prospective investors. Our disallowance of a full cost of service tariff operates as a refusal to guarantee potential investors that they will be able to recoup immediately all monies invested, however the adopted pricing mechanism assures them that they will receive a fair return on prudently incurred reasonable costs, subject to protection of the consumer interest for plant production below anticipated levels, as more fully defined below.

We are aware that prospective investors will not view the Wesco project as having an equivalent risk to that of a pipeline. In light of the nature of the project and the importance of its construction, we find that a rate of return on equity of 15% is reasonable and necessary.

VI. Penalty

Under circumstances involving total or partial failure of the plant output, the Presiding Judge attached the following specific condition:

the price is required to be reduced by the amount of any return on the common equity included in the contract price, applicable from and after any period when, for 30 consecutive days, energy production has fallen below 50 percent of the promised supply (250,000 MCF per day at approximately 970 Btu/cu. ft.) and continuing as long as production so falls short. __/

All the parties to the proceeding agreed that the penalty provision was unfair in that the elimination of return on equity coupled with a fixed unit rate would constitute a double penalty. Both Staff and CPUC suggested alternate penalty provisions based on reductions in the heating value of the gas produced and/or the load factor. Transwestern objects to the imposition of any form of penalty arguing that it is contrary to the concept of "project financing" and thereby endangers the viability of the project. Transwestern also argues that it would penalize Applicants for developments completely beyond their control. In its __/ Mimeo, p. 43.
Brief Opposing Exceptions, Transwestern challenges the proposed level of 970 Btu as being arbitrary and not based on any record showing the effect of delivery of less than 970 Btu content gas. It is noted that the record is devoid of any evidence concerning the minimum required level of Btu content for pipeline quality gas.

Related to the penalty provisions is the issue of minimum bill. In Opinion No. 622-A, Columbia LNG Corporation, et al., we incorporated a provision which enabled the seller to bill the buyer for all out-of-pocket expenses in the event the seller was unable to deliver any gas for a period exceeding one day. In that proceeding, the Commission also rejected the Applicants' proposed full cost of service tariffs however found that a minimum bill provision was "required by the public convenience and necessity as an equitable apportionment of the risk between customers and stockholders and in order to assure the financing of the project on reasonable terms to the consumer." /Staff has suggested that a similar provision be incorporated in this certificate. We are aware however, that the imposition of the foregoing provision would have to be coordinated with the imposition of any form of economic penalty resulting from a reduction in heating value of the SNG produced and/or the production level so that the magnitude of the latter penalties would not be greater than that under a minimum bill which becomes operative where there is a total failure of deliveries. If this were not done, the Applicants' incentive to continue deliveries would be reduced.

Due to the experimental nature of the project, it appears premature to establish penalty provisions at this time. In our view, we could more realistically assess the merits of establishing a minimum bill or penalty provision when the testing operations have commenced. At the juncture the Applicants would be able to submit data and reasonable forecasts of the Btu quality and the quantity of SNG to be produced. We would then also be better able to assess what is reasonable in terms of consecutive days without service, reduced service, and reduction in Btu content.

/ Opinion No. 622-A, 48 FPC 723, 730.

Staff advocated another proposal on brief which relates to the foregoing discussion. In the event that the plant does not produce its design capacity, 250,000 Mcf per day, or the Applicants are unable to deliver the total quantity of the gas, Staff suggests that Pacific Coal and Trans Coal be required to file curtailment plans with the Commission to provide for the allocation of the remaining production. Transwestern answers that the delivery obligation of the gasification companies are expressed in terms of percentages of output rather than absolute numbers. Thus even if the plant is not operating at design capacity, neither Trans Coal nor Pacific Coal will be in a position where they are unable to deliver the certificated quantity to their customers, i.e., the daily proportionate share of the SNG. We find no merit in the Staff's proposal.

Abandonment

During the proceedings, Staff suggested that there is a danger under Section 7(b) of the Natural Gas Act that the Applicants could abandon deliveries under certain circumstances. In the event that deliveries fall below the design capacity of 250,000 Mcf per day, Staff asserted that Transwestern should be required to seek abandonment authority for its natural gas service. In order to foreclose any possibility of abandonment, Judge Ellis conditioned the grant of the certificate to require the Applicants to execute and file a trust declaration that, to the extent the plant facilities were amortized through receipts from the sale of gas, legal title to such amortized portion would be held in trust for the perpetual use and benefit of California and Midwest consumers.

