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report

OIL SHALE  ○  COAL  ○  OIL SANDS

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The Pace Consultants Inc., has provided energy consulting and engineering services since 1955. The company's experience includes resource evaluation, process development and design, systems planning, marketing studies, licensor comparisons, environmental planning, and economic analysis. The Synthetic Fuels Analysis group prepares a variety of periodic and other reports analyzing developments in the energy field.

THE PACE CONSULTANTS INC.
SYNTHETIC FUELS ANALYSIS

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Capsule Summaries of the More Significant Articles in this Issue

Petrocorp Acquires New Zealand Synfuels

The Petroleum Corporation of New Zealand has agreed to assume the New Zealand Government's 75 percent interest in Synfuels. As detailed on page 1-1, the acquisition could boost Petrocorp's production of chemical methanol from 550,000 metric tons per year to about 980,000 metric tons per year. Or, depending on the market, the plant could provide increased synthetic gasoline production.

GAO Critiques DOE Budgeting Priorities for R&D

A GAO report, discussed on page 1-2, says that the Department of Energy (DOE) has no good way to establish budget priorities. In large part, it is the DOE budget process that determines R&D priorities.

DOE Announces SBIR Phase I Awards

DOE has selected 170 grant applications for funding under Phase I of its Small Business Innovation Research (SBIR) program. A partial list of the selected projects is given on page 1-2. The SBIR Phase II awards are discussed in the article on page 1-5.

Opinion Poll Supports a Strong National Energy Policy

A national survey on the Iraqi crisis revealed that 86 percent of Americans believe the United States should adopt a new national energy policy. As discussed on page 1-6, 86 percent of those surveyed said that United States energy strategy should include conservation and the development of alternate sources of energy.

Prospects for Synthetic Fuels Called Limited

A new study by UBS Phillips & Drew says it would take 5 to 10 years of sustained higher oil prices to accelerate the development and production of synthetic fuels. The article on page 1-7 reports that synthetic fuels currently contribute only 1 percent of the world oil supply and will amount to no more than 2 percent by the year 2000.

Chevron Says Alternative Energy Sources Will Not Be Competitive in this Decade

Chevron's World Energy Outlook predicts that plentiful, low-cost supplies of the basic fossil fuels--oil, gas and coal--make it unlikely that alternative energy sources will be competitive until well into the next century. The report says the question for the 1990s is not the cost or supply of energy, but the environment. See page 1-7 for a detailed discussion of Chevron's assessment of this issue.
GAO Endorses DOE Energy Strategy Efforts

A report from the United States General Accounting Office reiterates concern about the United States' increasing dependency on imported oil, and also questions the adequacy of generating capacity to meet future electricity needs. As discussed on page 1-9, the GAO supports the initiative to develop a national energy strategy.

Increase in Oil Demand Slowing Says BP

Even though world demand for oil increased 1.5 percent in 1989, it was the smallest increase in demand since 1986. World oil production increased by 1.7 percent in 1989, and in spite of this, world proved reserves of crude oil climbed significantly. See page 1-11 for further details.

Shell Sees Oil Production Peaking at 80 Million Barrels per Day

Shell predicts that oil production, with enhanced recovery techniques and new discoveries, will peak early in the next century at nearly 80 million barrels per day. Shell's Energy in Profile identifies three recent developments that will shape the future of the energy industry in the 1990s: energy supply security issues, political change in Eastern Europe and the USSR, and global climate change issues. These are discussed on page 1-12.

Liquid Fuels from Methane Could Compete with $22 Oil

A paper by F.M. Dautzenberg says that an "ideal" technology for producing gasoline from natural gas could become economical at a crude oil price of $22 per barrel. He further suggests that improved technology for methanol production could make it competitive with $15 oil. Dautzenberg's "ideal" technology is detailed on page 1-15.

IGT's Gas Heated Reformer Will Lower Methanol Production Costs

For 5 years, ICI has been developing the Gas Heated Reformer (GHR) in which the primary reformer receives heat directly from the process gas exiting the secondary reformer. As explained on page 1-18, this results in a compact pressurized reformer and replaces the massive multiple burner structure and substantial heat recovery systems of a conventional plant.

IGT Supports Research on Chemicals from Natural Gas

The Institute of Gas Technology has funded three projects related to the production of chemicals from natural gas. The projects, detailed on page 1-21, are: an improved process for production of synthesis gas for ammonia, microbial production of liquid fuels and chemicals from methane, and the catalytic conversion of methane to chemicals.
LLNL Oil Shale Project Starts 4 Ton/Day Retort

Lawrence Livermore National Laboratory has constructed a pilot plant to process 4 tonnes per day of commercially sized shale in a generic second generation Hot-Recycled-Solids (HRS) retorting system. The article on page 2-3 gives a description of the project, and outlines future plans for commercialization of the process.

Second Nahcolite Mining Project Moves Ahead

Denison Resources Corporation joins NaTec Resources Inc. in separate ventures that could together produce 1 million tons a year of sodium bicarbonate. The Denison mine would start producing 50,000 tons a year in 1992 and work up to 500,000 tons a year by 1995. Details are on page 2-5.

Occidental Reports Oil Shale Combustion Tests in Fluidized Boiler

Occidental Oil Shale has conducted two series of oil shale combustion tests for its MIS (modified in situ) demonstration project on Tract C-b. The results of the tests, performed at Tampella-Keeler's facility in Pennsylvania and Pyropower's pilot plant in California, are reported in detail on page 2-9. Coal and simulated MIS gas were also burned in the test runs.

Russell Publishes Book on Oil Shales of the World

P.L. Russell has published an extensive record of the many oil shale deposits of the world and has documented the various attempts to use these resources throughout history. This comprehensive work is reviewed on page 2-16.

Court Rules for Marathon in Oil Shale Claims Case

The United States Department of the Interior has been ordered to issue oil shale mining patents to Marathon Oil Company and three Colorado residents. As discussed on page 2-20, the dispute involved 983 acres of land in western Rio Blanco County, Colorado and six pre-1920 mining claims.

White River Resource Management Plan to be Revised

A resource management plan (RMP) is being prepared for the White River Resource Area headquartered in Meeker, Colorado. The Bureau of Land Management has solicited public input to help define the issues and planning criteria for the RMP. These issues are detailed on page 2-20.

Site Work Completed at Bi-Provincial Upgrader

This summer the major site preparation work for the Bi-Provincial Upgrader project near Wilton, Saskatchewan, Canada was finished. The project, jointly owned by the governments of Canada, Alberta and Saskatchewan and Husky Oil Company, will be capable of upgrading 46,000 barrels of heavy oil per day. See page 3-1 for details.
Alberta Commits $47 Million to OSLO Study

The Alberta Government has announced it will provide nearly $47 million to complete the engineering phase of the OSLO oil sands project. As discussed on page 3-2, this contribution represents about 36 percent of the $130 million total cost for the engineering phase, which is scheduled to be completed by the end of 1991.

Edmonton Selected for OSLO Upgrader Site

In July an OSLO task force decided to build the OSLO upgrader in Edmonton, Alberta, Canada, 445 kilometers from the OSLO project site. As discussed on page 3-5, the Edmonton site offers access to more sources of bitumen, a potential savings in construction, more available skilled manpower and a less severe climate.

Kearl Lake Project Passed One Million Barrel Production Mark

A review and update of the Kearl Lake pilot project begins on page 3-5. Operation of the in situ pilot began in December 1981. The technological advances achieved through the operation of this pilot project are discussed along with future objectives for the process technology.

Utah Pilot Plant Proposed

Buenaventura Resource Corporation proposes to build a small pilot plant near Weber State University in Utah. As discussed on page 3-9, Buenaventura holds the patent on a "cold" process to extract oil from tar sands.

Syncrude Plant Interests for Sale

 Shares amounting to nearly 55 percent of the Syncrude oil sands plant have been offered for sale. The Syncrude plant near Fort McMurray, Alberta, Canada currently produces 165,000 barrels of synthetic crude oil per day, about 10 percent of Canada's daily production. See page 3-9 for details.

ERCB Reviews 1989 Oil Sands Picture

The Energy Resources Conservation Board's review of oil sands and heavy oil activity in 1989 is discussed on page 3-11. The ERCB says that 1989 was a very slow year for oil sands drilling.

Near-Term Outlook for Canadian Heavy Oil Not Promising

A paper by G.H. Lenz, "Marketing of Heavy Oil, Synthetic Crude, and Derived Products," is discussed on page 3-13. Lenz says that the 1990s will see even greater reliance on foreign crude sources because of the current pricing environment. As the pricing structure changes, investments in refinery conversions and upgraders will become more attractive.
Economic Analysis Shows Promise for Energy-Integrated Process

The results of a thermodynamic second-law efficiency analysis for three different process configurations involving two-stage fluidized bed pyrolysis of tar sands are reported on page 3-16. This work, carried out by the Chemical Engineering Department at the University of Utah, also includes a capital and operating cost estimate for the most efficient design.

Canadian Data Show 65 Percent Drop in Oil Sands Expenditures in 1989

The Canadian Petroleum Association says that oil sands capital expenditures dropped 65 percent from $864 million in 1988 to $304 million in 1989. As detailed on page 3-18, operating costs rose 9.3 percent, and royalties and taxes increased by 4.3 percent in 1989.

ROPE Process Shows Promise on California Tar Sands

Experiments involving the ROPE (recycle oil pyrolysis and extraction) process, under development at Western Research Institute in Laramie, Wyoming, are summarized on page 3-24. Eight experiments were conducted in which California Arroyo Grande tar sand was processed in the presence of heavy oil recycle.

Solvent Extraction/Cosolvent Precipitation Process Modified

The Chemical Engineering Department at the University of Arkansas has been developing a solvent extraction process for the recovery of bitumen from tar sands for the past 5 years. The results of the first two phases of the project, detailed on page 3-27, show it is technically feasible to produce solid bitumen by amphiphilic phase behavior of the solvent-cosolvent system followed by a single distillation column for solvent recovery.

Alberta Proposes to Reduce Oil Sands Lease Periods

The Alberta Department of Energy has proposed changing the primary term for a lease issued out of a prospecting permit to 15 years. As discussed on page 3-33, leases issued in areas of known oil sands resources (development leases) would have a lease term of 10 years.

CTC Expanding Production and Marketing

Coal Technology Corporation (CTC) is constructing a $1.7 million expansion of its liquid coal processing facility. CTC produces coal-derived gasoline and diesel fuel and has recently opened its ninth outlet, marketing coal-derived fuels to the general public in a six-county area in Virginia. See page 4-1 for a complete summary.
Sasol Approves Six New Projects

Sasol has announced approval of the first six projects of a 20-project program that will cost an estimated total of $1.1 billion over the next 5 years. The six newly approved projects, projected to cost $451 million, are outlined on page 4-1. Three of the projects will be at Sasol One in Sasolburg and the other three will be at Sasol's Secunda facilities.

ENCOAL Completes Funding Negotiations

ENCOAL Corporation of Houston, Texas will demonstrate a process that converts low rank coals to two new, clean-burning, high value fuels. The new $72.6 million Liquids from Coal (LFC) process demonstration plant, discussed on page 4-3, will be jointly funded by ENCOAL and the United States Department of Energy under Round 3 of the Clean Coal Technology program.

New Coal Gasification/Cogeneration Project Planned in Virginia

Virginia Power will purchase 210 megawatts of power from a new integrated gasification combined cycle plant being built by Virginia Iron Industries. The $800 million project will use the COREX coal gasification technology, the first of its kind in the United States. See page 4-4 for further details.

Dow Syngas Gasifies One Million Tons of Coal

Destec Energy, Inc. has announced that the Dow Syngas Project recently surpassed 1 million tons of coal converted to syngas. The plant has been in operation for 3 years and the syngas produced is used to fuel 160 megawatts of power generation capacity. A complete summary of the project can be found on page 4-4.

DOE Delays CCT Round 4

The United States Department of Energy has announced that because of the uncertainties surrounding pending legislation, Round 4 of the Clean Coal Technology solicitations will be delayed. As discussed on page 4-6, unresolved issues in the pending Supplemental Appropriations Act and the Clean Air Act Amendments made the delay necessary. Round 4 is now scheduled for September 1991.

Three Firms Will Get Molten Carbonate Fuel Cell Funding

The United States Department of Energy has selected three firms to bring molten carbonate fuel cell technology into full-scale testing. Each of the 3-year projects is discussed on page 4-8. One of the firms will continue research efforts that could improve the fuel cell stack, while the other two have plans to construct and test full-size fuel cell stacks.
Economic Window of Opportunity Seen for Coprocessing

The MITRE Corporation conducted an economic analysis of the coprocessing of coal and petroleum resid compared to other alternative technologies of resid upgrading alone and coal liquefaction. A detailed summary of this effort begins on page 4-13.

Texaco Patents Process to Feed Sewage Sludge to Coal Gasifier

Texaco Inc. holds the patent on a process to gasify municipal sanitary sewage sludge. As described on page 4-20, raw municipal sanitary sewage is first separated into sewage sludge and liquid. The sludge is sheared without heating, dewatered and mixed with particles of coal for subsequent gasification.

Storage Stability of Coal-Derived Jet Fuels Tested

The Aero Propulsion and Power Laboratory funded two studies to investigate the feasibility of making military jet fuel from the liquid byproducts of the Great Plains Coal Gasification Plant. Penn State University and the National Institute for Petroleum and Energy Research have issued reports, summarized on page 4-21, on the thermal stabilities of coal-derived and petroleum-derived JP-8 fuels.

Symposium Highlights Progress in Bioconversion of Coal

The First International Symposium on the Biological Processing of Coal featured research reports on biological approaches to coal desulfurization and deashing, coal solubilization, coal gasification, conversion of coal gases, and cleanup of coal conversion wastes. Beginning on page 4-23, summaries are presented for nine projects involving direct bioconversion to liquid or gaseous products.

Simultaneous Grinding Increases Liquefaction Rate

Researchers at the University of Toronto in Ontario, Canada have shown a significant enhancement of coal conversion rates when a combination grinding-liquefaction process is used, compared to liquefaction alone. A summary of the experiments performed and the conversion results obtained is presented on page 4-25.

Texaco Tests Hot Gas Desulfurization System

Texaco Inc., in a project sponsored by the United States Department of Energy, is investigating both in situ and external hot gas desulfurization for coal gasification. A review of the Phase II work completed to date is provided on page 4-26. The project is a planned 5-year venture.

METC Programs Target Methods for Making Hydrogen from Coal

The United States Department of Energy’s Morgantown Energy Technology Center (METC) is sponsoring a number of research programs related to improved methods for manufacturing hydrogen from coal. Five METC-sponsored programs are summarized on page 4-27.
Coal-Water Fuels Draw Emphasis in Japan

Japan's New Energy Development Organization (NEDO) has been involved in extensive research and development aimed at increasing coal utilization in an environmentally responsible manner. Many private companies and the Japanese Government, as detailed on page 4-30, have cooperated to develop coal-water mixture (CWM) technology and to promote its commercialization in Japan.

Sasol Product Could Meet Reformulated Gasoline Specs

According to J.H. Fourie, the synthetic gasoline now produced by South Africa's Sasol Limited could probably meet the specifications for reformulated gasoline to be required by the new Clean Air Act amendments. A discussion of Sasol's facilities, process, and the environmental aspects of its product is provided on page 4-32.

Extensive Use of IGCC Seen for Europe

A paper by K.R.G. Hein, "German Coals: Utilization Now and in the Future," says that the future utilization of coal is strongly linked with the development of electrical power generation technology. As discussed on page 4-34, Hein says the first coal combined cycles will start their demonstration operation in Europe within the next few years.

Clean Coal Technologies Suggested for Pacific Rim

Argonne National Laboratory has been studying potential markets for United States clean coal technologies in the Asian Pacific Basin (APB). Argonne's study, summarized on page 4-36, selected 11 individual technologies, including integrated coal gasification combined cycle, that might be considered for application in the APB.

Uhde and Lurgi to Cooperate on Development of HTW Process

Uhde GmbH and Lurgi GmbH will jointly undertake further development of the Rheinbraun High Temperature Winkler (HTW) process for fluidized bed coal gasification. In 1989 a high pressure (20-25 bar) HTW pilot plant was started up at Wesseling in the Federal Republic of Germany. See page 4-39 for more details.

Final Economic, Social and Cultural Supplement to Powder River I EIS Issued

The supplement to the Powder River I Final Environmental Impact Statement (FEIS) has concluded that the Northern Cheyenne and Crow belief and value systems would be affected by development of Powder River I new mine and expansion/extension tracts. See page 4-44 for a discussion of the probable impacts and possible mitigation actions under consideration.
syn-fuels: general
PETROCORP ACQUIRES NEW ZEALAND SYNFUELS

The Petroleum Corporation of New Zealand (Petrocorp) has agreed to take over the New Zealand Government's 75 percent interest in Synfuels, a synthetic gasoline plant in Motunui. Petrocorp is a subsidiary of Fletcher Challenge Ltd., the country's largest company.

Mobil Oil of New Zealand Ltd., a unit of Mobil Oil Corporation, will retain its 25 percent interest in Synfuels and will continue as the plant operator.

The government will reportedly pay Petrocorp US$122 million to assume its 75 percent share of the Motunui plant. Petrocorp, in return for a guaranteed natural gas supply and price to the year 2009, will prepay the government about US$152 million for the plant's natural gas feedstock.

Petrocorp originally negotiated a deal to buy Synfuels in 1988, but the purchase was blocked by the New Zealand Commerce Commission on anti-trust grounds. As part of that agreement, Petrocorp also would have acquired the government's contracts for the natural gas feedstock for the plant supplied from the Maui offshore gas field. The government decided that such an acquisition would give Petrocorp control over most of the country's hydrocarbon energy resources.

This time the purchase agreement does not include the sale of the government's natural gas contracts. Instead, the government will retain the contracts while selling the marketing rights to Petrocorp. Thus, with a guaranteed supply and price until the contracts expire in 2009, Petrocorp agreed to prepayment for a portion of the natural gas feedstock for that period.

The New Zealand government was reportedly carrying a debt of about $720 million on the Synfuels plant. Yearly operating losses have been as high as $195 million by some accounts. However, a profit of US$140 million was reported for 1989.

The Motunui plant, which converts natural gas to methanol and then to gasoline, produced about 12,700 barrels per day of gasoline in 1989. Methanol was produced at a rate of about 4,100 metric tons per day.

Fletcher Challenge already owns a large methanol plant in nearby Waitara and a pipeline connecting the two plants has been put in place. With the acquisition of Synfuels, Petrocorp has a great deal of flexibility, "Either to produce more chemical methanol or more gasoline, depending on movements in the markets for both products," H. Fletcher, chief executive of Fletcher Challenge, was quoted as saying.

Petrocorp currently produces about 550,000 metric tons of chemical methanol a year. Production at the Motunui plant could boost that to about 980,000 metric tons a year. Conversely, methanol from the Waitara plant could be pipelined to the Motunui plant to allow increased gasoline production.

LANDFILL GAS TO DIESEL PLANTS PROPOSED

Public Service Company of Colorado says it plans to build the world's first plant to convert landfill gas into diesel fuel.

The process will use basic technology in first breaking down the landfill gas to carbon monoxide and hydrogen. The Syn-gas will then be run over an iron catalyst and reformed into hydrocarbon compounds and water. Refining the compounds will produce diesel, naphtha and wax.

The 100 barrel per day diesel plant, to be built in Pueblo, Colorado, is expected to cost $14 million. It has been estimated that there is enough methane at the site to run the plant for 20 years. In addition to diesel fuel, the plant will produce 50 barrels of naphtha per day and 80 barrels of high-grade wax per day. An engineering and construction contract has been awarded to Ultrasystems Engineers and Constructors.

This technology could possibly be used at more than 100 similar landfills in Canada and the United States. One such site in the Salt Lake City, Utah area is currently being considered.

National Energy Associates of Larkspur, California is studying the possibility of building a small refinery at the site to produce 300 to 500 barrels of diesel fuel per day, according to a report in Coal & Synfuels Technology. The refinery would be used by the city transit system to fuel their fleet of 435 buses. National Energy officials say the fuel would be cost competitive if the company can obtain the landfill gases free of charge.

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DOE ANNOUNCES SBIR PHASE I AWARDS

The United States Department of Energy (DOE) has selected 170 grant applications from small, high-technology firms in 32 states for funding under Phase I of its Small Business Innovation Research (SBIR) program.

According to DOE, the applications were chosen on the basis of scientific and technical merit from among 1,172 submitted in 30 technical research topics ranging from novel sources of electromagnetic radiation to innovative polymeric materials and composites.

DOE will begin negotiations with the firms immediately. The grants will average $50,000 for about 6 months and were expected to be awarded in July.

The SBIR program implements the Small Business Innovation Development Act of 1982. The program is designed to allow small, innovative firms to conduct federally-funded research and development, which will, in turn, help meet agency needs and serve as a base for technological innovation.

Under the grants, each firm attempts to determine the feasibility of its proposed concept. Then the firms are eligible to compete for a second phase with funding of up to $500,000 over 2 years, during which time the selected concepts would be further developed. DOE expects that between one-third and one-half of the original grants will be continued into the second phase.

A partial list of the selected companies and their research projects follows:

- ADA Technologies, Inc.: Development of a High-Temperature High-Pressure Ammonia Detector for Process Control of Hot-Gas-Stream Cleanup Systems
- CeraMem Corporation: A Ceramic Filter for Removal of Particulates from Flue Gas
- CeraMem Corporation: A Ceramic Filter for Removal of Particulates from Hot Gas Streams
- Clarke Rajchel Engineering: Fine Coal Beneficiation Using an Inexpensive and Safe True Heavy Liquid
- ElectroChem, Inc.: A Facilitated Transport Membrane for Hot Coal Gas Desulfurization
- TDA Research, Inc.: High Temperature Hydrogen Sulfide Removal
- Advanced Fuel Research, Inc.: Mild Gasification in Transport Reactors
- Energy Recovery Technology: High Efficiency Tar Sand Oil Recovery
- James W. Bunger and Associates, Inc.: Economic Enhancement of Tar Sands by Extraction of High-Value Products
- PSI Technology Company: High Temperature Removal of Particulates and NOx from Coal-Fueled Diesel Engine Exhaust
- ElectroChem, Inc.: Low Cost Iron Microparticles for Slurry Catalyzed Coal Liquefaction
- Starchem: Conversion of Methane to Methanol and Gasoline

GAO CRITIQUES DOE BUDGETING PRIORITIES FOR R&D

A report by the United States General Accounting Office (GAO) says, "According to DOE officials, DOE has no good way to establish budget priorities." It goes on to say that the DOE (United States Department of Energy) is, however, developing a national energy strategy to be submitted to the President by December 1990.

According to the report, the Office of Management and Budget (OMB) plays an important role in the process of allocating funds by setting "budgetary targets" for energy research and development (R&D). OMB officials say the targets for the new fiscal year are based on the previous year's budget. Future year projections are developed using the budget year as a baseline and assuming the policies and programs of the current year.

During the 1980s, administration policy was to undertake long-term, high-risk research. Accordingly, OMB budgetary targets reflected reduced funding levels for the applied technology areas of fossil, nuclear, conservation and renewable energy R&D.

It is the DOE budget process that determines R&D priorities. Over the past 10 years, energy R&D priorities have shifted from the energy technology program areas to the basic energy research program areas of general science and basic energy sciences. While funding for energy technology programs decreased almost 45 percent from 1980 to
1990, funding for basic energy research programs increased over 140 percent (see Figure 1). In addition, from 1983 to 1990, congressional appropriations for energy technology areas influenced priorities because they were generally greater than DOE requested.

Fossil Energy R&D

According to the report, DOE funding for fossil energy R&D decreased by 51 percent in actual dollars from $847.4 million in fiscal year 1980 to $418.3 million in fiscal year 1990, not including clean coal technology. Adjusting for inflation, funding decreased by almost 69 percent. (See Table 1).

The Clean Coal Technology (CCT) program was funded at $1.2 billion from 1986 to 1990, but these funds are separate from the fossil energy coal program funds. The CCT program provides financial assistance to demonstrate applications of emerging technologies that would enhance the use of coal in more efficient and environmentally acceptable ways. Similarly, the fossil energy coal program supports R&D technologies to expand coal utilization in an environmentally sound manner.

TABLE 1
CHANGE IN FOSSIL R&D FUNDING FROM FISCAL YEARS 1980 TO 1990 (Actual Year Dollars in Millions)

<table>
<thead>
<tr>
<th>Program</th>
<th>1980</th>
<th>1990</th>
<th>Change</th>
</tr>
</thead>
<tbody>
<tr>
<td>Coal</td>
<td>754.9</td>
<td>275.3</td>
<td>-63.5</td>
</tr>
<tr>
<td>Gas</td>
<td>30.7</td>
<td>14.4</td>
<td>-53.1</td>
</tr>
<tr>
<td>Petroleum</td>
<td>61.7</td>
<td>39.9</td>
<td>-35.3</td>
</tr>
<tr>
<td>Other Fossil</td>
<td>a</td>
<td>88.7</td>
<td></td>
</tr>
</tbody>
</table>

8 Appropriations for "Other Fossil" in fiscal year 1980 were included under the coal, petroleum, and gas programs.

FIGURE 1
CHANGE IN PERCENT OF TOTAL FOR ENERGY R & D PROGRAMS FROM 1980 TO 1990

SOURCE: GAO
Petroleum research under the fossil energy program concentrates on enhanced recovery of light and heavy oils.

The gas research program provides financial assistance in developing cost-effective diagnostic and extraction technologies to produce gas efficiently and economically from unconventional gas resources.

From fiscal years 1983 through 1990, DOE budget requests were less than actual appropriations for fossil R&D. These requested budgets reflected DOE's policy that it would withdraw federal support from near-term development and demonstration programs which could be carried forward by private industry. DOE stated that government research funding could then be directed toward solving fundamental problems and toward generic research in such areas as advanced coal cleaning, coal conversion, and enhanced oil recovery.

Basic, Applied and Developmental Research

From 1980 to 1990, DOE's energy R&D funds for development declined significantly from 72 percent of the total budget in 1980 to 44 percent in 1990. Over the same time period, funds for applied research increased only slightly and funds for basic research went from 13 percent to 39 percent of the total budget. (See Figure 2).

Of the total budget for basic research programs for the 10 year period 1980-1990, fossil energy research received 3.2 percent. For the same period, fossil energy research programs represented 17.4 percent of total applied research funding, and 17.1 percent of the development research budget.

1991 Budget Priorities

DOE's posture statement for its fiscal year 1991 budget overview stated that "the Department had no road map for developing top-down policy guidance. There was no Department-wide 5-year program plan and no good way to establish budget priorities."

For 1991, DOE stated that it would no longer focus only on "long-term, high-risk R&D" but would reflect a "proper balance of basic and applied R&D specifically directed toward national energy goals." DOE said research programs should look for areas with the greatest potential for a scientific or technological breakthrough that could significantly advance technology and competitiveness in the market.

---

**FIGURE 2**

FUNDING FOR BASIC AND APPLIED R & D FROM FISCAL YEARS 1980 TO 1990

![Graph showing funding for basic and applied R & D from fiscal years 1980 to 1990.](SOURCE: GAO)
DOE also stated that prioritization should reflect the "best pay-off in achieving energy, environmental, and safety and health goals."

The 1991 budget guidance stated that each program should contribute to the national energy goals of health and safety, a clean environment, energy security, United States/world competitiveness, and national defense.

DOE ANNOUNCES SBIR PHASE II AWARDS

The United States Department of Energy (DOE) has selected 66 projects for fiscal year 1990 funding under Phase II of its Small Business Innovation Research (SBIR) program. The awards will average about $490,000 for a 2-year period.

The selected projects cover a broad spectrum of energy-related research and development in the areas of conservation and renewable, fossil, and nuclear energy, as well as basic energy sciences, health and environmental research, magnetic fusion energy and high energy and nuclear physics, says DOE.

In 1989, under Phase I of the SBIR program, 154 projects were funded, out of 1,543 proposals submitted, for preliminary feasibility studies. These firms were eligible to submit grant applications to continue their work in 1990 under Phase II, the principal research and development phase. DOE selected 17 firms that applied by an early deadline for funding in order to avoid interruption in project work. Fifty-nine Phase II projects were selected last year.

A partial list of the 66 applications recommended for 1990 Phase II awards follows.

- Eltron Research, Inc: Electrochemical Natural Gas Conversion to More Valuable Species
- Energy Research Corporation: Low Cost and Improved Carbon Composites for Phosphoric Acid Fuel Cells
- Engineering Resources: Biological Production of Hydrogen
- Enhanced Insulations, Inc.: An Enhanced Oil Recovery Insulated Tubular
- General Pneumatics Corporation: A Natural Gas Liquefier for Vehicle Fuel
- Giner, Inc.: Corrosion Resistant Catalyst Supports for Phosphoric Acid Fuel Cells
- Membrane Technology and Research, Inc.: Novel Membranes for Natural Gas Liquids Recovery
- The Electrosynthesis Company, Inc.: Corrosion Resistant Carbons for Air Cathodes in Phosphoric Acid Fuel Cells
- ViRoLac Industries: A Direct Determination of Organic and Inorganic Sulfur in Coal by Controlled Oxidation
ENERGY POLICY & FORECASTS

OPINION POLL SUPPORTS A STRONG NATIONAL ENERGY POLICY

In a national survey on the Iraqi crisis, 86 percent of those responding said that the United States needs to adopt a new national energy policy, while a majority supports strong new measures to soften the effects of oil supply disruptions such as that caused by Iraq's invasion of Kuwait in early August and to ensure the security of future United States energy supplies.

The survey, commissioned by Texaco Inc. and conducted by New York-based Penn & Schoen Associates, Inc., during the weekend of August 18 and 19, encompassed 978 interviews nationwide. More than 30 questions were asked during the interviews, focusing on issues such as national energy policy, how long the crisis in the Middle East will last, and ways in which to manage the United States' growing dependency on imported oil.

The survey revealed a number of areas of concern by the American public:

- Some 46 percent of those surveyed believe that the situation in the Middle East will last many months to at least a year.
- Nearly half of those surveyed (49 percent) recognize that the United States imports about 50 percent of its crude oil needs.
- About three out of four people surveyed (73 percent) believe that Iraqi actions constitute a serious threat to the American economy and the nation's way of life.

Commenting on the results of the nationwide survey, Texaco Inc. president J.W. Kinnear said: "This poll reinforces our belief that Congress, the Administration, the oil industry and the American public should take concerted, urgent steps to secure the future energy needs of the United States by developing and implementing a strong national energy policy."

Kinnear said that the survey respondents suggested some areas of focus for inclusion in future energy policies for the United States:

- Conservation: 86 percent of those responding say that conservation should be part of a United States energy strategy.
- Incentives for exploration: 59 percent of those responding favor this as a component of a United States energy strategy.
- Incentives for refineries: 63 percent of those responding agree that new incentives for United States refineries need to be promulgated.
- Alternate energy: 86 percent believe that the United States should foster the development of alternate sources of energy as part of a national energy policy.
- Modifying United States tax law: 70 percent favor changing United States tax law to put United States petroleum companies on more equal footing with foreign competitors.

NCA STATEMENT SCORES COST OF MIDEAST CRISIS

In a statement by National Coal Association (NCA) president Richard L. Lawson concerning recent events in the Middle East, he said, "Last week's invasion of Kuwait by Iraq comes as no surprise." This once again focuses attention on the fact that imported oil is dominating the economy of this country and the world. It is yet another signal that the United States has never been more at risk in energy security than it is now, he said.

The United States imports more than 50 percent of its oil needs, and half of that comes from the Middle East. This continued dependence makes the United States vulnerable to supply disruptions and economic terrorism, said Lawson, and underscores the urgent need for a comprehensive national energy policy. In today's world, a short supply of oil makes a nation subject to political intimidation.

Lawson said that imported oil carries two prices: a value set by market forces and the "true cost" which is far above the market price. "For all Americans, this true cost includes keeping $8 billion aircraft carriers, $3 billion battleships, $1 billion cruisers, frigates and support ships at sea, and aircraft and, more importantly, the lives of American military personnel on the front lines."

According to Lawson, the Mideast oil embargo of 1973 caused the market price of oil to increase five-fold. The 1979 crisis caused the price to rise to about nine times the pre-embargo price. Economies were shaken, inflation raged and serious trade frictions began to appear. He said that the same thing may be happening again.

Whatever the eventual outcome of the situation in the Middle East, Lawson said it is certain that there will be an oil-driven crisis of one kind or another with regularity until the United States' vulnerability is diminished and flexibility is
gained. This has now been demonstrated not once, but four times.

The only flexibility in national energy forecasts is in American resources—coal and conservation, in partnership with domestic oil, natural gas, nuclear energy and alternate energy resources, he said.

## PROSPECTS FOR SYNTHETIC FUELS CALLED LIMITED

London stockbrokers UBS Phillips & Drew say that even if there is another oil supply crisis and prices rise dramatically in the early 1990s, there are unlikely to be enough new synfuels projects to add significantly to world oil supplies in the next 10 years. Synthetic fuels currently make up only about 1 percent of the world oil supply and will amount to no more than 2 percent by the year 2000, reports the Energy Economist. Table 1 shows the UBS Phillips & Drew synthetic fuels production forecast to the year 2010.

Much of the increase forecast for the 1990s is related to Canadian synthetic fuels and bitumen. The OSLO project, once onstream, could add 77,000 barrels per day of synthetic oil to Alberta's average daily production of 200,000 to 225,000 barrels.

The study by UBS Phillips & Drew predicts a sharp increase in the production of Orimulsion, the mixture of heavy Venezuelan Orinoco crude (78 percent) and water. Current Orimulsion production of 100,000 barrels per day is forecast to rise to 1.5 million barrels per day by the year 2010. A British utility, PowerGen, will reportedly burn Orimulsion next year at a 500 megawatt power plant in Lancashire, England.

As can be seen from the table, the study predicts that Brazilian production of alcohol fuel for motor vehicles will steadily decline and all production will stop by 2010. Brazil will rely on imports due to the high cost of domestic fuel production and the recent alcohol fuel shortages.

According to the study, it would take 5 to 10 years of sustained higher oil prices to accelerate the development and production of synthetic fuels. UBS Phillips & Drew say that probable higher oil prices in the next century coupled with huge reserves of tar sands, shale oil deposits and gas will inevitably result in an increased share for synfuels.

## CHEVRON SAYS ALTERNATIVE ENERGY SOURCES WILL NOT BE COMPETITIVE IN THIS DECADE

According to Chevron Corporation's World Energy Outlook, large resources of oil, gas, and coal will continue to provide a major portion of the world's energy supply. Because there will be plentiful, low cost supplies of the basic fossil fuels, says Chevron, "it is highly unlikely that alternative energy sources will be competitive with these fuels in this decade."

The question for the 1990s is not the cost or supply of energy, says the report. The issue for this decade is the environment. Public awareness of environmental concerns such as acid rain, global warming, waste disposal and water pollution is worldwide. Some environmental problems are

<table>
<thead>
<tr>
<th>TABLE 1</th>
<th>SYNTHETIC FUELS: PRODUCTION FORECAST 1990-2010</th>
<th>(Thousand Barrels per Day)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>1990</td>
<td>1995</td>
</tr>
<tr>
<td>Canadaa</td>
<td>330</td>
<td>600</td>
</tr>
<tr>
<td>SASOL (South Africa)</td>
<td>150</td>
<td>200</td>
</tr>
<tr>
<td>Brazil - fuel alcohol</td>
<td>200</td>
<td>100</td>
</tr>
<tr>
<td>Shale Oild</td>
<td>-</td>
<td>50</td>
</tr>
<tr>
<td>Orimulsion (Venezuela)</td>
<td>100</td>
<td>400</td>
</tr>
<tr>
<td>Other</td>
<td>20</td>
<td>50</td>
</tr>
<tr>
<td>Total</td>
<td>800</td>
<td>1,400</td>
</tr>
</tbody>
</table>

aSynthetic crude and bitumen
bMainly Australia
Source: UBS Phillips & Drew
linked to the extraction, manufacture and use of energy, and currently, the cheapest energy sources are fossil fuels. In order to achieve economic progress and have a cleaner environment, cleaner ways to produce and use fossil fuels must be developed, says Chevron.

Alternate energy sources such as solar or windpower are not yet technically or economically capable of supplying large energy demands. Energy requirements over the next decade are likely to be supplied largely by traditional fuels. However, all fossil fuel burning produces CO$_2$. Burning coal, the most abundant energy resource in the world, also releases SO$_2$, a major source of acid rain.

Energy efficiency improvements have reduced the environmental impact of energy consumption and have conserved valuable resources. Incorporating the latest technology into new buildings and equipment, replacing old technology in established industries and replacing old vehicles in transportation fleets, can slow the growth in total emissions without jeopardizing economic growth.

More use of natural gas is environmentally sound, says Chevron, because gas emits about half the CO$_2$ generated by an energy equivalent of coal. Policies for encouraging gas use, especially in developing countries with indigenous supply, would help to mitigate environmental problems.

Curbing global emissions is an international problem. Actions taken by nations—individually and collectively—will shape the demand for energy.

Some actions could turn energy consumption away from coal into oil and gas, hydro, renewables and even back to nuclear. Other actions could lead to efficiency improvements, stack gas cleaning, fuel reformulation and possibly new social patterns, such as mass transit and smaller homes, says the report.

Conservation has reduced energy use per unit of gross national product (GNP) in the industrialized countries. Despite this progress, total energy consumption will grow. More people, higher standards of living, and increased transportation needed for world trade, will push energy use upward, says Chevron. However, because new houses, machinery and vehicles are still considerably more efficient than the old ones they replace, the overall momentum of conservation is continuing.

Japan experienced the largest decline in energy use per unit of GNP—over 30 percent—since 1971-1973. (See Figure 1.) Energy consumption per unit of GNP in Western Europe has declined more slowly because many countries are still industrializing, which generally leads to slightly higher energy use.

The developing countries continue to have high energy/GNP ratios because industries which are the foundation of development—steel, cement, resource extraction and transportation—are all energy intensive.

While the 20 percent improvement in worldwide efficiency is important, the 35 percent reduction in oil use per unit of GNP is more dramatic (Figure 2). In fact, almost all the decline in energy use has been from oil. According to Chevron, price has been the main force behind this reduction.
Oil Price Outlook

Contrary to expectations, the cost of producing oil has been falling over the past few years. Many new development projects have been announced which previously appeared to be uneconomic.

Chevron says several reasons explain this:

- Increased competition in the oil service sector
- Rapid assimilation of cost-reducing oil production techniques
- Changes in taxation and fiscal terms of producer countries
- Advances in enhanced oil recovery (EOR) and exploration technology

Nonetheless, Chevron does not believe that oil prices will return to the $10 a barrel level (1990 dollars) of the pre-1973 period.

At the same time, large sources of potential oil supply appear to be available at production costs not too much higher than today's. This implies that there are limits on the rate at which real oil prices—that is prices corrected for inflation—can rise.

The economics of producing conventional oil will be a primary factor in determining the price of oil well into the next century. Much of this oil is located in OPEC countries. These countries have large reserves and very productive wells, making their oil among the lowest cost to produce.

Chevron’s geologists believe that, of the ultimately recoverable conventional oil, we have consumed almost one-third, identified about one-half and are still looking for the rest. Over the first 70 years of this century, the oil price was held down by the discovery of larger and larger oil fields, many of which are still producing today.

However, coaxing oil out of a field becomes more difficult as the field matures. Production rates start out high and then decline by 5 percent to 10 percent each year until the field is “depleted.” At this point only about one-third of the original oil in place has been recovered. Oil will continue to be produced from existing fields at a declining rate for many years. But, new sources of oil will have to be developed to maintain and increase total production. Some of this new oil will be found in frontier areas—mainly offshore, in the Arctic and in Africa, Asia and Latin America—where relatively little oil exploration has taken place.

Much oil can also be recovered from older reservoirs. Extracting the remaining oil requires the use of higher cost EOR techniques, including injection of steam, CO₂, chemicals and microbes. Later on, similar techniques, as well as mining, can be used to develop the very large, known deposits of extra heavy oil, bitumens and tar sands.

Both EOR and extra heavy oils are being produced today on a small scale. As prices fell in the late 1980s, interest in these projects waned. However, current data from pilot and commercial projects suggest that the cost of recovering this oil, using the newest technology, is not much above current oil prices.

As demand grows, requiring more of this unconventional oil to maintain overall production rates, oil prices can be expected to rise to cover the costs. Higher prices will also reduce the rate of oil consumption growth. Eventually, Chevron agrees that alternatives to naturally occurring hydrocarbons will be required to meet the liquid fuel needs of a growing world population. However, they state that work on pilot projects indicates that the full cost of equivalent energy from alternative sources (shale oil, coal liquids or methanol) might be in the range of two to three times the current price of conventional oil. This puts alternative fuels off until after the middle of the next century (Figure 3, next page).

###

GAO ENDORSES DOE ENERGY STRATEGY EFFORTS

In June the United States General Accounting Office (GAO) sent to the Congressional Energy and Environmental Committee document B-239501 “Developing Strategies for Energy Policies in the 1990s.”

A November 1988 transition report by GAO on the Department of Energy (DOE) summarized a number of major policy, management, and program issues facing the new Secretary of Energy. That report described GAO’s concern for the nation’s increasing vulnerability to oil supply disruptions; the growing uncertainty regarding future electric generating capacity; and the health, safety, and environmental problems associated with various energy options. In an effort to address a broad range of energy issues, the President announced in July 1989 that DOE would develop a national energy strategy to guide future energy policy decisions.

The information contained in the new GAO report updates and supplements the information contained in the transition report and discusses continuing concerns about several energy issues: energy consumption, increased dependence on imported oil from Persian Gulf sources that are more likely to be interrupted, uncertainty over the adequacy of future electric generating capacity, and concern for the potentially adverse environmental effects of energy consumption. In addition, the President’s initiative to develop a national energy strategy is discussed.
Securing sufficient and reliable future energy supplies to meet the increased United States energy demand projected for the 1990s is a major issue facing the nation. Since 1983, United States energy consumption has increased by about 16 percent, and an upward trend is expected to continue through the year 2000. Petroleum is used more than any other energy source in the United States, supplying about 41 percent of the nation's total energy needs.

With the increase in total energy consumption, two potentially disturbing energy supply trends are emerging:

The United States is becoming increasingly dependent on imported oil, particularly from the strategically sensitive Persian Gulf. This trend increases the nation's vulnerability to potential oil supply disruptions and increased oil prices.

Questions are being raised as to whether there will be adequate generating capacity to meet future electricity needs. Electricity consumption has been steadily increasing in recent years and is projected to continue through the year 2000. Additional generating capacity is only in the early stages of construction and may not be completed in time to meet electricity needs during the 1990s.

It is also increasingly being recognized that energy consumption creates potentially serious environmental, health, and safety consequences, whose possible solutions can be costly to address.

As directed by the President, DOE is developing a much needed national energy strategy that it expects will integrate and balance concerns for energy choices against other national concerns, such as environmental protection and economic growth. On April 2, 1990, DOE issued its interim report on the national energy strategy, which outlined goals for the strategy, obstacles to achieving the goals, and options for resolving these obstacles. Between April and December 1990, DOE plans to analyze the information in the interim report along with other data to develop an energy strategy to be released by the President in January 1991. The GAO concurs that this effort to develop a national energy strategy is a step in the right direction toward addressing the nation's future energy needs and the environmental and budgetary implications that should be considered when developing energy policies.

Environmental Effects of Energy Choices

In recent years, energy issues have become increasingly linked to environmental problems caused by energy fuel choices. The use of fossil fuels, in particular, has contributed to global warming, ozone pollution, and acid rain.

More recently, additional concern has been expressed about carbon dioxide emissions which, thus far, can only be reduced by decreasing fossil fuel consumption. There is general consensus that these carbon dioxide emissions contribute to a warming of the earth's surface temperature, which could have serious adverse health and environmental effects. The concern for increased levels of carbon dioxide emissions has focused attention on actions to mitigate the negative environmental effects of fossil fuel use.

In announcing the need to develop a national energy strategy, the President stated that the United States is at a critical juncture in ensuring the availability of reliable, competitively priced supplies of clean energy in the 1990s. According to DOE, the national energy strategy will enable policymakers to chart a course, set a pace, and evaluate United States progress in providing the reliable energy sup-
plies the economy needs while protecting the nation's health, safety, and environment.

The GAO states that it supports the initiative to develop a national energy strategy and believes that such a strategy is sorely needed and long overdue. Timely completion of the strategy is important because the electric utility industry, the automotive industry, and others in the energy sector will be making decisions about what technologies and energy sources to pursue, particularly as changes to the Clean Air Act occur. Because of its importance, GAO plans to monitor DOE's efforts to develop a national energy strategy.

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INCREASE IN OIL DEMAND SLOWING SAYS BP

The 2 percent growth in world energy demand experienced in 1989 was the slowest rate of growth since 1983, according to "BP Statistical Review of World Energy," released in June. BP attributes the slowdown to higher oil prices, a slightly reduced rate of economic growth and to exceptionally warm weather.

The worldwide demand for oil has been strong in recent years. As a result, world oil consumption in 1989 moved past the 1979 peak to nearly 65 million barrels per day. Though world demand for oil increased 1.5 percent over the 1988 level, it was the smallest increase in demand since 1986. World oil consumption figures show that much of this increase can be attributed to Asia.

Between 1970 and 1979, world oil consumption grew by 860 million metric tons. In the 1980s, however, the growth in world oil consumption was only 80 million metric tons. A decrease in consumption in the OECD (Organization for Economic Cooperation and Development), USSR and Eastern Europe in the 1980s was offset by continued growth in Latin America, the Middle East, Africa and, most notably, Asia.

Crude oil prices rose from $15 per barrel in 1988 to $18 per barrel in 1989 in spite of an increase in OPEC oil production of 2.1 million barrels per day. One major reason for the rise in price, says BP, was the large decline in production from the United States, the USSR and the United Kingdom. Overall, world oil production rose by 1.7 percent in 1989.

During the 1970s, OPEC accounted for more than half of the world’s oil production. In the mid-1980s OPEC’s share dropped to one-third of the total, but has started to increase once again.

In spite of increased production, world proved reserves of crude oil again climbed significantly in 1989. Proved reserves worldwide now amount to just over 1 trillion (10^{12}) barrels, an increase of some 60 percent since 1970. A breakdown of reserves by country is given in Table 1. A large in-

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**TABLE 1**

<table>
<thead>
<tr>
<th>Country</th>
<th>Thousand Million Barrels</th>
<th>Share of Total</th>
<th>RP</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>North America</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>USA</td>
<td>34.1</td>
<td>3.4%</td>
<td>10.0</td>
</tr>
<tr>
<td>Canada</td>
<td>8.3</td>
<td>0.8</td>
<td>11.1</td>
</tr>
<tr>
<td>Total North America</td>
<td>42.4</td>
<td>4.2%</td>
<td>10.4</td>
</tr>
<tr>
<td><strong>Latin America</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Argentina</td>
<td>2.3</td>
<td>0.2%</td>
<td>13.8</td>
</tr>
<tr>
<td>Brazil</td>
<td>2.8</td>
<td>0.1</td>
<td>11.0</td>
</tr>
<tr>
<td>Ecuador</td>
<td>1.5</td>
<td>0.2</td>
<td>14.7</td>
</tr>
<tr>
<td>Mexico</td>
<td>56.4</td>
<td>5.6</td>
<td>55.7</td>
</tr>
<tr>
<td>Venezuela</td>
<td>58.5</td>
<td>5.8</td>
<td>84.7</td>
</tr>
<tr>
<td>Others</td>
<td>3.7</td>
<td>0.4</td>
<td>13.3</td>
</tr>
<tr>
<td>Total Latin America</td>
<td>125.2</td>
<td>12.2%</td>
<td>50.9</td>
</tr>
<tr>
<td><strong>Western Europe</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Norway</td>
<td>11.6</td>
<td>1.1%</td>
<td>20.2</td>
</tr>
<tr>
<td>United Kingdom</td>
<td>3.8</td>
<td>0.4</td>
<td>5.5</td>
</tr>
<tr>
<td>Others</td>
<td>3.0</td>
<td>0.3</td>
<td>15.5</td>
</tr>
<tr>
<td>Total Western Europe</td>
<td>18.4</td>
<td>1.8%</td>
<td>12.6</td>
</tr>
<tr>
<td><strong>USSR &amp; Eastern Europe</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>USSR</td>
<td>58.4</td>
<td>5.8%</td>
<td>13.1</td>
</tr>
<tr>
<td>Eastern Europe</td>
<td>1.5</td>
<td>0.1</td>
<td>10.1</td>
</tr>
<tr>
<td>Total USSR &amp; E. Europe</td>
<td>59.9</td>
<td>5.9%</td>
<td>13.0</td>
</tr>
<tr>
<td><strong>Middle East</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Abu Dhabi</td>
<td>92.2</td>
<td>9.1%</td>
<td>1.0</td>
</tr>
<tr>
<td>Dubai &amp; N. Emirates</td>
<td>5.9</td>
<td>0.4</td>
<td>12.4</td>
</tr>
<tr>
<td>Iran</td>
<td>92.9</td>
<td>9.2</td>
<td>89.1</td>
</tr>
<tr>
<td>Iraq</td>
<td>100.0</td>
<td>9.9</td>
<td>97.0</td>
</tr>
<tr>
<td>Kuwait</td>
<td>94.5</td>
<td>9.3</td>
<td>2.0</td>
</tr>
<tr>
<td>Neutral Zone</td>
<td>5.2</td>
<td>0.5</td>
<td>35.5</td>
</tr>
<tr>
<td>Oman</td>
<td>4.3</td>
<td>0.4</td>
<td>20.1</td>
</tr>
<tr>
<td>Qatar</td>
<td>4.5</td>
<td>0.4</td>
<td>31.5</td>
</tr>
<tr>
<td>Saudi Arabia</td>
<td>255.0</td>
<td>2.5%</td>
<td>92.9</td>
</tr>
<tr>
<td>North Yemen</td>
<td>1.0</td>
<td>**</td>
<td>14.4</td>
</tr>
<tr>
<td>South Yemen</td>
<td>3.0</td>
<td>0.3</td>
<td>14.5</td>
</tr>
<tr>
<td>Syria</td>
<td>1.7</td>
<td>0.2</td>
<td>14.5</td>
</tr>
<tr>
<td>Others</td>
<td>0.1</td>
<td>0.1</td>
<td>7.9</td>
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<tr>
<td>Total Middle East</td>
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<tr>
<td><strong>Africa</strong></td>
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<tr>
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<td>23.7</td>
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<td>0.4</td>
<td>14.0</td>
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<tr>
<td>Gabon</td>
<td>0.7</td>
<td>**</td>
<td>9.2</td>
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<tr>
<td>Libya</td>
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<td>2.3</td>
<td>54.9</td>
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<tr>
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<td><strong>Asia &amp; Australasia</strong></td>
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<tr>
<td>Japan</td>
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<td>Australia</td>
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<td>New Zealand</td>
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<td>11.4</td>
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<tr>
<td>Total Asia &amp; Australasia</td>
<td>46.8</td>
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<td><strong>Total World</strong></td>
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<td>44.4</td>
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<td>Of which OECD &amp; LDCs</td>
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<td>91.8</td>
<td>54.2</td>
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<tr>
<td>OPEC</td>
<td>737.1</td>
<td>75.6</td>
<td>92.3</td>
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</table>

*Over 100 years
**Less than 0.05
crease in reserves in 1987 resulted from a substantial revision in stated reserves by four countries (Iran, Iraq, Abu Dhabi, and Venezuela). The increase in 1989 was mainly attributable to Saudi Arabia.

Along with the increase in reserves came an increase in the calculated reserves to production ratio. The worldwide reserves/production ratio now stands at 44 years, higher than at any point in the last 20 years.

SHELL SEES OIL PRODUCTION PEAKING AT 80 MILLION B/D

In Energy in Profile, the Shell Briefing Service (SBS) identifies three recent developments that it says will help to shape the future of the energy industry over the decade of the 1990s.

Energy Supply Security Issues

Shell says that oil still plays a dominant role in supplying the world's energy. The current crude oil reserve/production ratio is 42 years. Oil reserves could rise if the price of oil increases because of the improved economic viability of enhanced recovery methods and the greater incentive to seek out new fields. Oil production may remain at or above present levels.

Figure 1 shows Shell's forecast of future crude oil production. With enhanced recovery techniques and new discoveries projected, Shell sees oil production peaking very early in the next century at nearly 80 million barrels per day.

The cost of production of Middle East crude oil is substantially lower than that of much non-OPEC production. With non-OPEC production tending to level off, and demand buoyant, says Shell, OPEC's market share seems set to increase. Even if price increases boost new non-OPEC production, there will be a lag of some years before that oil reaches the market.

By the end of the 1990s, the OECD (Organization for Economic Cooperation and Development) countries are expected to be more reliant on OPEC oil, says Shell. Issues of supply security, which were highlighted by the energy crisis of the early 1970s, may return. Efforts to conserve energy and to switch to alternative fuels may be renewed.

Political Change in Eastern Europe and the USSR

The pace of political change in Eastern Europe and the USSR accelerated at the end of 1989. The established Communist regimes in the German Democratic Republic, Bulgaria, Czechoslovakia and Romania collapsed. In free elections held in some Eastern European countries in the first few months of 1990, the task of reversing economic decline was given to new political groups. According to Shell, some introduction of market principles now appears possible in all these countries.

Consequently, foreign investment is being encouraged. New laws on joint ventures are either in place or planned and, in some countries, 100 percent foreign investments are being allowed. The USSR is the world's largest producer of crude oil and has 37 percent of the world's reserves of natural gas. Thus, says Shell, the possibilities of joint ventures between state-owned oil and gas companies, or between state-owned companies and the private sector could have an impact on the future development of the energy industry in coming years.

Global Climate Change Issues

The combustion of fossil fuels, particularly for transportation and power generation, makes a significant contribution to man-made emissions of carbon dioxide into the atmosphere. This and other greenhouse gases, such as methane and the chlorofluorocarbons, increase the possibility of global warming and climate change.

Many in government and industry have suggested that it would be prudent to adopt precautionary measures to reduce carbon dioxide emissions. An assessment of the scientific evidence, and a consideration of possible approaches to combat the effect, are included in the work of the Intergovernmental Panel on Climate Change.

Using energy is fundamental to economic activity and
forecasts show (Figure 2) that the combustion of fossil fuels will continue to be central to meeting the world's energy needs for the foreseeable future. Policy makers are faced with devising policies that accommodate a rapidly growing world population, the necessity for economic development with its associated energy requirements and the desire to reduce carbon dioxide emissions. Attention has therefore become focused on measures to raise energy efficiencies.

Over the past 20 years energy intensities in the OECD countries have declined. Nevertheless, says Shell, there remains substantial potential to raise the efficiency of energy use still further. If governments decide to implement energy efficiency programs or introduce economic instruments to encourage greater energy efficiency, the energy industry has much to offer by way of expertise. The industry will also need to be involved in transferring energy efficient technology to developing countries and to the emerging economies of Eastern Europe.

###

IEW POLLS ENERGY FORECASTERS

The International Energy Workshop (IEW), a unit of the International Institute of Applied Systems Analysis, met in Honolulu, Hawaii in June. The IEW is an international network of energy analysts which has been meeting since 1981 to compare energy projections. The annual IEW poll of participants compares their forecasts for the international price of crude oil, primary energy consumption, energy production, energy trade, and gross national products.

As shown in Figure 1, IEW respondents to the poll since 1983 have almost continuously revised downward their forecast of 1990 oil prices as the oil price drifted downward. Because the latest poll was taken before the latest crisis in the Middle East, it was undoubtedly made obsolete overnight. However, Figure 2 shows the range of projections for oil prices to the year 2010.

Although near-term price forecasts had to be revised regularly, Figure 3 (next page) shows that most of the IEW forecasters have not been changing their estimates for oil price growth rates in the period 2000 to 2010.
FIGURE 3
OIL PRICE GROWTH RATES
AS IMPLIED BY
POLL MEDIANS
1985 - 1990

SYNTHETIC FUELS REPORT, SEPTEMBER 1990
LIQUID FUELS FROM METHANE COULD COMPETE WITH $22 OIL

A paper by F.M. Dautzenberg of Catalytica Associates describes the characteristics of “ideal” technology for producing gasoline and middle distillate from natural gas. Catalytica’s investigations indicate that such “ideal” technology could become economical at a crude oil price of $22 per barrel provided the necessary research is successfully carried out.

Dautzenberg, speaking at the American Institute of Chemical Engineers spring meeting, further suggested that improved technology for methanol production could possibly make it competitive with $15 oil.

Natural Gas to Liquid Hydrocarbons

Several possibilities were evaluated for converting natural gas to liquid hydrocarbons (gasoline/diesel):

- Conventional technology
- Oxidative coupling
- Fischer-Tropsch
- "Idealized" selective oxidation

Conventional technology is represented by Mobil’s methanol-MTG process, a commercial operation in New Zealand producing 14,500 barrels of gasoline per day since 1986. It was used as the base case reference point for comparing alternative process schemes. Two such alternatives are oxidative coupling and Fischer-Tropsch synthesis. The other alternative, referred to as "idealized" selective oxidation, is a hypothetical scheme based on the supposition that a catalyst breakthrough will allow oxidation of methane and oligomerization of the resulting intermediate in a single reactor. Although laboratory success in such chemistry has not been reported as yet, the economic evaluation of the conceptual process provides an indication of what may ultimately be achievable for economics of a methane to liquids process.

In Dautzenberg’s ideal scheme, the transformation of methane into gasoline occurs in a single reactor (Figure 1). Two different catalysts may be envisioned, one for methane activation and another for oligomerization of the intermediate product. Provisions must be made to remove and capture the large heat of reaction; a tube-and-shell reactor and steam generation system serve that purpose. The gasoline-forming reactions produce water and light hydrocarbons. The latter are aromatized separately and combined with the gasoline product.

**FIGURE 1**

DIRECT CONVERSION OF NATURAL GAS INTO LIQUID HYDROCARBONS

Idealized Process Scheme

\[ n\text{CH}_4 + \frac{1}{2n}\text{O}_2 \rightarrow (\text{CH}_2)_n + n\text{H}_2\text{O} \]

SOURCE: DAUTZENBERG
This process requires the fewest unit operations reasonably conceivable for a methane-to-gasoline process. Only the two reactors and the heat management and product separation units are included, and no recycle streams are involved. The economics of this simple process show what may be ultimately achievable.

For the two emerging technologies and the "idealized" selective oxidation scheme, the capital investments for a 14,500 barrel per day capacity plant are summarized in Figure 2. For each case, the crude oil price at which the technology becomes viable is also indicated. In calculating these numbers, the availability of remote natural gas at $0.50 per thousand standard cubic foot was assumed. For comparison, the conventional methanol-MTG technology has been included.

**FIGURE 2**

**COMPARISON OF EMERGING MTL TECHNOLOGIES**

<table>
<thead>
<tr>
<th>14,500 bbl/day at W. Canada Location</th>
</tr>
</thead>
<tbody>
<tr>
<td>&quot;Idealized&quot; MTL</td>
</tr>
<tr>
<td>Fischer-Tropsch</td>
</tr>
<tr>
<td>Oxidative Coupling</td>
</tr>
<tr>
<td>Methanol/MTG</td>
</tr>
</tbody>
</table>

**SOURCE: DAUTZENBERG**

The results show that at current (early 1990) crude prices none of the alternatives will be viable. This is also valid for the "idealized" selective oxidation case. It also appears that oxidative coupling is slightly less attractive than conventional technology, while the Fischer-Tropsch approach only offers a small advantage. There is a considerable gap between the emerging and conventional technologies versus the "idealized" selective oxidation case, indicating that significant capital cost reductions are potentially achievable through new catalyst developments. The key hurdle will be the development of a catalyst(s) system that avoids overoxidation of feedstock, reaction intermediates and products. With such a catalyst, the manufacturing of liquid hydrocarbons at a transfer price of approximately $0.70 per gallon may become feasible. This means that technology for the conversion of remote gas may become competitive at crude prices of about $22 per barrel, says Dautzenberg.

**Natural Gas to Methanol**

An "idealized" concept for methanol synthesis is to react methane and oxygen to produce methanol directly (Figure 3, next page). The process centers around a magical catalyst placed in a reactor analogous to a catalytic partial oxidation reactor.

In the scheme for direct oxidation, natural gas is compressed, desulfurized, and preheated in a furnace prior to entering the reactor. Oxygen is preheated in the same furnace before being mixed with the methane. Reaction heat produced in the tubular reactor is removed and used to create high pressure steam.

Higher hydrocarbons (C₂-C₄) present in the natural gas feed are assumed to react with the same conversion and selectivity as methane. Heat from the reaction is used to supply the energy needs of the plant: high-pressure steam for natural gas compression and the turbines in the oxygen plant, and lower-pressure steam for the product distillation column and preconditioning the boiler feed water.

Methanol is recovered from the reactor effluent by cooling, flashing, and distilling in a single column. Fusel oil, taken as a sidestream at the top of the column. Fusel oil, taken as a sidestream at the top of the column, non-condensibles, taken overhead, are used to fuel the furnace. Water and heavies are purged from the bottom of the column.

Surprisingly, Catalytica's work found that direct oxidation is not significantly better than emerging low-temperature synthesis technology. This is caused by the need for an oxygen plant and the relatively expensive reactor.

With relatively cheap natural gas at $0.50 per thousand standard cubic foot, it appears that both new low temperature methanol synthesis as well as direct oxidation technology may deliver methanol at approximately $0.32 per gallon. Both approaches therefore have the potential to produce methanol competitive with gasoline at a crude oil price of $15 per barrel. The CO₂/H₂O sensitivity of the catalyst appears to be a key vulnerability of the low-temperature synthesis technology, while avoiding over-oxidation is the key challenge for direct oxidation of methane to methanol.
FIGURE 3
IDEALIZED DIRECT METHANOL SYNTHESIS

SOURCE: DAUTZENBERG
ICI'S GAS HEATED REFORMER WILL LOWER METHANOL PRODUCTION COSTS

Present day methanol production technology based on the steam reforming of light hydrocarbons has advanced to the point where the scope for further gains in energy efficiency is small. Overall efficiency has risen from 58 percent in early designs to 72 percent with current designs. This improvement has however been accompanied by rising capital costs as extra heat recovery equipment has been added. Today, world scale methanol plants are very capital intensive. ICI has therefore been trying to significantly reduce capital costs without loss of efficiency.

The minor processing steps of desulfurization and distillation are not going to yield significant savings. The synthesis stage has been the focus of development efforts over the past 15 years by ICI and others. With the current copper-based heterogeneous catalysts, further substantial cost reductions in this area are not expected.

By contrast, the reforming stage with its associated gas cooling and steam raising equipment represents almost one-half of the total investment in process equipment, and has considerable potential for cost savings.

For the past 5 years, ICI has been intensively involved in developing the concept of the Gas Heated Reformer (GHR) in which the primary reformer receives heat directly from the process gas exiting the secondary reformer. This results in a compact pressurized reformer and replaces the massive multiple burner structure and substantial heat recovery systems of a conventional plant.

Current Practice

The production of carbon oxides and hydrogen by the reaction of steam with a hydrocarbon feedstock requires a large amount of heat at high temperature (1,500°F to 1,800°F) with a catalyst.

The reforming reaction has traditionally been carried out in a large number of catalyst-filled tubes placed inside a furnace box.

The combination of high temperature and pressure imposes severe demands on the reformer tubes, which must have thick walls to withstand the stresses, and be fabricated from expensive alloys. In order to recover as much of the heat from the fluegas as possible, a large and expensive heat recovery system must be provided. A large proportion of the heat is recovered by raising and superheating high pressure steam.

ICI Gas Heated Reformer

The main features of the ICI gas heated reformer include:

- The heat required for the primary reforming stage is supplied directly by cooling down the reformed gas. Makeup is provided by combusting some of the partially reformed gas from the GHR with oxygen in a secondary reformer.

- Use of process heat for the reformer duty eliminates both the reforming furnace and the need for a steam raising system.

- The tubes in the GHR only need to withstand a relatively modest differential pressure, rather than full process pressure. This greatly reduces the weight and cost of the tubes.

- Heat transfer in the GHR is predominantly by convection, instead of by radiation as in a conventional fired primary reformer. This means the volume of a GHR can be 15 times smaller than the volume of a fired reformer of the same throughput.

- The combination of reduced size and thinner-walled tubes makes the unit much faster to start up and shut down.

The Methanol Flowsheet

ICI's development work on a total methanol process incorporating the GHR has been carried out on the basis of a world scale, single stream plant of 2,000 tons per day capacity. A typical flowsheet is shown in Figure 1 on the next page. Natural gas feedstock is compressed to reforming pressure, and heated to 445°F before passing through a low temperature purification unit to remove catalyst poisons. Process steam requirements are met by directly contacting the gas with hot water in a saturator. After the feed-gas stream has been further heated to 445°F before passing through a low temperature purification unit to remove catalyst poisons. Process steam requirements are met by directly contacting the gas with hot water in a saturator. After the feed-gas stream has been further heated to 445°F before passing through a low temperature purification unit to remove catalyst poisons. Process steam requirements are met by directly contacting the gas with hot water in a saturator. 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After the feed-gas stream has been further heated to 445°F before passing through a low temperature purification unit to remove catalyst poisons. Process steam requirements are met by directly contacting the gas with hot water in a saturator. After the feed-gas stream has been further heated to 445°F before passing through a low temperature purification unit to remove catalyst poisons. Process steam requirements are met by directly contacting the gas with hot water in a saturator. After the feed-gas stream has been further heated to 445°F before passing through a low temperature purification unit to remove catalyst poisons. Process steam requirements are met by directly contacting the gas with hot water in a saturator.

Reforming takes place in two stages:

- Gas enters the tube side of the GHR where it absorbs heat and is partially reformed over a catalyst.

- The resulting gas is partially combusted with oxygen in a secondary reformer and further reformed. The gas stream which leaves this vessel in excess of 1,800°F provides the reforming heat load for the GHR.

Future Development

According to ICI, the combination of the GHR technology with ICI's Low Pressure Methanol Process can produce an overall design with high feedstock efficiency and with capital cost savings arising from greater simplicity. Further work is...
still required to finalize the design of the oxygen blown secondary reformer, to optimize the flowsheet and to quantify the size of the cost benefits.

###

**OBSTACLES IDENTIFIED FOR COMMERCIALIZATION OF METHANE OXIDATIVE COUPLING**

The United States Department of Energy's Morgantown Energy Technology Center (METC) has conducted a systems study of an oxidative-coupling-based gasoline from natural gas plant. The study includes a preliminary process design, cost estimations, and an economic evaluation. Technological issues that are likely to become barriers for commercialization of the process were identified. This work was reviewed by H.P. Loh for the American Institute of Chemical Engineers meeting in Orlando, Florida last March.

METC states that oxidative coupling technology is not yet ready for commercialization. Major barriers include formulating a catalyst that minimizes carbon dioxide formation and physical disintegration, finding a reactor construction material that does not catalyze the combustion reaction, and developing a control scheme that assures safe operation outside of the flammability limits. The single most important reason for the high costs of an oxidative-coupling-based gasoline plant is the high temperature heat that the process generates.

Liquids can be produced from natural gas using the oxidative-coupling-based technology in a two-step process: methane is first converted to ethylene, and the ethylene is then converted to gasoline components. Methane conversion is through oxidative coupling chemistry, and ethylene conversion uses the Mobil olefins to gasoline and distillates (MOGD) process.

Oxidative coupling chemistry activates the methane molecule using a family of catalysts based on an oxide of multi-valence transition metals. The molecule is broken down through (1) the presence of oxygen, which has a strong affinity with the hydrogen atom; (2) the high temperature environment; and (3) the active reaction sites provided by the catalyst.

The first step in oxidative coupling chemistry is formation of methyl radicals, followed by coupling of radicals to form higher hydrocarbons through dozens of reaction mechanisms. The products include ethylene, ethane, and other hydrocarbons, with water, carbon monoxide, and carbon dioxide as byproducts. Ethylene is the most desirable product, and provides the feed to the MOGD process.

The MOGD process uses ZSM-5 zeolite, and is judged to be a relatively mature technology. Therefore, only the methane conversion to ethylene through oxidative coupling has been studied at METC.

The oxygen required for the methane conversion reaction can be introduced into the system in two forms: the molecular oxygen supplied as part of the gaseous feed, or as a part of the atomic crystal lattice of the metal oxide catalyst. The reaction is said to be in the co-feed mode if oxygen is supplied by gaseous sources and in the redox mode if the oxygen comes from the crystal lattice.

Coking, a side reaction that produces carbon and plugs the catalyst and reduces its reactivity, requires that the catalyst be regenerated after a period of operation. Regeneration also replenishes the oxygen used from the catalyst when operating in the redox mode.

**Base-Case Process**

In the base-case process described by Loh, oxygen from an air separation plant reacts with natural gas at 800°C in a fixed-bed catalytic reactor. Methane is converted to higher paraffins and olefins through the oxidative coupling reaction. The reactor effluent also contains water, carbon dioxide, and carbon monoxide byproducts as well as unreacted methane and oxygen. The stream containing olefins and paraffins is further converted to gasoline through the MOGD process. The olefins are dimerized to gasoline components, which are condensed while the uncondensed paraffins and small amounts of unreacted olefins are recycled. Eventually, the paraffins are purged.
The base-case gasoline plant produces 50,000 barrels per day of gasoline and diesel fuel from natural gas (97 percent methane). The raw material consumptions are 480 million standard cubic feet per day of natural gas (as raw material and fuel) and 7,950 tons per day of oxygen. The byproduct production rates are 3,300 tons per day of carbon dioxide and 4,200 tons per day of water. The oxidative coupling reaction generates large amounts of reaction heat. In the base-case plant, 56 percent of that heat is recovered, generating a respectable 100 megawatts of electricity.

In order to control the reactor temperature, a methane recycle stream is introduced to the reactor along with the net natural gas feed. The actual gas throughput for the oxidative coupling unit (including net feed and recycle) is 1,400 million standard cubic feet per day. The large size of this plant is demonstrated by comparing the amount of gas handled with the amount of syngas produced at the Great Plains Coal Gasification Plant in North Dakota. At the Great Plains plant, 137 million standard cubic feet per day of substitute natural gas is produced from coal gasification. The base-case plant, therefore, would require the output from more than three Great Plains gasification plants. The gas handling rate in the base-case plant is 10 times the Great Plains gas production rate.

**Economics**

The capital cost requirement for a base-case plant located on the North Slope of Alaska is estimated to be $1.7 billion (Table 1).

**TABLE 1**

<table>
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<th>Process Section</th>
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<td>Quench Column</td>
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<tr>
<td>Carbon Dioxide Removal</td>
<td>15</td>
</tr>
<tr>
<td>Absorber-Stripper</td>
<td>40</td>
</tr>
<tr>
<td>Olefin Conversion</td>
<td>53</td>
</tr>
<tr>
<td>Gasoline Stabilization</td>
<td>5</td>
</tr>
<tr>
<td>Air Separation Plant</td>
<td>124</td>
</tr>
<tr>
<td>Waste Heat Boiler</td>
<td>45</td>
</tr>
<tr>
<td>Power Plant</td>
<td>84</td>
</tr>
<tr>
<td>Off-Site</td>
<td>250</td>
</tr>
<tr>
<td>Total Installed Cost (TIC)</td>
<td>$737</td>
</tr>
</tbody>
</table>

In order to understand why the capital and operating costs are so high, material and heat balances and major process units were analyzed. As a result, high temperature heat generation was identified as the reason for high costs. The issues needing to be addressed during the commercialization stage were also identified.

**Impact of Heat Generation**

METC found that the single most important element in cost escalation is the excessively high temperature heat that is generated.
Apart from the main reaction that converts methane to ready for commercialization.

Apart from the main reaction that converts methane to ethylene, there are side reactions that convert feed and byproduct hydrocarbons into carbon dioxide. The most common pathway for carbon dioxide formation is a gas-phase combustion reaction. Regardless of mechanism, the formation of carbon dioxide generates much more heat in the process than any other desired chemical reaction.

In order to avoid the excessive temperature rise that could result from the exothermic reaction, methane is mixed with a cooled, recycled methane stream before entering the oxidative coupling reactor. In the base-case plant, the recycle stream is about five times the net methane feed-rate, requiring that the equipment handle six times the net throughput. Thus the equipment cost escalates significantly.

The solution to high-temperature heat generation is to suppress carbon dioxide formation. The lower the carbon dioxide selectivity, the lower the high-temperature heat generation. What is needed then is a catalyst that has a very low methane-to-carbon dioxide selectivity. Desirable catalysts, most likely dual-function, should promote ethylene formation and suppress carbon dioxide formation.

Other Commercialization Considerations

There are issues other than the heat generation problem that need to be addressed for successful commercial operation. These issues are directly or indirectly related to the economics, and include environmental and other technical considerations. One such consideration is flammability. Ethylene, ethane, and carbon monoxide are the fuel gases produced from the reaction between methane and oxygen. There are potentially four pairs of flammable mixtures in the process streams: methane-oxygen, ethylene-oxygen, ethane-oxygen, and carbon monoxide-oxygen. Each pair has its own flammability range, which is a function of temperature, pressure, and the concentration and properties of other fuels and inerts such as carbon dioxide, nitrogen, and water. The oxygen content must be maintained at a level outside these ranges to avoid a potential explosion.

METC concludes that for gasoline production from natural gas, the expensive steam reforming route is the only practical option today. Oxidative coupling technology, which began as a replacement for the steam-reforming technology, is not yet ready for commercialization.

IGT SUPPORTS RESEARCH ON CHEMICALS FROM NATURAL GAS

The Institute of Gas Technology (IGT) has funded three projects related to the production of chemicals from natural gas under its Sustaining Membership Program (SMP). Researchers recently concluded an SMP project to develop an improved process for the production of synthesis gas for ammonia from natural gas. Two SMP/GRI (Gas Research Institute) joint efforts still in progress involve the microbial production of liquid fuels and chemicals from methane and the catalytic conversion of methane to chemicals.

Synthesis Gas for Ammonia

IGT scientists have proposed a process in which air reacts with natural gas under partial oxidation conditions, thereby producing synthesis gas containing the nitrogen needed to produce ammonia. In the new process, part of the nitrogen is used for ammonia production; the excess nitrogen is removed in a cryogenic step that also recovers energy through the expansion of waste nitrogen.

IGT conducted its research in existing high-temperature, high-pressure fluidized-bed reactors to determine whether such an operation would provide the best method for production of the synthesis gas. Nineteen tests were completed in a 4-inch-diameter reactor to obtain a data base for determining the economic feasibility of the process.

Researchers demonstrated partial oxidation of methane at conversions of 63 percent using an inert alumina and 97 percent using a catalyst as the bed material. Reactor operating conditions for the parametric tests were at a pressure of 300 psig and at temperature ranges of 1,610° to 1,990°F. The effects of varying the ratios of natural gas to steam, natural gas to air, and space velocity were determined using a catalyst. Researchers then conducted a 72-hour design-point test and an extended 8-hour test of steady operation.

In most of the tests, trace carbon formations acceptable in fluidized-reactor operation were observed. Some catalyst deactivation, as well as elution of solids from the reactor bed occurred, but improved catalyst preparation may minimize or eliminate both. Targeted methane conversions and product-gas compositions were achieved.

The Foster Wheeler Corporation has since conducted preliminary studies showing that a $15 million investment to retrofit an existing 1,000 ton per day ammonia plant with the new technique would reduce natural gas requirements by about 18 percent. For a new, 2,200 ton per day ammonia plant, capital-cost reductions of 10-15 percent are estimated.

Microbial Production of Chemicals

The goal of this project is to gather data to determine the technical and economic feasibility of the microbial use of methane for the production of value-added chemicals.
Researchers are studying microbial, biochemical, and physiological factors that stimulate the growth of methanotrophs on methane, as well as the use of methane-grown cells as biocatalysts.

Methanotrophs are a group of microorganisms that use methane for their growth. Some methanotrophs are reported to accumulate certain chemicals, such as acetic acid, polysaccharide gums, poly-beta-hydroxy butyric acid, and natural pigments, along with such typical biological compounds as proteins, nucleic acids, carbohydrates, and lipids.

Methanotrophs can also produce chemicals by co-oxidizing another carbon compound. In this experiment, methane is the fuel used by the microorganism to regenerate its biocatalytic system. Usually, the co-oxidation product accumulates in the reaction medium. Biocatalytic co-oxidation of some chemicals results in the formation of one enantiomer—one specific molecular configuration (optical isomer) of the product—rather than a mixture of both enantiomers. Such co-oxidation techniques are known as stereospecific and regiospecific oxidation.

A preliminary survey by Battelle Memorial Institute on behalf of IGT and GRI indicated that specific optical isomers are of great interest to the chemical industry and that the preferred production method may be a biological one.