In its Brief on Exceptions, Transwestern stated its intent not to abandon the facilities or discontinue sales and suggested that the following condition be attached to the certificate in lieu of that proposed in the Initial Decision:
Neither Applicants nor any successor or assignee of applicant shall voluntarily abandon the operation of the plant facilities necessary for the sales authorized hereunder or discontinue such sales until such time as the Commission has, after due hearing, found that the continuation of such sales is unwarranted or that the present or future public convenience or necessity permits such abandonment.

The foregoing language tracks Section 7(b) of the Natural Gas Act and provides adequate protection to the consumers. We therefore find that the certificate should be conditioned accordingly.

Pre-empted Capacity

In its Brief on Exceptions, Staff argues that the Applicants' certificates should be conditioned to require the coal gasification companies to pay for any new facilities which might be required as a result of the pre-empted capacity of the pipeline. It is anticipated that the project supply will utilize approximately twenty-five percent of Transwestern's pipeline capacity. Staff's concern is that a new cheaper source of supply might become available to satisfy demand at a price lower than that projected for the coal gas. However, Staff states the following:

But in the absence of evidence that at the time the proposed coal gasification project comes on line there will be domestic production sufficient to eliminate the forecasted short-fall of supply at prices below that of the synthetic gas produced from coal, and in the absence of other less costly alternative (Tr.498), the Commission Staff supports the grant of a certificate as hereinafter conditioned, on this record Applicants' proposal represents the cheapest additional increment of gas currently available to applicants. _/

_/ Initial Brief, p. 8.

Staff, in conjunction with the other parties, recognizes the positive benefit that this additional supply will bring to the consumers. Although this supplemental supply will result in more efficient utilization of existing pipeline capacity today, Staff advocates the imposition of a burden on the Applicants' to shoulder the domestic energy situation change. We find no merit in this suggestion.

The Commission further finds:

(1) Transwestern Pipe Line Company is a natural gas company subject to the jurisdiction of the Natural Gas Act; and its receipt of coal gas into its lines at a point near Gallup, New Mexico, its transportation of mixed natural gas to its terminus at the California border, its delivery of the quantity of mixed gas equal to the coal gas received, are required by the public convenience and necessity.

(2) Transwestern Coal Gasification Company and Pacific Coal Gasification Company will, upon the inception of the respective sales for resale of mixed natural and coal gas, become natural gas companies subject to the jurisdiction of the Natural Gas Act as hereinafter set forth; and their sales and deliveries are required by the public convenience and necessity.

(3) The conditions hereto attached are required by the public convenience and necessity.

(4) Transwestern Pipe Line Company's transportation tariffs T-1, T-2 and T-3 are acceptable for filing.

(5) The revised "Comparison of Cost Estimates" admitted in evidence by our order of in this proceeding shall not be a basis of calculation of the initial rate herein established.
(6) The initial rate should reflect the change in coal costs established by the Amendment of March 7, 1975, Western Gasification Agreement No. 1, between Utah International and Transwestern Coal Gasification Company and Pacific Coal Gasification Company admitted in evidence by our order of ______.

(7) The initial decision should be adopted as the decision of the Commission except as modified and supplemented by this Opinion and Order.

The Commission orders:

(A) Certificates are hereby issued to Pacific Coal Gasification Company and Transwestern Coal Gasification Company authorizing them to make the transfers, sales and deliveries, and to build, connect, maintain and operate the facilities proposed and required to effectuate the transfers, sales, deliveries and transportation so authorized.

(1) Pacific Coal Gasification may sell to Pacific Lighting Service Company, at the Arizona-California border near Needles, California, a quantity of mixed natural gas equal to Pacific Coal's delivered share of the coal gas output from the gasification plant proposed to be constructed by the Applicants in New Mexico.

(2) Transwestern Coal Gasification Company may sell to the following:

(a) Pacific Lighting Service Company, at the Arizona-California border near Needles, California, a quantity of mixed natural gas equal to one-half of Transwestern Coal's share of the coal gas output from the gasification plant proposed to be constructed by the Applicants in New Mexico; and

(b) Cities Service Gas Company, upon the issuance by this Commission of required authorization. One-half of Transwestern Coal's share of the coal gas output from the gasification plant will be delivered and transferred to Transwestern Pipeline Company, into their main line near Gallup, New Mexico, for the account of Cities. Cities will receive displacement deliveries at existing Transwestern Pipeline delivery points in Harper and Beaver Counties, Oklahoma, and Hemphill County, Texas. The three-party sale to Cities is contingent upon the corresponding final action on Cities' certificate application in Docket No. CP74-185. Should such authorization for any reason not issue or should Cities for any reason not accept any such authorization, then Transwestern Coal is authorized to sell all of its portion of the project gas to Pacific Lighting Service Company.

(3) Transwestern Pipeline Company may --

(a) transport, in its existing pipe lines, from a connection point near Gallup, New Mexico to its delivery point at the California border, a quantity of mixed natural gas equal to the coal gas received from Pacific Coal and Transwestern Coal to the Pacific Lighting Service Company;

(b) transfer and deliver to Cities Service Gas Company, at the existing points of delivery in Texas and Oklahoma, a quantity of natural gas equal in heating value to the quantity of coal gas referred to in sub-paragraph (2) (b) above, all in effectuation of the three-party natural gas sales contracts among Transwestern Coal, Transwestern Pipeline Company and Cities Service Gas Company;

(c) file, place into effect, and charge accordingly its proposed rate schedules T1, T2, and T3; and
(d) credit its deliveries pursuant to clauses (2)(a) and (b) against the contract demand authorizations provided in its currently effective service agreements with Pacific Lighting Service Company and Cities Service Gas Company.

(B) The authorizations provided for in paragraph (A) are subject to the following terms and conditions:

(1) Pacific Coal Gasification Company and Transwestern Coal Gasification Company initiating service and sale for resale at a rate of $1.38 per Mcf during the first six months of the testing period. At or before the end of the six month period, Pacific Coal Gasification Company and Transwestern Coal Gasification Company shall file a revised tariff rate schedule under Section 4 of the Natural Gas Act or request an extension of the initial rate of $1.38 per Mcf, stating the grounds on which such extension is necessary. Any difference between costs reasonably and prudently incurred and the initial rate of $1.38 shall be amortized over the remaining life of the contracts.

(2) If a Section 4 filing is not made prior to completion of the testing period it is incumbent upon the Applicants to make such filing within 90 days from the commencement of the first regular delivery in order for the Commission to make a determination of the just and reasonable rate.

(3) Pacific Coal Gasification Company and Transwestern Coal Gasification Company shall neither cause nor permit the transfer or assignment of their respective interests in this project to any other party in which they do not exercise a controlling interest, without prior approval of the Commission.

(4) Notwithstanding any other condition herein attached, in the event of failure of the gasification process, in whole or in part, Pacific Coal Gasification Company and Transwestern Coal Gasification Company shall cause prompt action to be taken by all reasonable means to mitigate any losses and to credit any benefits derived from such actions.

(5) Pacific Coal Gasification Company and Transwestern Coal Gasification Company shall, at all times, make available to the Commission their books and records.

(6) Pacific Coal Gasification Company and Transwestern Coal Gasification Company shall not hereafter permit, without prior Commission approval, the further amendment or revision of the coal or synthetic gas sales contracts.

(7) No later than six months prior to the initiation of sales and services authorized herein, Pacific Coal Gasification Company and Transwestern Coal Gasification Company shall file a revised tariff rate schedule and executed service agreements covering sales and services certified by Paragraph A, or resulting from such certification.

(C) The authorizations granted herein shall not take effect as to the construction of any facility, or the transportation and sale of any commingled coal gas, until those necessary federal, state and local authorizations for the construction of the coal gasification project have been secured, and a copy of each has been submitted to the Commission.

(D) The general terms and conditions set forth in the Commission’s Regulations under the Natural Gas Act and particularly those contained in Parts 154 and 157.20 thereof shall attach to the certificate issued herein.

(E) The facilities authorized herein shall be constructed and placed in actual operation, and the proposed sale and delivery of gas authorized herein shall commence on or before December 31, 1979.

(F) The initial decision is adopted as the decision of the Commission as supplemented and modified by this Opinion and Order.

By the Commission.

(SEAL)

Kenneth F. Plumb, Secretary.
I. INTRODUCTION

This memorandum outlines an accompanying detailed proposal wherein the Federal Government and a joint venture group of private companies would reactivate the presently suspended Colony Dow West Oil Shale Project near Parachute Creek, Colorado, by October of this year. Field start of construction could begin April 1, 1976, with a target completion date of June 30, 1979.