IGT also has a research project with GRI to develop reactor systems to enhance the microbial production rates and yields of fuels and chemical methane. Through joint efforts, researchers have been able to acquire a large collection of methanotrophs, determine the key physiological and engineering parameters, and achieve enhanced growth of several strains at medium to high pressures.

IGT scientists have demonstrated stereospecific as well as regiospecific oxidation of several chemicals. Some of the resulting products are known or expected to be industrially important chemicals.

**Catalytic Oxidative Coupling**

The initial goal of this SMP research was to prepare and screen catalysts that will promote the oxidative coupling of methane to ethylene. The objective has been expanded to include the production of styrene and other high-value chemicals.

IGT is preparing catalysts using both primary and secondary promoters/stabilizers. Researchers are characterizing these catalysts following analyses for pore-size distribution, catalyst surface area, particle density, bulk phases, crystalline structure, morphology, stoichiometric form, and composition. They are screening selected catalysts by studying reaction kinetics and product formation in a fixed-bed reactor system at temperatures in the range of 600° to 800°C, pressures from 1 to 100 atmospheres, and methane/oxygen ratios from 3 to 30.

Researchers have already prepared and tested 45 catalysts. As a result of this work, seven inventions were disclosed and four patent applications were made, including one for a process to make aryl olefins (e.g., styrene).
RECENT GENERAL PUBLICATIONS

The following papers were presented at the Opportunities in the Synfuels Industry Symposium, held August 27-29 in Bismarck, North Dakota:

Nagata, N., "Synfuels in Japan."

Fourie, J.H., "Update on the Synfuels Industry."

The following papers were presented at the combined 73rd Canadian Chemical Conference and 40th Canadian Chemical Engineering Conference held July 15-20 in Halifax, Nova Scotia, Canada:

Davis, B.H., et al., "Isotopic Tracer Studies of the Methanol to Gasoline Reaction."

Calverley, E.M., et al., "The Role of CO₂ in the Methanol and Higher Alcohol Syntheses Over a K₂CO₃ Promoted Cu/ZnO/Cr₂O₃ Catalyst."


Bakhshi, N.N., et al., "Syngas Conversion to Gasoline Range Hydrocarbons over NiCo/HZSM5 Catalysts."


McCarty, J.G., "Prospects for High Yield Methane Catalytic Conversion."

Mills, P.L., et al., "Investigation of Reaction Pathways and Role of Oxygen Sources in Methane Conversion to Hydrocarbons over MgO Using the Tap Reaction System."

COMING EVENTS

1990

SEPTEMBER 4-6, HERNING, DENMARK – Symposium on Strategic Energy Supply for the Future.
SEPTEMBER 5-7, CAMBRIDGE, UNITED KINGDOM – Coal Structure and Reactivity.
SEPTEMBER 10-14, PITTSBURGH, PENNSYLVANIA – Seventh Annual International Pittsburgh Coal Conference.
SEPTEMBER 16-19, PITTSBURGH, PENNSYLVANIA – Advanced Research and Technology Development Contractors Review.
SEPTEMBER 23-25, CALGARY, ALBERTA, CANADA – CERI International Oil & Gas Markets Conference.
SEPTEMBER 23-26, NEW ORLEANS, LOUISIANA – Annual Meeting of the Society of Petroleum Engineers.
SEPTEMBER 24-27, PITTSBURGH, PENNSYLVANIA – Direct Liquefaction Contractors Review Meeting.
OCTOBER 2-4, BRUSSELS, BELGIUM – Coal Trans 90.
OCTOBER 5, WUHAN, CHINA – First International Conference on Energy Conversion and Energy Sources.
OCTOBER 11-12, BRUSSELS, BELGIUM – Conference on Clean Power From Coal: Worldwide Market Opportunities.
OCTOBER 15-18, NAGOYA, JAPAN – Third International Conference on Circulating Fluidized Beds.
OCTOBER 17-18, PALO ALTO, CALIFORNIA – Ninth EPRI Conference on Coal Gasification Power Plants.
NOVEMBER 2-3, JAMSHEDPUR, INDIA – All-India Seminar on Recovery of Coal Chemicals and Scope for Industries Based on Them.
NOVEMBER 5-8, PITTSBURGH, PENNSYLVANIA – Indirect Liquefaction Contractors Review Meeting.
NOVEMBER 6-8, LEXINGTON, KENTUCKY – Eastern Oil Shale Symposium.
NOVEMBER 11-16, CHICAGO, ILLINOIS – American Institute of Chemical Engineers Fall Meeting.
NOVEMBER 26, PHOENIX, ARIZONA – Fuel Cell Seminar.
DECEMBER 3-5, BRISBANE, QUEENSLAND, AUSTRALIA – Fourth Australian Coal Science Conference.
DECEMBER 3-6, NEW ORLEANS, LOUISIANA – Third Annual Oil, Gas, Coal and Environmental Biotechnology Symposium.
DECEMBER 4-6, ORLANDO, FLORIDA – Power-Gen ’90.
DECEMBER 19-20, BRUSSELS, BELGIUM – European Energy Conference.

1991

JANUARY 20, SANTA BARBARA, CALIFORNIA – Environmental and Economic Impacts of Coal Utilization.

SYNTHETIC FUELS REPORT, SEPTEMBER 1990
FEBRUARY 17-21, CARACAS, VENEZUELA – Symposium on the Future of Heavy Oil & Tar Sands.

MARCH 7-8, DORTMUND, FEDERAL REPUBLIC OF GERMANY – Coal Gasification 1991.

MARCH 11-13, PITTSBURGH, PENNSYLVANIA – Energy in the 90s Conference.

APRIL 3-5, LONDON, UNITED KINGDOM – International Conference on Coal in the Environment.

APRIL 7-11, HOUSTON, TEXAS – American Institute of Chemical Engineers Spring Meeting.

APRIL 9-12, FIRENZE, ITALY – International Symposium on Alcohol Fuels.

APRIL 14-19, ATLANTA, GEORGIA – 201st American Chemical Society National Meeting.

APRIL 22-25, CLEARWATER, FLORIDA – 16th International Conference on Coal and Slurry Technologies.

MAY 21-22, BILLINGS, MONTANA – Sixteenth Biennial Low-Rank Fuels Symposium.

AUGUST 3-9, BOSTON, MASSACHUSETTS – 26th Intersociety Energy Conversion Engineering Conference.

AUGUST 18-21, PITTSBURGH, PENNSYLVANIA – American Institute of Chemical Engineers Summer National Meeting.


AUGUST 25-30, NEW YORK, NEW YORK – 202nd American Chemical Society National Meeting.

SEPTEMBER 16-20, NEWCASTLE-UPON-TYNE, UNITED KINGDOM – International Conference on Coal Science.

SEPTEMBER 24, SAN JUAN, PUERTO RICO – Energy '91: Energy for the Americas.

OCTOBER 13, WASHINGTON, D.C. – Ninth International Conference on Coal Research.

OCTOBER 20-25, BUENOS AIRES, ARGENTINA – Thirteenth World Petroleum Congress.
PROJECT ACTIVITIES

PARACHUTE CREEK PROJECT UPDATED

Unocal Corporation has been publicizing its Parachute Creek Oil Shale Project more than in the past. Project overviews were presented at the "Alternate Energy '90" conference and also at the "23rd Oil Shale Symposium."

Unocal’s long standing interest and commitment to oil shale originated more than 60 years ago when the company began acquiring properties in the Piceance Basin of the Green River Formation of Colorado, Wyoming and Utah. The company’s holdings, in the Parachute Creek area of Garfield County, Colorado, consist of about 50,000 acres, including 40,000 acres of oil shale lands. The potentially recoverable shale oil on Unocal property is estimated to total $33$ billion barrels.

Unocal began construction of its oil shale mining and retorting project in January 1981. The project includes a mine, a shale retorting plant, a raw shale oil upgrading facility, provisions for disposal of the retorted shale, and the necessary support facilities. Construction was completed in 1983. The retort is designed to process 12,800 tons of shale and produce 10,000 barrels of shale oil per stream day.

To reduce the economic risks of this pioneer project, Unocal secured a $400 million contract in 1981 from the United States Government under the Defense Production Act. This contract guaranteed a product price of $42.50 per barrel, adjusted for inflation, and has allowed the continued operation of this plant despite the sharp drop in world oil prices that occurred after the completion of the project.

Oil Shale Mine

Shale for the project is mined from the rich Mahogany zone of the Parachute Creek section of the Green River geologic formation. The shale currently being mined has an average yield of 38 gallons of shale oil per ton.

The entrance to the underground mine is located about 1,000 feet above the valley floor and opens on the south side of Long Ridge, which forms the north wall of the East Fork of Parachute Creek.

The mine is an underground, room-and-pillar operation. The pillars are left in place to support the roof, but allow recovery of 60 percent of the resource from the mine zone. The mining sequence is a five-step process:

- A drill jumbo is used to drill the face.
- The holes are charged with ANFO (Ammonium Nitrate/Fuel Oil), and then detonated.

Retorting Plant

The Unishale-B Retort was constructed on a 5-acre bench site just outside the mine entrance. Figure 1 (on the next page) is a retort schematic. Crushed shale enters the solids feeder underneath the retort where a 10-foot diameter piston forces the shale upward into the retort. Shale oil product acts as a liquid seal in the feed chute to maintain the retort pressure.

As the oil shale rises through the retort cone it is contacted by a counter-current flow of hot recycle gas entering the top of the retort dome. The hot recycle gas provides the heat required for the retorting process. The kerogen in the oil shale decomposes into liquid and gaseous organic products which diffuse from the shale particles, leaving behind a carbonaceous deposit on the retorted material. The oil vapor is cooled and condensed by the cool incoming shale. The bulk of the liquid product trickles down through the shale and the balance, in the form of mist, is carried from the retort by the cooled gases.

The gas and liquid are separated from the shale in the slotted-wall section of the lower retort cone. Oil and solids disengage from the gas in the section that surrounds the lower cone. The liquid level in this section is controlled by withdrawing oil product.

Retorted shale is forced up above the retort cone and is scraped off the pile. It falls down chutes through the retort into a cooling vessel and is cooled by sprayed water.

Dry, cooled, retorted shale leaves the cooling vessel and is depressured through a seal leg. The retorted shale is transported by conveyors and trucks to the canyon floor. It is then spread, compacted, contoured, covered with soil and vegetated with native and introduced species.

The gases leaving the retort from the disengaging section are scrubbed and cooled in a Venturi scrubber. The scrubbed gas is divided into a make-gas stream and a recycle...
stream. The recycle stream is heated prior to injection into the top of the retort. The retort make-gas is processed in a Unisulf plant to remove sulfur and used as plant fuel.

After the solids suspended in the raw shale oil are removed, the oil is transported by pipeline to the upgrading facility which is located 8 miles south of the retort.

Project Performance

All pioneer plants experience unexpected problems that inhibit early performance, and Unocal's retort is no exception.

Construction of the plant was completed in the fall of 1983, but start-up was not achieved until mid-1986. The plant start-up phase was completed in 1988 when commercial production rates were reached.

For all of 1987, production of shale oil was 17 percent of design. In 1988, production nearly doubled to about 32 percent of design, almost 1 million barrels. For 1989, the plant consistently performed at between 50-60 percent of design on a short-term basis, but merely matched the previous year's total. Technological improvements completed during an extended mid-year shut down resulted in a 25 percent increase in the project's daily production rates.

Over 3 million barrels of raw shale oil have been produced to date.

During start-up, significant progress was made in solving problems that initially prevented sustained, high rate operation. The major problem area was in the system for removing the processed shale from the retort vessel and cooling it for disposal.

As retorted shale reaches the top of the retort, it forms a natural angle-of-repose pile. In the original design, an Archimedes spiral truncated the center of the pile. The solids were pushed to the sloped sides of the pile where they fell by gravity to the cooling system. However, the retorted shale in the commercial plant decrepitates to a much finer consist than expected. This finer particle size, combined with the force of the counter-current flowing recycle gas, resulted in an increased angle of repose that made the Archimedes spiral ineffective. The scraper was redesigned after an extensive research program in early 1984.

The finer than expected retorted shale also caused problems in the cooling system. In the original shale cooling design, the hot retorted shale was cooled with a water spray. The generated steam flowed co-currently with the retorted shale and was withdrawn prior to depressurizing. The finer consist
has a low permeability that inhibits water penetration into the material and steam flow out. This made it extremely difficult to efficiently contact the hot retorted shale with water. As a result, steam was trapped within the partially cooled solids. The subsurface steam caused solids flow instabilities and pressure control problems.

To solve this problem, extensive modifications were made to the shaft cooler. Further modifications were made to optimize the seal legs to depressure the low permeability, fine consist, retorted shale. Fine solids have to be depressurized in a very controlled manner to maintain controlled solids flow.

The retort now has regularly produced 7,000 barrels per day of raw shale oil. Feed with a higher Fisher Assay than design, up to 41 gallons per ton, has also been routinely processed. The plant was designed for 34 gallons per ton feed.

Oil recovery in the retort was increased significantly in 1988 and again in 1989 by installing new crushers that made it possible to decrease the rock size fed to the retort. The design feed consist was +1/8 inch by -2 inch. The raw shale is now crushed and screened to a consist of +0.25 inch by -1 inch. This decreased feed size has resulted in an oil production increase of more than 25 percent.

The recycle gas temperature was increased in 1989 from 1,040°F to 1,090°F. This change has further increased oil recovery.

Products from Shale Oil Syncrude

The syncrude is a superior refinery feed. This is especially evident in the level of contaminants and in resid content. Typical inspections of the commercially produced syncrude are shown in Table 1. This table also includes inspections of Arabian Light crude, the world standard for light crudes.

Some 65 to 70 percent of the syncrude yields high quality transportation fuels on distillation, and the remainder is an excellent hydrocracker or FCC (fluid cat cracker) feed. Syncrude can be completely converted into high quality transportation fuels. By choosing the processing route for the gas oil, production of gasoline, jet fuels or diesel can be maximized.

Unocal's syncrude is and has been coprocessed with conventional crude oils at several refineries in the Midwest and Rocky Mountains. Over 3 million barrels of syncrude have been refined into the complete spectrum of conventional petroleum products and entered the ordinary course of commerce in the United States.

###

LLNL OIL SHALE PROJECT STARTS 4 TON/DAY RETORT

Lawrence Livermore National Laboratory (LLNL) is studying above ground oil shale retorting and has constructed a pilot plant to process 4 tonnes per day of commercially sized shale in a generic second generation Hot-Recycled-Solid (HRS) retorting system. In the fall of 1988, the system was designed to process up to 7 millimeter shale particles. Construction of the pilot plant occurred between January 1989 and January 1990. During construction, cold flow tests in lucite models were performed to aid in the design effort. In February 1990, the completed pilot plant was cold flow tested with raw shale continuously recirculated around the loop. The pilot plant began hot operation in April 1990.

An update on the project was presented at the Fourth Annual Oil Shale and Tar Sands Contractors Review Meeting held in Morgantown, West Virginia in April.

Project Description

The LLNL Hot-Recycled-Solid (HRS) process, shown in Figure 1 on the next page, uses a solid heat carrier as the source of heat for shale pyrolysis. Retorted shale leaving the retort is burned in a combustor, recycled and mixed with the raw shale to provide the process heat. Additional energy is recovered from the solid discharged after the combustor. Typically a recycle to raw shale ratio of three or four to one is used for processing Green River oil shale. This limits combustor temperatures and avoids excessive carbonate decomposition.

Figure 1 shows the major components in the solid circulation loop. Identified in the figure are five key components:

<table>
<thead>
<tr>
<th></th>
<th>Syncrude</th>
<th>Arab. Li.</th>
</tr>
</thead>
<tbody>
<tr>
<td>Gravity, °API</td>
<td>40</td>
<td>34</td>
</tr>
<tr>
<td>Sulfur, wppm</td>
<td>5</td>
<td>17,000</td>
</tr>
<tr>
<td>Nitrogen, wppm</td>
<td>60</td>
<td>800</td>
</tr>
<tr>
<td>Carbon Residue, Wt%</td>
<td>0.05</td>
<td>3.6</td>
</tr>
<tr>
<td>Heavy Metals, wppm</td>
<td>nil</td>
<td>20</td>
</tr>
<tr>
<td>V + Ni + Fe</td>
<td>nil</td>
<td>20</td>
</tr>
<tr>
<td>Distillation, Vol%</td>
<td>X - 100°F</td>
<td>100</td>
</tr>
<tr>
<td></td>
<td>1000°F</td>
<td>85</td>
</tr>
<tr>
<td></td>
<td>1000°F+</td>
<td>15</td>
</tr>
</tbody>
</table>
(1) a high-throughput, short residence time fluid-bed mixer,
(2) a moving packed-bed pyrolyzer with crossflow gas sweep, (3) a pneumatic transport air lift pipe combustor, (4) a delayed-fall combustor, with a 5 second solid residence time and (5) a fluidized bed combustor/classifier to control solid discharge and provide a pressure differential to balance the loop.

Fluid-Bed Mixer

Raw and retorted shale must be mixed to begin the pyrolysis process.

For the 4-tonne-per-day facility LLNL has chosen a two-stage, 15-centimeter diameter, fluid-bed mixer, with a nominal 30 second solid residence time. The active bed height is 40 centimeters. By providing a short residence time fluid-bed mixer followed by a moving packed bed pyrolyzer, LLNL accomplished the following: (1) the amount of gas required for fluidization is reduced (compared to a fluid-bed mixer and pyrolyzer in one unit), (2) variation in shale residence time in the fluid bed is not a problem because the packed bed smooths out these variations and in fact may be desirable, with coarse shale spending more time in the bed to achieve thermal equilibrium, and (3) separating mixing and pyrolysis functions may have processing advantages, such as water recovery separate from oil recovery.

Packed-Bed Pyrolyzer

The shale leaving the mixer enters a 20-centimeter diameter by 125-centimeter high packed bed pyrolyzer with cross-flow gas removal. The shale entering the pyrolyzer is already intimately mixed in and the pyrolyzer simply provides the residence time for oil generation. A residence time of 3 minutes is provided at a 3:1 recycle to raw ratio. Shorter residence times are achieved by simply maintaining a lower bed level. Features include: (1) uniform residence time of solid, (2) short path length for oil vapor collection, (3) smaller reactor volume (less voidage) and less gas sweep than fluid beds, and (4) process flexibility (can reduce residence time by lowering bed height).

Air Lift Pipe

Combustion kinetics in solid-recycle systems is poorly understood due to the complexity of the process: the intrinsic kinetics of char combustion is sensitive to processing conditions and residual carbon and hydrogen content, sulfur combustion may be important, and solid slip velocities and other particle dynamics are not well known.

LLNL plans to answer some of the questions concerning combustion at the full particle size range in a 5.4-centimeter diameter 10-meter high lift pipe system. The lift is designed with 100 percent of the air needed to combust the shale. This represents at least a 30 percent air excess because com-
Complete combustion will not be possible in the residence time provided.

**Delayed Fall Combustor**

Following the lift, the solid is separated in a classifier and tumbles through a series of rods which impede the fall while air is blown either co- or counter-current with the solid. Design of this unit assumes a 5 second solid residence time and enough air to finish combustion.

**Fluid-Bed Combustor**

After the delayed fall combustor, the solid falls into a vessel where the level is maintained to provide a pressure block between the combustion and pyrolysis atmospheres. Upward flowing gas in a stand pipe creates a pressure differential.

In the HRS retorting system the fluid-bed combustor will perform four functions:

- Reject excess solid from the circulating loop in such a way that the rejected material includes the smallest circulating particles
- Provide a surge tank to smooth irregularities in solids loop flow
- Provide char combustion as needed to raise the temperature to that desired at the retort inlet
- Provide an increase in gas pressure to balance the pressure decrease which occurs in the lift pipe

The combustor is designed with a 1-minute shale residence time to accommodate surges in the solid recycle loop. At commercial-scale, based on bed cross-sectional area, a maximum of 10-15 percent of the total combustion could occur in this unit.

**Future Work**

LLNL plans to operate the 4-tonne-per-day pilot plant to demonstrate proof-of-concept, determine scale-up parameters and produce shale oil for detailed characterization studies. Based on operating experience, they will then finalize design of a 100-tonne-per-day test of the HRS process to be built with government/industry support at a field site in western Colorado.

The ultimate goal is the development of an advanced oil shale retorting scheme to the point where commercialization can proceed with an acceptable risk level. Successful testing at three scales prior to commercialization would provide the necessary technical basis for assessing economics and risk.

The three scales are: (1) the 4-tonne-per-day laboratory pilot plant, (2) a 100-tonne-per-day field pilot plant, and (3) a 1,000-tonne-per-day field pilot plant, followed by a commercially-sized demonstration module (12,000 tonnes per day) which could be constructed by private industry within a 10 year time frame. Each scale represents a factor of 3 increase in vessel diameter over the previous scale, which is not unreasonable for solid-handling equipment.

The first step was constructing a 4-tonne-per-day pilot plant at LLNL, described previously. The next step is design and construction of the 100-tonne-per-day field pilot plant. Conceptual design of this facility was performed by Bechtel, with an estimated total construction cost of $18 million.

###

**WESTERN SLOPE REFINING AGAIN CEASES OPERATION**

Western Slope Refining Company in Fruita, Colorado has stopped producing gasoline and the work force has been scaled back from 130 to 12 pending a decision on the fate of the historically troubled operation.

The refinery's owner, Gary Williams Company of Denver, Colorado has not commented on future plans for the facility.

Partly because of the history of groundwater problems at the refinery, some observers anticipate the plant will be sold piecemeal and dismantled.

Sally Allen, a vice president with Gary Williams Company, stopped short of saying the refinery is for sale but said the firm is studying the economics of reopening or looking for investors.

Gasoline production was stopped in July, but the facility still provides terminal services as a convenience for local gasoline buyers.

Faced with financial problems, Gary Williams Company idled the plant in 1985 and then reopened it in 1989 after emerging from a Chapter 11 bankruptcy proceeding. The refinery had contracted to process all the crude oil produced at Unocal's Parachute oil shale plant but shipments were sporadic and the refinery operation was never profitable for Gary Williams.

###

**SECOND NAHCOLITE MINING PROJECT MOVES AHEAD**

Denison Resources Corporation, a Grand Junction, Colorado and Australian partnership, is the second firm plan-
ning to begin mining huge sodium reserves in the oil shale area of the Piceance Basin.

The company joins NaTec Resources Inc. in separate ventures that could together produce 1 million tons a year of sodium bicarbonate.

"We expect western Colorado and Wyoming to become the leaders in world sodium bicarbonate production," said G. Peters, a partner in Denison Resources.

Denison's parent company is Ameralia Inc., a Utah corporation listed on the NASDAQ exchange.

The $10 to $13 million Denison mine would start in late 1992 producing 50,000 tons a year and working up to 500,000 tons a year by 1995.

That would give Denison about 10 percent of the North American sodium market. The project is expected to employ about 30 people.

Both the Denison and NaTec mines will use an underground solution mining process, injecting hot water down one deep shaft, letting it dissolve the nahcolite, bringing it up another shaft and cooling the water to drop the nahcolite out of the solution.

Denison has a lease from the United States Bureau of Land Management and has begun a year-long environmental impact study (see article in Resource section of this issue).

The main environmental concerns focus on the impacts of drilling on ground and surface water, truck traffic on livestock and county roads, and protecting the layers of oil shale above the sodium.

Once the sodium mining of the two companies is in full production, they may build a slurry pipeline to Rifle, Colorado.

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DOE OIL SHALE PROGRAM REVIEWED

An overview of the United States Department of Energy (DOE) Oil Shale Research and Development (R&D) Program was presented at the 23rd Annual Oil Shale Symposium held in Golden, Colorado by J.D. Batchelor, director of DOE's Office of Oil, Gas and Shale Technology.

As the growth in worldwide petroleum supplies begins to wane, and demand exceeds supply, oil shale can be expected to be an important resource. The similarity of oil shale liquids to crude oil may give shale oil the advantage in the competition for liquid fuel markets, said Batchelor.

As a resource, oil shale is second only to coal, worldwide, on a BTU basis. The United States has 34 percent of the world's most promising deposits, estimated to be about 1,929 billion barrels of shale oil equivalent.

Presently, the only large scale plant operating in the United States is the Unocal facility in Parachute, Colorado, built under a price guarantee from the Synthetic Fuels Corporation in the early 1980s. Except for the recent proposal by Occidental Oil Shale Inc. for a jointly sponsored modified in situ demonstration project on Tract C-b, other interests in oil shale development have been deferred indefinitely.

The DOE oil shale R&D program is directed toward fostering the development of an economically competitive and environmentally acceptable industry. The compelling need for competitive new energy supplies in the early 1980s supported larger budgets. At that time, oil shale R&D funding was as high as $19 million. After crude oil prices dropped and the urgency for alternative fuel supplies became less crucial, DOE oil shale R&D funding dropped to the present level of about $9 million annually.

Research activities supported by DOE are aimed at reducing costs and resolving environmental issues. DOE projects to reduce cost are ongoing on most of the steps involved in producing shale oil including mining, feed preparation and material handling, retorting, and waste disposal. No research is being done on upgrading.

According to Batchelor, mining activities include research on blasting models, safe explosives, a water jet assisted mining machine and shale beneficiation.

In the surface retorting area, there is research on the hot recycle solids retorting process being developed by Lawrence Livermore National Laboratory (LLNL) for western shales. For eastern shales, research is continuing on the KENTORT II process at the University of Kentucky and on the Pressurized Fluid Bed Hydrogen Retorting Process at the Institute for Gas Technology (IGT). Work on the Recycle Oil Pyrolysis and Extraction Process at the Western Research Institute (WRI) and on Supercritical Fluid Extraction at Morgantown Energy Technology Center (METC) is in the early research stage.

The hot recycle solids retort (LLNL) consists of a delayed fall combustor, a fluid bed gas block, a fluid bed mixer to mix combusted and raw shale, a moving bed retort with radial gas offtakies and a retorted shale transport lift pipe. LLNL has obtained encouraging results for this process and is seeking joint industrial support for future research.

The KENTORT II process includes three fluid bed reactors: a pyrolysis reactor heated with gas from the gasifier, a gasifier to reduce sulfur and buffer the retort from combusted shale, and a combustor as a heat source.

The pressurized fluidized bed hydrogen retorting process uses finely ground beneficiated shale and increases oil yield by high pressure hydrogen retorting.

Laboratory R&D is directed at:

- Defining coking and cracking kinetics
- Sulfur and nitrogen reactions
- Attrition and decrepitation properties
- Identifying reaction mechanisms and defining their kinetics in slow and fast heat-up regimes
- Pyrolysis at short residence time
- Conversion of beneficiated shales

Environmental research is an important part of the DOE program, said Batchelor. DOE research in this area consists primarily of: spent shale pile modeling using indoor lysimeters, and remediation activities related to the Rock Springs site in Wyoming.

DOE funded research to study utilization of products in higher valued end uses includes:

- Combusted shale for road bed stabilization
- Improved asphalt from shale oil or additives from shale oil
- Identification of the process streams and conditions needed to produce higher value products

Also under development is a $2.3 million plan, funded half by Occidental Oil Shale Inc., $400,000 by the State of
funds last year. The total cost of the project is estimated at $200 million and could employ as many as 200 workers.

The proposed test facility would have a 7-year lifespan, producing 1,200 barrels of synthetic crude oil a day.

In order for the project to proceed, the $8 million appropriation must also be approved by the United States Senate. Recent events in the Middle East are likely to influence decisions to support accelerating oil shale development activities in the United States.

Support of the oil shale industry in previous years has been provided through the Western States Enhanced Oil Shale Recovery Program. The program has aided efforts to improve mining techniques, develop enhanced oil shale recovery methods and find economic byproducts.

The New Paraho Corporation has developed one such oil shale byproduct that company officials hope will provide economic stability in a fluctuating crude oil market. New Paraho has developed a shale-based asphalt to resurface roads.
OCCIDENTAL REPORTS OIL SHALE COMBUSTION TESTS IN FLUIDIZED BOILER

Occidental Oil Shale’s planned modified in situ (MIS) demonstration project on Tract C-b will result in two low-grade fuels—oil shale mined out during creation of the underground MIS retorts, and low-BTU off-gas from the retorts. Oxy plans to burn these fuels in a circulating fluidized bed combustor (CFB). The project is being designed to burn these fuels plus supplemental coal, readily available in the area, to provide additional BTUs to generate the amount of steam and power planned for the project. The demonstration project will provide process steam requirements and up to 50 megawatts of power for internal use and external sales. According to a presentation by R. Moore at the Symposium on Opportunities in the Synfuels Industry held in Bismarck, North Dakota in August, engineering studies for a commercial facility of 25,000 barrels per day also envision integrating MIS and aboveground retorting technologies and using a CFB boiler to burn shale fines, low BTU gas and other waste streams.

Oil shale at the C-b tract in the horizons that will be mined for the MIS retorting process varies in grade from under 20 gallons per ton (GPT) to over 40 GPT. This corresponds to a range of 2,000 to 4,000 BTU per pound in higher heating value. The analysis of the expected grade of shale to be mined for the project is shown in Table 1. The shale is about 15 percent organic matter, 30 percent carbonate minerals such as dolomite and calcite, and 55 percent inert minerals. The calcium compounds are expected to provide for sulfur capture in the CFB boiler. In the current design, the shale represents about 47 percent of the energy to the CFB boiler and contains 45 percent of the sulfur.

The low BTU modified in situ gas stream is laden with H₂S from the shale retorting and contains about 70 BTU per standard cubic foot. This represents about 23 percent of the BTUs in the boiler design and 51 percent of the sulfur load. The composition of the average gas is shown in Table 2.

### TABLE 1

<table>
<thead>
<tr>
<th>Ultimate Analysis</th>
<th>As Received, Wt%</th>
</tr>
</thead>
<tbody>
<tr>
<td>Carbon</td>
<td>17.74</td>
</tr>
<tr>
<td>Hydrogen</td>
<td>1.80</td>
</tr>
<tr>
<td>Nitrogen</td>
<td>0.34</td>
</tr>
<tr>
<td>Sulfur</td>
<td>0.99</td>
</tr>
<tr>
<td>Oxygen</td>
<td>9.97</td>
</tr>
<tr>
<td>Ash</td>
<td>68.13</td>
</tr>
<tr>
<td>Moisture</td>
<td>1.03</td>
</tr>
</tbody>
</table>

| Dolomite (MgCa(CO₃)₂)    | 20.15            |
| Calcite (CaCO₃)          | 7.75             |
| Grade, Gallons/Ton       | 27               |
| Heating Value, BTU/Lb    | 2,799            |
| Pounds of Sulfur/MMBTU   | 3.54             |

### TABLE 2

MIS RETORT OFFGAS ANALYSIS (Volume Percent)

<table>
<thead>
<tr>
<th>Component</th>
<th>Volume Percent</th>
</tr>
</thead>
<tbody>
<tr>
<td>Hydrogen</td>
<td>8.5</td>
</tr>
<tr>
<td>Nitrogen</td>
<td>53.9</td>
</tr>
<tr>
<td>Oxygen</td>
<td>0.1</td>
</tr>
<tr>
<td>Carbon Monoxide</td>
<td>2.9</td>
</tr>
<tr>
<td>Carbon Dioxide</td>
<td>29.1</td>
</tr>
<tr>
<td>Methane</td>
<td>1.3</td>
</tr>
<tr>
<td>C₂</td>
<td>0.4</td>
</tr>
<tr>
<td>C₃</td>
<td>0.2</td>
</tr>
<tr>
<td>C₄</td>
<td>0.1</td>
</tr>
<tr>
<td>C₅+</td>
<td>0.15</td>
</tr>
<tr>
<td>Ammonia</td>
<td>0.15</td>
</tr>
<tr>
<td>Hydrogen Sulfide</td>
<td>0.75</td>
</tr>
<tr>
<td>Other Sulfur</td>
<td>0.0002</td>
</tr>
<tr>
<td>Water</td>
<td>2.5</td>
</tr>
</tbody>
</table>

| Heating Value, BTU/Scf | 70 |
| Pounds of Sulfur/MMBTU | 9.1 |

Supplemental coal is available from several operating coal mines within trucking distance of the C-b site. Coal represents the remaining 30 percent of the BTUs into the boiler and introduces about 4 percent of the sulfur.

In addition, small waste streams, such as sour water stripper overheads, rich in ammonia, may also be combusted in the CFB boiler in the demonstration project.

### CFB Pilot Plants

A test series was run at Tampella-Keeler’s facility in Williamsport, Pennsylvania. A second test series was run at Pyropower’s pilot plant in San Diego, California.

The Tampella-Keeler test facility is the largest CFB pilot unit in the United States. It is rated at about 10 million BTU per hour fired load. It is about 3 feet in internal diameter and is the same height as commercial units (70 feet). During testing that covered one and a half weeks, 100 tons of oil shale and 10 tons of coal were burned. In or-
order to simulate MIS gas, recycled flue gas spiked with natural gas and \( \text{H}_2\text{S} \) was injected into the boiler.

The Pyropower pilot plant is rated at 2 million BTU per hour fired load. It is about 16 inches by 16 inches in inside dimension and about 30 feet high. During the testing which covered about 2 weeks, 20 tons of oil shale and 5 tons of coal were burned. MIS gas was simulated with recycled flue gas spiked with propane and \( \text{H}_2\text{S} \).

**Combustion Behavior**

Moore reported that all three fuels burned intensely and very efficiently in both pilot plants. Carbon utilization was over 99 percent in all runs. The main fuel, oil shale, proved very reactive due partly to its high volatiles content. On introduction into the bed, much of the organic matter promptly devolatilizes. The loss of volatiles and decomposition of the calcite and dolomite, results in a highly porous and fragile particle which tends to decrepitate into fines. As a result, though the size of the shale was below 0.25 inch at Tampella-Keeler and below 0.75 inch at Pyropower, much of the combusted solid ended up as fly ash recovered in the baghouse. A smaller stream, typically less than 20 percent of the ash, was withdrawn as bottom ash.

**Sulfur Capture**

Various investigators have shown in bench scale tests that western oil shale could be an effective absorbent for sulfur dioxide in a fluid bed boiler. One of the major objectives of the pilot tests was to verify that low sulfur emission limits could be achieved. The data are to be used to obtain permits for the facility from state regulators and to allow the manufacturers to provide accurate cost estimates and guarantee plant performance. For runs at the Tampella-Keeler plant, Figure 1 shows the sulfur dioxide (\( \text{SO}_2 \)) in the stack gas for all the runs at various temperatures. Over 95 percent sulfur capture was achieved by the minerals inherent in the shale ash. The sulfur capture efficiency decreased with increasing temperature and fell off rapidly above 1,600°F.

![FIGURE 1
SULFUR DIOXIDE RESULTS](image-url)
The shale ash contains about 30 percent calcite and dolomite (mostly the latter) which represents a calcium to sulfur ratio of 3.0 at normal conditions. However, the shale appears to be more effective than typical limestone. Other tests achieved very high sulfur reductions at Ca/S molar ratios that are well below those expected when coal is burned with limestone as the sorbent. This is due primarily to the phenomena, noted above, in which the shale particles break down into many fines affording a high amount of reactive surface for the SO₂.

The tests at the Pyropower unit gave generally similar results to those observed at Tampella-Keeler. The dependence on temperature was similar.

**NOₓ Emissions**

Shale is a high nitrogen fuel and on this basis one would expect high nitrogen oxide emissions. Burning shale alone did result in elevated levels of NOₓ emissions which would require some control technology. Burning shale in combination with low BTU gas and with coal resulted in acceptable emission levels. The unique characteristics of the shale resulted in behavior that is not typical of normal coal/limestone results in a CFB boiler. As the bed temperature decreased, the NOₓ in the flue gas actually increased.

The experimental data from Tampella-Keeler are shown in Figure 2. The data clearly show the increasing NOₓ level with decreasing temperature. The effect of secondary air injection, within the limits of the experimental conditions, was not significant.

At present, no plausible explanation for the temperature dependence of the NOₓ levels is known.

During the Pyropower tests, more emphasis was given to the study of NOₓ and its control. Table 3 (on the next page) summarizes the emission data from these tests. Again the same temperature dependency was observed.

Ammonia injection into the outlet of the CFB boiler is one NOₓ control technology. One test simulated injection of an ammonia stream produced during the MIS retorting. The ammonia is recovered from the MIS gas.
TABLE 3
PYROPOWER RESULTS, NITROGEN OXIDE EMISSIONS

Design Mix: 47% Shale; 23% MIS Gas; and 30% Coal on BTU Basis

<table>
<thead>
<tr>
<th>Run</th>
<th>Feed</th>
<th>Temperature</th>
<th>Ca/S Ratio</th>
<th>NOₓ ppm</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Design Mix</td>
<td>1,600</td>
<td>3.0</td>
<td>187</td>
</tr>
<tr>
<td>2</td>
<td>Design Mix</td>
<td>1,550</td>
<td>3.0</td>
<td>222</td>
</tr>
<tr>
<td>4</td>
<td>Design Mix, Low Load</td>
<td>1,470</td>
<td>3.0</td>
<td>263</td>
</tr>
<tr>
<td>5</td>
<td>Decrease Shale</td>
<td>1,550</td>
<td>0.0</td>
<td>140</td>
</tr>
<tr>
<td>6</td>
<td>High S MIS Gas</td>
<td>1,550</td>
<td>0.0</td>
<td>148</td>
</tr>
<tr>
<td>7</td>
<td>Shale with FG Recirc</td>
<td>1,470</td>
<td>6.6</td>
<td>574</td>
</tr>
<tr>
<td>9</td>
<td>Shale with S in Recirc</td>
<td>1,550</td>
<td>3.3</td>
<td>238</td>
</tr>
<tr>
<td>11</td>
<td>Design with NH₃</td>
<td>1,530</td>
<td>0.0</td>
<td>Varied</td>
</tr>
<tr>
<td>12</td>
<td>Shale Alone</td>
<td>1,550</td>
<td>6.7</td>
<td>395</td>
</tr>
</tbody>
</table>

wash water in a sour water stripper. This ammonia waste stream was injected into the bottom bed and cyclone outlet at various ratios. Injecting 100 percent into the bottom of the bed lowers NOₓ somewhat; injecting it all to the top of cyclone results in the lowest NOₓ emission level.

It was concluded that shale, alone or in combination with other low quality fuels, can be burned and achieve low NOₓ emission levels by using standard ammonia injection or by using the sour water ammonia produced during the shale retorting.

Ash Characteristics

In both test units over 80 percent of the ash was recovered as fly ash in the baghouse. The baghouses at both test units showed no problem in handling the heavy loading of fly ash or in blowing the ash from the bags.

The quantity and particle size of shale ash did require that precautions be taken in the waste heat recovery sections of the two pilot plants. The fine ash did build up on the heat transfer surfaces in the waste heat boilers and the economizers.