This 48,000 barrel per stream day facility will provide the earliest possible demonstration of the economic results and environmental effects of a commercial-size oil shale facility utilizing the most advanced existing U. S. technology. It could also serve as a yardstick for evaluating ensuing synthetic fuels projects.

II. THE PROPOSED PROGRAM

TOSCO believes that the Dow West Project can be reactivated by private industry if Government would lessen some of the uncertainties which are now deterring private investment in oil shale plants. In TOSCO's view, this would be accomplished by a Government commitment to purchase the products of the plant. The purchase price could be reduced substantially by a Government commitment to guarantee loans to The Project up to 75% of the capital required.

Based on this concept, TOSCO would undertake to reactivate the Colony Project and is submitting herein detailed cost and price analyses to form the basis for a contract between the Federal Government and the Colony Project.
The capital and operating cost projections are based on the detailed estimates prepared by the Managing Contractor, TOSCO and the Operator of the Colony Project (Atlantic Richfield).

Based on these projections, the proposed Contract Price for the oil product in March 1975 dollars is largely a function of project financing.

CASE A. If the Project is financed by 75% government-guaranteed loans at an interest rate of 8-1/2% and by 25% equity participation, the Contract Price would be $11.15 per barrel, in March 1975 dollars, based on March 1975 costs.

CASE B. If the Project is financed by 60% government-guaranteed loans at an interest rate of 8-1/2% and by 40% equity participation, the Contract Price would be $12.80 per barrel, in March 1975 dollars, based on March 1975 costs.

CASE C. If the Project could be financed totally by equity participation, the Contract Price would be $16.75 per barrel, in March 1975 dollars, based on March 1975 costs.

All the Contract Prices would be subject to adjustment for inflation or deflation of costs as determined, principally, by accepted indices. Any adjustments not attributable to changing economic conditions would result in substantial penalty to the equity participants.

The proposed Contract Prices assume that equity participation can be obtained with a discounted cash flow return to the participants of 12% in the all equity Case C. In the government-guaranteed loan Cases A and B, the discounted cash flow return would be 15% on equity capital only. In all cases, a substantial amount of the discounted cash flow to participants would be in the form of income tax credits and deductions; and the Contract Price is reduced to reflect these tax benefits.

The program assumes that all products would be sold at prevailing market prices. If the Contract Price is higher than the market price at the time of production, the Government would pay the difference to The Project. If the Contract Price is lower than the market price, the difference would be paid into a Government-managed fund established for this project. During the period when the contract price is higher than the market price, this fund would have a negative balance. If the fund accumulates a positive balance above an appropriate reserve amount because of market prices exceeding the Contract Price, this balance would be shared by Government and The Project in proportion to the amount of capital costs financed by government-guaranteed debt.

An important consideration to industry participation in The Project is the right to an assured supply of sulfur-free shale oil. It is therefore
assumed that Venture Participants will be entitled to purchase the products from the Government at the plant site at prices reflecting true market values. Any products not so purchased could be used, stockpiled or sold by the Government.

Venture Participants would be responsible for transportation of products purchased, including financing, constructing and operating the proposed product pipeline from the Project to the Four Corners line at Aneth, Utah.

III. COST ASSUMPTIONS

The production of shale oil is a mining and manufacturing process; and the largest components of the ultimate price are the recovery of capital and interest on capital. The Case A Contract Price quoted above is based on a total project cost of $902.8 million in March, 1975, dollars, including $79.1 million for prepaid raw materials costs (shale reserves) and $84.7 million for interest during construction.

This cost assumption is based on Mid-1974 estimates and includes adjustment for inflation since component bids were obtained. It also contains a normal 5 percent contingency allowance for estimate variances and unforeseen expenses.

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<th>COMPONENT</th>
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<tr>
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<td>Community Planning &amp; Development</td>
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### CAPITAL COSTS ALREADY EXPENDED OR COMMITTED**

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* Included in Grand Total of $902.8 million.

**As of proposed start of field construction, April 1, 1976.
# Contract Price Components

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## Income from Sales

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## Raw Materials--Shale

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### Direct Operating Costs

#### Labor

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### Contract Price

|                  | $11.15 | $12.60 | $16.75 |

*Includes such costs as Mine Predevelopment Project Staff, Employee Recruiting and Training, Startup and Fixit Expenses.
IV. PROJECT FINANCING -- GUARANTEED LOANS

In Cases A and B, The Project would be financed by equity contributions and by issuance of Project debentures guaranteed by the full faith of the United States Government. The equity contributions to The Project would be in the form of cash, land and reserves, and expenditures already incurred. Equity capital would be paid in and Project debentures would be issued on a schedule to match capital outlays. At all times during the construction period, paid-in equity capital would exceed its share of the total Project costs. The equity participants would be responsible only for contributing their respective equity shares and would have no obligation with regard to the debt financing guaranteed by the Government.

For example, in Case A, the equity contribution during construction would consist of capital costs already incurred, including oil shale reserves ($79.1 million) and other capital costs already expended or committed ($49.1 million), as detailed on Page 6 above. Equity participants would also make cash contributions to The Project during the 3-1/4 year construction period (See Capital Flow Chart – Page 22).

At start-up, total equity investment would be $225.0 million.

The first government-guaranteed Project debentures would be issued shortly in advance of construction start and additional debentures would be issued each quarter during the 3-1/4 year construction period. (See Capital Flow Chart).

At start-up, total Project debt would be $676.9 million.

Project debt would be serviced and amortized by payment of interest only during the first year after start-up and by level payments of principal and interest thereafter over the remaining 19 years of The Project. An appropriate sinking fund would be established for retirement of the debentures.

Equity participants will recover a portion of their investment during the construction period in the form of federal and state income tax deductions and credits. For those participants capable of utilizing all federal and state credits, total equity investment would be recovered sometime during the fourth year of operations at target production levels, or approximately seven years after initial equity contribution was paid in. Return on equity would come from net cash flow over the remaining sixteen years of The Project.

If the capital costs in Cases A and B, including capital costs during the first two years after start-up, should vary from the March 1975 estimate, the equity investment and guaranteed debt would be increased or decreased proportionately. The Contract Price would be adjusted according to formulas provided in Section V which contain disincentives for capital cost increases not attributable to inflation.

V. CONTRACT PRICE ADJUSTMENTS

The proposed Contract Price would be a firm price for the life of The Project subject to adjustment for inflation or deflation of capital outlay and
direct operating costs such as labor and materials and actual changes in such
costs as taxes, insurance and electric power.

A. Adjustments for Changing Economic Conditions during Construction

At start-up of production, the Contract Price would be adjusted
to reflect variations in Project capital costs above or below the March
1975 estimate, to the extent they are attributable to inflation or
deflation, as measured by appropriate indices.

B. Adjustments for Capital Cost Variations Not Attributable to Changing
Economic Conditions

The Capital Cost estimate set forth above is a sound estimate,
prepared at a cost of more than $12 million; but, in the event that
capital costs, including those during the first two years after start-up,
should exceed an amount attributable to changing economic conditions,
the Price adjustment would be in an amount sufficient to amortize the
additional cost and pay interest on the debt portion, but no interest or
return would be paid on the additional equity investment. This adjustment
formula would establish a disincentive to discourage non-inflation
related capital cost increases.

C. Adjustments for Operating Cost Variations Attributable to Changing
Economic Conditions

In the Contract Price, the operating costs components which
lend themselves to measurement by indices will be adjusted by

appropriate indices (basis: March, 1975). Those components are:

- Wages and Salaries
- Purchased Electric Power
- Materials for Mining, Crushing, Spent Shale Disposal
  and Plant Maintenance
- Catalysts, Chemicals and Ceramics

Adjustments for certain components which cannot be measured
by indices will be in accordance with actual increases or decreases in
cost (basis: March, 1975). These components are:

- Fringe Benefits
- Taxes
- Insurance
- Compliance with Government Regulations
- By-Product Credits

The above formula provides a strong incentive for the Project
Management to hold operating costs to estimated levels, and Equity
Participants will bear the risk of increases not attributable to changing
economic conditions.
D. Variations in Production Levels

The Contract Price is based on total production of 304,560,700 barrels of shale oil over the life of the Project. Production schedule is for 8,726,700 barrels in the first year after start-up; 13,090,000 barrels in the second year; and 15,708,000 barrels annually for the ensuing 10 years. In the event that additional capital costs are required to achieve these scheduled production levels, the only adjustment to Contract Price would be as provided in Section V (b) above.

If the Project proves capable of producing the 304,560,700 barrels in less than twenty years, Equity Participants would be responsible for providing any additional capital required to achieve the accelerated output and would accelerate payments to the sinking fund for debt service from the incremental annual income. The Contract Price would apply to the total volume produced.