Both manufacturers feel that soot blowing will control the dust buildup in the heat transfer tubes. The units will be conservatively designed for proper tube spacing, soot blowers, and baghouse capacity.

The fly ash from the pilot plant tests has been tested using the Environmental Protection Agency's TCLP method and was found to have no leachable heavy metals or organics. Thus the ash can be handled as a non-hazardous material. Tests are currently underway to determine the material's properties as cement additive, roadbase enhancer and waste stabilizer. Preliminary results are encouraging, says Oxy.

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RAMEX PATENTS OIL SHALE GASIFICATION PROCESS

United States Patent Number 4,928,765, issued to D.H. Nielson and assigned to Ramex Syn-Fuels International is titled "Method and Apparatus for Shale Gas Recovery." This invention claims to provide an improved process and apparatus for gasification of shale in situ, as a result of the controlled application of heat by means of a downhole heater within a subterranean shale deposit. Field tests have shown that by closely regulating the heating source's combined output of conductive and radiant heat, an operating temperature of approximately 1,200°F may be readily maintained throughout a substantial diameter surrounding the heater-containing borehole, to yield a substantial volume of commercially acceptable gas. More specifically, during startup, heat is applied at a temperature above 1,000°F to initiate the reaction and thereafter maintained below 1,500°F as the shale decomposes.

Within the shale bed formation there are no convective currents and thus, only conductive and radiant heat transfer need be considered. Experimental shale work in the past has concentrated on processes wherein temperatures are produced below 1,000°F. Analyses of the present process have shown that by operating at 1,200°F, the optimum amount of conductive heat transfer contributes about 1,000 degrees to the shale body while radiant heat transfer comes into play above that point. It is found that when
operating at 1,200 degrees, approximately four times the heat transfer rate is achieved as at 1,000°F. A notable benefit of operating at this temperature is that the kerogen content of the shale yields 100 percent gas thereby eliminating the need for costly above ground equipment for separating out liquids or otherwise treating the gas.

The process is said to produce an operating temperature within the shale bed which has been found to be constant, throughout the bounds of a reaction zone, from the edge adjacent the borehole heater, to the outermost perimeter of the reaction zone. By maintaining a specified temperature of the heater, this operation will continue for an extended period, estimated for at least 5 years and with the volume and BTU value of the product gas remaining constant.

Figure 1 is a vertical evaluation, partly in section, of an oil shale gasification system according to the invention.

Included is a unitary heater assembly, generally designated 10 which is lowered into a borehole 12 drilled into a shale formation.

With the burner operating, the temperature of the housing becomes elevated and heat is conducted to the juxtaposed inner ring 64 of the shale formation surrounding the heater assembly. Initially, the temperature of the shale is slowly evaluated above its ambient temperature, in the area immediate the heater. This temperature rise gradually radiates outwardly and when a temperature of 1,200°F is reached in the shale body, reaction occurs in the kerogen to convert it to the gaseous state. The radial extent of this ever increasing reaction zone 66 is determined by the range of the constant zone of 1,200 degree temperature within the shale.

The radiant heat transfer is reflected in Figure 1 by the arrows 70 while the path of the converted gas is represented by the inwardly directed arrows 72.

As the gas migrates through the reaction zone it ultimately reaches the inner ring 64 and thence passes into the gas space 74.

The produced gas collecting within the gas space 74 is extracted therefrom by a vertically disposed gas opening 82 formed in the housing periphery. Directly communicating with this gas opening is a vertically disposed product gas line 84, extending upwardly through the heater top wall and thence up through the borehole to the surface where the gas line enters a product receiver.

The invention claims natural gas is produced which, on average, will yield over 70 thousand cubic feet daily and at a value of over 800 BTU. An important feature is that this production will be substantially constant for a significant period of time, such as 5 or more years. During this period, the reaction zone 66 will progressively increase in diameter and the 1,200 degree temperature is maintained constant throughout the zone.
It is said that the most feasible arrangement for a gas field is to sink a plurality of the boreholes 100 feet apart along x and y axes.

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**LLNL FINDS COKING LOSS PROPORTIONAL TO RECYCLE RATIO**

Lawrence Livermore National Laboratory (LLNL) has for some time been studying the cracking and coking of shale oil vapors during retorting. As stated by P.H. Waltman at the 1990 Oil Shale Symposium held in Golden, Colorado in May, the objective of this work has been first to quantify oil yield losses in the Hot-Solids-Recycle (HRS) oil shale process due to these reactions, and second, to determine if cracking and/or coking are favorable oil upgrading reactions that can be used advantageously in the HRS process. A certain level of cracking and coking is unavoidable in the HRS process.

According to Wallman, the first objective of quantifying oil yield losses for a simple fluidized-bed process has been accomplished, but oil quality effects of cracking and coking have only been studied under high-severity conditions, i.e., with oil destruction conversions much higher than the conversions typical of the HRS process.

Figure 1 shows schematically the main process units of a generic HRS process: a pyrolyzer for heating raw shale to a pyrolysis temperature around 500°C with a stripping gas that usually also serves mixing purposes, and a combustor that raises the temperature of the pyrolysis residue for recycle as heat carrier to the pyrolyzer. Different process arrangements have been proposed for both the pyrolyzer and the combustor.

Common to all HRS processes utilizing burned shale as heat carrier is contact between the oil product vapor and the burned shale. Such contact has been shown to produce coking of the oil vapor onto the surface of the burned shale. It was also observed that shale oil vapor undergoes chemical changes merely as a result of residence time at high temperatures (such as 500°C) even in the absence of solid surfaces. The main manifestation of these changes is production of light hydrocarbon gas ($C_3$ and lighter hydrocarbons) from the oil. This light gas production is commonly referred to as "cracking," whereas the surface-induced oil-loss mechanism is referred to as "coking" because coke is the main product. These definitions are not strict in a chemical sense because coking produces significant amounts of light gas, and cracking probably produces minute amounts of coke.

Based on experimental results obtained with both a long-exposure-time apparatus and a short-exposure-time apparatus, LLNL has been able to derive a mathematical model of the cracking and coking reactions.

Figure 2 (on the next page) shows the effect of changing the recycle ratio in the fluidized-bed HRS process. The results show that oil yield losses in the categories coke and absorbed oil increase proportionally to the recycle ratio. This is because coke and adsorbed oil are approximately independent of recycle ratio at 2.2 milligrams coke/(grams recycle shale) and 0.4 milligrams adsorbed oil/(grams recycle shale). The cracking loss also increases with recycle ratio. Any extra cracking associated with quenching of a very hot recycle solid such as would be required at recycle ratios less than two is not included in the model. Hence, the cracking loss should not be extrapolated to recycle ratios lower than two.

Figure 3 (on the next page) shows the effect of changing the pyrolysis temperature in the fluidized-bed retort. Interestingly, the results show a broad oil loss minimum in the temperature range 500-525°C. The increase in oil loss at higher temperature is due to increased "homogeneous" cracking (the cracking rate increases rapidly with temperature), whereas the loss at lower temperature is a result of increased coking and adsorbed (unstripped) oil. Wallman says this is mainly a result of the pyrolysis zone moving deeper into the fluidized bed because of slower pyrolysis kinetics. A longer contact between the emerging oil vapors and the downflowing solids leads to more coke and adsorbed oil.
results in Figure 3 clearly show that retorting Colorado oil shale in an HRS process should not be carried out at temperatures below 500°C unless there is a specific reason to coke part of the oil product.
INTERNATIONAL

RUSSELL PUBLISHES BOOK ON OIL SHALES OF THE WORLD

Oil Shales of the World, Their Origin, Occurrence and Exploitation, by P.L. Russell, has been published by Pergamon Press. This long-awaited work provides, in the author's words, "a record of the many oil shale deposits of the world and documents, to the extent possible, the many and varied attempts to utilize these resources before such records are lost or forgotten."

The book's 750-page contents reflect a serious attempt to justify the word "world" in its title. Chapters are included for the following countries:

AFRICA

Algeria
Lesotho
Mozambique
South Africa
Tunisia
Zaire
Zimbabwe

EGYPT

MOROCCO

REPUBLIC OF SOUTH AFRICA

Cape Province
Natal
Orange Free State
Transvaal

NORTH AMERICA

CANADA

UNITED STATES

CENTRAL AMERICA

Costa Rica
Nicaragua
Panama

SOUTH AMERICA

Argentina
Brazil
Chile
Paraguay and Venezuela
Peru

ASIA

Asia (General)
Burma
China
Japan
Malaysia
Russia (See Eastern Europe)
Thailand

MIDDLE EAST

Israel
Jordan
Pakistan
Syria
Turkey

AUSTRALASIA

Australia and Tasmania
New Zealand

EUROPE (CENTRAL)

Bulgaria
Czechoslovakia
Hungary
Poland
Romania
Yugoslavia

EUROPE (EASTERN)

Russia

EUROPE (WESTERN)

Austria
Belgium-Luxembourg
France
Germany (Federal Republic)
Italy
Norway
Portugal
Spain
Sweden
Switzerland
United Kingdom

Russell notes that the earliest known use of oil shale was as a decorative stone found in the buildings of ancient Mesopotamia. The Romans also used the oil shales of Autun to decorate their early temples in France. The first or earliest use of oil shale as a fuel is unknown, but it was
known as "Moses stone" in ancient Egypt and an 800 A.D. legend in Austria indicates that shale oil was known by that date. Other early uses of oil shales are of record.

The first modern attempts at commercial production and use of shale oil began in the 1830-1860 period. While some of these efforts were economically successful, the discovery of petroleum in the United States in 1859, and elsewhere soon after, was the death knell of most economic production of shale oil.

Shale oil industries in Scotland, Australia, France, Russia, China and several other countries have been active over the years since 1860; the Scottish industry operated for over 100 years. However, most shale oil operations had only short periods of profitability following which production, if any, was subsidized for various reasons including war-time needs for liquid fuels.

The fluctuating supply of natural crude oil, together with rapidly changing prices, has resulted in many worldwide attempts to replace or supplement natural crude with oil from oil shales that are found in at least 50 countries. Many of these attempts at utilization are presented in the book. The breadth of coverage may be gauged by the table of contents for the chapter on Russia:

History
Geology
   General Distribution and Origins
      Cambrian Oil Shale Fields
      Devonian Fields
      Upper Carboniferous-Lower Permian Fields
      Triassic Oil Shales
      Jurassic and Cretaceous Fields
      Paleogene Oil Shale
      Neogene Oil Shale
Origin of Shales
Resources
   Baltic Region (Ordovician Age)
      Estonia
      Tapa
      Dictyonema Shales
      Leningrad
      Chudovo-Babinskoye
   Pripyat Region (Devonian Age)
      Lyuban
      Turow
      Bolyshskoye
   Timan-Perchora Region (Jurassic and Cretaceous Age)
      Izhemski Rayon
      Vychegodski Region (Jurassic and Cretaceous Age)
      Sylsiski Rayon
      Yarengski Rayon
   Volga Region (Jurassic and Cretaceous Age)
      Obschchertovskoye
      Perelyb-Blagodatovka
      Chagan

Kashpir-Khvalynskaya
   Kenderlyskoye Region (Upper Carboniferous-Lower Permian Age)
Baysun Region
   Amu-Daraya and Kyzyl Kum
Total USSR Oil Shale Resources
Mining
   Estonia
   Mining Methods
      Multiple-Room Method
      Cut Room System
      Transverse Holes System
      Pillar Method
   Leningrad Region
      Underground Extraction Pre-1938
Quarrying
   Current Development
      Underground Operations
      A Room-and-Pillar Mine
      Open Pit Mining
Oil Shale Processing Pre-1938
   Estonia
      State Oil-Shale Industry Plant
      Oil Syndicate Plant
      Estonian Mineral-Oil A.G. Plant
      New Consolidated Gold Fields Plant
Refining and Treating Pre-1938
   State Oil-Shale Industry Plant
   Oil Shale Syndicate Plant
   Estonian Mineral-Oil A.G. Plant
   New Consolidated Gold Fields Ltd.
Recent Developments
   Processing
      The Kiviter Retort
      The Galoter Retort
Environmental Problems
   Future Plans
      Direct Combustion

Although it could have been considerably improved by more attention to proofreading and the addition of an overall summary, Russell's book is clearly a volume which should be owned by anyone seriously interested in oil shale. Nowhere else is it possible to find in one location such wide-ranging historical information on oil shales around the world.

##

**OIL SHALE INTEREST SEEN IN INDIA**

Oil India Ltd. is reportedly requesting governmental approval to develop Disang oil shales located in northeastern India. Oil and Gas Journal reported that Oil India estimated that the oil shale deposits, which are in the hilly
areas of Manipur, Nagaland, Arunachal Pradesh, and Mizoram and encompass 10,000 square kilometers, could contain resources amounting to 438 billion barrels of shale oil equivalent.

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**SHALE OIL RESIDUE COULD BE USED ON ROADS IN RUSSIA**

A recent article in the Russian-language journal *Oil Shale* notes that the utilization of shale oil residues is a complex problem whose solution is especially urgent from an ecological point of view. Shale oil residue is defined as a mixture of shale oil and ash left behind when shale oil is purified from mechanical impurities. It amounts to over 5 percent of the total shale oil produced.

In the Institute "Lengiproneftekhim" a new shale residue processing plant has been designed. The residues obtained by centrifuging heavy shale oil are homogenized in a disperser-emulsifier and then partly mixed with the residue obtained by thermal settling of total shale oils.

The commercial product, mixed residues is used as a fuel in electric power stations. The dispersed residues are used in road construction.

The trade balance of the plant, based on a model road emulsion composition and the presumable yearly consumption of utilities, has been calculated. The capital expenditures for the plant would be recovered in 2.7 years.

####
WATER

FWS PROPOSES TO LIST RAZORBACK SUCKER AS ENDANGERED SPECIES

On May 22 the United States Department of the Interior, Fish and Wildlife Service, published a notice in the Federal Register that proposes to list the razorback sucker (*Xyrauchen texanus*) as an endangered species pursuant to the Endangered Species Act.

This native fish is found in limited numbers throughout the Upper and Lower Colorado River Basin. Evidence of natural recruitment has not been found in the past 30 years, and numbers of adult fish captured in the last 10 years demonstrate a downward trend. Significant changes have occurred in razorback sucker habitat through diversion of water, introduction of non-native fishes, and construction and operation of dams. Further changes are anticipated as these activities continue.

Once known as the humpback sucker, the adult razorback sucker is readily identifiable by the abrupt sharp-edged dorsal ridge behind its head and a large fleshy subterminal mouth that is typical of most suckers. Adult fish are relatively robust, often exceeding 6 pounds in weight and 24 inches in length.

The razorback sucker was once abundant throughout the Colorado River Basin. There are many accounts of razorback sucker abundance during early settlement of the Lower Basin and a significant commercial fishery for them existed in southern Arizona in the early 1900s. Residents living along the Colorado River near Clifton, Colorado observed several thousand razorback suckers during spring runoff in the 1930s and early 1940s.

In recent times, razorback sucker distribution has been reduced to about 750 miles of the Upper Basin and to 200 miles of the Lower Colorado River. Sizeable numbers of adult razorback suckers still occur in Lake Mohave. No significant additions to these populations have been documented in recent years and these existing fish are estimated to be up to 40 years old, and were hatched prior to impoundment.

Disappearance of razorback suckers from Lower Basin reservoirs 40 to 50 years after impoundment has been documented. It is predicted that the Lake Mohave population is following this trend and may be extirpated before the year 2000.

The razorback sucker was proposed for listing as a threatened species on April 23, 1978. The proposal was withdrawn on May 27, 1980, in accordance with provisions of the 1978 amendments to the Endangered Species Act. These provisions required the Service to include critical habitat in the listing of most species and to complete the listing process within 2 years or withdraw the proposal from further consideration.

A petition was received from the Sierra Club, National Audubon Society, the Wilderness Society, Colorado Environmental Coalition, Southern Utah Wilderness Alliance, and Northwest Rivers Alliance on March 15, 1989. The petition requested the Service to list the razorback sucker as an endangered species. A positive finding on this petition was made in June 1989 and subsequently published in the Federal Register on August 15, 1989. This notice also stated that a status review was in progress and that the Service was seeking information until December 15, 1989. This proposal constitutes the final finding for the petitioned action.

The razorback sucker has declined substantially in the past 80 years because of major alterations in their habitats, dissection of the river system with dams, and the introduction of many new species to their ecosystem. Although they have been included on the protected list of all Colorado Basin states, except Wyoming (where they are extirpated) and New Mexico (where no records of razorback sucker exist) they have continued to decline. They are presently one of the most endangered fishes in the Colorado River Basin.

Critical Habitat

The Endangered Species Act requires that, to the maximum extent prudent and determinable, the Secretary propose critical habitat at the time the species is proposed to be listed as endangered or threatened. The Service finds that designation of critical habitat is not determinable or prudent at this time for the razorback sucker.

There is limited information on the specific habitat needs of the razorback sucker. Though habitat occupied by the razorback sucker has been identified and spawning has been documented in several areas, it is questionable as to whether these areas are adequately meeting the life history needs of the razorback if there has been little or no recruitment. The razorback sucker cannot perpetuate itself in the wild if there is little or no recruitment of young fish into the population. It would not be in the best interest of the species to identify existing habitats as critical habitat when the Service is unable to identify those specific areas needed to bring about recruitment. Hence, the Service finds that critical habitat is not determinable at this time.

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RESOURCE

COURT RULES FOR MARATHON IN OIL SHALE CLAIMS CASE

In June, United States District Judge Sherman Finesilver or-
dered the Interior Department to issue oil shale mining patents to Marathon Oil Company and three Colorado resi-
dents seeking title to 983 acres of land in western Rio Blanco County, Colorado.

In 1986, the company and three individuals—Joan Savage and Barbara Cliff Toner of Rifle and the late Cameron Cliff—applied for patents on their claims.

When the department refused to continue processing the claims, the claim holders filed suit in October 1989. In a 58-page opinion, Judge Finesilver noted the plaintiffs had complied with department standards and the agency actually had recommended issuing patents in February 1989. He or-
dered the Interior Department to turn over the 983 acres of oil shale land for a $2.50-per-acre filing fee, saying the agency abused its discretion in the governmental process.

"The department is under no legal obligation to perpetuate a moratorium on patenting mining claims," Judge Finesilver wrote in his ruling. "Indeed, the department is awaiting a congressional signal that may not come soon." (As of this writing it appears that legislation to rewrite the mining laws will die in Congress again this year.)

Finesilver ordered the department to issue patents by July 20 on the six pre-1920 mining claims. However, the Depart-
ment of the Interior then filed an appeal with the 10th Circuit Court of Appeals and was granted a stay. Argu-
ments before the Court of Appeals will probably be made early next year.

NEW PARAHO ASSUMES OIL SHALE LEASES FROM SHELL

New Parahoe Corporation, based in Lakewood, Colorado, has assumed seven oil shale leases in Utah from Shell Western E & P Inc. Shell reserves a 0.20 percent overriding royalty on the mineral leases.

The lease numbers are:

ML42360
ML42362
ML42363
ML42477
ML42478

WHITE RIVER RESOURCE MANAGEMENT PLAN TO BE REVISED

The Bureau of Land Management (BLM) is initiating a Resource Management Plan (RMP) for the White River Resource Area headquartered in Meeker, Colorado.

The plan amendment process which was initiated in February 1990 has been canceled. Issues identified for that process and the public input received will be carried forward into the RMP. A resource management plan and environ-
mental impact statement (EIS) will be prepared; scheduled completion is the spring of 1993.

BLM solicited public input to help define the issues and the planning criteria for the RMP. Three public meetings were held in June to discuss the issues and to collect public com-
ments.

Description of the Planning Area

The White River Resource Area is located in northwestern Colorado and includes all of Rio Blanco County and small portions of northern Garfield and southern Moffat counties. The entire resource area contains 2,125,000 acres; 1,432,000 acres is public land managed by the BLM, 58,000 acres is managed by the State of Colorado, and 635,000 acres is privately owned. In addition to the 1,432,000 acres of public land, there is an additional 697,000 acres of other federal, state, and private land upon which the BLM manages the mineral estate.

The area supports a large variety of resident and migratory wildlife species. Public lands support a large percentage of the spring, fall, and winter range for the resident deer popula-
tion. Three endangered bird species have been documented in the area, and two endangered fish species have been iden-
tified in the waters within the resource area. Also, several rare and sensitive plant and animal species are known to be in the resource area.

The White River Resource Area also contains a variety of important minerals such as oil and gas, coal bed methane, oil shale, coal, and sodium.

The issues to be considered in the RMP include oil and gas leasing (including coal bed methane), off highway vehicle (OHV) designations, wild horse management, land owner-
ship adjustments, special management area designations, black footed ferret reintroduction, public access and recreation management.

Oil and Gas

The oil and gas portion of the plan, including coal bed methane, will determine which public lands and minerals should be made available for oil and gas leasing, and what lease stipulations may be necessary to protect other resource values.

Anticipated oil and gas issues include:

- Determine if existing lease stipulations are proper and sufficient to protect other resources
- Determine if there is additional federal mineral estate that should be considered for oil and gas leasing
- The cumulative impacts of oil and gas developments
- Clarification of stipulations applied at lease issuance
- Lease stipulations necessary to protect wildlife, fragile soils, water resources, and other resource values
- The impact of lease stipulations on oil and gas development

Planning criteria for addressing the oil and gas issue include:

- Identify lands eligible for leasing through consultation and application of laws and regulations
- Assess the availability of the lands to incur oil and gas development, and the availability of the resource for development
- Compare the public values of oil and gas development with the public values of other alternative uses which may be precluded or impacted

Off Highway Vehicle Designations

The OHV portion of the RMP will determine areas to be open, closed, or limited to general use or OHV uses.

The issues anticipated for the OHV portion include:

- Designate as either open, closed or limited
- If limited, the limitations to be applied

Wild Horse Management

The wild horse management issue will determine what adjustments need to be made to the herd management area and to the wild horse herd due to possible use of a portion of the existing area for disposal of oil shale overburden and spent shale.

Land and Mineral Ownership Adjustments

Land and mineral ownership adjustment decisions will determine whether lands and/or minerals will be available for disposal and acquisition and what method of disposal or acquisition will best serve the public interest.

Issues considered for land and mineral ownership adjustments include:

- What lands and/or minerals are suitable for land and mineral ownership adjustment actions
- Which methods of land and minerals ownership adjustments are most suitable
- Which withdrawals should be revoked or modified

The proposed planning criteria used to address the land and mineral ownership adjustment issue are:

- Location, resource values, and manageability of the lands and minerals identified for disposal or acquisition
- The disposal or acquisition authorities under which the lands and/or minerals may be conveyed

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The conditions, including any activity planning requirements, which must be met in order to allow conveyance

- The management objectives to be served by disposal or acquisition
- Identifying the withdrawals to be modified or revoked in support of these actions

Special Management Area Designations

BLM will analyze for designation areas which have resource values suitable for special management. These areas can be nominated from the public or within the BLM.

Black Footed Ferret Reintroduction

This decision will determine the feasibility and possible locations for the reintroduction of the threatened and endangered black footed ferret in the White River Resource Area.

Issues to consider in reintroduction of the black footed ferret include:

- Areas suitable for reintroduction
- Other resources impacted by reintroduction
- Constraints on other resources
- Criteria for suitability of reintroduction

The proposed planning criteria to address the reintroduction of the black footed ferret are:

- Identify what areas are suitable for reintroduction
- Identify what protection measures would be required for reintroduction
- Identify what resources would be impacted by reintroduction

The schedule for completing the White River Resource Management Plan/EIS is as follows:

October 18, 1991 - Draft RMP/EIS released to public
January 17, 1992 - End of comment period
September 30, 1992 - Proposed RMP/Final EIS released to public
August 30, 1993 - Record of Decision

BLM TO PREPARE EIS FOR NAHCOLITE PROJECT

Denison Resources (USA) Corporation has submitted a mine development plan for a nahcolite solution mine to extract sodium resources from the Rock School Lease, located on public land in northwest Colorado. The Bureau of Land Management's (BLM) White River Resource Area has determined that this proposal represents a major federal action with the potential for significant impact and will, therefore, prepare an Environmental Impact Statement (EIS) to evaluate the proposal.

Rock School Sodium Lease

The Rock School Sodium Lease totals approximately 1,320 acres of public land within the Piceance Creek Basin in Rio Blanco County approximately 35 miles southwest of Meeker, Colorado. The lease area is generally flat with limited areas of moderate relief. Vegetation in the area includes Big Sagebrush Shrubland, Pinyon-Juniper Woodland and Greasewood Sage Bottomlands.

Denison's Proposed Mine Development Plan

Denison proposes to construct and operate a commercial-scale nahcolite solution mine that would produce a maximum of 50,000 tons per year of sodium bicarbonate over a 30-year period. The product would be produced by in situ solution mining of nahcolite. The proposal involves a phased approach to development, with initial production of 30,000 tons per year increasing by the third year of operation to 50,000 tons per year. The proposed project would include a well field for in situ solution mining; a handling and processing plant; evaporation ponds; and associated transportation, access and support facilities.

The solution mining process, shown in Figure 1 on the next page, would involve pumping a hot barren liquor through surface pipelines to the well head and into the nahcolite bearing formation. A solution cavity would form and the saturated liquor would be returned to the processing plant where the liquid would be removed, the sodium bicarbonate dried, processed, and placed into 50 pound bags for shipment. Well depth would be between 2,000 and 2,800 feet. Cavity size may be from 100 to 125 feet in diameter and up to 500 feet in depth. Pillars with diameters of approximately 50 feet would separate the solution cavities. As many as 6 to 10 wells would be in operation at any one time. The anticipated life of a production well would be 5 to 7 years.

Evaporation ponds, covering about 10 acres, would be utilized to receive waste streams resulting from the mining operation.

The sodium solution mine is proposed to operate 360 days per year, 24 hours per day, allowing for 5 days
per year of scheduled down time. The proposed operation would employ between 26 and 31 people.

Disturbed areas associated with the well field would be reclaimed and revegetated after cavities are mined out. Selected wells would continue to be used for monitoring groundwater once they are no longer used for production.

Total surface acreage within the boundaries of the plant site and well field would be approximately 97 acres.

Issues and Alternatives

Tentative issues to be addressed in the EIS include:

- The potential impact on surface and groundwater quality and quantity
- The potential impacts on the oil shale resources in the area
- The potential impacts of reducing solution mining buffer zones from 500 feet to 100 feet on contiguous lease boundaries

BLM plans to complete the draft EIS for public review by March 22, 1991. The final EIS will be released to the public on November 1, 1991, with a decision being made on the proposal by December 31, 1991.

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RECENT OIL SHALE PATENTS

"Multi-Stage Wax Hydrocracking," John J. Lipinski, James R. Nye, Milos Soudek - Inventors, Coastal Eagle Point Oil Company, United States Patent Number 4,935,120, June 19, 1990. A process for hydrodewaxing a petroleum or shale oil fraction, e.g., petroleum distillate, over a shape selective zeolite in the presence of hydrogen wherein the dewaxing is conducted in at least two stages, with some reheating of first effluent. Dewaxed feed, and a high octane gasoline byproduct are obtained as products.

"Treatment of Concentrated Industrial Wastewaters Originating from Oil Shale and the Like by Electrolysis Polyurethane Foam Interaction," Joan E. Tiernan - Inventor, United States Department of Energy, United States Patent Number 4,929,359, May 29, 1990. Highly concentrated and toxic petroleum-based and synthetic fuels wastewaters such as oil shale retort water are treated in a unit treatment process by electrolysis in a reactor containing oleophilic, ionized, open-celled polyurethane foams and subjected to mixing and laminar flow conditions at an average detention time of six hours. Both the polyurethane foams and the foam regenerate solution are re-used. The treatment is a cost-effective process for waste-waters which are not treatable, or are not cost-effectively treatable, by conventional process series.

"Method and Apparatus for Shale Gas Recovery," Donald H. Nielson - Inventor, Ramex Syn Fuels International, United States Patent Number 4,928,765, May 29, 1990. A process for the in situ gasification of shale avoids the necessity of initially fracturing the shale bed and includes the placement of a gas-fired heater assembly within a bore hole followed by the application, from above ground, of fuel gas and combustion air, both of which are regulated to maintain an initial start-up temperature of over 1,000 °F and thereafter a constant temperature of below 1,500 °F throughout a reaction zone formed in the surrounding shale bed. Specifically, a production temperature of 1,200 °F has been found most desirable. By maintenance of this temperature, voids created in the reaction zone as kerogen is retorted to evolve natural gas, become black body radiators assisting to insure a sustained, constant high volume extraction of natural gas having a BTU value of over 800 and devoid of any liquids. The apparatus includes the provision of fuel gas and combustion air supply lines leading from above ground to the interior of the heater assembly, together with a product gas line having a gas extraction opening through the side wall of the heater assembly adjacent its top.
STATUS OF OIL SHALE PROJECTS

COMMERCIAL PROJECTS (Underline denotes changes since June 1990)

ACORN PROJECT – Southern Pacific Petroleum NL and Central Pacific Minerals NL (S-10)

In 1985 Southern Pacific Petroleum NL and Central Pacific Minerals NL (SPP/CPM) studied the potential for developing a demonstration retort based upon mining the Kerosene Creek Member of the Stuart oil shale deposit in Queensland, Australia.

This study utilized data from a number of previous studies and evaluated different retorting processes. It showed potential economic advantages for utilizing the Taciuk Process developed by Umatac and AOSTRA (Alberta Oil Sands Technology and Research Authority) of Alberta, Canada. Batch studies were carried out in 1985, followed by engineering design work and estimates later the same year. As a consequence of these promising studies a second phase of batch testing at a larger scale was carried out in 1986. A series of 68 pyrolysis tests were carried out using a small batch unit. A number of these tests achieved oil yields of 105 percent of Modified Fischer Assay.

As a result of the Phase 2 batch tests, SPP updated their cost estimates and reassessed the feasibility of the Taciuk Processor for demonstration plant use. The economics continued to favor this process so the decision was made to proceed with tests in the 100 tonne per day pilot plant in 1987. A sample of 2,000 tonnes of dried Stuart oil shale was prepared in late 1986 early 1987. The pilot plant program was carried out between June and October 1987.

Engineering is underway to firm up the project definition for a semicommercial demonstration plant. The project is referred to as the Acorn Project. During the last quarter of 1987, SPP carried out a short drilling program of 10 holes at the Stuart deposit in order to increase information on the high grade Kerosene Creek member. This is a very high grade seam (134 liters per tonne) with 150 million barrels of reserves. SPP carried out a basic design engineering study in 1988. The current conceptual design is for a plant processing approximately 6,000 tonnes per stream day of as mined feed shale, and producing 4,250 barrels per day of liquid products.

According to SPP, the estimated cost is A$90 million for such a demonstration plant, including services connection and product storage. At current prices for low sulfur fuel oil in Australia, it is likely that operation of the demonstration plant will at least break even and possibly earn as much as 15 percent DCFROI. After a year of operation it is expected that sufficient data and operating experience will have been gathered to scale up the technology to full commercial size (25,000 tonnes per day).

The first commercial module could be in production by the middle of 1994.

Project Cost: For commercial demonstration module A$90 million

CATHEDRAL BLUFFS PROJECT – Cathedral Bluffs Shale Oil Company: Occidental Oil Shale, Inc. (S-20)

Federal Oil Shale Lease Tract C-b, located in Rio Blanco County in the Piceance Creek Basin of northwestern Colorado, is managed by Occidental Oil Shale, Inc., doing business as Cathedral Bluffs Shale Oil Company. A modified detailed development plan for a 57,000 barrels per day modified in situ plant was submitted in March 1977 and subsequently approved in April 1977. The EPA issued a conditional Prevention of Significant Deterioration (PSD) permit in December 1977 which was amended in 1983.

Project reassessment was announced in December 1981 in view of increased construction costs, reduced oil prices, and high interest rates. The project sponsors applied to the United States Synthetic Fuels Corporation (SFC) under the third solicitation in January 1983 and the project was advanced into Phase II negotiations for financial assistance. On July 28, 1983 the SFC announced it had signed a letter of intent to provide up to $2.19 billion in loan and price guarantees to the project. However, Congress abolished the SFC on December 19, 1985 before any assistance could be awarded to the project.

Three headframes—two concrete and one steel—have been erected. Four new structures were completed in 1982: control room, east and west airlocks, and mechanical/electrical rooms. The power substation on-tract became operational in 1982. The ventilation/escape, service, and production shafts were completed in Fall 1983. An interim monitoring program was approved in July 1982 to reflect the reduced level of activity.

Water management in 1984 was achieved via direct discharge from on-tract holding ponds under the NPDES permit. Environmental monitoring has continued since completion of the two-year baseline period (1974-1976).

On April 1, 1987, the Bureau of Land Management, United States Department of the Interior, granted Cathedral Bluffs Shale Oil Company a suspension of operation and production for a minimum of five years. Meanwhile, pumping of the mine inflow water continues in order to keep the shaft from being flooded.

Occidental has proposed a $200 million "proof-of-concept" modified in situ (MIS) demonstration project to be located on the C-b tract. Oxy says that a 1,200 barrel per day facility combining modified in situ with surface retorting would cost $200 million over a 10-year period. The company said in 1989 it would contribute $100 million if the Department of Energy would contribute $70 mil-
COMMERCIAL PROJECTS (Continued)

lion. State and local governments would be expected to come up with the other $30 million through tax incentives, property tax relief, royalty reductions and enterprise zones. Engineering design is expected to start in 1990. Preliminary funding of the engineering studies was approved under the Department of Energy's fiscal year 1990 budget.

Project Cost: $200 million for demonstration

CHATHAM CO-COMBUSTION BOILER – New Brunswick Electric Power Commission (S-30)

Construction on the Chatham circulating bed demonstration project was completed in 1986 with commissioning of the new boiler. A joint venture of Energy, Mines and Resources Canada and the New Brunswick Electric Power Commission, this project consists of a circulating fluidized-bed boiler of Lurgi design that supplies steam to an existing 22-MW turbine generator. High-sulfur coal was co-combusted with carbonate oil shales and also with limestone to compare the power generation and economics of the two co-combustants in the reduction of sulfur emissions. A full capacity performance-guarantee test was carried out in May 1987, on coal, lime and oil shale. Testing with oil shale in 1988 showed shale to be as effective as limestone per unit of calcium contained. However, bulk quantities of oil shale were found to have a lower calcium content than had been expected from early samples. No further oil shale testing is planned until further evaluations are completed.

CLEAR CREEK PROJECT – Chevron Shale Oil Company (70 percent) and Conoco, Inc. (30 percent) (S-40)

Chevron and Conoco successfully completed the operation of their 350 tons per day semi-works plant during 1985. This facility, which was constructed on property adjacent to the Chevron Refinery in Salt Lake City, Utah, was designed to test Chevron Research Company's Staged Turbulent Bed (STB) retort process. Information obtained from the semi-works project will allow Chevron and Conoco to proceed with developing a commercial shale oil operation in the future when economic conditions so dictate.

Chevron is continuing to develop its Colorado River water rights through its participation in a joint venture with two other energy companies.

Project Cost: Semi-Works - Estimated at $130 million

COLONY SHALE OIL PROJECT – Exxon Company USA (S-50)

Proposed 47,000 barrels per day project on Colony Dow West property near Parachute, Colorado. Underground room-and-pillar mining and Tosco II retorting was originally planned. Production would be 66,000 TPD of 35 GPT shale from a 60-foot horizon in the Mahogany zone. Development suspended 10/4/74. Draft EIS covering plant, 196-mile pipeline to Lisbon, Utah, and minor land exchanges released 12/17/75. Final EIS has been issued. EPA issued conditional PSD permit 7/11/79. Land exchange consummated 2/1/80. On August 1, 1980, Exxon acquired ARCO's 60 percent interest in project for up to $400 million. Preferred pipeline destination was changed to Casper, Wyoming, and Final EIS supplement was completed. Work on Battlement Mesa community commenced summer 1980. Colorado Mined Land Reclamation permit was approved October 1980. Site development was initiated. C.F. Braun awarded contract 12/80 for design and construction of Battlement Mesa facilities. DOE granted Tosco $1.1 billion loan guarantee 8/81.

On May 2, 1982, Exxon announced a decision to discontinue funding its 60 percent share of the Colony Shale Oil Project. Tosco responded to the decision by exercising its option to require Exxon to purchase Tosco's 40 percent interest. Exxon has completed an orderly phasedown of the project. Construction of Battlement Mesa has been completed and Exxon has announced its intention to sell the Mesa complex. An Exxon organization remained in the Parachute area for several years to perform activities including reclamation, some construction, security, safety, maintenance, and environmental monitoring. These activities were designed to maintain the capability for further development of the Colony resource when economics become attractive. In December 1989, Exxon closed its Grand Junction project office.

Project Cost: Estimated in excess of $5 - $6 billion

CONDOR PROJECT – Central Pacific Minerals - 50 percent; Southern Pacific Petroleum - 50 percent (S-60)

Southern Pacific Petroleum N.L. and Central Pacific Minerals N.L. (SPP/CPM) announced the completion on June 30, 1984 of the Condor Oil Shale Joint Feasibility Study. SPP/CPM believe that the results of the study support a conclusion that a development of the Condor oil shale deposit would be feasible under the assumptions incorporated in the study.
COMMERCIAL PROJECTS (Continued)

Under an agreement signed in 1981 between SPP/CPM and Japan Australia Oil Shale Corporation (JAOSCO), the Japanese partner funded the Joint Feasibility Study. JAOSCO consists of the Japan National Oil Corporation and 40 major Japanese companies. The 28 month study was conducted by an engineering team staffed equally by the Japanese and Australian participants and supported by independent international contractors and engineers.

From a range of alternatives considered, a project configuration producing 26.7 million barrels per year of sweet shale oil gave the best economic conclusions. The study indicates that such a plant would involve a capital cost of US$2,300 million and an annual average operating cost of US$265 million at full production, before tax and royalty. (All figures are based on mid-1983 dollars.) Such a project was estimated to require 12 years to design and complete construction with first product oil in Year 6, and progressive build-up to full production in three further stages at two-year intervals.

The exploration drilling program determined that the Condor main oil shale seam contains at least 8,100 million barrels of oil in situ, measured at a cut-off grade of 50 liters per ton on a dry basis. The case study project would utilize only 600 million barrels, over a nominal 32 year life. The deposit is amenable to open pit mining by large face shovels, feeding to trucks and in-pit breakers, and then by conveyor to surface stockpiles. Spent shale is returned by conveyor initially to surface dumps, and later back into the pit.

Following a survey of available retorting technologies, several proprietary processes were selected for detailed investigation. Pilot plant trials enabled detailed engineering schemes to be developed for each process. Pilot plant testing of Condor oil shale indicated promising results from the “fines” process owned by Lurgi Gmbh of Frankfurt, West Germany. Their proposal envisages four retort modules, each processing 50,000 tons per day of shale, to give a total capacity of 200,000 tons per day and a sweet shale oil output, after upgrading, of 82,100 barrels per day.

Raw shale oil from the retort requires further treatment to produce a compatible oil refinery feedstock. Two 41,000 barrels per day upgrading plants were incorporated into the project design.

All aspects of infrastructure supporting such a project were studied, including water and power supplies, workforce accommodation, community services and product transportation. A 110 kilometer pipeline to the port of Mackay is favored for transfer of product oil from the plant site to marine tankers. The study indicates that there are no foreseeable infrastructure or environmental issues which would impede development.

Market studies suggest that refiners in both Australia and Japan would place a premium on Condor shale oil of about US$4 per barrel over Arabian Light crude. Average cash operating cost at full production is estimated at US$20 per barrel of which more than US$9 per barrel represents corporation taxes and royalty.

During July 1984 SPP, CPM, and JAOSCO signed an agreement with Japan Oil Shale Engineering Corporation (JOSECO). JOSECO is a separate consortium of thirty-six Japanese companies established with the purpose of studying oil shale and developing oil shale processing technology. Under the agreement, SPP/CPM mined 39,000 tons of oil shale from the Condor deposit, crushed it to produce 20,000 tons and shipped it to Japan in late 1984.

JOSECO commissioned a 250 tonne per day pilot plant in Kyushu in early 1987. The Condor shale sample was processed satisfactorily in the pilot unit.

In 1988 SPP/CPM began studies to assess the feasibility of establishing a semi-commercial demonstration retorting plant at Condor similar to that being designed for the Stuart deposit. Samples of Condor shale were shipped to Canada for testing in the Taciuk process.

Project Cost: $2.3 billion (mid-1983 U.S. dollars)

ESTONIA POWER PLANTS — Union of Soviet Socialist Republics (S-SO)

About 95 percent of USSR's oil shale output comes from Estonia and Leningrad district. Half of the extracted oil shale comes from surface mines, the other half from underground workings. Each of the nine underground mines outputs 3,000 to 17,000 tons per day; each of the surface mines outputs 8,000 to 14,000 tons per day.

Exploitation of kukersite resources was begun by the Estonian government in 1918. In 1980, annual production of oil shale in the USSR reached 42 billion tons of which 36 million tons come from the Baltic region. Recovered energy from oil shale was equivalent to the energy in 43 million barrels of oil. Most extracted oil shale is used for power production rather than oil recovery. In 1989, annual production of oil shale in the Baltic region was as low as 28 million tons. More than 60 percent of Estonia's thermal energy demand is met by the use of oil shale.

Fuel gas production was terminated in 1987. The first of their kind ever put into operation, two oil-shale-fueled power plants have an annual output of 1,600 megawatts each.

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STATUS OF OIL SHALE PROJECTS (Underline denotes changes since June 1990)

COMMERCIAL PROJECTS (Continued)

FUSHUN COMMERCIAL SHALE OIL PLANT — Fushun Petrochemical Corporation, SINOPEC, Fushun, China (S-90)

The oil shale retorting industry in Fushun began in 1928 and has been operating for 60 years. Annual production of shale oil topped 780,000 tons in 1959. In that period, shale oil accounted for 30-50% of total oil production in China.

At Fushun, oil shale overlies a coal bed which is being mined. Because the oil shale must be stripped in order to reach the coal, it is economical to retort the shale even though it is of low grade. Fischer Assay yield is about 55% oil, on average.

Currently, only 40 retorts are operating, each retort processing 200 tons of oil shale per day. Other retorts have been shut down because of site problems not related to the operation of the retorts. Shale oil production is on the order of 100,000 tons per year.

Direct combustion of oil shale fines in an ebullated bed boiler has been tested at Fushun Refinery No. 2.

Shale oil is currently being used only as a boiler fuel, but a new scheme for upgrading Fushun shale oil was recently studied. In the proposed scheme, shale oil is first treated by exhaustive delayed coking to make light fractions which are then treated successively with dilute alkali, and sulfuric acid to recover the acidic and basic non-hydrocarbon components as fine chemicals. The remaining hydrocarbons, containing about 0.4 percent N can then be readily hydrotreated to obtain naphtha, jet fuel and light diesel fuel. This scheme is said to be profitable and can be conveniently coupled into a existing petroleum refinery.

GARY REFINERY — Western Slope Refining Company (S-100)

Western Slope Refining Company owns a refinery in Fruita, Colorado at the southwestern edge of the Piceance Basin. The refinery was constructed in 1957 by the American Gilsonite Company to process gilsonite, a solid hydrocarbon ore that is mined in Northeastern Utah. Gary Energy acquired the refinery in 1973 after American Gilsonite discontinued the refining of gilsonite. The refinery was expanded and upgraded into a modern facility capable of processing a wide variety of raw materials into finished transportation fuels. In the early 1980's modifications were made to the refinery to process shale oil.

Gary Refining had a contract to purchase 8,600 barrels per day of hydrotreated shale oil from the Unocal Parachute Creek facility. A contract was also signed with the Defense Fuel Supply Center to provide 5,025 barrels per day of shale-derived military jet fuel (JP-4) to the Air Force over a four year period.

The processing scheme planned for the shale oil was geared toward maximizing the yield of JP-4. The Air Force requirements were that JP-4 be produced solely from a shale oil feedstock. Therefore, the crude, vacuum, and hydrocracking units would be blocked out, each with a separate operating cycle.

Upgraded shale oil is planned to eventually be delivered to the refinery via a pipeline from the Parachute upgrading facility to the Fruita site.

In early March 1985 Gary Refining Company shut down the refinery and filed for protection from creditors under Chapter 11 of the United States Bankruptcy Code. The United States Bankruptcy Court approved the company's Reorganization Plan in July 1986. Under the Plan, payments to creditors will begin after delivery of shale oil from the Unocal plant. The bankruptcy documents indicated that borrowing to make the modifications to refine shale oil was a major factor in the failure.

In January, 1989 it was announced that the refinery, now known as Western Slope Refining Company, would reopen in March, 1989. Western Slope Refining Company began operation in April, 1989. Toll calcining of petroleum coke, as well as fractionation of crude and atmospheric residuum in the crude and vacuum units is underway. Full refinery operation began in July.

Although there are no guarantees regarding quantity, the firm's contract with Unocal Corporation now is for everything that company's Parachute Creek oil shale plant can produce. Unocal officials believe they can now consistently produce 5,000 barrels of synthetic fuel a day. The processing of Unocal's syncrude will be supplemented with other regional crude oils. Because the contract with the Air Force for jet fuel has expired, it is not known whether the military test effort will be revived.

In January 1990, it was announced that, because of operating losses, most refinery operations would be curtailed.

Project Cost: Not Disclosed

ISRAELI RETORTING DEVELOPMENT - PAMA (Energy Resources Development) Inc. (S-270)

Israeli oil shale development is being coordinated by PAMA (Energy Resources Development) Ltd. PAMA was founded by several major Israeli corporations with the support of the government.

At the time of the collapse of petroleum prices, in 1986, PAMA had completed a detailed design of a demonstration plant for production of oil. The design was based on adaptation of an American process employing a shaft-like reactor. As a result of the change in oil prices, this plan was shelved, and instead PAMA is directing its efforts to the development of a new extraction process.

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COMMERCIAL PROJECTS (Continued)

which is tailored to the specific properties of Israeli oil shale, thus promising certain advantages over existing processes developed elsewhere. The process rests on the use of both fluidized and entrained beds, and the work is carried out in a pilot plant which can process around 100 kg/hr of oil shale. Preliminary results are encouraging.

In 1988 PAMA signed an agreement with Brazil's Petrobras to test Israeli shale in the Petrosex process.

PAMA has completed extensive studies, lasting several years, which show that the production of either oil or power (the latter by direct combustion of the oil shale) is technically feasible. Furthermore, the production of power still appears economically viable, despite the uncertainties regarding the economics of production of oil from shale.

PAMA has already embarked on a program for demonstrating the direct combustion of oil shale for power. A demo plant will be built that is in fact a commercial plant co-producing electricity to the grid, and low pressure steam for process application at a factory adjacent to one of the major oil shale deposits. The oil-shale-fired boiler, to be supplied by Ahlstrom, Finland, is based on a circulating fluid bed technology.

The boiler will deliver 50 tons per hour of steam at high pressure. Low-pressure steam will be sold to process application in a chemical plant, and electricity produced in a back-pressure turbine will be sold to the grid. Commissioning was begun in August 1989 and oil shale firing was begun in October. Process steam sales began in November 1989 and electricity production started in February, 1990.

PAMA and Israel Electric (the sole utility of Israel) have embarked on a project to build a full scale oil shale-fired commercial power plant, which will consist of eight 120-megawatt units. The first unit is scheduled to go into operation in 1996.

Project Cost: $30 million for combustion demo plant

JORDAN OIL SHALE PROJECT – Natural Resources Authority of Jordan (S-110)

Jordan's oil shale deposits are the country's major hydrocarbon resource. Near-surface deposits of Cretaceous oil shale in the Iribid, Karak, and Ma’an districts contain an estimated 44 million barrels of oil equivalent.

In 1986, a cooperative project with Romania was initiated to investigate the development of a direct-combustion oil-shale-fired power plant. Jordan is also investigating jointly with China the applicability of a Fushun-type plant to process 200 tons per day of oil shale. A test shipment of 1,200 tons of Jordanian shale was sent to China for retort testing. Large-scale combustion tests have been carried out at Kloeckner in West Germany and in New Brunswick, Canada.

A consortium of Lurgi and Kloeckner completed in 1988 a study concerning a 50,000 barrel per day shale oil plant operating on El Lajjun oil shale. Pilot plant retorting tests were performed in Lurgi's LR pilot plant in Frankfurt, Germany.

The final results show a required sales revenue of $19.10 per barrel in order to generate an internal rate of return on total investment of 10 percent. The mean value of the petroleum products ex El Lajjun complex was calculated to be $21.40 per barrel. A world oil price of $15.60 per barrel has to be reached to meet an internal rate of return on total investment of 10 percent.

In 1988, the N.R.A. announced that it was postponing for 5 years the consideration of any commercial oil shale project.

KIVITER PROCESS - Union of Soviet Socialist Republics (S-120)

The majority of Baltic oil shale (kukersite) found in Estonia and the Leningrad district in the Soviet Union is used for power generation. However, over 4 million tons are retorted to produce shale oil and gas. The Kiviter process, continuous operating vertical retorts with crosscurrent flow of heat carrier gas and traditionally referred to as generators, is predominately used in commercial operation. The retorts have been automated, and have throughput rates of 200 to 220 tons of shale per day. Retorting is performed in a single retorting (semi-coking) chamber. In the generators, low temperature carbonization of kukersite yields 75 to 80 percent of Fischer assay oil. The yield of low calorific gas (3,350 to 4,200 KJ/cubic meters) is 450 to 500 cubic meters per ton of shale.

To meet the needs of re-equipment of the oil shale processing industry, a new generator was developed. The first 1,000 ton-per-day generator of this type was constructed at Kohila-Jarve, Estonian SSR, USSR, and placed in operation in 1981. The new retort employs the concept of crosscurrent flow of heat carrier gas through the fuel bed, with additional heat added to the semi-coking chamber. A portion of the heat carrier is prepared by burning recycle gas. Raw shale is fed through a charging device into two semi-coking chambers arranged in the upper part of the retort. The use of two parallel chambers provides a larger retorting zone without increasing the thickness of the bed. Additional heating or gasification occurs in the mid-part of the retort by introducing hot gases or an oxidizing agent through side combustion chambers equipped with gas burners and recycle gas inlets to control the temperature. Near the bottom of the retort is a cooling zone where the spent shale is cooled by recycle gas and removed from the retort. The outside diameter of the retort is 9 meters.
STATUS OF OIL SHALE PROJECTS (Underline denotes changes since June 1990)

COMMERCIAL PROJECTS (Continued)

The experience of the 1,000 TPD unit was taken into consideration to design two new units. In January, 1987, two new 1,000 TPD retorts were put in operation also at Kohtla-Jarve. Alongside these units, a new battery of four 1,500 TPD retorts, with a new circular chamber design, is planned. Oil yield of 85% of Fischer Assay is expected. Due to tightened regulations for environmental protection, the terms of the new battery commissioning have been shifted to 1994-1995.

Oil from kukersite has a high content of oxygen compounds, mostly phenols. Over 50 shale oil products (predominantly non-fuel) are currently produced. These products are more economically attractive than traditional fuel oil. The low caloric gas produced as by-product in the gas generators has a hydrogen sulfide content of 8 to 10 grams per cubic meters. After desulfurization, it is utilized as a local fuel for the production of thermal and electric power.

Project Cost: Not disclosed

MAOMING COMMERCIAL SHALE OIL PLANT – Maoming Petroleum Industrial Corporation, SINOPEC, Maoming, China (S-130)

Construction of the Maoming petroleum processing center began in 1955. Oil shale is mined by open pit means with power-driven shovels, and electric locomotives and dump-cars. Current mining rates are 3.5 million tons of oil shale per year. Approximately one-half is suitable for retort feed. The Fischer Assay of the oil shale averages 6.5% oil yield.

Two types of retort are used: a cylindrical retort with gasification section, and a rectangular gas combustion retort. Oil shale throughput is 150 and 185 tons per day per retort, respectively. The present facility consists of two batteries containing a total of 48 rectangular gas combustion retorts and two batteries with a total of 64 cylindrical retorts.

Current production at Maoming is approximately 100,000 tons of shale oil per year. Although the crude shale oil was formerly refined, it is now sold directly as fuel oil.

Shale ash is used in making cement and building blocks.

A 50 megawatt power plant burning oil shale fines in 3 fluidized bed boilers is planned.

MOBIL PARACHUTE SHALE OIL PROJECT – Mobil Oil Corporation (S-140)

Mobil is no longer considering development plans for its shale property located on 10,000 acres five miles north of Parachute. The project was planned to have initial production of 10,000 to 25,000 barrels per day with an incremental buildup to 100,000 barrels per day. The United States Bureau of Land Management completed an Environmental Impact Statement preparatory to future permit applications. A Corps of Engineers Section 404 permit application was submitted.

Project Cost: Estimated $8 billion for 100,000 BPD production

MOROCCO OIL SHALE PROJECT – ONAREP (S-150)

During 1975 a drilling and mining survey revealed 13 oil shale deposits in Morocco including three major deposits at Timahdit, Tangier, and Tarfaya from which the name T3 for the Moroccan oil shale retorting process was derived.

In February 1982, the Moroccan Government concluded a $4.5 billion, three phase joint venture contract with Royal Dutch/Shell for the development of the Tarfaya deposit including a $4.0 billion, 70,000 barrels per day plant. However, the project faces constraints of lower oil prices and the relatively low grade of oil shale. No significant activity is underway except the resource evaluation and conceptual design studies for a small demo plant.

Construction of a pilot plant at Timahdit was completed with a funding from the World Bank in 1984. During the first quarter of 1985, the plant went through a successful shakedown test, followed by a preliminary single retorting test. The preliminary test produced over 25 barrels of shale oil and proved the fundamental process feasibility of the T3 process. More than a dozen single retort tests were conducted to prove the process feasibility as well as to optimize the process conditions. The pilot plant utilizes the T3 process developed jointly by Science Applications, Inc., and the Office National de Recherche et d'Exploitation Petrolières (ONAREP) of Morocco. The T3 process consists of a semi-continuous dual retorting system in which heat from one vessel that is being cooled provides a portion of the energy that is required to retort the shale in the second vessel. The pilot plant has a 100 tons of raw shale per day capacity using 17 GPT shales. The design of a demonstration plant, which will have an initial output of 280 barrels per day, rising to 7,800 barrels per day when full scale commercial production begins, has been deferred. A commercial scale mine development study at Timahdit was conducted by Morrison-Knudsen.
STATUS OF OIL SHALE PROJECTS (Underline denotes changes since June 1990)

COMMERCIAL PROJECTS (Continued)

The T-3 process will be used in conjunction with other continuous processes in Morocco. In 1981/1982, Science Applications, Inc., conducted for ONAREP extensive process option studies based on all major processes available in the United States and abroad and made a recommendation in several categories based on the results from the economic analysis. An oil-shale laboratory including a laboratory scale retort, computer process model and computer process control, has been established in Rabat with assistance from Science Applications, Inc.

Project Cost: Not disclosed

PARACHUTE CREEK SHALE OIL PROGRAM – UNOCAL Corporation (S-160)

In 1920 Unocal began acquiring oil shale properties in the Parachute Creek area of Garfield County, Colorado. The 49,000 acres of oil shale lands Unocal owns contain over three billion barrels of recoverable oil in the high-yield Mahogany Zone alone. Since the early 1940s, Unocal research scientists and engineers have conducted a wide variety of laboratory and field studies for developing feasible methods of producing usable oils from shale. In the 1940s, Unocal operated a small 50 ton per day pilot retort at its Los Angeles, California refinery. From 1955 to 1958, Unocal built and operated an upflow retort at the Parachute site, processing up to 1,200 tons of ore per day and producing up to 800 barrels of shale oil per day.

Unocal began the permitting process for its Phase I 10,000 barrel per day project in March 1978. All federal, state, and local permits were received by early 1981. Necessary road work began in the Fall 1980. Construction of a 12,500 ton per day mine began in January 1981, and construction of the retort started in late 1981. Concurrently, work proceeded on a 10,000 barrels per day upgrading facility, which would convert the raw shale oil to a high quality syncrude.

Construction concluded and the operations group assumed control of the project in the Fall 1983. After several years of test operations and resulting modifications, Unocal began shipping upgraded syncrude on December 23, 1986.

In July 1981, the company was awarded a contract under a United States Department of Energy (DOE) program designed to encourage commercial shale oil production in the United States. The price will be the market price or a contract floor price. If the market price is below the DOE contract floor price, indexed for inflation, Unocal will receive a payment from DOE to equal the difference. The total amount of DOE price supports Unocal could receive is $400 million. Unocal began billing the U. S. Treasury Department in January, 1987 under its Phase I support contract.

In a 1985 amendment to the DOE Phase I contract, Unocal agreed to explore using fluidized bed combustion (FBC) technology at its shale plant. In June 1987, Unocal informed the U.S. Treasury Department that it would not proceed with the FBC technology. A key reason for the decision, the company said, was the unexpectedly high cost of the FBC facility. Preliminary cost and engineering studies showed that costs would exceed $352 million compared to an original estimate of about $260 million.

As of March 1990, Unocal had shipped over 3,000,000 barrels of syncrude from its Parachute Creek Project. Unocal announced the shale project booked its first profitable quarter for the first calendar quarter of 1990. Positive cash flow had been achieved previously for select monthly periods; however, this quarter's profit is the first sustained period of profitability. Recent cost cutting efforts have lowered the breakeven point on operating costs approximately 20 percent. The future of the project depends on the ability to maintain this production level.

In August 1989, a new crusher system was installed which produces a smaller and more uniform particle size to the retort. Also, retort operations were modified and the retorting temperature increased. As a result, average production in November and December reached approximately 7,000 barrels per day.

Project Cost: Phase I - Approximately $700 million

PETROSIX – Petrobras (Petroleio Brasileiro, S.A.) (S-170)

A 6 foot inside diameter retort, called the demonstration plant, has been in continuous operation since 1984. The plant is used for optimization of the Petrosix technology. Oil shales from other mines can be processed in this plant to obtain data for the basic design of new commercial plants.

A Petrosix pilot plant, having an 8 inch inside diameter retort, has been in operation since 1982. The plant is used for oil shale characterization and retorting tests, developing data for economic evaluation of new commercial plants.

An entrained bed pilot plant has been in operation since 1980. It is used to develop a process for the oil shale fines. The plant uses a 6 inch inside diameter pipe (reactor) externally heated.

A spouted bed pilot plant having a 12-inch diameter reactor, has been in operation since January, 1988. It processes oil shale fines coarser than that used in the entrained bed reactor.
COMMERCIAL PROJECTS (Continued)

A circulating fluidized bed pilot scale boiler was started up in July, 1988. The combustor will be tested on both spent shale and oil shale fines to produce process steam for the Petrosix commercial plants.

A nominal 2,200 tons per day Petrosix semi-works retort, 18 foot inside diameter, is located near Sao Mateus do Sul, Parana, Brazil. The plant has been operated successfully near design capacity in a series of tests since 1972. A United States patent has been obtained on the process. This plant operating on a small commercial basis since 1981, currently produces 850 barrels per day of crude oil, 40 tons per day of fuel gas, and 18 tons per day of sulfur. The operating factor since 1981 until present has been 93 percent.

As of December 31, 1989, the plant records were as follows:

<table>
<thead>
<tr>
<th>Operation</th>
<th>Hours</th>
<th>Tons</th>
<th>Tons</th>
<th>Tons</th>
</tr>
</thead>
<tbody>
<tr>
<td>Operations time, hrs</td>
<td>112,000</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Oil Produced, Bbl</td>
<td>2,800,000</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Processed Oil Shale, tons</td>
<td></td>
<td>7,200,000</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Sulfur Produced, tons</td>
<td></td>
<td>463,000</td>
<td></td>
<td></td>
</tr>
<tr>
<td>High BTU Gas, tons</td>
<td></td>
<td>101,000</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

A 36-foot inside diameter retort, called the industrial module, is being constructed and at the end of 1989 was 85 percent complete. Total investment when complete will be US$104 million. When the plant becomes operational in 1992, the annual operating cost is estimated to be US$39 million. With the sale of gas to a local consumer and anticipated revenue from products, the rate of return on the overall project is estimated to be about 13 percent. The completion date is now indefinite.

When the 36-foot (11-meter) diameter commercial plant commences operations, the daily production of the two plants will be:

<table>
<thead>
<tr>
<th>Product</th>
<th>Shale Oil</th>
<th>Processed Shale</th>
<th>LPG</th>
<th>High BTU Gas</th>
<th>Sulfur</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>3,870 Bbl</td>
<td>7,800 tons</td>
<td>39  tons</td>
<td>132 tons</td>
<td>98 tons</td>
</tr>
</tbody>
</table>

Some 35 hectares of the mined area has been rehabilitated since 1977. The schedule for 1989 and 1990 is to rehabilitate 65 hectares. Rehabilitation comprises reforestation, revegetation with local plants and reintegration of wild local animals, bringing back the local conditions for farming and recreational purposes.

Current shale oil production is sent by truck to a refinery 150 kilometers from the plant and is stabilized through the FCC unit in a mixture with heavy gasoil.

Sulfur production is sold directly to clients from local paper mill industries.

Project Installed Costs: $68.4 (US) Million (industrial module)

RAMEX OIL SHALE GASIFICATION PROCESS—Ramex Synfuels International, Inc. and Greenway Corporation (S-180)

On May 6, 1985 Ramex began construction of a pilot plant near Rock Springs, Wyoming. The pilot plant consisted of two specially designed burners to burn continuously in an underground oil shale bed at a depth of 70 feet. These burners produce an industry quality gas (greater than 800 BTUs per standard cubic foot).

In November 1986, Ramex announced that Greenway Corporation had become the controlling shareholder in the company.

On November 24, 1987, Ramex announced the completion of the pilot project. The formation was heated to approximately 1200 degrees creating a high-BTU gas with little or no liquid condensate. The wells sustained 75 mcf a day, for a period of 3 months then were shut down to evaluate the heaters and the metals used in the manufacturing of the heaters. The test results indicated a 5 year life in a 10 foot section of the shale with a product gas of 800 BTU or higher per standard cubic foot.

Ramex announced in November 1987 the start of a commercial production program in the devonian shale in the eastern states of Kentucky and Tennessee. In April 1988, Ramex announced the project would be moved to Indiana. A total of 7 wells have now been drilled. Gas tests resulted in ratings of 1,034 and 968 BTU. Two production volume tests showed 14,000 and 24,000 cubic feet per day.

In late July, 1988 a letter agreement was signed between Tri-Gas Technology, Inc., the licensee of the Ramex process in Indiana, and J. M. Slaughter Oil Company of Ft. Worth, Texas to provide funding for drilling a minimum of 20 gas wells, using the Ramex oil shale gasification process, on the leases near Henryville, Indiana.
COMMERCIAL PROJECTS (Continued)

Arrangements were made with Midwest Natural Gas to hook up the Ramex gas production to the Midwest Pipeline near Henryville. As of May, 1989 Ramex had been unsuccessful in sustaining long-term burns. They therefore redesigned the burner and built a much larger model (600,000 BTU per hour vs 40,000 BTU per hour) for installation at the Henryville site. A new burner with improved metallurgy was planned to be installed in November, 1989.

In November, 1989 Ramex completed its field test of the Devonian Shales in Indiana. The test showed a gas analysis of 47% hydrogen, 30% methane and little or no sulfur. Ramex contracted with a major research firm to complete the design and material selection of its commercial burners and also to develop flow measurement equipment for the project. Ramex received a patent on its process on May 29, 1990.

Raines is currently reviewing sites throughout the western and eastern United States to determine the location of the next test facility. Ramex is also investigating potential applications in Israel.

Project Cost: Approximately $1 million for the pilot tests.

RIO BLANCO OIL SHALE PROJECT – Rio Blanco Oil Shale Company (wholly owned by Amoco Corporation) (S-190)


First retort was 30' x 30' x 166' high and produced 1,907 barrels of shale oil. It burned between October and late December 1980.

Second retort was 60' x 60' x 400' high and produced 24,790 barrels while burning from June through most December of 1981.

Program cost $132 million. Company still prefers open pit mining-surface retorting development because of much greater resource recovery of five versus two billion barrels over life of project. Cannot develop tract efficiently in that manner without additional federal land for disposal purposes and siting of processing facilities. In August 1982, the company temporarily suspended operations on its federal tract after receiving a 1 year lease suspension from the United States Department of Interior. In August 1987, the suspension was renewed.

Federal legislation was enacted to allow procurement of off-tract land that is necessary if the lease is to be developed by surface mining. An application for this land was submitted to the Department of Interior in 1983. Based on the decision of the director of the Colorado Bureau of Land Management an environmental impact statement for the proposed lease for 84 Mesa has been prepared by the Bureau of Land Management. However, a Record of Decision has never been issued due to a suit filed by the National Wildlife Federation.

Rio Blanco submitted a MIS retort abandonment plan to the Department of Interior in Fall 1983. Partial approval for the abandonment plan was received in Spring 1984. The mine and retort are currently flooded but were pumped out in May 1985 and June 1986 in accordance with plans approved by the Department of the Interior. Data from the pumpout are being evaluated. Stringent monitoring is continuing.

Rio Blanco operated a $29 million one to five TPD Lurgi pilot plant at Gulf’s Research Center in Harmarville, Pennsylvania until late 1984 when it was shut down. This $29 million represents the capital and estimated operating cost for up to 5 years of operation. The company has not as yet developed commercial plans or cost estimates. On January 31, 1986 Amoco acquired Chevron’s 50 percent interest in the Rio Blanco Oil Shale Company, thus giving Amoco a 100 percent interest in the project. Amoco has no plans to discontinue operations.

Project Cost: Four-year process development program cost $132 million
No cost estimate available for commercial facility.

RUNDLE PROJECT – Central Pacific Minerals/Southern Pacific Petroleum (50 percent) and Esso Exploration and Production Australia (50 percent) (S-200)

The Rundle Oil Shale deposit is located near Gladstone in Queensland, Australia. In April 1981, construction of a multi-module commercial scale facility was shelved due to economic and technical uncertainties.

Under a new agreement between the venturers, which became effective in February 1982, Esso agreed to spend A$30 million on an initial 3 year work program that would resolve technical difficulties to allow a more precise evaluation of the economics of development. During the work program the Dravo, Lurgi, Tosco, and Exxon retorting processes were studied and tested. Geological and environmental baseline studies were carried out to characterize resource and environmental parameters. Mine planning and materials handling methods were studied for selected plant capacities. Results of the study were announced in September 1984. The first stage of the project which would produce 5.2 million barrels per year from 25,000 tons per day of shale feed was estimated to cost $645 million (US). The total project (27 million barrels per year from 125,000 tons per day of shale feed) was estimated to cost $2.65 billion (US).

In October 1984 SPP/CPM and Esso announced discussions about amendments to the Rundle Joint Venture Agreement signed in 1982. Those discussions were completed by March 1985. Revisions to the Joint Venture Agreement now provide for:

Payment by Esso to SPP/CPM of A$30 million in 1985 and A$12.5 in 1987.

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COMMERCIAL PROJECTS (Continued)

Each partner to have a 50 percent interest in the project.

Continuation of a Work Program to progress development of the resource.

Esso funding all work program expenditures for a maximum of 10 years, and possible funding of SPF/CPM's share of subsequent development expenditures. If Esso provides disproportionate funding, it would be entitled to additional offtake to cover that funding.

Project Cost: See above

TRANS NATAL T-PROJECT — Trans Natal, Gencor, Republic of South Africa (S-220)

Current developments in oil shale conversion by Gencor, one of the larger South African mining companies, have proved to be very promising and a feasibility study was completed in 1987. A technical study involving retorting test samples of oil shale mixed with coal has been carried out. It was found that by recycling the heavy oil fraction, it is possible to successfully retort a 50:50 mix of torbanite and coal.

The project will consist of an underground mine with mining height of 1 to 2.3 meters. The material to be mined is a mixture of torbanite and bituminous coal. The deposit would be capable of supporting an output of 14,000 barrels of syncrude per day. Retorting will be accomplished with Lurgi L.R retorts. The torbanite yields 250 liters of oil per metric ton, and the coal yields 100 liters per ton.

The investigation phase of the Torbanite Project (T-Project) was completed at the end of June 1989 and was submitted for approval to the South African government in September 1989. This project has now for financial reasons been indefinitely postponed.

Project Cost: $1.0 billion

UTT - 3000 RETORTING PROCESS — Union of Soviet Socialist Republics (S-230)

The UTT-3000 process, otherwise known as the Galoter retort, is a rotary kiln type retort which can accept oil shale fines. Processing of the Baltic shales in UTT-3000 retorts makes it possible to build units of large scale, to process shale particle sizes of 22 millimeters and less including shale dust, to produce liquid fuels for large thermal electric power stations, to improve operating conditions at the shale burning electric power stations, to increase (thermal) efficiency up to 86-87 percent, to improve sulfur removal from shale fuel, to produce sulfur and other sulfur containing products (such as thiophene) by utilizing hydrogen sulfide of the semicoke gas, and to extract valuable phenols from the shale oil water. Overall the air pollution (compared to direct oil shale combustion) decreases.

The two UTT-3000 units built at the Estonian GRES with a productivity of 3,000 tons per day are among the largest in the world and unique in their technological principles. However, as of late 1988, these units had still not reached full design capacity.

A redesign of particular parts and reconstruction of the units was done in 1984 to improve the process of production and to increase the period of continuous operation.

As a result of these changes, the functioning of the UTT-3000 improved dramatically in 1984 in comparison with the period of 1980-1983. For instance, the total amount of shale processed in the period 1980-1983 was almost the same as for only 1984, i.e. 79,100 tons versus 80,100 in 1984. The total shale oil production for the period 1980-83 was 10,500 tons and approximately the same amount was produced only in 1984. The average output of shale oil per run increased from 27 tons in 1980 to 970 tons in 1984. The output of electric energy for Estonia-Energo continued constant in 1983 and 1984, by burning part of the shale oil in the boilers of Estonia GRES.

By the end of 1984, 159,200 tons of shale was processed and 20,000 tons of shale oil was produced at UTT-3000.

In 1985, the third test of the reconstructed boiler TP-101 was carried out by using the shale oil produced at the UTT-3000. The improvement of the working characteristics of UTT-3000 has continued.

Recently, the LO VGNIPII (the name of the Research Institute) has designed for Estonia an electric power station that would use shale oil and produce 2,600 megawatts. A comparison of its technical-economical characteristics with the corresponding ones of the 2,500 megawatts power station with direct burning of raw shales was made. It was found that the station on shale oil would be more economical than the station with direct burning of shale.
STATUS OF OIL SHALE PROJECTS (Underline denotes changes since June 1990)

COMMERCIAL PROJECTS (Continued)


The Yaamba Oil Shale Deposit occurs in the Yaamba Basin which occupies an area of about 57 square kilometers adjacent to the small township of Yaamba located 30 kilometers (19 miles) north-northwest of the city of Rockhampton, Australia.

Oil shale was discovered in the Yaamba Basin in 1978 during the early stages of a regional search for oil shale in buried Tertiary basins northwest of Rockhampton. Exploration since that time has outlined a shale oil resource estimated at more than 4.8 billion barrels in situ extending over an area of 32 square kilometers within the basin.

The oil shales which have a combined aggregate thickness of over 300 meters in places occur in 12 main seams extending through the lower half of a Tertiary sequence which is up to 800 meters thick toward the center of the basin. The oil shales subcrop along the southern and southwestern margins of the basin and dip gently basinward. Several seams of lignite occur in the upper part of the Tertiary sequence above the main oil shale sequences. The Tertiary sediments are covered by approximately 40 meters of unconsolidated sands, gravels, and clays.

In December, 1988 Shell Australia purchased a part interest in the project. The Yaamba Joint Venture now comprises Peabody Australia Pty. Ltd., with 41.66% percent interest, Shell Company Australia with 41.66% interest, Beloba Pty. Ltd. with 10%, Central Pacific Minerals N.L. with 3.3% and Southern Pacific Petroleum N.L. with 3.3%. Beloba Pty. Ltd. is owned 50% each by SPP and CPM. Peabody Australia manages the Joint Venture which holds two "Authorities to Prospect" for oil shale in an area of approximately 1,080 square kilometers in the Yaamba and Broad Sound regions northwest of Rockhampton. The "Authorities to Prospect" were granted to the Yaamba Joint Venture by the government of the State of Queensland. In addition to the Yaamba Deposit, the "Authorities to Prospect" cover a second prospective oil shale deposit in the Herbert Creek Basin approximately 70 kilometers northwest of Yaamba. Drilling in the Herbert Creek Basin is still in the exploratory stage. Further exploratory drilling of the Herbert Creek Basin is also continuing.

A Phase I feasibility study, which focused on mining, waste disposal, water management, infrastructure planning, and preliminary ore characterization of the Yaamba oil shale resource, has now been completed. Environmental baseline investigations were carried out concurrently with this study. Further investigations aimed at determining methods for maximum utilization of the total energy resource of the Yaamba Basin and optimization of all other aspects of the mining operation, and collection of additional data on the existing environment are continuing.

During 1988, activities in the field included the extraction of samples for small scale testing and the drilling of four holes for further resource delineation.

This project has been temporarily suspended due to continuing low oil prices.

Project Cost: Not disclosed

R&D PROJECTS

JULIA CREEK PROJECT - Placer Exploration Limited (S-290)

A preliminary study was conducted in 1980 to determine feasibility of a large scale extraction of oil from the Julia Creek deposit of northwestern Queensland, Australia. The project concept involves surface mining, above-ground retorting, and on-site upgrading to produce either a premium refinery feedstock or marketable fuels, particularly kerosene and diesel.

The project developer was CSR Ltd, but as a result of purchasing CSR's mineral interests within Australia, Placer Pacific Ltd. is now owner of the project.

The project has proven reserves of shale amenable to open-cut mining containing about 2 billion barrels of crude shale oil. The average oil content of the shale is approximately 70 litres per dry tonne.

Work carried out jointly by CSR and CSIRO on the development of a new retorting process based on spent shale ash as a recirculating solid heat carrier has been concluded and patents for retorting and hydrotreating processes have been obtained.

No development is planned.
R & D PROJECTS (Continued)

LLNL HOT RECYCLED-SOLIDS (HRS) RETORT – Lawrence Livermore National Laboratory, U. S. Department of Energy (S-300)

Lawrence Livermore National Laboratory (LLNL) has, for over the last five years, been studying hot-solid recycle retorting in the laboratory and in a one-tonne-per-day pilot facility and have developed the LLNL Hot Recycled-Solids Retort (HRS) Retort (CBR) process as a generic second generation oil shale retorting system. Much progress has been made in understanding the basic chemistry and physics of retorting processes and LLNL believes they are ready to proceed to answer important questions to scale the process to commercial sizes. Field pilot plant tests at 100 and 1,000 tonnes per day are planned at a mine site in western Colorado. Pending DOE approval, a joint government/industry sponsored test at 100 tonnes per day could begin as early as October 1991.

In this process, raw shale is rapidly heated in a gravity bed pyrolyzer to produce oil vapor and gas. Residual carbon (char), which remains on the spent shale after oil extraction, is burned in a fluid bed combustor, providing heat for the entire process. The heat is transferred from the combustion process to the retorting process by recycling the hot solid, which is mixed with the raw shale as it enters the pyrolyzer. The combined raw and burned shale (at a temperature near 500 degrees C) pass through a moving, packed-bed retort containing vents for quick removal and condensation of product vapors, minimizing losses caused by cracking (chemical breakdown to less valuable species). Leaving the retort, the solid is pneumatically lifted to the top of a cascading-bed burner, where the char is burned during impeded-gravity fall, which raises the temperature to nearly 650 degrees C. Below the cascading-bed burner is a final fluid bed burner, where a portion of the solid is discharged to a shale cooler for final disposal.

In 1990, LLNL upgraded the facility to process 4 tonnes-per-day of raw shale, working with the full particle size (0.25 inch). Key components of the process will be studied at this scale by adding a delayed-fall combustor and fluid-bed mixer and replacing the rotary feeders with air-actuated valves, suitable for scaleup. LLNL plans to continue to operate the facility and continue conceptual design of the 100 tonne per day pilot-scale test facility.

NEW PARAHOO ASPHALT FROM SHALE OIL PROJECT—New Paraho Corporation (S-310)

New Paraho Corporation is a wholly owned subsidiary of Energy Resources Technology Land, Inc. New Paraho Corporation plans to develop a commercial process for making shale-oil-modified road asphalt. Researchers at Western Research Institute (WRI) and elsewhere have discovered that certain types of chemical compounds present in shale oil cause a significant reduction in moisture damage and a potential reduction in binder embrittlement when added to asphalt. This is particularly true for shale oil produced by direct-heated retorting processes, such as Paraho.

In order to develop this potential market for shale oil modified asphalts, New Paraho has created an initial plan which is to result in (1) proven market performance of shale oil modified asphalt under actual climatic and road use conditions and (2) completion of a comprehensive commercial feasibility study and business plan as the basis for securing subsequent financing for a Colorado-based commercial production facility.