If the Project proves capable of producing more than 304,560,700 barrels of oil product, the Equity Participants would have sole responsibility for obtaining additional shale reserves, for providing necessary capital and for marketing the incremental output. Government would have no obligation to purchase the incremental output or to guarantee any debt capital for the achievement of such increases.

VI. SOME POSSIBLE EFFECTS OF CONTRACT PRICE ADJUSTMENTS

Based on the adjustments provided in Section V, it is possible to project the effect of possible Project cost increases attributable to changing economic conditions or other causes. For example, in Case A (75% government-guaranteed loans and 25% equity):

(a) Five percent per year inflation from March 1975 to start-up would increase the price per barrel \$1.71 including \$0.91 per barrel additional operating costs.

(b) A \$50 million increase in capital costs attributable to inflation would increase the Contract Price \$0.75 per barrel. A \$50 million increase in capital costs not attributable to inflation would increase the Contract Price \$0.13 per barrel.

(c) A debt interest rate of 10-1/2% instead of 8-1/2% would increase the Contract Price \$0.67 per barrel.

VII. OPERATION OF THE PROJECT

It is proposed that the Venture Participants would have responsibility for Project operation, subject to appropriate supervision by Government contract officers. The Participants would provide management for the Project.
The principal marketable product of the Project will be hydrotreated shale oil of the following specification:

- API Gravity: 40.0
- Sulfur, wt.%: Nil
- Nitrogen, wt.%: 0.06
- Product Yields, vol.%:
  - Gasoline & Naphtha (IBP-400°F): 43.0
  - Gas Oil (400-950°F): 57.0
  - Residium (950°F +): None

This is a premium quality sulfur-free distillate, superior to any presently known conventional petroleum crude. The nearest comparable conventional crudes are probably West Texas sweet crude of 42.6 °API gravity with 0.10 sulfur; Nigerian Light, 38 °API gravity with 0.10 sulfur; and Algerian Zargaitine 41.5 °API gravity with 0.10 sulfur. In addition, the Project will produce anhydrous ammonia and sulfur for marketing.

Each Venture Participant would have the right to contract to purchase from the Government, at the beginning of each calendar quarter year for the life of the Project, its equity percentage of all marketable products acquired by the Government under its contract. The purchase price would be the average U.S. market price for the most comparable crude petroleum in the preceding calendar quarter, with appropriate adjustment for location.

VIII. ADVANTAGES OF THE PROCUREMENT/LOAN GUARANTEE APPROACH

Press reports indicate that Government is considering a range of incentive programs to encourage industry to produce synthetic domestic fuels. The program suggested in Case A is one particularly appropriate to assure reactivation of the Colony Dow West Project -- the first commercial-size plant. TOSCO believes that a program which combines contract purchasing and guarantees of debt financing by the federal government would be in the public interest for several reasons:

1. Government guarantee of debt substantially reduces the Contract Price for oil. 75% guaranteed debt financing could reduce the price as much as $5.60 per barrel; 60% guaranteed debt, $1.62 per barrel.

2. There is ample precedent for such a program. Procurements and Loans under the Defense Production Act and Maritime Administration loan guarantees are two prominent examples.

3. Loan guarantees during 1976-1979 and contract purchasing in 1979 forward involve only Congressional authorization. In the absence of default on government-guaranteed loans, the need for federal appropriations would come only if Government had to re-sell its purchased oil at a loss; and the contract prices in the TOSCO proposal make such a loss unlikely. Indeed, the prospects for upside gain to Government are more likely under the TOSCO formula.
4. The TOSCO proposal limits the need for Government administration to contract supervision. Experienced private management personnel will build and operate the facility.

5. The proposal is not a cost plus contract. Construction and operating costs are measured largely against indices and any cost increases not allowable under the contract will reduce return on equity. Profits are dependent upon efficient operations at target production levels. Substantial equity investment, including shale reserves, will be totally lost if the Project fails completely.

If the shale oil produced by the reactivated Colony Project proves to be competitive with imported oil -- as TOSCO believes it will -- the Nation will have unlocked a vast source of potential embargo-proof energy and reduced its dollar drain. Subsequent plants would be a known risk and private capital could be acquired at reasonable rates. The Colony Project will provide permanent employment for some 1,000 workers and construction employment for some 2,000 workers. The plant will enhance the state and local tax base of Colorado. Tax revenues of 65¢ or more per barrel of shale oil marketed will be generated.