The cost of carrying out this initial, market development phase of the commercial development plan is approximately $2.5 million, all of which will be funded by Paraho. The major portion of the work to be conducted during this initial phase consists of producing sufficient quantities of shale oil to accommodate the construction and evaluation of several test strips of shale oil-modified asphalt pavement. Mining of 3,900 tonnes of shale for these strips occurred in September 1987. The shale oil was produced in Paraho’s pilot plant facilities, located near Rifle, Colorado in August, 1988. The retort was operated at mass velocities of 418 to 538 pounds per hour per square foot on 23 to 35 gallon per ton shale and achieved an average oil yield of 965 percent of Fischer Assay. In 1988, New Paraho installed a vacuum still at the pilot plant site to produce shale oil asphalt from crude shale oil.

Six test strips were constructed in 1989 in Colorado, Utah and Wyoming. The test strips will now be evaluated over a period of several years, during which time Paraho will complete site selection, engineering and cost estimates, and financing plans for a commercial production facility.

The size of the commercial production facility is currently envisioned as a plant capable of producing 3,000 to 5,000 barrels per day of shale oil. At this level of production, the plant would serve approximately 70 percent of the Colorado, Utah and Wyoming markets for asphalt paving.

Based upon current engineering estimates, the initial commercial facility will cost $200 - $250 million to design, engineer and construct. If the project is able to obtain financing and to maintain its proposed schedule, construction of the commercial plant would commence in the 1991-1992 time frame.

At the present time, Paraho states that it has access to two different resource sites upon which the commercial production facility could be located: a site on the Mahogany Block in northwest Colorado; and the Paraho-Ute properties, located near Vernal, Utah. Of these options, the Mahogany site represents the most economically viable alternative and, accordingly, is the preliminary location of choice.

Approximately 1,500 acres of the Mahogany Block are still controlled by the Tell Ertl Family Trust and are available to New Paraho although the largest part of the original block was sold to Shell Oil Company. New Paraho also maintains control of approximately 3,400 acres of oil shale leases on state lands in Utah.

SYNTHETIC FUELS REPORT, SEPTEMBER 1990
STATUS OF OIL SHALE PROJECTS (Underline denotes changes since June 1990)

R & D PROJECTS (Continued)

Project Cost: $2,500,000. The company spent $100,000 in 1987, $1,100,000 in 1988 and $778,000 in 1989 on shale oil asphalt research.

YUGOSLAVIA INCLINED MODIFIED IN SITU RETORT – United Nations (S-330)

Oil shale deposits in Yugoslavia are mainly located in the eastern part of the country, almost entirely in the Republic of Serbia. The best geologically evaluated oil shale deposit is located near the town of Aleksinac, in the lower Juzna Moravica River valley. Oil shale dips from the surface at an angle of 30 to 40 degrees up to a depth of 600 meters where it then levels, although the oil shale seams are not planar.

An experimental 3.5 tons per day gas combustion retort was built and tested in 1955 to 1962. In addition, retorting in an indirect retort was carried out in Sweden on 100 tons of Aleksinac oil shale in 1957. A joint effort by several UN consultants from the United States and Yugoslavia national staff produced the Inclined Modified In Situ (IMIS) Method to cope with the dipping oil shale seams characteristics of the Aleksinac Basin. To achieve the appropriate void formation 23 percent of the shale rock would be mined. Design criteria for the IMIS retort include an oil shale yield of 115 liters per ton, and a retort height of 100 meters. The retort injection mixture would be 50 percent air and 50 percent steam. As a future development, eight modules of IMIS retorts would be in operation at a time, producing 15,700 barrels per day of oil.

Surface retorts would produce 4,470 barrels per day of oil, making the total capacity at Aleksinac 20,000 barrels per day at full production (about 1 million tons per year). For the mined shale, interest has been expressed in adapting the T3 retort system under development in Morocco. The overall resource recovery rate would be about 49 percent.

Construction time for a 20,000 barrels per day facility is estimated to be 11 years. The estimated project cost was about $650 million (US). The estimated shale oil net production cost was $21.00 (US) per barrel and the upgrading cost was estimated to be $7.00 (US) per barrel.

In the mined brown coal area, the coal mine workings can provide access to the oil shale for an initial pilot module. Go-ahead for a full-scale 20,000 barrels per day operation would be given only after the results of the pilot module are known. The pilot module has been designed by Energoprojekt, Belgrade, with UNDP support. Establishment of the IMIS experiment had been expected in 1988 but is now postponed to at least 1992.

The project is currently considered to be suspended.

Project Cost: US$12,000,000
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## STATUS OF OIL SHALE PROJECTS

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PROJECT ACTIVITIES

SITE WORK COMPLETED AT BI-PROVINCIAL UPGRADE

Major site preparation work for the Bi-Provincial Upgrader project near Wilton, Saskatchewan, Canada was completed by early summer. The project site was completely laid out, graded with paved strips in place, and several major underground services in by the first of June.

Most of the construction will be done with discrete lump sum contracts. Of an expected 150 to 200 contracts, 138 had been awarded by late May.

Husky is providing support to the construction contractors and licensors. Husky will handle commissioning and start-up.

Employment during construction will climb rapidly to a peak of 2,800 in March 1991 and taper off abruptly in 1992 towards June 1992 start-up. Figure 1 shows the overall project schedule. The permanent staff will number about 300.

The Bi-Provincial Upgrader involves the construction and operation of a 46,000 barrel per day heavy oil upgrader near Lloydminster. The total project cost is estimated to be $1.267 billion. Figure 2, on the next page, shows how the project will be integrated with the existing refinery nearby.

Three governments and Husky Oil will be joint owners of the Bi-Provincial Upgrader. Each will invest its ownership share of total project costs: Canada 31.67 percent; Alberta 24.17 percent; Saskatchewan 17.50 percent; and Husky Oil 26.67 percent.

The Bi-Provincial Upgrader, will convert the abundant supplies of heavy oil and bitumen crude from the Lloydminster/Cold Lake areas into high quality synthetic crude oil, which can then be processed into transportation fuels and petrochemical feedstocks.

FIGURE 1

SUMMARY SCHEDULE FOR UPGRADE

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ADJACENT

DETAILED DESIGN

CONSTRUCTION

COMMISSIONING

Startup and Commissioning

SYNTHETIC FUELS REPORT, SEPTEMBER 1990
FIGURE 2
PROCESS SCHEMATIC OF BI-PROVINCIAL UPGRADER AND EXISTING REFINERY

Alberta Energy Minister R. Orman has announced the Alberta government will provide nearly $47 million to complete the engineering phase of the OSLO (Other Six Leases Operation) oil sands project near Fort McMurray, Alberta, Canada.

Alberta’s contribution will represent 36 percent of the estimated $130 million total cost for the engineering phase. The Canadian federal government will contribute up to $45.5 million, 35 percent of the total, for the engineering phase. The OSLO consortium partners—Esso Resources, Canadian Occidental Petroleum, Gulf Canada Resources, PanCanadian Petroleum, Petro-Canada, and Alberta Oil Sands Equity—will fund the remainder. The Alberta government has already spent $10.5 million on the OSLO project to date.

In making the announcement, Orman noted that the commitment of funds shows the Alberta government’s confidence in the future of OSLO. "Completion of the engineering design phase has been extended by 6 months because of the federal government’s February 20, 1990 announcement that it was withdrawing funding for the construction and operating phases of the project. The Alberta government continues to work hard with the OSLO partners to ensure the project is completed,” he said.

The engineering phase is scheduled to be completed by the end of 1991. Engineering work has recently focused on an Edmonton-area upgrader to be linked directly to OSLO’s Fort McMurray bitumen production.

The OSLO project, first announced in September 1988, is an oil sands project expected to begin producing 80,000 barrels a day of high-quality synthetic crude oil in 1997. The estimated cost of the project is $4 billion.
of the integrated complex and the results from the first year of operation. Smith presented this review in a paper entitled "The Co-op Upgrader," which was submitted to the Canadian Society for Chemical Engineering Symposium in Calgary, Alberta earlier this year.

Consumer's Co-operative Refinery, prior to adding the upgrader, was a conventional light oil refinery with a capacity of 50,000 barrels per day. Its principle feedstock was Interprovincial Sweet Mixed Blend crude oil with a gravity of 37 API and sulfur content of 0.5 weight percent.

The purpose of the Upgrader Project was to convert this refinery into a facility that could process 50,000 barrels per day of Saskatchewan medium and heavy crude oil with a gravity of 22 API and sulfur content of up to 4.5 weight percent. To accomplish this, four new processing units were added to the complex and significant revamping of many of the existing refinery units also took place.

The four units added were a fixed bed residual oil hydrotreater (ARDS), a distillate hydrotreater/hydrocracker (DHU), a hydrogen generation unit, and sulfur recovery facilities. These units are fully integrated into the refinery processing scheme as shown in Figure 1. The refinery processing units and their capacities before and after the project are shown in Table 1 on the next page.

A phased start-up was conducted with the hydrogen plant coming onstream in mid-October of 1988 followed by the DHU and ARDS in late November and the sulfur plant in early December. The initial start-up went very well although mechanical problems associated primarily with insufficient winterization prevented the complex from reaching a high onstream factor.

**Hydrogen Plant**

Problems were experienced with the control valves of the PSA (Pressure Swing Adsorption) unit used to purify the hydrogen gas. Winterization proved to be inadequate and at temperatures below -20°C, the operation of the valves became so sluggish that the computer control system could not adequately compensate and the unit kept shutting down. Also significantly impacted by cold weather were the hydrogen make-up compressors. These reciprocating
TABLE 1

UNIT CAPACITIES

<table>
<thead>
<tr>
<th>Unit</th>
<th>Original</th>
<th>Revamped or New</th>
</tr>
</thead>
<tbody>
<tr>
<td>Crude Unit</td>
<td>50 MBPSD</td>
<td>50 MBPSD</td>
</tr>
<tr>
<td></td>
<td>(38 API)</td>
<td>(22 API)</td>
</tr>
<tr>
<td>Vacuum Unit</td>
<td>20 MBPSD</td>
<td>25.4 MBPSD</td>
</tr>
<tr>
<td>Delayed Coker</td>
<td>7 MBPSD</td>
<td>9.3 MBPSD</td>
</tr>
<tr>
<td>FCCU</td>
<td>19.5 MBPSD</td>
<td>19.5 MBPSD</td>
</tr>
<tr>
<td>Cat. Poly</td>
<td>4.4 MBPSD</td>
<td>5.7 MBPSD</td>
</tr>
<tr>
<td>Hvy Nap Unifiner</td>
<td>14 MBPSD</td>
<td>14 MBPSD</td>
</tr>
<tr>
<td></td>
<td>(300 ppm S,</td>
<td>(1500 ppm S,</td>
</tr>
<tr>
<td></td>
<td>10 ppm N)</td>
<td>135 ppm N)</td>
</tr>
<tr>
<td>Platformer</td>
<td>14 MBPSD</td>
<td>14 MBPSD</td>
</tr>
<tr>
<td></td>
<td>(72 N+2A,</td>
<td>(60 N+2A,</td>
</tr>
<tr>
<td></td>
<td>96 RON)</td>
<td>98.5 RON)</td>
</tr>
<tr>
<td>ARDS</td>
<td>-</td>
<td>30 MBPSD</td>
</tr>
<tr>
<td>DHU</td>
<td>-</td>
<td>12 MBPSD</td>
</tr>
<tr>
<td>Hydrogen Production</td>
<td>-</td>
<td>65 MMSCFD</td>
</tr>
<tr>
<td>Sulfur Recovery</td>
<td>14 LTPSD</td>
<td>270 LTPSD</td>
</tr>
</tbody>
</table>

On June 26, 1989, a tube ruptured in the feed preheat furnace resulting in an explosion and fire which destroyed the heater and shut the unit down for 6 months.

Distillate Hydroprocessor (DHU)

This unit has operated smoothly from its initial start-up in November 1988 to the present. It has met or exceeded its original design requirements for cetane improvement and has proven capable of producing a diesel product that will exceed the latest Environmental Protection Agency requirements for both sulfur and aromatics.

Sulfur Recovery Section

The environmental control section of the complex consists of a sour water stripper, a DGA regenerator, two three-stage (stripper) Claus sulfur plants and a Sulfreen tail gas treating unit.

The sour water stripper and DGA regenerator have run well since December 1988.

The Sulfreen unit has only been on stream for 48 hours during the past year as there has been insufficient tail gas available to operate it.

Since start-up in December 1988, both sulfur plants have had serious mechanical problems. Operating for long periods of time with only one plant on-line at severely turned down rates (sometimes as low as 10 percent of the original design) has led to serious plugging and corrosion in the condensers and run-down system, and overheating and tube leakage in the fired reheaters. When the plants have operated at or near design rates, they have performed well.

Revamps

Almost every unit in the existing refinery was revamped to some extent to handle the processing of heavy crude oil. Most have been successful.

However, removal of nitrogen from the naphtha streams going to the catalytic reformer is vital if the required octanes are to be met. To date, the recommended catalysts for nitrogen removal, particularly from naphthas, have not performed to expectations, says Smith.

The production of Alcan anode grade coke from heavily hydrotreated residual oils is also a challenge. The refinery has not yet mastered the technique of continuously producing an on-specification coke.

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SYNTHETIC FUELS REPORT, SEPTEMBER 1990

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RECORD HORIZONTAL WELL DRILLED AT HEAVY OIL PROJECT

CS Resources Ltd. of Montreal, Quebec, Canada has recently set a record for the horizontal interval of a well, according to The Roughneck. CS Resources drilled 1,047 meters horizontally at Pelican Lake last December and January. The company's vice president of engineering, P. Coffin, said, "We are probably the only oil company in the world that has not drilled a single vertical well."

In the past 2 years, the company reportedly drilled 18 horizontal wells, 13 of which are at the Pelican Lake experimental heavy oil recovery project in northeast Alberta. Eight wells are in operation and producing 14 degree oil, the other 5 are being completed for production. The oil is transported by truck to the nearest pipeline terminal, 110 kilometers away.

According to Coffin, the wells at Pelican Lake demonstrated that production increased in relationship to the amount of reservoir accessed by the wellbore. On the fifth well of last winter's five-well expansion, CS Resources set out to see how far they could drill horizontally. Coffin said they were not trying to set a record. "We just drilled to our economic limit."

Using an experienced drilling team, the company began drilling the horizontal well at a build rate of 6 degrees per 30 meters at 118 meters. At a true vertical depth of 415 meters, the hole was at 90 degrees. The end of the angle build took place at a drilled depth of 572 meters.

The team continued drilling horizontally for 1,047 meters, leaving the well with a total 1,332 meters horizontal displacement. According to Coffin, the team used a conventional long radius drilling assembly in reaching the record-setting distance.

KEARL LAKE PROJECT PASSED ONE MILLION BARREL PRODUCTION MARK

In 1979 CDC Oil & Gas Limited (now Canterra Energy Ltd., a subsidiary of Husky Oil Ltd.) and Tenneco Oil began pilot operations aimed at developing an in situ bitumen recovery process on Oil Sands Lease T87 in the Kearl Lake area of the Athabasca deposit. The location of this pilot is shown in Figure 1 on the next page.

According to D.H. Burger, some 188 test holes had been drilled through 1989 to evaluate the lease. In the northern half of the lease the overburden is thin enough to permit surface mining. In the southern half of the lease, in situ recovery will be required. The total bitumen in place has been estimated to be 10.7 billion barrels, divided almost equally between the mining and the in situ areas.

The Kearl Lake pilot was developed with the following objectives in mind:

- Evaluate the use of horizontal hydraulic fractures to develop injector to producer communication
- Optimize steam injection rates
- Maximize bitumen recovery
- Assess the areal and vertical distribution of heat in the reservoir
- Evaluate the performance of wellbore and surface equipment
- Determine key performance parameters such as bitumen production rates (CDOR), steam-oil
Construction of the pilot began in the first quarter of 1980, and start-up of the first pattern began on December 12, 1981. In February 1983, the Alberta Oil Sands Technology and Research Authority (AOSTRA) joined the project team.

The original layout included three different types of wells grouped into an "A" pattern and a "B" pattern.

The "A" pattern was a 5.37 acre inverted seven-spot pattern with peripheral steam injection. The purpose of the peripheral injection was to isolate the pattern from the surrounding reservoir. The "B" pattern, as originally drilled, was a 2.69 acre inverted five-spot pattern surrounded by eight steam injection wells.

As a result of "A" pattern experience, it was decided not to inject steam into the peripheral wells at the "B" pattern. The pattern was also converted from a five-spot to a nine-spot, in order to better capture condensed steam and mobilized bitumen, and in order to recover the bitumen in the pattern in less time.

"A" pattern steam injection was shut-in in September 1986 in order to save fuel costs. Despite the lack of steam injection, production from three "A" pattern wells has continued.

In 1988 a high rate steam injection test was conducted on the "B" patterns. In 1989 Esso Resources Canada Limited purchased Tenneco's interest in the lease and the pilot, a confidential test to control steam outflow from the "B" patterns was initiated, and the 1-millionth barrel of bitumen was produced on November 23, 1989. This production is far higher than has been achieved by any other in situ pilot in the Athabasca bitumen deposit.

Technological Advances

Bitumen Production and Steam-Oil Ratios. The trends of average steam injection rates and bitumen production rates for the "A" pattern are shown in Figure 2 on the next page. During the balanced injection period, the injection rates into all injection wells (including the peripheral wells) were about the same. As can be seen by Figure 2, the highest production rates were achieved during this period. Communication had also been well established to all production wells by that time. Reservoir pressures in the steam zone were also much higher than at other times. However, the instantaneous steam-oil ratios were also high.

Interwell Communication. Very little bitumen production occurred in this pilot until good, hot interwell communication had been established. The Kearl Lake pilot demonstrated that effective interwell communication could be established over distances of at least 300 feet.

Considerable improvements in the time and energy required to establish this communication were achieved with each successive start-up at the pilot.

Effect of High Steam Injection Rates. In late 1987, it was noted that the bitumen production rates of individual "B" pattern wells were not as high as those achieved in "A" pattern wells. It was also noted that the reservoir steam zone temperature was lower in the "B" pattern than it had been in the "A" pattern. Therefore, a test was devised in which an attempt was made to increase the "B" pattern steam zone pressure by increasing steam injection rates at the central injection wells.

The results of this test are shown in Figure 3 on the next page. The reservoir pressure did not increase as much as was expected because a large portion of the injected steam was migrating outside the pattern. Yet in spite of the smaller than expected increase in the reservoir pressure, the increase in the bitumen production rates (40 percent on
FIGURE 2
'A' PATTERN RATE PERFORMANCE

SOURCE: BURGER & KISMAN

FIGURE 3
'B' PATTERN HIGH RATE STEAM INJECTION TEST

SOURCE: BURGER & KISMAN
Long term plans are to operate a prototype commercial project before proceeding to a commercial operation. However, these plans are on hold pending the required improvement in world oil prices.

Future Objectives

Although this pilot has been successful, Husky says much work still needs to be done before the process technology will be sufficiently developed to begin a commercial project.
CORPORATIONS

UTAH PILOT PLANT PROPOSED

Buenaventura Resource Corporation owns the exclusive license to use a patented process to economically extract oil from tar sands in the United States and Canada. The "cold" process was invented by Park Guymon of Weber State University.

The two step process uses no heat in extracting heavy oil from tar sands. Asphalt can be made from the oil, or it can be refined for use as a motor oil. The company is currently assessing the market for these products.

According to the company's president, T. Bachtel, the process will be developed in three phases. The first phase is a small pilot plant to be installed at or near Weber State University. The plant is being built in Texas and will be shipped to Utah this fall for installation. The project's second phase will be a larger pilot plant and the third phase will be a commercial-scale plant.

Buenaventura has been working on developing the new process in Uintah County, Utah since 1986. Funding for the project is being sought from the State of Utah and the United States Department of Energy.

SYNCRUDE PLANT INTERESTS FOR SALE

Shares amounting to nearly 55 percent of the Syncrude oil sands plant have been offered for sale. Those offering to sell their interests in Syncrude Canada Ltd. are: Petro-Canada with 17 percent ownership, the Alberta Government with 16.7 percent, Gulf Canada with 9 percent, Canadian Occidental Petroleum with 7.2 percent, and Amoco Canada/Encor with 5 percent ownership.

The 12-year old Syncrude plant, located near Fort McMurray, completed a C$1.2 billion expansion a year ago, and is reportedly producing 165,000 barrels of synthetic crude oil per day, about 10 percent of Canada's daily production.

Crude prices this spring made Syncrude's operations profitable with costs running at about C$15 per barrel. Energy analysts have predicted a fall in world oil prices, but recent developments in the Middle East may change the situation considerably.

Alberta Energy Company owns a 10 percent interest in Syncrude and company officials have expressed confidence in the plant's potential for significant profits. Esso Resources, with a 25 percent interest, has no intention of selling either.

Esso officials have even indicated a possible willingness to increase their share in Syncrude.

Petro-Canada Inc. has also offered for sale 10 major western Canadian oil and gas property packages, including its interests in Bigoray, Boundary Lake, Connorsville, Crossfield, House Mountain, Nipisi Gilwood, Paddle Prairie, Snipe Lake, Swan Hills and Virginia Hills.

Amoco Canada Petroleum Company Ltd. through the acquisition of Dome Petroleum Limited in 1988, has a net 3.75 percent interest in Syncrude and manages another 1.25 percent, owned by Encor Energy Corporation Inc.

"We have been saying since the merger that our Syncrude interest was up for sale if the price was right," said J. Davis, Amoco Canada's vice president of planning and development. The company has formalized the process by officially putting its share of Syncrude on the market.

GULF SEES CONTINUING MAJOR ROLE FOR OIL SANDS

In its annual report, Gulf Canada Resources Limited says that oil sands production will continue to play a major role. At Syncrude, despite coker shutdowns for maintenance and a year-end fire in 1989, Gulf's 9 percent share of gross sales averaged 13,400 barrels per day, about the same as 1988. However, says the report, improved coker performance is expected to result in reduced shutdown costs and supply interruptions, and will also provide for increased volumes.

Discoveries such as Eaglesham and Salt Creek and extensions to known accumulations at Sylvan Lake and Enchant added nearly 6 million barrels to gross proved reserves plus probable liquids reserves in 1989.

Overall, however, gross proved reserves of liquids declined 3 percent to 374 million barrels, as decreases in both conventional crude oil and Syncrude reserves more than offset an increase in natural gas liquids (NGL) reserves.

Gulf has a 20 percent interest in the proposed OSLO oil sands mining project. Canada's government announced in February 1990 that it will not proceed with its offer of financial assistance for the construction and operating phases of the project, although it will provide its share of funding for the engineering phase. Basic planning and engineering work for OSLO continues, and financing and development alternatives are under review.
According to the report, Gulf is reviewing its western Canada assets with the intention of buying, selling or trading interests. The goal is larger interests in significant properties and a reduction in the overall property count, to improve operating efficiency and performance.

In 1989 Gulf purchased interests in 26 properties and sold interests in 57 properties. The most notable acquisition was an additional 24 percent interest in the Nordegg gas unit and gas plant, which Gulf now operates, increasing the company's total interest to 37 percent.

Outlook

In 1990, more than half of Gulf's planned capital and exploration expenditures will be targeted for western Canada, but the total for that area will be about 15 percent less than the $224 million spent in 1989.

The company expects its overall gross sales of western Canada liquids to increase slightly in 1990. Conventional crude oil production should remain stable, sales of NGLs should increase and synthetic crude oil production is expected to increase to around 15,000 barrels per day.

SUNCOR OIL SANDS REPORTS LOSS IN SECOND QUARTER

Suncor's Oil Sands Group has reported a loss of $20 million for the second quarter of 1990. The Group reported earnings of $14 million for the same period last year.

According to Suncor, the main reason for the decrease was a maintenance shutdown resulting in lower production. Operations were shut down for nearly 6 weeks, after which only partial production was resumed for 2 weeks. Full production began again in mid-July.

Earnings for the first 6 months of this year were $1 million, compared to earnings of $16 million for the first half of 1989. Higher crude prices in the first quarter offset the second quarter loss incurred by the maintenance shutdown.

###
GOVERNMENT

ERCB REVIEWS 1989 OIL SANDS PICTURE

In *Energy Alberta* 1989 the Energy Resources Conservation Board (ERCB) says that oil sands and heavy oil activity in 1989 can be characterized by two interrelated activities: technological and environmental problem-solving. "Advances in science now hold the promise of more efficient and environmentally sound oil sands developments."

Team Approach to Issues

Preparatory work began on the proposed $4 billion OSLO project during 1989. Although OSLO does not plan to file a formal application with the ERCB until the fall of 1990, the ERCB initiated the Application Review Team (ART) approach to processing and evaluating the OSLO oil sands project.

The OSLO ART team is addressing such matters as basic resource information, both surface and subsurface, technological aspects related to efficient resource recovery and plant operation, the environmental impact assessment process, emission concerns, fish and wildlife impacts and an analysis of jobs, business opportunities and infrastructure requirements in nearby communities.

ERCB says this approach was first used in 1986 for Syncrude's mine and plant expansion, and again in 1988 for the Suncor Debottlenecking Project.

According to the report, a review of Suncor's debottlenecking considered all aspects of the proposal including resource conservation, regional and local environmental controls and socioeconomic impacts. One element of this project was Suncor's Naphtha Recovery Unit, which in 1989 began recovering hydrocarbon liquids and scavenging volatile gases escaping from the tailings—a major source of odor complaints in the area.

Odor Complaints Investigated

Hydrocarbon odors continue to be a major concern in Fort McMurray and Fort McKay, says the report. Both Suncor and Syncrude have ongoing programs to investigate odor sources and mitigate off-site impacts. The ERCB and Alberta Environment want to correlate each complaint to specific plant operations and eliminate its cause.

A Regional Air Quality Coordinating Committee, established in 1988, has developed an enhanced odor investigation procedure. The hiring of a manager and two additional staff is expected to significantly improve odor tracking in 1990.

Technological Developments Continue

With the goal of lowering mining and extraction costs and reducing environmental impacts, OSLO continues to assess its program of experimental dredging and cold water recovery of bitumen at a site north of Fort McMurray.

Developing an extraction process which significantly reduces the tailings and sludge—byproducts of the current hot water extraction processes used—would reduce water requirements, lowering the costs of impounding the tailings and thus lowering the costs of their ultimate reclamation. Also, the large area typically covered by tailings ponds may sterilize substantial oil sands reserves located below the ponds for many years.

The ERCB approved an OSLO pilot project in northeast Calgary to test a modified hot water extraction method to clarify tailings, reduce sludge accumulation, and ultimately yield a substance that does not require large structures to impound tailings. OSLO is also using this test facility to develop the engineering design specifications for the particular oil sands ore it will be using in its commercial plant.

In Situ Developments

During 1989, the board approved four new applications for experimental horizontal drilling in the Wabasca and Cold Lake areas. According to the report, such wells hold the promise of increased recovery from oil sands reservoirs.

Esso Resources received approval to test a new coal combustion technology at its Cold Lake in situ operations. Esso originally applied to use coal to generate steam for its development at Cold Lake, but subsequently applied to use natural gas when the project was downsized. The board approved the use of gas, with a proviso that Esso continue its investigations into the use of coal, which it now can do.

In a joint venture with TransAlta Utilities, Esso and Shell will receive federal, provincial and industry funding of $7.5 million. According to ERCB, the pilot project will be the first full-scale test of an efficient coal-burning furnace designed to raise the large volumes of steam required.

This pilot project has the potential to improve the economics of in situ oil sands facilities, and will address environmental issues associated with coal mining and transportation.

In response to concerns that water availability is being affected by oil sands projects, the ERCB and Alberta Environment jointly released "Guidelines for Water Use in In Situ Oil Sands Facilities in Alberta" in May 1989. The goal of the new guidelines is to reduce fresh water requirements and waste water disposal volumes.
The Cold Lake Air Quality Task Force published the results of a local emission survey during 1989. Results indicated that in situ oil sands operations have minimal impacts on air quality, but recommended an annual review of regional air quality and suggested the relocation of static monitoring stations. These recommendations now are being implemented.

**Oil Sands Drilling Fluctuates**

Full development of Esso Cold Lake, BP Wolf Lake and other schemes have been held back because of uncertainty in oil prices and markets.

While in 1989 there was reduced drilling within large, developed oil sands schemes, drilling in the mineable areas continued, primarily by OSLO, to evaluate the extent of reserves and the thickness of pay zones within its lease.

Although 1989 can be characterized as a very slow year for oil sands drilling, says ERCB, the opportunities for increased drilling in the future appear promising.

###
NEAR-TERM OUTLOOK FOR CANADIAN HEAVY OIL
NOT PROMISING

Canadian and American oil markets are unstable in the face of increasing demand and declining domestic production. The future role of heavy crudes and bitumens in meeting the world's energy requirements is bright, however the present is bleak, says G.H. Lenz in a paper presented at the Canadian Society for Chemical Engineering Symposium held in Calgary, Alberta, Canada. His paper, "Marketing of Heavy Oil, Synthetic Crude, and Derived Products," examines the impact of key industry parameters upon the market for heavy oil.

Canadian heavy oils have been marketed primarily within the interior of Canada and the United States. Sixty percent of the heavy oil produced in Canada is sold in the American Midwest. The next largest markets are the Canadian prairie provinces and Ontario. Plentiful supplies of light crude in the past permitted Canadian refiners to avoid investments in conversion facilities.

Crude Supply and Demand

The supply of domestic crude oil in both Canada and the United States is declining and the proportion of heavy crude in the total is increasing. With the early 1990 pricing environment, it is likely that the trend to ever greater reliance on foreign crude sources will continue over the next decade, according to Lenz. This trend is depicted in Figure 1. The crude pricing structure within North America will be significantly altered as a result of these shifts in the supply and demand balance.

Crude Supply, Logistics and Pricing

As domestic light crude production declines, local refiners will come to rely on imported light crude. They will then be facing higher light crude costs primarily as a result of increased transportation costs.

The North American crude oil market has enjoyed stable logistics, with surplus crude in the interior being pipelined to

FIGURE 1
CRUDE SUPPLY AND DEMAND
FOR CANADA AND UNITED STATES

SOURCE: LENZ
the more populous coastal regions. At the coast domestic light crude is priced to compete with imported crudes. This means that light crude in the interior is priced at a discount to the prices commanded at the United States Gulf Coast (USGC). Domestic crude from the continental interior is priced at USGC prices minus the transportation differential to distribution centers.

The growing shortfall of domestic crude is, however, shifting the pricing mechanism away from the USGC into the interior. For instance, when the Chicago area finds itself short of domestic crude it begins to import foreign crude, which is priced at the USGC price plus transportation. Refiners must pay world price plus transportation for foreign crude or bid higher prices for domestic crude. According to Lenz, this will result in domestic prices rapidly escalating to USGC plus transportation. Producers benefit as the higher prices flow back to the wellhead.

The shift towards the new pricing structure is underway, says Lenz, but it will be several years before the new situation becomes common throughout the year. In the meantime, the pricing structure will vary seasonally with product demand.

Heavy crude and bitumen blends, competing for market share against foreign heavy crudes in Chicago, are already priced on a Chicago parity basis. However, in the shift to Chicago parity pricing of light crudes, the light to heavy crude differential will widen by the increase in the light crude price. This will encourage Canadian investment in conversion and/or upgrading facilities.

Light to Heavy Crude Differentials and Conversion Investment

The pricing spread between light and heavy crudes is fundamental to the refining market for heavy oils, says Lenz. The discount applied to heavy oils is a function of the crude supply situation, processing cost and the value of the products obtainable. Historically it has taken a spread of over US$4.50 per barrel to spur conversion investment.

Hurdles to refinery investment include the need for massive capital investment in environmental projects, and existing surplus capacity in the downstream sector. Billions of dollars will be required to minimize the adverse environmental impacts of petroleum product production and use. The current profitability of the downstream sector cannot support simultaneous demands to reduce emissions while increasing the proportion of heavier feeds, says Lenz.

Investment in facilities to upgrade bitumen and heavy crude to synthetic crude quality is another means to increase the market for heavy oils. However, this form of investment requires a much larger light to heavy differential; typically a spread of US$8.00 per barrel is required.

Investments such as the Husky and Co-op upgraders will increase the Canadian market for heavy crudes and bitumen blends. Both of these projects will produce synthetic crudes, and will create markets for heavy oil production. The Co-op upgrader is actually a hybrid, producing both products and synthetic crude from their heavy crude charge.

Investment Climate

As shown in Figure 2 on the next page, Lenz expects light to heavy crude differentials to increase through the 1990s, limited by conversion economics. The forecast spread is not sufficient to encourage the construction of stand alone upgraders, he says, but will support refinery conversion investments.

Canadian refiners planning an expansion of a refinery should consider a heavy oil processing option, says Lenz. The incremental costs of these facilities is likely to be more than compensated for by lower acquisition costs for feedstock and the greater security inherent in using domestic supplies.

Countries such as Venezuela and Saudi Arabia have recognized the benefits of close ties to the downstream. Their downstream integration efforts have helped in securing demand for their heavy crude. This trend has already begun to impact the market for Canadian heavy crude. Canadian refiners and producers must realize they are operating within the world market for both crude and products.

Residual Product Demand

According to Lenz, growth in refined product demands is expected to continue at a modest pace. Current government forecasts anticipate annual growth rates of 0.8 to 2.0 percent per annum to the year 2000.

The major residual product of heavy oil is asphalt, for which demands are expected to rise at 2 percent per year over the next decade. However, the seasonal nature of the demand for asphalt will continue to cause problems for producers.

Another residual product is heavy fuel oil (HFO). The high sulfur fuel oil from heavy oils is increasingly difficult to market and current prices from HFO will not support investment in desulfurization facilities. In addition, growing public concern for the greenhouse effect is likely to result in punitive legislation against this fuel.

Synthetic Crude Markets

Synthetic crude is a valuable light crude extender for many refiners. It is not a substitute, as conventional refineries can typically only tolerate 10 to 15 percent synthetic crude in the feed before product quality begins to suffer. However, a gradual rise in the quality of synthetic crude is expected to increase the acceptable proportion of synthetic crude in total feed for conventional refiners.

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Canadian refiners west of Quebec can process 225,000 barrels per day of synthetic crude. By 1995, a total of 315,000 barrels per day of synthetic crude is expected to be available. According to Lenz, there should be no difficulty in marketing this quantity in Canada and the United States.
ECONOMICS

ECONOMIC ANALYSIS SHOWS PROMISE FOR ENERGY-INTEGRATED PROCESS

The University of Utah's Department of Chemical Engineering has carried out a thermodynamic second-law efficiency analysis for three different process configurations involving two-stage fluidized bed pyrolysis of tar sands. A capital and operating cost estimate was then developed for the most efficient design. This work was described at the last Oil Shale and Tar Sands Contractors Review Meeting held at the Department of Energy's Morgantown Energy Technology Center.

In the first stage of the selected process, tar sand particles are pyrolyzed at 475°C and near-ambient pressure, in an atmosphere of recycle gas, to produce oil vapors and coke, which remains on the sand particles. In the second stage, the coke is burned with air at 575°C and near-ambient pressure to produce combustion gas and clean sand. Most of the heat of combustion is transferred rapidly from the second to the first stage by heat pipes. The design incorporates very efficient heat exchanger networks with the result that the process is energy self-sufficient. The second-law analysis indicated that the process is considerably more efficient than a conventional hot-sand recyle process.

Lost work calculations were made for the three alternative generic thermal processes shown in Figure 1. All three schemes utilize separate fluidized beds for the pyrolysis and combustion reactions. In the first case, heat of combustion is transferred to the pyrolysis bed by recycle pyrolysis gas used to fluidize that bed. In Case 2, recycle hot sand carries heat of combustion to the pyrolysis bed. In Case 3, heat of combustion is transferred directly by heat pipes to the pyrolysis bed. In all three cases, three sets of external heat exchangers are used to recover energy from hot pyrolysis gases, hot sand, and hot flue gases.

For making comparisons of the three alternatives, two situations were considered. The first was the energy self-sufficient condition at the minimum bitumen content. The results are given in Table 1 on the next page. Case 1 has the highest specific energy recovery, but must operate with a relatively high tar-sand bitumen content of 11 percent, and a rela

![Figure 1: Three Schemes for Transferring Heat from the Combustion Zone to the Pyrolysis Zone](synthetic-fuels-report-september-1990.jpg)

(a) Recycle of Hot Pyrolysis Gas (b) Recycle of Hot Sand (c) Use of Heat Pipes

SYNTHETIC FUELS REPORT, SEPTEMBER 1990

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TABLE 1

LOST WORK ANALYSIS AT MINIMUM ENERGY
SELF-SUFFICIENCY CONDITION

<table>
<thead>
<tr>
<th>Energy Transfer Mode</th>
<th>Pyrolysis Gas Recycle</th>
<th>Hot Sand Recycle</th>
<th>Use of Heat Pipes</th>
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<tbody>
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<td>Bitumen Weight Fraction (Minimum Value)</td>
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<td>0.085</td>
<td>0.085</td>
</tr>
<tr>
<td>Combustion Temperature (K)</td>
<td>810</td>
<td>750</td>
<td>785</td>
</tr>
<tr>
<td>Hot Sand Recycle Ratio</td>
<td>0</td>
<td>18</td>
<td>0</td>
</tr>
<tr>
<td>Fluidizing Gas/Tar Sand Ratio</td>
<td>2</td>
<td>0.35</td>
<td>0.05</td>
</tr>
<tr>
<td>Energy Recovered From Hot Sand (kJ/kg Tar Sand)</td>
<td>373</td>
<td>317</td>
<td>352</td>
</tr>
<tr>
<td>Total Lost Work (kJ/kg Tar Sand)</td>
<td>739</td>
<td>539</td>
<td>423</td>
</tr>
<tr>
<td>Thermodynamic Efficiency, %</td>
<td>5.5</td>
<td>10.8</td>
<td>30.0</td>
</tr>
</tbody>
</table>

A second comparison, summarized in Table 2, was based on maximum thermodynamic efficiency. This condition of minimum lost work was achieved for Cases 1 and 2 by increasing combustion-bed operating temperature at the expense of minimum bitumen content, and for Case 3 by decreasing combustion temperature at the expense of increased heat transfer area of the heat pipes. Again, the minimum lost work was achieved by Case 3. This case also operated with the lowest bitumen content (7.3 percent). Because Case 3 was found to have the highest second-law efficiency and could be operated with the minimum bitumen content, it was selected for a preliminary process design and economic evaluation.

Process Designs

Preliminary process designs were developed for Case 3 at production levels of 15,000 and 50,000 barrels per day of synthetic crude oil. At the lower level, the weight percent bitumen in the tar sand was taken as 12, while 10 was taken

TABLE 2

LOST WORK ANALYSIS AT MAXIMUM THERMODYNAMIC EFFICIENCY

<table>
<thead>
<tr>
<th>Energy Transfer Mode</th>
<th>Pyrolysis Gas Recycle</th>
<th>Hot Sand Recycle</th>
<th>Use of Heat Pipes</th>
</tr>
</thead>
<tbody>
<tr>
<td>Bitumen Weight Fraction (Minimum Value)</td>
<td>0.12</td>
<td>0.09</td>
<td>0.073</td>
</tr>
<tr>
<td>Combustion Temperature (K)</td>
<td>942</td>
<td>817</td>
<td>723</td>
</tr>
<tr>
<td>Hot Sand Recycle Ratio</td>
<td>0</td>
<td>5.0</td>
<td>0</td>
</tr>
<tr>
<td>Fluidizing Gas/Tar Sand Ratio</td>
<td>0.70</td>
<td>0.10</td>
<td>0.05</td>
</tr>
<tr>
<td>Energy Recovered From Hot Sand (kJ/kg Tar Sand)</td>
<td>520</td>
<td>388</td>
<td>291</td>
</tr>
<tr>
<td>Total Lost Work (kJ/kg Tar Sand)</td>
<td>670</td>
<td>469</td>
<td>372</td>
</tr>
</tbody>
</table>

SYNTHETIC FUELS REPORT, SEPTEMBER 1990
at the higher level. The tar sand was assumed to be from a Utah deposit with zero water content. Considerable effort was spent in developing an efficient heat exchanger network. With the pyrolysis reactor operating at 475°C, and the combustion reactor operating at 575°C, it was necessary to integrate the following tasks:

- Cool pyrolysis gases from 475 to 380°C
- Cool flue gas from 575 to 140°C
- Cool spent sand from 575 to 140°C
- Heat tar sand from 25 to 475°C
- Heat air from 25 to 400°C
- Heat recycle gas from 38 to 475°C

A network for accomplishing these tasks with an integrated, thermally balanced, high-efficiency heat exchange system was developed.

**Economic Evaluation**

Equipment sizes and estimated costs were calculated for production levels of 15,000 and 50,000 barrels per day. Estimated total capital investments were $137,460,000 and $462,780,000 for the two production levels.

**TABLE 3**

<table>
<thead>
<tr>
<th>Item</th>
<th>15,000 Bbl/Day</th>
<th>50,000 Bbl/Day</th>
</tr>
</thead>
<tbody>
<tr>
<td>1. Mined Tar Sand at $5/Ton, 330 Days/Year</td>
<td>$49,121</td>
<td>$195,660</td>
</tr>
<tr>
<td>2. Variable Operating Costs: Cooling Water, $0.11/1,000 Gal</td>
<td>220</td>
<td>690</td>
</tr>
<tr>
<td></td>
<td>Electricity, $0.065/kWh</td>
<td>-6,702</td>
</tr>
<tr>
<td>3. Fixed Process Costs: Direct Operation Cost (DOL): 6 Men Shift, $19/hr</td>
<td>904</td>
<td>904</td>
</tr>
<tr>
<td></td>
<td>Operating Supervision, 50% DOL</td>
<td>452</td>
</tr>
<tr>
<td></td>
<td>Operating Payroll Burden, 50% DOL</td>
<td>452</td>
</tr>
<tr>
<td></td>
<td>Operating Supplies, 20% DOL</td>
<td>181</td>
</tr>
<tr>
<td></td>
<td>Maintenance, 5% FCI</td>
<td>6,330</td>
</tr>
<tr>
<td></td>
<td>Plant Overhead, 50% DOL</td>
<td>452</td>
</tr>
<tr>
<td></td>
<td>Administrative Cost, 50% DOL</td>
<td>452</td>
</tr>
<tr>
<td></td>
<td>Taxes and Insurance, 4% FCI</td>
<td>5,060</td>
</tr>
<tr>
<td></td>
<td>Depreciation, 10% FCI</td>
<td>12,650</td>
</tr>
</tbody>
</table>

Estimated annual operating costs are summarized in Table 3 for the two production levels. The total annual operating costs of $69,572,000 and $252,851,000 for the 15,000 and 50,000 barrel per day levels are equivalent to $14.05 and $15.32 per barrel of oil, respectively. These values are very sensitive to the assumed cost of mined tar sand, which contributes from $10 to $12 per barrel of oil to the annual operating cost.

The economic evaluation does not consider on-site upgrading of the synthetic crude oil, which might be needed before the oil can be transported and marketed. Light hydrotreating at the site can serve this purpose.

###

**CANADIAN DATA SHOW 65 PERCENT DROP IN OIL SANDS EXPENDITURES IN 1989**

Data released by the Canadian Petroleum Association in August show that investment in oil sands operations in 1989 was essentially restricted to maintenance and repair expenditures. Oil sands capital expenditures dropped 65 percent to $304 million from $864 million in 1988.

Overall the Canadian petroleum industry's upstream sector last year spent a total of $16.2 billion in Canada, 3.3 percent less than in 1988. Operating costs rose 9.3 percent, royalties and taxes increased 4.3 percent while exploration and capital expenditures declined 19.3 percent. Frontier expenditures declined 36 percent to $348 million, the lowest level since 1972.

Operating costs (including general and administration costs) rose 9.3 percent despite ongoing industry efforts to control costs. Because of the decline in oil production, the unit cost increases was even more pronounced. However, the oil sands sector was considerably more effective than conventional operations at holding down operating costs (Table 1, on the following page).

Regionally the industry spent 80 percent or $13 billion of the total in Alberta. Indications as of August were that 1990 exploration and capital expenditures by the upstream sector will be about 10 to 12 percent higher than in 1989.

###

**ECONOMICS OF HEAVY OIL WILL CONTINUE TO BE CHALLENGING**

Heavy oil and bitumen are low-priced hydrocarbons that are difficult to produce and market. Yet they are the most abundant resources in Alberta and Saskatchewan, Canada.
Canadian reserves total nearly 500 billion cubic meters. The importance of this vast deposit becomes clear when considering the distribution of the conventional oil reserves of the world, shown approximately in Figure 1 on the next page.

A paper presented at the Seventh Heavy Oil and Oil Sands Technical Symposium by S.M. Farouq Ali, of the University of Alberta, says that in the long run, Canada is in an excellent position to develop a sizeable proportion of its heavy oil resources profitably. His paper, entitled "How to Make Money Producing Heavy Oil?", examines the problems surrounding heavy oil production and offers partial solutions to increase the profitability of the operations.

Developing a heavy oil reservoir may require a lead time of 15-20 years, says Farouq Ali. As examples, Esso’s successful Cold Lake project took 25 years to develop, and Shell’s Peace River project dates back to 1962 when the Athabasca project was initiated. Not only is a long-term commitment necessary for developing a heavy oil/bitumen resource, but vast investments are needed. And the author warns, "don’t expect to make a profit on pilot operations."

**Primary Production**

Heavy oil primary production is known to be economical in some areas in Alberta and Saskatchewan, with recoveries in the 5 to 10 percent oil-in-place range, the lower number being far more common. With low rates under primary production conditions, some of the ways of increasing profitability are to use large spacings, minimize well workovers, minimize measurements and engineering, and minimize manpower.

It is possible to develop practices unique to a given oilfield, in order to operate profitably. Some examples given by the author are: producing rather than restricting sand with the fluids, selection of the right bottomhole pump, design of cost-effective wells site facilities, and proper treating systems.

**Waterflooding**

Heavy oil waterfloods are notoriously inefficient, he says, not even considering factors such as viscous fingering and reservoir heterogeneities. However, heavy oil waterfloods can be profitable, even though the incremental recovery may be less than 5 percent. The author cited a comparison of the observed and theoretical performance of Lloydminster waterfloods, for oil viscosities in the 950 to 6,500 megapascal second range. The additional oil recovery was 1 to 2 percent of the original oil in place.

**Enhanced Oil Recovery**

For heavy oils, enhanced oil recovery (EOR) means steam injection, says the paper. Nearly 80 percent of the EOR production of heavy and light oils in Canada, the United States, and Venezuela is by some form of steam injection. Figure 2 (on a following page) shows classifications of EOR methods for heavy oil recovery. However, few of these methods have been commercially successful in the field. The reasons for this are related to the mobility ratio and the capillary number. Following is a brief discussion of several EOR methods in the context of Alberta and Saskatchewan heavy oil reservoirs.

**Steam Injection**

Application of heat is the best way of lowering oil viscosity, and steam injection is the most effective way of heating the oil. The trouble is that formation water, the rock matrix, and the adjacent formations use up a large fraction of the injected heat. This becomes prohibitive in thin formations of 10 meters or less. Furthermore, it may not be possible to inject steam at a high enough rate due to very high viscosity, as in the case of bitumen. Above all, geology must be considered. The presence of bottom water may overrule steam injection, depending on bottom water thickness, vertical permeability, and other conditions.
Cyclic Steam Stimulation (CSS)

CSS has been successful in the Pikes Peak, Saskatchewan reservoir. A variation of CSS, where steam injection is carried out under fracture pressures has been developed for Cold Lake, and has been commercially successful in some areas. Beyond these two operations, however, CSS has not been profitable. Steamflooding (combined with CSS) has been highly successful in California, Indonesia (largest steamflood), and other countries. But the heavy oils of Alberta and Saskatchewan often occur under unfavorable reservoir conditions, e.g., thin formations, bottom water, and unfavorable rock-fluid reactions. Steam injection, even when it works, is a low margin, high cost process.

In Situ Combustion

In this process, heat is generated within the reservoir by means of oxidation of about 10 percent of the in-place oil. Heat generation occurs at very high temperatures (around
700°C) over a small area. According to the author, the success of the process depends on whether the in-place cold oil has sufficient mobility to permit the "firefront" to advance. Field experience has shown in situ combustion to be more operable in the case of lighter oils.

Husky experiments with in situ combustion over a 20-year period in Saskatchewan resulted in additional oil being recovered, but the operation was uneconomical. This is true of most firefloods. Over 100 firefloods have been conducted in the United States and Canada, and very few have been profitable, mainly because of the operating cost and the unpredictability of the process.

Immiscible Carbon Dioxide Process

In this process, a relatively small volume of carbon dioxide (20 percent hydrocarbon pore volume) is injected in the water-alternating gas (WAG) mode, with a water-gas ratio of about four. According to the author, under optimum conditions (oil viscosity around 1,000 megapascal seconds, low gas saturation, etc.), an incremental recovery of 15 percent, or more, is possible. Its main advantage is that it can be used in thin formations, and relatively large well spacings and existing wells may be used. It may be the only EOR process currently available for heavy oil formations that are unsuitable for thermal methods, but very few field tests have been conducted.

Chemical Floods

Figure 2 shows that many types of chemical floods are possible. Combinations include caustic-surfactant-polymer floods. They perform well in unsealed laboratory experiments, but mostly fail in the field. While chemical floods may have a bright future, he says, at the present time they simply do not work.

Innovations to Lower Cost

Innovations to lower the costs sometimes take the form of reduced engineering, which is short-sighted. The author says
that the complexities of EOR methods, such as steam injection, call for careful design and surveillance.

California heavy oil operations offer examples of innovations to increase profitability of steam injection, but are not necessarily applicable in Canada. One innovation is cogeneration, where the thermal energy is used to generate electricity prior to being injected into the formation. This results in a savings of $5 per barrel, which makes heavy oil production in California profitable. A notable example is the Kern River cogeneration plant, which produces 300 megawatts of electricity in addition to 131,000 barrels per day of steam.

Other measures to be considered are vapor recovery systems to recover light ends from casing gas, and injection of the produced hot water, where applicable. Wellhead steam quality measurement can result in savings, in spite of the initial investment, because it would permit efficient utilization of steam.

Also, developing new markets for heavy oil is as important as producing it, he says. An interesting example is Oilmulsion, in Venezuela. This is an emulsion of heavy oil and water, which can be burned directly in power plants.

Horizontal Wells

Horizontal wells can be a viable production acceleration method. In heavy oil production, they are particularly useful when the formation is thin, or it is desirable to employ low pressure drawdowns, as would be the case if sand production or water coning is a problem. But the experience in heavy oil fields is very limited with regard to primary production, and even more so in the case of steam injection. Thus caution is necessary. In addition, a horizontal well may cost two to four times as much as a vertical well in Lloydminster.

Conclusions

Heavy oil production is a low profit operation under the best of conditions. A careful engineering survey of a given operation may reveal ways to save money. Innovations may be possible in the most cost-intensive areas, such as lifting. However, cautions the author, whenever possible use the proven methods.

###
SHELL PATENTS ELECTRICAL PREHEAT EXTRACTION PROCESS

United States Patent Number 4,926,941 issued to C.A. Glandt et al. and assigned to Shell Oil Company is titled "Method of Producing Tar Sand Deposits Containing Conductive Layers."

The patent notes that several proposals have been made for various means of electrical or electromagnetic heating of tar sands. One category of such proposals has involved the placement of electrodes in conventional injection and production wells between which an electric current is passed to heat the formation and mobilize the tar. A novel variation, employing aquifers above and below a viscous hydrocarbon-bearing formation, has been disclosed. Another system and method for in situ heat processing of hydrocarbonaceous earth formations utilizes elongated electrodes inserted in the formation and bounding a particular volume of a formation. A radio frequency electrical field is used to dielectrically heat the deposit. The electrode array is designed to generate uniform controlled heating throughout the bounded volume.

Another patent discloses a waveguide structure bounding a particular volume of earth formation. The waveguide is formed of rows of elongated electrodes in a "dense array" defined such that the spacing between rows is greater than the distance between electrodes in a row. The "dense array" of electrodes is designed to generate relatively uniform heating throughout the bounded volume.

As can be seen from these examples, previous proposals have concentrated on achieving substantially uniform heating in a block of a formation so as to avoid overheating selected intervals. The common conception is that it is wasteful and uneconomic to generate nonuniform electric heating in the deposit. The electrode array utilized by prior inventors therefore bounds a particular volume of earth formation in order to achieve this uniform heating. However, the process of uniformly heating a block of tar sands by electrical means is extremely uneconomic. Because conversion of fossil fuel energy to electrical power is only about 38 percent efficient, a significant energy loss occurs in heating an entire tar sand deposit with electrical energy.

Shell claims to have discovered an economic method of selective heating particularly applicable to thick tar sand deposits containing thin, high conductivity layers. These thin conductive layers are typically shales into which the tar sand was alluvially deposited, but may also be water sands with or without salinity variations, or layers which also contain hydrocarbons but have significantly greater porosity. A thin conductive layer is heated to a temperature that is sufficient to form an adjacent thin preheated zone, in which the viscosity of the tar is reduced to a level sufficient to allow steam injection into the thin preheated zone. Electrical heating is then discontinued, and the deposit is steam flooded. The thin conductive layers to be heated are preferably in the lower portion of the tar sand deposit, and the electrically heated zones are typically only a small fraction of the total tar sand deposit. This localized heating generates a uniformly heated plane (the shale layer) within the tar sand deposit.

For geological reasons, shale layers are almost always found within a tar sand deposit because the tar sands were deposited as alluvial fill within the shale. Conductivity ratios between the shales and the tar sands range from about 10:1 to about 100:1. If the conductive layers chosen for electrical heating are near the bottom of the deposit, then injected steam can rise through the deposit and heated oil can drain downwards into the flowing steam channel.

Low-frequency electrical power (preferably at 60 Hz or below) is used to heat the thin conductive layers in a heavy oil or tar sand deposit. Electrodes are installed in wells spaced in parallel rows (Figure 1), and electrodes within a row may be energized from a common voltage source. The electrodes within a row form a plane of electrodes in the formation. The spacing between electrodes in the row, spacing between the rows, and diameter of the electrode are selected to prevent overheating (vaporization of water) at the electrodes.

The electrodes do not make electrical contact with the formation over the major thickness of the tar sand deposit, which improves the vertical confinement of the electrical current flow.
As the thin conductive layers are electrically heated, the conductivity of the layers will increase. This concentrates heating in those layers. As a result, the thin conductive layers heat rapidly, with relatively little electric heating of the majority of the tar sand deposit. The tar sands adjacent to the thin conductive layers are then heated by thermal conduction from the electrically heated shale layers in a period of a few years, forming a thin preheated zone immediately adjacent to each thin conductive layer. As a result of preheating, the viscosity of the tar in the preheated zone is reduced, and therefore the preheated zone has increased injectivity. The total preheating phase is completed in a relatively short period of time, preferably no more than about 2 years, and is then followed by injection of steam and/or other fluids.

One simulation presented in the patent shows that after the initial preheating phase of about 2 years, steam injection may be initiated, and steadily increased to a rate of about 1,400 barrels per day. After about 7 years, live steam reaches the production well, and steam injection is reduced. At the completion of the recovery project, almost 80 percent of the hydrocarbon originally in place is recovered.

The oil recovery and steam injection rates for a 5-acre pattern using the proposed process are more akin to conventional heavy oil developments than to tar sands with no steam injectivity. The total electrical energy utilized was less than 10 percent of the equivalent energy in steam utilized in producing the deposit, thus, the ratio of electrical energy to steam energy was very favorable. Also, the economics of the process are significantly improved relative to the prior approaches of uniform electrical heating of an entire tar sand deposit.

A 5-day test was also conducted in a larger 6-inch screw reactor system using the Asphalt Ridge tar sand. Analyses of the variations in the elemental compositions of the product oils and heavy oil recycle indicate that steady-state conditions may have been achieved after 3 days.

Vaughn stated that the experimental results obtained to date confirm the feasibility of the ROPE concept to produce oil yields greater than conventional pyrolysis processes. To further develop the ROPE process, it was tested with California Arroyo Grande tar sand.

A total of eight experiments were conducted in which the Arroyo Grande tar sand resource was processed in the presence of a heavy oil recycle. A number of modifications to the ROPE process equipment resulted from these tests that improved the processability of the Arroyo Grande tar sand. In particular all screw barrels were refabricated to produce much tighter clearances between the barrels and screw flights. This greatly improved the conveyance characteristics of the screws.

The improved process development unit (PDU) shown in Figure 1 consists of the following subsystems.

- Feed screw reactor
- Extraction/Pyrolysis screw reactor
- Drying screw reactor
- Heavy oil recycle system
- Product oil recycle system
- Reflux condensers and flasks
- Sweep gas injection system
- Spent solids collection tank

Feed Screw Reactor

Tar sand is fed directly into the feed screw conveyor. For conveyance of Arroyo Grande tar sand, the feed screw is oriented slightly downslope and operated at room temperature. No oil is mixed with the feed. This differs from the other tar sands tested, which require heat and/or oil to be added for adequate conveyance.

Extraction/Pyrolysis Screw Reactor

The bitumen enters the extraction/pyrolysis screw, which is oriented more horizontally compared with the upslope of earlier versions. Heavy oil is recycled cocurrently with the incoming tar sand where extraction and pyrolysis of the total mixture occurs. The extraction occurs almost immediately. The residence time of the slurry mixture is controlled by the feed rate and also by the speed of the screw. Electric heaters also surround this screw reactor, and the conversion of slurry and heavy oil recycle is controlled by adjusting the reactor temperature.

ROPE PROCESS SHOWS PROMISE ON CALIFORNIA TAR SANDS

The ROPE (recycle oil pyrolysis and extraction) process has been under development at Western Research Institute (WRI) in Laramie, Wyoming. A summary of certain experiments through early 1990 was given by P. Vaughn at the Oil Shale and Tar Sands Contractors Review Meeting held at Morgantown Energy Technology Center this spring.

A schematic of the ROPE process, which utilizes heated screw conveyors, is shown in Figure 1 on the next page.

Prior to 1989, tests were conducted in a 2-inch screw reactor system using Asphalt Ridge tar sand and Sunnyside tar sand. Oil yields from the Asphalt Ridge tests were in the range of 80 to 89 percent of total organics and exceeded Fischer Assay yields. Hydrocarbon-group-type analysis indicates that ROPE process product oil is a good feedstock for the production of unleaded gasoline and aviation fuels.
Drying Screw Reactor

Residual hydrocarbons on the sand are pyrolyzed at a higher temperature in the third screw conveyor. This final pyrolysis temperature is controlled to produce a dry material containing only residual carbon, mineral matter, and a minimum amount of residual oil. A product oil rinse is injected in the lower portion of the drying screw to assist in removal of the residual oil.

Experiments

After the initial three shakedown tests five experiments were performed. The first three tests were run for approximately 24 hours, the fourth for 17 hours, and the final test was run for 120 hours. During the tests, the temperatures in the pyrolysis screw varied between 625 and 750°F while the temperatures in the drying screw were kept between 950 and 1,000°F.

Total oil recovery as a percent of feed material ranged from 8.8 to 13.3 percent. Sand loading in the heavy oil and product oils will reduce these preliminary yield figures. Only in the case of test 5 was this done at the time of Vaughn's paper. In the case of test 5, the true oil yield obtained was determined to be 110.7 percent of Fischer Assay.

The 120-hour experiment (test 5) was performed in an effort to approach steady-state operation and to evaluate the replacement of the initial inventory of the heavy oil recycle. It is theoretically possible to operate at a tar sand feed rate and pyrolysis temperature so that the conversion of heavy oil is offset by fresh bitumen in the tar sand feed. These conditions will maintain a steady inventory of heavy oil without the need to add product oil to the heavy oil recycle.

Results from analysis of heavy oil recycle samples qualitatively suggest that 120 hours is sufficient to replace the initial heavy oil inventory of SAE 50-weight oil.

WRI concludes that California Arroyo Grande tar sand can be processed using the ROPE process without any major operational difficulty. Oil yields from at least the 5-day test exceeded Fisher Assay yield, and steady-state operation was achieved.

###

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3-25
ULTRASONIC EXTRACTION METHOD PATENTED

United States Patent Number 4,891,131 issued to M.A. Sadeghi et al. and assigned to Tar Sands Energy Ltd. of Santa Barbara, California is titled "Sonication Method and Reagent for Treatment of Carbonaceous Materials."

The process of the invention (Figure 1) is initiated with an ambient temperature solution in either a closed or open system. The process does not require application of heat energy as such. It can be initiated at any ambient temperature above 0°C. Sonic generators provide effective cavitation at solution temperatures of approximately 45°C to 55°C. This temperature is achieved autogenously in the process by heat produced in situ in part by the energies released by ultrasonic waves and partly by exothermic reactions between alkaline sodium silicates and the inherently active acids and other reactive moieties present in the carbonaceous material. The product of this reaction is a water-miscible separation reagent.

The mined tar sand is crushed usually to particles from about 60 to 80 standard United States mesh size to provide a feedstock which can be immersed in a pretreatment tank containing an aqueous solution of separation reagent. The ratio of tar sand to solution depends on the concentration of the reagent, the energy and frequency of sonication and the depth of the suspension. Usually the ratio of tar sand to liquid is from 10 to 35 percent by weight. The separation reagent is formed using sonication and can be recovered and/or recycled to the pretreatment tank. During the pretreatment soak, the separation reagent penetrates the bitumen/sand interface and contacts the surface of the sand particles.

After tar sand has been pretreated with the separation reagent, it enters a sonication unit where ultrasonic energy is applied. Cavitation, induced by ultrasonic waves, provides additional reagent penetration of the bitumen/sand grain bond and results in the detachment of the bitumen from the sand grains. A light fraction of bitumen floats to the surface of the solution where it is skimmed off. Essentially bitumen-free sand grains and charcoal-like solids remain in the bottom of the sonication tank. They are collected and sent to a washing unit.

Oil floats to the top of the suspension. Clean clay is removed from the aqueous reagent phase by clarification and/or filtration and the reagent is then recycled for reuse. The agglomerates are screened from the clean sand and can...
be combusted to provide heat and power for the process; strategic metals such as titanium, germanium and nickel can be recovered as metal oxides from the ash.

During sonication, minute vacuum bubbles form and implode. This action creates heat and mechanical energy at many locations throughout the suspension. The sonication action participates along with the surfactant activity or the sonication itself of the separation reagent in removing bitumen from the surface of the particles. It also acts to first separate lighter, less viscous, non-asphaltene fractions from the bitumen and to agglomerate the remaining heavier (asphaltene and preasphaltene) fractions into agglomerates containing substantially all the heavy metal impurities. The local heat and intense local turbulence due to sonication also causes the inorganic base to react with acid-containing polar groups in the bitumen to form water miscible surfactant compounds which enter the water phase as the separation reagent. Sonication is responsible for the formation of micelles and vesicles which participate in the upgrading and refining of the separated bitumen. The in situ formation of the separation agent was discovered during an investigation of the use of inorganic alkaline reagents in the processing of tar sands. Initial experiments were conducted using aqueous sodium silicate solutions.

The process, after an initial run to produce the separation reagent in situ, requires only small, make-up quantities of chemical since it operates essentially as a closed system.

###

SOLVENT EXTRACTION/COSOLVENT PRECIPITATION PROCESS MODIFIED

The Department of Chemical Engineering at the University of Arkansas, in cooperation with Diversified Petroleum Recovery, Inc. (DPR) of Little Rock, Arkansas, has been developing a solvent extraction process for the recovery of bitumen from tar sands for the past 5 years.

During Phase I of the project, the Mineral Research Institute (MRI) at the University of Alabama, Tuscaloosa, developed a pretreatment beneficiation process for domestic tar sands that upgrades relatively low grade tar sands to relatively high grade tar sands. The basis of the beneficiation was grinding followed by flotation in which a large fraction of the original mineral content of the feed tar sand is rejected. During Phase II of the project, the work formerly done at MRI was shifted to the University of Nevada, Reno (UNR).

The original process concept was based on the cyclic saponification/desaponification of fatty acids as a solvent for bitumen (Herter process). During Phase II work at the University of Arkansas, the following conclusions were reported to the Oil Shale and Tar Sands Contractors Review Meeting:

- The sand cannot be reasonably washed as a settled phase but must be washed in counter-current equipment.
- The least expensive method of cleaning the sand for disposal is to wash the sand counter-currently with the fresh solvent, settle the sand as it leaves the extraction equipment, flash dry the solvent from the sand and then steam strip the sand as it exits the dryer.
- Saponification and desaponification of a fatty acid from the original Herter process is too expensive because it requires two reactors and a counter-current water washing system to remove the salt of the fatty acid from the spent sand.
- Solvent-cosolvent systems containing alcohols (e.g., isopropyl and propyl) and brine form azeotropes with heptane, toluene and other organics which precludes solvent recovery by relatively inexpensive means.

Thus the process concept originally developed at Arkansas, known as the Wood-Beaver Process, has been completely changed by eliminating the fatty acid, which had to be removed from the spent sand by a counter-current alcohol wash.

The fatty acid solvent has now been replaced with toluene, which solubilizes essentially all the bitumen. By using a counter-current wash of the sand with toluene during extraction, the sand exits the extraction system as a dense phase slurry of clean sand in clean toluene. The toluene can then be removed from the sand in a dryer (e.g., a flash dryer) followed by a steam purge as the sand exits the dryer. A commercial schematic for this extraction system is shown in Figure 1 on the next page.

The original cosolvents were mixtures of brine and alcohols. Because of azeotropes and other unfavorable phase behavior, all attempts to use a multistage (up to three stages were considered) flash system or a single distillation column for solvent recovery for recycle were unsuccessful. Eventually an organic compound was discovered which when mixed with brine would cause bitumen precipitation and also allow solvent recovery by use of a single distillation column followed by a toluene-brine settler off the bottoms of the column. The solvent recovery system envisioned for the commercial plant is shown in Figure 2 on a following page.

According to the University of Arkansas, the commercial process shown schematically in Figures 1 and 2 has been shown by laboratory and process development unit (PDU) results to be technically feasible to produce solid bitumen by
amphiphilic phase behavior of the solvent-cosolvent system followed by a single distillation column for solvent recovery.

The solid, particulate bitumen from the settler can probably best be subsequently handled by melting and evaporation of the entrained solvent. The molten bitumen can then be air blown or treated in any other suitable fashion to produce asphalt.

It is planned to produce about 40 pounds of solid bitumen from each of three resources—Alabama, Oklahoma and Utah by the end of summer 1990. The characteristics of the bitumen and suitability of these bitumens for asphalt uses will be investigated by UNR.

DPR will continue to work with the University of Arkansas to complete an economic analysis for a commercial venture. The final economics work for the commercial plant will be completed during the Phase III portion of the project, June 1990 to June 1991.
DEMO PLANT PLANNED FOR SESA PROCESS

The SESA (solvent extraction and spherical agglomeration) process for recovering bitumen from mined oil sand was devised by the Canadian National Research Council (NRC) and is under license to Terra Energy Ltd. The process employs a naphtha solvent under controlled conditions, where the fines and other solids are agglomerated into free-settling spherical nodules. Under the joint sponsorship of the Alberta Oil Sands Technology and Research Authority and NRC, a comparative engineering and economic study of commercially sized Hot Water- and SESA-based plant complexes has been completed. The study was discussed by G.W. Govier and B.D. Sparks at the Oil Sands 2000 symposium in Edmonton, Alberta, Canada earlier this year.

The existing mining extraction plants in Alberta use versions of the Hot Water (HW) process, originally developed in the 1920s. Briefly this process comprises dispersing mined oil sands ore in hot water and then gravity separating a bituminous froth from the coarse sand tailings. A middlings stream of suspended fine solids and clays is treated separately, by flotation, to scavenge any entrapped bitumen. The combined froths are dissolved in naphtha and centrifuged to remove solids and water. After removal of naphtha the bitumen is upgraded to synthetic crude oil (SCO).

While the HW process has been technically and economically successful, the basic requirement for fine dispersion of the ore in alkaline, hot water has resulted in massive quantities of aqueous tailings. The coarse sand fraction settles readily but the fines and associated residual hydrocarbons form a stable, non-compacting sludge which must be stored in large tailings ponds. At the present time there is no environmentally or economically acceptable means of treating the existing tailings ponds in such a way as to allow satisfactory land restoration.

An improved method such as solvent extraction would be attractive because of the potentially high recovery of oil from all grades of ore. However, the presence of fines in oil sands ore can inhibit the separation of the produced bitumen solutions from the residual solids, resulting in processing difficulties.

In order to overcome this solids-liquid separation problem the SESA process combines solvent extraction with another technique called spherical agglomeration. Spherical agglomeration (SA) is a process in which liquid-suspended fine particles can be formed into larger, dense agglomerates by means of suitable agitation in the presence of a second liquid, which must be immiscible with the suspending medium. The naturally water wet condition of the particles comprising oil sands make this system an ideal candidate for application...
of SA technology. In this case bitumen is dissolved in a hydrocarbon solvent which then acts as the solids suspending medium. As the solids are already water wet, additional amounts of water can be used as the immiscible second liquid to bind the solids into agglomerates. Agitation by tumbling is the driving force for solids agglomeration. Phase separation results in a clean bitumen solution and a solids tailings with a relatively low bitumen and solvent content.

In 1974 the SESA concept was proposed, with the aim of treating low grade ore only. The process utilized agglomeration to mechanically desolventize the extracted oil sands solids. A minimum of 15 weight percent fines in the oil sand ore was required to provide sufficient agglomerate strength to allow the formation of large spheres (about 10 millimeters) which gave optimum solvent separation through a layering-compaction mechanism.

Terra Energy Ltd. (TEL) obtained the license for this technology in 1974 and subsequently contracted MHG International to carry out a technical and economic evaluation. It was apparent from these early studies that solvent recovery and the ability to treat all grades of oil sands were important aspects for successful application of the process.

In 1983-84, Petro-Canada undertook an evaluation of a number of different, generic bitumen extraction schemes. The SESA process was selected for study by virtue of its being a leading example of the solvent extraction type. Process modifications were made so that all grades of oil sands could be treated. In the scheme finally adopted, agglomeration was restricted to binding together the fines and coarser particles, present in all feed grades, to form small aggregates (1 millimeter). These aggregates showed the same rapid solid-liquid separation characteristics as the coarse sand which is the predominant particulate species in high grade ores.

**Process Description**

A successful pilot plant testing program was carried out at the Process Research Laboratory in Calgary. A simplified flow diagram for the process is shown in Figure 1. The feed system transports ore into the extraction/agglomeration unit where the extracting solvent and water are contacted with the ore. The unit is a tumbler device rotating at low speed (about 10 to 20 percent of the critical rpm). Mixing of the ore, solvent and water is assisted by a charge of steel rods. The extraction solvent is a recycled dilute bitumen solution.
from a later stage of the process; the presence of bitumen greatly improves the dissolving power of naphtha, which is the primary solvent. Water, in controlled amounts, can be added as liquid, or steam if additional energy is required to thaw frozen feed. The process is operated at 50°C, and no additives, such as alkali, are required.

Bitumen dissolution and sand agglomeration occur concurrently in the tumbler. Water (or steam) added to the system is preferentially adsorbed by the ore grains, displacing bitumen and solvent from their surfaces in the process. In the presence of appropriate amounts of water the solid particles adhere to each other, through the capillary action of the surface water films, to form multi-particle agglomerates from which the bulk of the bitumen and solvent is excluded. Agglomeration is very rapid and some undissolved bitumen can be occluded within the growing agglomerates. The tumbling charge of steel rods in the vessel continuously breaks down agglomerates as they form, thereby re-exposing any trapped bitumen to the extracting solvent and allowing more opportunity for bitumen to be dissolved. This continuous formation and destruction of agglomerates also assists in controlling agglomerate size within the most desirable range (0.5-1.5 millimeters). Control of particle size is the key factor for the successful operation of the next process stage, which is separation of the agglomerated, extracted solids from the rich bitumen solution.

Vacuum filtration has been selected as the most appropriate solids-liquid separation technique for this process. As the pan filter rotates, the retained solids are washed countercurrently with progressively cleaner solvent to remove entrained bitumen solution.

The filtered, washed solids from the SESA process contain 4-6 weight percent solvent and are virtually free of bitumen. Most of the residual solvent has been displaced from the internal porosity of the agglomerates and is only weakly held in the larger pores of the filter cake. An important aspect of the process is the economical recovery of this solvent. The means selected to accomplish this goal is a rotating, tubular dryer, utilizing both indirect heating and internal steam stripping.

Figure 2 compares bitumen recovery results for the SESA and HW processes. The SESA results are straightforward, showing an almost constant recovery at all feed grades. In the case of the HW process the results are more confusing, largely owing to the paucity of hard recovery data to be found in the public domain.

Regardless of which set of results is considered it is apparent that recovery of bitumen by the HW process decreases dramatically as the ore grade drops below 9 weight percent bitumen; this is not so for the SESA process.

**Economic Results**

The economic objective of the second phase of study was to make a comparison of the economics of the HW and the SESA processes, each operating at 30,000 barrels per day of synthetic crude oil and each meeting required environmental standards. For the HW process two possible environmental standards were considered: Case I corresponding to the current and projected operations of Suncor and Syncrude and Case II corresponding with anticipated more stringent requirements for the next generation of mining-extraction plants. The capital and operating costs for an 11.6 percent grade feed, on a unit of production basis (1989 dollars per barrel of synthetic crude oil) are compared to other unit production costs presented in Table 1 on the next page. The
Case II situation, reflecting anticipated environmental standards, is considered the more realistic and appropriate for comparison purposes. For Case II, the SESA unit costs are lower than that of the HW process by $1.54 per barrel of synthetic crude oil for an oil sand feed grade of 11.6 percent (Table 1) and range to well above $10.00 per barrel at lower grades.

Demonstration Plant

The definitive design and final (± 10 percent) cost estimate for a SESA demonstration plant was scheduled to be completed in mid-1990. The plant is to be located in the Fort McMurray area.

The preliminary estimate of the capital and operating requirements for the demonstration plant was some $10.5 million and $6.6 million, respectively.

Funding for the demonstration plant has not yet (August 1990) been arranged but Terra is seeking an oil industry partner to share with it, and the Alberta and federal governments, in the cost of the plant.

Terra hopes to construct the plant during the winter of 1990 and operation is planned for the summers of 1991 and 1992.

### TABLE 1

**SESA/HW EXTRACTION PROCESS DESIGN AND COST COMPARISON STUDY**

Unit Production Costs By Plant Area (Can. $/Barrel SCO)

<table>
<thead>
<tr>
<th>Process</th>
<th>SESA</th>
<th>HW</th>
</tr>
</thead>
<tbody>
<tr>
<td>Feed (t/h)</td>
<td>2210</td>
<td>2240</td>
</tr>
<tr>
<td>Grade (%)</td>
<td>11.6</td>
<td>11.6</td>
</tr>
<tr>
<td>Recovery (%)</td>
<td>94.2</td>
<td>93.0</td>
</tr>
</tbody>
</table>

**Case I**

1. Mining $6.72 $6.81
2. Extraction 4.86 2.75
3. Tailings Handling 2.14 1.61
4. Upgrading 6.17 6.17
5. Utilities 3.46 3.82
6. Plant Offsite Facilities 8.00 7.89
7. Site Reclamation 0.10 0.12

Unit Production Cost - Case I $31.45 $29.24

**Case II**

1. Mining $6.72 $6.81
2. Extraction 4.86 2.75
3. Tailings Handling 2.14 5.45
4. Upgrading 6.17 6.17
5. Utilities 3.46 3.82
6. Plant Offsite Facilities 8.00 7.89
7. Site Reclamation 0.10 0.10

Unit Production Cost - Case II $31.45 $32.99

Note: Unit production cost includes all costs—capital and operating—discounted at 10%; production discounted at 10%.
CANADIAN RESERVES OF SYNTHETIC CRUDE OIL INCREASE

The Canadian Petroleum Association's (CPA) annual study of established reserves shows further deterioration in the remaining established reserves of conventional crude oil in producing fields, offset by additions to developed oil sands reserves.

In 1989 the remaining oil reserves in producing fields declined 4.1 percent to 4,691 million barrels. Only 54 percent of conventional crude oil production was replaced by reserve additions in the producing regions, leading to a further decline in productive capacity.

The drop in conventional crude oil reserves was offset by additions to pentanes plus and synthetic crude oil reserves.

The latter are calculated on the basis of each plant's developed capacity over the approved period of operations. The 1989 reserves report reflects the increased capacity of the Syncrude plant. As a result, synthetic crude oil reserves increased by 113 percent to 2,051 million barrels, as shown in Table 1. The net increase in reserves amounts to 208 million barrels.

According to CPA, the continuing slide in the productive capacity of conventional light and medium crude oil points towards greater reliance on imported oil in the first half of the 1990s until additional oil sands and new offshore production comes on stream.