This is a Government/Industry program which is fair to both: In exchange for insurance against the risk of unremunerative future price fluctuations and abnormal borrowing costs, the industry participants would provide Government with a detailed cost yardstick for evaluating other similar projects and would share with Government any profits resulting from future market price increases.

IX. A SUGGESTED ACTION PROGRAM

It is important to note that weather conditions in the Western oil shale region strongly favor commencement of plant construction in early spring. The Dow West Project would have to be released no later than October of this year in order for field construction to begin in the spring of 1976. TOSCO therefore urges that the Government decide as soon as possible whether the proposed contractual arrangements described above warrant serious consideration. If the Government's decision is affirmative, TOSCO suggests the following action programs:

March - July, 1975

1. Government reacts to contract proposal and preliminary understanding is reached on principal terms and conditions, subject to negotiation on definitive contract terms.


3. TOSCO undertakes to interest private industry in reactivating the Colony Project in accordance with preliminary understanding with Government.

4. Simultaneously, Government considers existing legislative authority for the proposed program and seeks additional authority from Congress if necessary.
July – September, 1975

5. Government and Venture Participants negotiate and execute definitive contracts.

6. Simultaneously, Government concludes E.I.S. evaluation and, if favorable, issues necessary permits for project construction.

October 1, 1975

7. The Project is released for construction.

April 1, 1976

8. Construction Field Start.

June 30, 1979

9. Construction Completed; Operations begin.

BACKGROUND INFORMATION

In 1964, TOSCO organized a joint venture and began acquiring oil shale lands on which to utilize the TOSCO technologies. The venture also constructed and operated large-scale development and demonstration facilities for mining and processing oil shale. In 1969, Atlantic Richfield Company joined the venture and became operator of the semi-works facility. The development work in the ensuing three years successfully completed semi-works phase development of the TOSCO II process and completed studies of commercial mining, spent shale disposal, and environmental protection techniques and costs.

In 1973, TOSCO and Atlantic Richfield selected C F Braun & Company as Managing Contractor to design and build a commercial oil shale complex on 4,600 acres of private lands known as The Dow West Property and located on Parachute Creek, north of Grand Valley, Colorado. Preparation of detailed engineering work for construction began in June, 1973, for a facility to mine 66,000 tons per day of oil shale and produce for market approximately 48,000 barrels per stream day of hydrotreated sulfur-free shale oil plus commercial quantities of by-products, chiefly ammonia and sulfur.

In January, 1974, Ashland Oil, Inc. and Shell Oil Company joined the commercialization program, and acquired certain options to obtain an interest in the Dow West Property which is presently owned 40 percent by TOSCO and 60 percent by Atlantic Richfield.
considerations make the project a logical choice for the nation's first oil shale commercial demonstration:

1. Extensive pre-construction work on Dow West has already been completed, and the project can be ready for construction start within 6 - 9 months of go ahead. The Managing Contractor has in hand specifications for responsible bids on major plant components and offsite facilities. Indeed, construction has already been started on the plant access road and on railroad siding.

2. The Department of the Interior has nearly completed a draft Environmental Impact Statement for the proposed plant and offsite facilities, including a pipeline for the oil product.

3. The nature of the deposit -- oil content, hydrology, and mineability -- is clearly established. More than 1.2 million tons of shale have already been mined on Dow West. Mining techniques and costs are known and reserves for a long-term production facility are established.

4. The Project will use the TOSCO II retorting process, recognized in the industry as America's most advanced oil shale surface retorting technology. The TOSCO II has been proved in both a 25 ton per day pilot plant and semi-works operations, processing some 1,000 tons per day of oil shale to produce 850 barrels per day of shale oil from Dow West shale in a simulated commercial operation demonstration.
TOSCO PROPOSAL FOR FINANCING OIL SHALE PROJECT

**CAPITAL FLOW CHART**

**CASE A**

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<th>Construction Quarter</th>
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<th>Cumulative Proceeds from Issuance of Debt - $MM</th>
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<th>Proceeds from Equity Contribution</th>
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**TOTAL** 818.18* 802.34* 225.84

*Does not include Interest During Construction of $84.7 million.
### POSSIBLE CONTRACT PRICE ADJUSTMENTS

#### CASE A

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**TOSCO PROPOSAL FOR FINANCING OIL SHALE PROJECT**