The annual estimates are compiled by the Association's Reserves Committee and 16 reservoir engineering experts, with assistance from the Alberta Energy Resources Conservation Board and the energy departments of other producing provinces.

ALBERTA TO REDUCE OIL SANDS LEASE PERIODS

The Alberta Department of Energy has issued draft regulations which will shorten the standard lease period for oil sands leases.

Under the proposed regulations, the primary term for a lease issued out of a prospecting permit will be 15 years. It is then renewable for three additional terms of 15 years each.

For leases which are issued in areas of known oil sands resources (development lease), the term of a lease will be 10 years.

A type A lease (one issued under the previous regulations) is renewable at the end of its second term, for a further term of

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<table>
<thead>
<tr>
<th>TABLE 1</th>
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<tbody>
<tr>
<td>DEVELOPED NON-CONVENTIONAL RESERVES IN CANADA</td>
</tr>
<tr>
<td>REMAINING ESTABLISHED RESERVES</td>
</tr>
<tr>
<td>(Thousand Barrels)</td>
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<table>
<thead>
<tr>
<th>Regions</th>
<th>Remaining Reserves at 1988-12-31</th>
<th>Remaining Reserves at 1989-12-31</th>
<th>Net Change in Reserves During 1989</th>
</tr>
</thead>
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<tr>
<td></td>
<td>1</td>
<td>1,843,603</td>
<td>207,822</td>
</tr>
<tr>
<td>Developed Synthetic Crude Oil</td>
<td>2</td>
<td>283,179</td>
<td>207,822</td>
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<tr>
<td>Alberta</td>
<td>3</td>
<td>75,357</td>
<td>207,822</td>
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<tr>
<td></td>
<td>4</td>
<td>2,051,425</td>
<td>207,822</td>
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<tr>
<td>Developed Bitumen</td>
<td>5</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Alberta</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Developed synthetic crude oil reserves are calculated on the basis of each plant's developed capacity over the approved period.</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Developed bitumen reserves are those recoverable from developed experimental/demonstration and commercial projects.</td>
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<td></td>
<td></td>
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</table>

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15 years if the lessee has submitted to the department a plan for the development of the oil sands in the location, and the Minister is satisfied that the plan is adequate and that the plan will be completed during the 15-year renewal term.

The Minister is not to approve a plan more than 5 years before the expiry of the initial term of a lease issued out of a permit or an oil sands development lease or more than 5 years before the expiry of the second term of a 21-year type A lease. In the case of a 10-year development lease, the Minister is not to approve a plan which does not commit to production from the lease by the end of the 10-year term.

If a lease is eligible for renewal, it may be renewed only as to the part or parts of the location that contain sufficient recoverable bitumen reserves to carry out the approved plan for a period of 40 years.

The overall objective of the new system is to ensure ample reserves are in the hands of those who most want to develop them and that they are induced to do so.

The key proposal of the draft regulation is to ensure that existing leases be in production, at the rate specified in the lease, at the end of its second term in order to be renewed for the third term.

This requirement is significant because only one (Syncrude’s T17) of the 93 second-term leases which expire between 1996 and 2003 is currently producing at or greater than its specified capacity.

There are currently a total of 103 second-term leases which comprise about one-third of oil sands leases, but they cover essentially all of the surface-mineable oil sands and almost 50 percent of recoverable oil sands reserves (Suncor’s producing lease T04 is in its third term). Renewability for the third term may now be hinged to production plans for that period.

In many cases, if a lessee cannot produce at the lease’s specified capacity (most commonly 25,000 barrels per day) by committing to, for example, 60,000 barrels per day of bitumen production, the 40-year formula would allow retention of 0.7 billion barrels.

However, many of the better mineable leases contain 5 billion proven recoverable barrels. In these circumstances there would be a substantial return to the Crown of high-quality oil sands rights for development by others.

The draft regulations also include a proposal allowing the 40-year allowance to be substantially increased where the lessee’s bitumen is upgraded.

In the most favorable case, where bitumen is upgraded to synthetic crude oil of 35⁰ API or higher, an additional 20 years worth of reserves would be retained.

If the lessee’s ownership share in an upgrader equals or exceeds his share of the upgrader throughput, a further 30 years reserves would be retained, for a total allowance of 90 years.

The ability of the department to set terms and conditions upon renewal will be applied to first-term leases (when they enter their second terms) in the form of a pre-production charge which will be refunded against bitumen production.

The proposed charge of $5 per hectare per year upon renewal, escalating to $25 per hectare per year over 5 years, can be offset by $1 per barrel of bitumen produced for the lease during its first or second term. The charge is designed to encourage pilot activity and discourage the surrender of high-quality reserves.

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The following papers were presented at the Canadian Society for Chemical Engineering Symposium, "Heavy Oil: Upgrading to Refining," held May 9 in Calgary, Alberta, Canada:

- Dawson, W.H., "Primary Upgrading and New Emerging Technologies."
- Sanford, E.C., "Fundamentals of Heavy Oil Upgrading."
- Bishop, W., "LC-Finer Operating Experience at Syncrude."
- Smith, R., "The Co-op Upgrader."
- Chase, S., "Bi-Provincial Upgrader Project."
- Lynn, J., "OSLO Project Update."
- Gray, M.R., "Synthetic Crude Oil Composition and Hydrotreating."
- Redelmeier, R.J., "Upgrading and Processing Synthetic Crude Oil."
- Candido, D., "Use of Heavy Oil and Synthetic Crude in Conventional Refineries."
- Lenz, G.H., "Marketing of Heavy Oil, Synthetic Crude, and Derived Products."

The following papers were presented at the combined 73rd Canadian Chemical Conference and 40th Canadian Chemical Engineering Conference held July 15-20 in Halifax, Nova Scotia, Canada:

- Leopold, C.L., "Pilot-Scaled Plant for Heavy Oil Emulsions Treatment."
- Ng, F.T.T., et al., "Catalytic Upgrading of Heavy Oil Emulsions."
- Chornet, E., et al., "Pretreatment and Hydrotreating of Heavy Oils using a High Shear Jet Reactor."
- de Bruijn, T.J.W., et al., "Upgrading Heavy Oil Emulsions by using their Water as Reactant."
- Ng, F.T.T., et al., "Application of Homogeneous Catalysis for Heavy Oil Upgrading."

The following papers were presented at the CIM/SPE International Technical Meeting held June 10-13 in Calgary, Alberta, Canada:

- Tsang, P., "Perspective of a Fireflood Process Using Low Air Injection Rates."
- Vittoratos, E., "Flow Regimes During Cyclic Steam Stimulation at Cold Lake."
Asgarpour, S., et al., "Enhanced Heavy-Oil Production by Horizontal Drilling - Case Study."


**OIL SANDS - PATENTS**

"Methods of Producing Tar Sand Deposits Containing Conductive Layers," Carlos A. Glandt, Michael Prats, Harold J. Vinegar - Inventors, Shell Oil Company, United States Patent Number 4,926,941, May 22, 1990. A method is disclosed for producing thick tar sand deposits by preheating of thin, relatively conductive layers which are a small fraction of the total thickness of a tar sand deposit. The thin conductive layers serve to confine the heating within the tar sands to a thin zone adjacent to the conductive layers even for large distances between rows of electrodes. The preheating is continued until the viscosity of the tar in a thin preheated zone adjacent to the conductive layers is reduced sufficiently to allow steam injection into the tar sand deposit. The entire deposit is then produced by steam flooding.

"Process and System for Recovering Oil from Oil Bearing Soil Such as Shale and Tar Sands and Oil Produced by Such Process," Jeersannidhi M. Narasimhan, Jr., Jeersannidhi M. Thirumalachar - Inventors, Source Tech Earth Oils Inc., United States Patent Number 4,929,341, May 29, 1990. Oil bearing soil is contacted in a contacting zone with a liquid medium comprising water and a lipophilic solvent which is miscible or soluble with water. The medium can include a yield improving agent comprising a water soluble acidic ionic salt or a water soluble ionic acid. The contacting produces an emulsion which comprises the oil from the oil bearing soil and the liquid medium. The inorganic portion of the soil is dispersed in the emulsion and it is separated from the emulsion by gravity or other suitable means. The emulsion is broken by an emulsion breaking agent into two phases. The two phases are allowed to separate into two layers. The first layer comprises the oil and minor amounts of the liquid medium. The second layer comprises the liquid medium and minor amounts of the oil. The first layer is then recovered. The medium from the second layer can be recycled into the contacting zone.
STATUS OF OIL SANDS PROJECTS

COMMERCIAL PROJECTS (Underline denotes changes since June 1990)

ASPHALT FROM TAR SANDS — James W. Burger and Associates, Inc. (T-5)

J. W. Burger and Associates, Inc. (JWBA) has initiated a project for commercialization of Utah Tar Sands. The product of the initial venture will be paving and specialty asphalts. The project contemplates a surface mine and water extraction of bitumen followed by clean-up and treatment of bitumen to manufacture specification asphaltic products. JWBA has secured rights to patented technology developed at the University of Utah for extraction and recovery of bitumen from mined ore.

In 1988, JWBA completed a feasibility study which examined the technology, markets, resources and economics for asphalt production. Results showed a strong potential for profitability at today's prices and costs. Level of profitability is sensitive to site-specific factors and price variations. Results also showed the need for further development of technology applicable to the consolidated, oil-wet resources typical of Utah and other domestic deposits.

In February, 1989, JWBA received an award of $500,000 from the United States Department of Energy to further develop the technology and to conduct site-specific optimization. The award was one of about 30 given nationwide.

A 100 pound per hour PDU has been designed and constructed; it is currently in the start up phase. Preliminary results are highly encouraging in that the process is operating according to design expectations.

All candidate sites in the Uinta Basin are currently under consideration including Asphalt Ridge, P.R. Spring, Sunnyside and White Rocks. The commercialization plan calls for completion of research in 1990, construction and operation of a field plant by 1991 and commercial operations by 1994. The schedule is both technically realistic and financially feasible. The company is receiving strong interest for private financing of the commercial development.

Project Cost:

<table>
<thead>
<tr>
<th>Category</th>
<th>Cost</th>
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<tbody>
<tr>
<td>Research and Development</td>
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</tr>
<tr>
<td>Pilot project</td>
<td>$5 million</td>
</tr>
<tr>
<td>Commercial Facility</td>
<td>to be determined</td>
</tr>
</tbody>
</table>

BI-PROVINCIAL UPGRADE — Husky Oil Operations Ltd. (T-10)

Husky Oil is proceeding with the design and construction of a heavy oil upgrader to be located near the Alberta/Saskatchewan border at Wilton, near Lloydminster, Saskatchewan. The facility will be designed to process 46,000 barrels per day of heavy oil and bitumen from the Lloydminster and Cold Lake deposits. The primary upgrading technology to be used at the upgrader will be H-Oil ebullated bed hydrocracking followed by delayed coking of the hydrocracker residual. The output will be 46,000 barrels per day of high quality synthetic crude oil.

Engineering and design of the plant was initiated in June 1984 under terms of an agreement between Husky Oil Operations Ltd. and the governments of Canada, Alberta, and Saskatchewan.

Phase 1 of the project (design engineering and preparation of control estimate) was completed in March 1987. Detailed engineering and construction were placed on hold pending negotiation of fiscal arrangements with the governments of Canada, Alberta and Saskatchewan.

In September, 1988, Husky and the governments of Canada, Alberta and Saskatchewan, signed a binding joint venture agreement to finance and build the Bi-Provincial Upgrader. Project completion is targeted for late 1992.

In February, 1989 the Bi-Provincial Upgrader Joint Venture announced the award of $120 million in engineering contracts, with work to start immediately and be in full swing by April, 1989.

Detailed engineering and design is approximately 55% complete as of April 30, 1990. Engineering will be completed by the 1st quarter of 1991. Procurement of major equipment is well underway with purchasing of bulk materials and miscellaneous equipment to continue through to 3rd quarter of 1990.

Site preparation has been completed. The award of major civil contracts began early in 1990. Major mechanical contracts will be started in the 3rd quarter 1990. The Construction Management Team moved their operations to site offices in March. The construction force is expected to peak at 2,400 persons by the 3rd quarter 1991.

Project Cost: Upgrader Facility estimated at C$1.267 billion

BITUMOUNT PROJECT - Solv-Ex Corp. (T-20)

The Solv-Ex Bitumount Project will be a phased development of an open pit mine and an extraction plant using Solv-Ex's process for recovery of bitumen and metals.

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STATUS OF OIL SANDS PROJECTS (Underline denotes changes since June 1990)

COMMERCIAL PROJECTS (Continued)

Solv-Ex will use a naphtha solvent to boost the power of hot water to separate oil from sand. The increased efficiency of the process increases oil yield and also allows metals such as gold, silver and titanium to be extracted from the very clean sand. Analyses of the pilot plant tailings (after bitumen extraction) showed that these minerals are readily recoverable.

In February, 1989, a viable processing flowsheet was finalized which not only recovers the originally targeted gold, silver and titanium values but also the alumina values contained in the resource. Synthetic crude oil would represent less than 15 percent of the potential mineral values recoverable from the Bitumount Lease.

The results of this work indicate that the first module could be a single-train plant, much smaller than the 10,000 barrels per calendar day plant originally envisaged. The optimum size will be determined in the preconstruction feasibility study and this module is estimated to cost not more than C$200 million.

The Bitumount lease covers 5,874 acres north of Fort McMurray, Alberta. Bitumen reserves on the lease are estimated at 1.4 billion barrels.

Solv-Ex is currently looking for potential financial partners to expand the project.

BURNT LAKE PROJECT - Suncor Inc., Alberta Energy Company Ltd. and Canadian Hunter Exploration Ltd. (T-30)

The Burnt Lake in situ heavy oil plant is located on the Burnt Lake property in the southern portion of the Primrose Range in northeast Alberta. Initial production levels will average 12,500 barrels per day.

According to the companies, the Burnt Lake project is a milestone because it will be the first commercial development of these heavy oil resources on the Primrose Range. This will require the close cooperation of Canada's military.

The multi-phase Burnt Lake project, which will involve cyclic steaming, was put on hold in 1986 due to low oil prices, then revived in 1987. The project as of early 1989 has again been halted. Alternative recovery processes are under evaluation.

According to initial plans, the project was supposed to be designed after the thermal recovery project Suncor operated nearby at Fort Kent. There slant wells were drilled in clusters and cyclic steamed.

Future stages could double production to 25,000 barrels per day. Burnt Lake is estimated to contain over 300 million barrels of recoverable heavy oil.

COLD LAKE PROJECT - Esso Resources Canada Limited (T-50)

Cyclic steam stimulation is being used to recover the bitumen. Processing equipment consists of a water treatment and steam generation plant and a treatment plant which separates produced fluids into bitumen, associated gas and water. Plant design allows for all produced water to be recycled.

In September 1983 the Alberta Energy Resources Conservation Board (AERCB) granted Esso Resources Canada Ltd. approval to proceed with construction of the first two phases of commercial development on Esso's oil sands leases at Cold Lake. Subsequent approval for Phases 3 and 4 was granted in June 1984 and for Phases 5 and 6 in May 1985.

Shipments of diluted bitumen from Phases 1 and 2 started in July 1985, augmented by Phases 3 and 4 in October, 1985 and Phases 5 and 6 in May, 1986. During 1987, commercial bitumen production at Cold Lake averaged 60,000 barrels per day. Production in early 1988 reached 85,000 barrels per day. A debottlenecking of the first six phases has added 19,000 barrels per day in 1988, at a cost of $45 million.

The AERCB approved Esso's application to add Phases 7 through 10, which will eventually add another 44,000 barrels per day. A decision has been made not to complete the facility at this time. Phases 9 and 10 have been postponed indefinitely.

However, all construction will be completed on the central processing plant for Phases 7 and 8 and partially completed for the field facilities. The construction is 70% completed.

Project Cost: Approximately $770 million for first ten phases

DAPHNE PROJECT - Petro-Canada (T-60)

Petro-Canada is studying a tar sands mining/surface extraction project to be located on the Daphne leases 65 kilometers north of Fort McMurray, Alberta. The proposed project would produce 75,000 barrels per day. The project is expected to cost $3.8 billion (Canadian). To date over 350 core holes have been drilled at the site to better define the resource.
STATUS OF OIL SANDS PROJECTS (Underline denotes changes since June 1990)

COMMERCIAL PROJECTS (Continued)

Currently, the project has been suspended pending further notice.

Project Cost: $3.8 billion (Canadian)

DIATOMACEOUS EARTH PROJECT – Texaco Inc. (T-70)

Texaco has placed its Diatomite Project, located at McKittrick in California's Kern County, in a standby condition. The Project will be reactivated when conditions in the industry dictate. The Company stressed that the Project is not being abandoned, but is being put on hold due to the current worldwide energy supply picture. As of March, 1988, the Lurgi pilot unit is being maintained in condition for future operations.

The Company estimates that the Project could yield in excess of 300 million barrels of 21 to 23 degrees API oil from the oil-bearing diatomite deposits which lie at depths up to 1,200 feet. The deposits will be recovered by open pit mining and back filling techniques.

Project Cost: Undetermined

ELECTROMAGNETIC WELL STIMULATION PROCESS – Uentech Corporation, A Subsidiary of ORS Corporation (T-80)

Universal Energy Corporation of Tulsa, Oklahoma changed the company's name to Oil Recovery Systems (ORS) Corporation in June 1986. Through its subsidiary, Uentech Corporation, Universal Energy sponsored research and development at the Illinois Institute of Technology Research Institute (IITRI) on a single-wellbore electromagnetic stimulation technique for heavy oil. The technique uses the well casing to induce an electromagnetic field in the oil-bearing formation. Both radio frequency and 60 cycle electric voltage are used. The radio frequency waves penetrate deeply into the formation while the 60 cycle current creates resistive heating.

The first field test with a commercial well, initially producing about 20 barrels per day, was put into production in December 1985 in Texas, on property owned by Coastal Oil and Gas Corporation. In June 1986, ORS received permits from the Alberta Energy Resources Conservation Board, and stimulation started in a well in the Lloydminster area in Alberta, Canada. This well was drilled on a farmout from Husky Oil in the Wildmere Field. Primary production continued for about 60 days, during which the well produced about 6 barrels per day of 11 degrees API heavy oil. The well was then shut down to allow installation of the ORS electromagnetic stimulation unit. After power was turned on and pumping resumed on June 10, a sustained production of 20 barrels per day was achieved over the following 30 days. The economic parameters of the operation were within the range expected. Process energy costs have been demonstrated at around $1/bbl.

This well was shut-in after seven months of operation due to high operating costs associated with severe sand production. Two other wells utilizing the Technology have been completed in the Wildmere Field with encouraging results initially. However, attempts to mitigate the sanding problems have not been successful and these wells were also shut-in after approximately one year of operation.

Additional work is being undertaken in Canada. Most recently, a 12 degree API heavy oil well in Alberta increased production from 20 barrels to nearly 80 barrels per day. Another well in Saskatchewan increased from 75 to about 125 BOPD after application of the Technology. Approximately 20 wells are expected to apply the Technology within Canada during 1989. This work is being performed by Electromagnetic Oil Recovery Limited (EOR), a Calgary headquartered affiliate. EOR signed a contract in 1988 with Shell which will lead to a field test of the Technology in Europe during 1989.

ORS Corporation participated in two wells drilled in California in 1986 near Bakersfield. Severe sand production problems and low initial well productivity prevented a commercial installation although reservoir temperature was demonstrated to increase in excess of 150 degrees Fahrenheit. Another ORS affiliate, Pogue Oil Recovery Technologies, drilled an additional well in 1987 on the White Wolf farmout from Tenneco Oil. The wells were eventually shut-in in 1988 due to low productivity, sanding problems, and low oil prices.

A demonstration field test began in Brazil in late 1987. The test well was initially completed in September 1987. The initial test well resulted in increasing production from the initial level of 1.1 barrels per day up to 14 barrels per day. The process will be applied to an additional 4 wells during 1989 before a decision is made to expand the well stimulation program to potentially several hundred oil producing wells in Brazil.

Project Cost: Not disclosed

ELK POINT PROJECT – Amoco Canada Petroleum Company, Limited. (T-90)

The Elk Point Project area is located approximately 165 kilometers east of Edmonton, Alberta. Amoco Canada holds a 100 percent working interest in 6,600 hectares of oil sands leases in the area. The Phase 1 Thermal Project is located in the NW 1/4 of Section 28, Township 55, Range 6 West of the 4th Meridian.
STATUS OF OIL SANDS PROJECTS (Underline denotes changes since June 1990)

COMMERCIAL PROJECTS (Continued)

The primary oil sands target in the area is the Lower Cummings sand of the Mannville Group. Additional oil sands potential is indicated in other Mannville zones including the Colony, Clearwater, and the Sparky.

Amoco Canada has several development phases of the Elk Point Project. The current phase 1 of the Project involves the drilling, construction, and operation of a 13-well Thermal Project (one, totally enclosed 5-spot pattern), a continuation of field delineation and development drilling and the construction of a product cleaning facility adjacent to the Thermal Project. The delineation and development wells are drilled on a 16.19 hectare spacing and are cold produced during Phase 1.

Construction of the Phase 1 Thermal Project and cleaning facility was initiated in May 1985. The cleaning facility has been operational since October 1985. Cyclic Steam injection into the 13-well project was initiated in July, 1987 with continuous steam injection commencing on April 20, 1989.

In February, 1987, Amoco Canada received approval from the Energy Conservation Board to expand the development of sections 28 and 29. To begin this expansion, Amoco drilled 34 wells in the north half of section 29 in 1987-88, using conventional and slant drilling methods. Pad facilities construction occurred in 1988. A further 24 delineation wells were drilled in 1989 and further limited drilling is expected to take place in 1990.

Oil production from current wells at Amoco's Elk Point field totals 1,200 cubic meters per day. Production with new wells will gradually increase totals to approximately 1,280 cubic meters per day. Further development of the Project to the planned second phase will concentrate on reduced well spacing and expanding operations to include some huff and puff (cyclic) steam stimulations in the future.

Project Cost: Phase I - $50 Million (Canadian)

ELK POINT OIL SANDS PROJECT – PanCanadian Petroleum Limited. (T-100)

PanCanadian received approval from the Alberta Energy Resources Conservation Board (ERCB) for Phase I of a proposed 3 phase commercial bitumen recovery project in August, 1986.

The Phase I project would involve development of primary and thermal recovery operations in the Lindbergh and Frog Lake sectors near Elk Point in east-central Alberta. Phase I operations include development of 16 sections of land where 129 wells were drilled by the end of 1988.

PanCanadian expects Phase I recovery to average 3,000 barrels per day of bitumen, with peak production at 4,000 barrels per day. Tentative plans call for Phase II operations starting up in the mid 1990's with production to increase to 6,000 barrels per day. Phase III would go into operation in the late 1990's, and production would increase to 12,000 barrels per day.

Thus far, steam stimulation has been applied experimentally in two sections, and the results are being evaluated while study proceeds on a pilot steam flood process in one of these sections.

As of June 1989, low prices for heavy crude and lack of economics for expensive enhanced oil recovery methods have caused PanCanadian to delay Phase I plans. Meanwhile the company continues to streamline primary operations, to evaluate steam stimulation results and to plan experimental steam flood pilots.

Project Cost: Phase I = C$90 Million

FOREST HILL PROJECT – Greenwich Oil Corporation (T-110)

Greenwich Oil Company is developing a project which entails modification of existing, and installation of additional, injection and production wells to produce approximately 1,750 barrels per day of 10 degrees API crude oil by a fire flooding technique utilizing injection of high concentration oxygen. Construction began in the third quarter 1985. Loan and price guarantees were requested from the United States Synthetic Fuels Corporation under the third solicitation. On August 21, 1985 the Board directed their staff to complete contract negotiations with Greenwich by September 13, 1985 for an award of up to $60 million. Contract was signed on September 24, 1985. Project now has 21 injection wells taking 150 tons per day of 90 percent pure oxygen. The oil production rate reached 1,200 barrels per day.

On January 9, 1989, Greenwich filed for reorganization under Chapter 11 of the Bankruptcy Act. Oxygen injection has been temporarily suspended but water is being injected into the burned-out sand zones to move unreacted oxygen through the combustion zone and to scavenge heat. Oil production is 700 barrels per day.

Project Cost: Estimated $42.5 million
STATUS OF OIL SANDS PROJECTS (Underline denotes changes since June 1990)

COMMERCIAL PROJECTS (Continued)

LINDBERGH COMMERCIAL PROJECT – Amoco Canada Petroleum Company Ltd. (T-120)

Amoco (formerly Dome Petroleum) received approval from the Alberta Energy Resources Conservation Board for a commercial project in Lindbergh. The project will cover five sections and was planned to be developed at a rate of one section per year for five years. It will employ "huff-and-puff" steaming of wells drilled on 10 acre spacing, and will require capital investment of approximately $158 million (Canadian). The project is expected to encompass a period of 12 years and will result in peak production of 12,000 barrels of oil per day, which when coupled with production from two experimental plants and additional wells will raise the daily area production to about 15,000 barrels per day.

Due to the dramatic decline of oil prices, drilling on the first phase of the commercial project has been halted. A total of 46 slant wells have been drilled to date and placed on primary production. Low oil prices have forced a delay in the proposed commercial thermal development. In 1990, Amoco plans to drill an additional 10 slant wells and put on primary production.

Project Cost: $158 Million

LINDBERGH COMMERCIAL THERMAL RECOVERY PROJECT – Murphy Oil Company Ltd. (T-130)

Murphy Oil Company Ltd., has completed construction and startup of a 2,500 barrel per day commercial thermal recovery project in the Lindbergh area of Alberta. Project expansion to 10,000 barrels per day is planned over nine years, with a total project life of 30 years. The first phase construction of the commercial expansion involved the addition of 53 wells and construction of an oil plant, water plant, and water source intake and line from the north Saskatchewan River.

Murphy has been testing thermal recovery methods in a pilot project at Lindbergh since 1974. Based on its experience with the pilot project at Lindbergh, the company expects recovery rates in excess of 15 percent of the oil in place. Total production over the life of this project is expected to be in excess of 12 million cubic meters of heavy oil.

The project uses the a huff-and-puff process with about two cycles per year on each well. Production is from the Lower Grand Rapids zone at a depth of 1,650 feet. Oil gravity is 11 degrees API, and oil viscosity at the reservoir temperature is 85,000 centipoise. The wells are directionally drilled outward from common pads, reducing the number of surface leases and roads required for the project.

The project was suspended for a year from September 1988 to August 1989 when three wells were steamed. Murphy plans to gradually increase activity and to reach commercial capacity of 2,500 barrels per day within the next few years.

Project Cost: $30 million (Canadian) initial capital cost
$12 million (Canadian) operating costs plus $12 million capital additions annually are anticipated

NEWMARK HEAVY OIL UPGRADER – NewMark Energy, Inc., a partnership of Consumers Co-Operative Refineries Ltd. and the Saskatchewan Government (T-140)

Construction and commissioning of the upgrader was completed in October, 1988. The official opening was held November 9, 1988.

The refinery/upgrader combination has been running at 50,000 barrels per day of crude through the refinery itself. From that, 30,000 barrels per day of heavy resid bottoms are sent to the new Atmospheric Residual Desulfurization unit which performs primary upgrading. From there 12,000 barrels per day is being run through the Distillate Hydrotreater which improves the quality of the distillate fuel oil streams by adding hydrogen.

The 50,000 barrels per day heavy oil upgrading project was originally announced in August 1983.

Co-Operative Refineries provided 5 percent of the costs as equity, plus the existing refinery, while the provincial government provided 15 percent. The federal government and the Saskatchewan government will provide loan guarantees for 80 percent of the costs as debt.

NewMark selected process technology licensed by Union Oil of California for the upgrader. The integrated facility is capable of producing a full slate of refined products or alternately 50,000 barrels per day of upgraded crude oil or as will be the initial case, some combination of these two scenarios.

Project Cost: $700 million
STATUS OF OIL SANDS PROJECTS (Underline denotes changes since June 1990)

COMMERCIAL PROJECTS (Continued)

OSLO PROJECT — Esso Resources, Petro-Canada, Canadian Occidental, Gulf Canada, PanCanadian Petroleum, Alberta Oil Sands Equity

The OSLO joint venture is planning a 77,000 barrel per day oil sands mining, extraction and upgrading plant 60 kilometers north of Fort McMurray. Production is scheduled to begin in 1997.

The OSLO joint venture consists of Esso Resources (25 percent), Canadian Occidental Petroleum (20 percent), Gulf Canada Resources (20 percent), Petro-Canada (15 percent), PanCanadian Petroleum (10 percent) and Alberta Oil Sands Equity (10 percent). To the end of 1989, $75 million has been spent on project studies.

The Canadian federal government and the Province of Alberta have signed a Statement of Principles with members of the OSLO joint venture to proceed with the development of the integrated oil sands project. A final decision to proceed with the construction of the project will be made by July, 1990.

Projections are for a $4 - 4.5 billion development. The governments will participate in a portion of the capital costs as a development incentive. Capital costs will be supplied or raised by the project sponsors, including a portion of funding from private lenders which will be guaranteed by the governments.

The project would use conventional surface mining techniques to strip the overburden and mine the oil sands. At the plant, the bitumen would be extracted from the sand by warm water and chemicals and fed into an upgrader. There, it would be converted into synthetic crude oil with properties similar to conventional light crude oil—suitable as feedstock for Canadian refineries. OSLO has selected the high-conversion Veba Combi Cracking process for upgrading.

Current efforts are focused on technical process selection and seeking regulatory approvals. Public consultation and environmental assessment considerations are key to obtaining these approvals.

In 1991, assuming the project meets specified economic criteria, major contracts will be tendered and construction will begin. Production is expected to start in 1997.

The OSLO reserves are of higher quality than most of what remains at Syncrude, and OSLO's layer of overburden is thinner, advantages that will help make OSLO's estimated production costs slightly lower than those of Syncrude.

Project Cost: $4.1 billion estimated

PEACE RIVER COMPLEX — Shell Canada Limited

Shell Canada Limited expanded the original Peace River In Situ Pilot Project to an average production rate of 10,000 barrels per day. The Peace River Expansion Project, or PREP I, is located adjacent to the existing pilot project, approximately 55 kilometers northeast of the town of Peace River, on leases held jointly by Shell Canada Limited and Pecten Canada Limited.

The expansion, at cost of $200 million, required the drilling of an additional 213 wells for steam injection and bitumen production, plus an expanded distribution and gathering system. Wells for the expansion were drilled directionally from eight pads. The commercial project includes an expanded main complex to include facilities for separating water, gas, and bitumen; a utility plant for generating steam; and office structures. Additional off-site facilities were added. No upgrader is planned for the expansion; all bitumen extracted is diluted and marketed as a blended heavy oil. The diluted bitumen is transported by pipeline to the northern tier refineries in the United States and the Canadian west coast for asphalt production.

An application to the Energy Resources Conservation Board received approval in early November 1984. Drilling began in February 1985. Construction began June 1985. The expansion was on stream October 1986. This expansion is only the first step of Shell's long-term plan to develop the Peace River oil sands.

On January 25, 1988 the ERCB approved Shell Canada's application to expand the Peace River project from 10,000 barrels per day to approximately 50,000 barrels per day.

PREP II, as it will be called, entails the construction of a stand-alone processing plant, located about 4 km south of PREP I. PREP II would be developed in four annual construction stages, each capable of producing 1,600 cubic meters per day.

However, due to low world oil prices and continual uncertainty along with the lack of improved fiscal terms the project has been postponed indefinitely.

Some preparatory site work was completed in 1988 consisting of the main access road and drilling pads for PREP II. This work would enable a quick start should the decision to proceed occur in the near term.

Project Cost: $200 million for PREP I
$570 million for PREP II

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COMMERCIAL PROJECTS (Continued)

PRIMROSE LAKE COMMERCIAL PROJECT -- Amoco Canada Petroleum Company and Alberta Energy Company (T-170)

Amoco (formerly Dome) proposed a 25,000 barrels per day commercial project in the Primrose area of northeastern Alberta. Amoco is earning a working interest in certain oil sands leases from Alberta Energy Company. Following extensive exploration, the company undertook a cyclic steam pilot project in the area, which commenced production in November 1983, and thereby earned an interest in eight sections of adjoining oil sands leases. The 41 well pilot was producing 2,000 barrels per day of 10 degrees API oil in 1984.

The agreement with Alberta Energy contemplates that Amoco can earn an interest in an additional 194,280 of adjoining oil sands lands through development of a commercial production project. The project is estimated to carry a capital cost of at least $C1.2 billion and annual operating cost of $C140 million. Total production over a 30 year period will be 190 million barrels of oil or 18.6 percent of the oil originally in place in the project area. Each section will contain four 26-well slant-hole drilling clusters. Each set of wells will produce from 160 acres on six acre spacing. The project received Alberta Energy Resources Conservation Board approval on February 4, 1986. A subsequent amendment to the original scheme was approved on August 18, 1988. The 12,800 acre project will be developed in three phases. Four 6,500 barrel per day modules will be used to meet the 25,000 barrel per day target.

In 1989, Amoco undertook some additional work at the site by drilling a horizontal well.

Due to depressed bitumen prices, the proposed drilling schedule remains postponed. The commercial project will proceed when oil prices return to levels which make the project viable.

Project Cost: $1.2 billion (Canadian) capital cost
$140 million (Canadian) annual operating cost

SCOTFORD SYNTHETIC CRUDE REFINERY - Shell Canada Limited (T-180)

The project is the world's first refinery designed to use exclusively synthetic crude oil as feedstock, located northeast of Fort Saskatchewan in Strathcona County.

Initial capacity is 50,000 barrels per day with the design allowing for expansion to 70,000 barrels per day. Feedstock is provided by the two existing oil sands plants, Syncrude and Suncor. The refinery's petroleum products are gasoline, diesel, jet fuel and stove oil. Byproducts include butane, propane, and sulfur. Sufficient benzene is produced to feed a 300,000 tonne/year styrene plant. Refinery and petrochemical plant officially opened September 1984.

Project Cost: $1.4 billion (Canadian) total final cost for all (refinery, benzene, styrene) plants.

SUNCOR, INC., OIL SANDS GROUP - Sun Company, Inc. (72.8 percent), Ontario Energy Resources Ltd. (25 percent), publicly (2.2 percent) (T-190)

Suncor Inc. was formed in August 1979, by the amalgamation of Great Canadian Oil Sands and Sun Oil Co., Ltd. In November 1981 Ontario Energy Resources Ltd., acquired a 25 percent interest in Suncoor Inc.

Suncor Inc. operates a commercial oil sands plant located in the Athabasca bituminous sands deposit 30 kilometers north of Fort McMurray, Alberta. It has been in production since 1967. A four-step method is used to produce synthetic oil. First, overburden is removed to expose the oil-bearing sand. Second, the sand is mined and transported by conveyors to the extraction unit. Third, hot water and steam are used to extract the bitumen from the sand. Fourth, the bitumen goes to upgrading where thermal cracking produces coke, and cooled vapors form distillates. The distillates are desulfurized and blended to form high-quality synthetic crude oil, most of which is shipped to Edmonton for distribution.

Current remaining reserves of synthetic crude oil are 298 million barrels.

In 1989, the Oil Sands Group recorded earnings of $34 million compared with a loss of $11 million for 1988. Earnings for the last six months were $22 million compared with a profit of $1 million for the same period of 1988.

Production at Oil Sands Group was strong in 1989, averaging 57,200 barrels per day compared with 49,000 barrels per day in 1988.

Work will continue of the Debottlenecking project but a phased approach to the project will increase plant capacity without the large upfront cash requirements of the original proposal.

Project Cost: Not disclosed
STATUS OF OIL SANDS PROJECTS (Underline denotes changes since June 1990)

COMMERCIAL PROJECTS (Continued)

SUNNYSIDE PROJECT - Amoco Production Company (T-200)

Amoco Corporation is continuing to study the feasibility of a commercial project on 1,120 acres of fee property and 9,600 acres of combined hydrocarbon leases in the Sunnyside deposit in Carbon County, Utah. Research is continuing on various extraction and retorting technologies. The available core data are being used to determine the extent of the mineable resource base in the area and to provide direction for any subsequent exploration work.

A geologic field study was completed in September 1986; additional field work was completed in 1987. In response to Mono Power Company's solicitation to sell their (federal) lease interests in Sunnyside tar sands, Amoco Production acquired Mono Power's Combined Hydrocarbon Leases effective August 14, 1986. Amoco continued due diligence efforts in the field in 1988. This work includes a tar sand coring program to better define the resource in the Combined Hydrocarbon Lease.

Project Cost: Not disclosed

SUNNYSIDE TAR SANDS PROJECT – GNC Energy Corporation (T-210)

A 240 tons per day (120 barrels per day) tar sands pilot was built by GNC in 1982 in Salt Lake City, which employs ambient water flotation concentration which demonstrated that tar sands could be concentrated by selective flotation from 8 percent bitumen as mined to a 30 to 40 percent richness.

Chevron in 1983 built and operated a solvent leach unit that, when added in back of a flotation unit at Colorado School of Mines Research Institute in Denver, produced a bitumen dissolved in a kerosene solvent with a ratio of 1:3 which contained 5 percent ash and water. Chevron also ran a series of tests using the solvent circuit first followed by flotation and found it to be simpler and cheaper than the reverse cycle.

Kellogg, in a series of tests during 1983/1984, took the product from the CSMRI tests and ran it through their Engelhard ARTCAT pilot plant in Houston and produced a 27 degrees API crude out of the 10 percent API bitumen, recycled the solvent, and eliminated the ash, water, and 80 percent of the metals, nitrogen, and sulfur.

Today GNC has a complete process that on tests demonstrates 96 to 98 percent recovery of mined bitumen through the solvent and flotation units and converts 92 percent of that stream to a 27 degrees API crude with characteristics between Saudi Light and Saudi Heavy.

GNC has 2,000 acres of fee leases in the Sunnyside deposit that contain an estimated 307 million barrels of bitumen. It has applied to BLM for conversion of a Sunnyside oil and gas lease to a combined hydrocarbon lease. The first commercial facility will be 7,500 barrels per day. In response to a solicitation by the United States Synthetic Fuels Corporation (SFC) for tar sands projects that utilize mining and surface processing methods, GNC requested loan and price guarantees of $452,419,000. On November 19, 1985 the SFC determined that the project was a qualified candidate for assistance under the terms of the solicitation.

On December 19, 1985, the SFC was cancelled by Congressional action. GNC is now attempting to finance independently of United States government assistance. Studies have been completed by M. W. Kellogg and Engelhard indicating feasibility, after the decline in prices beginning in January 1986 of a 7,500 barrels per day plant which converts the ART-treated bitumen to 31 percent gasoline and 69 percent diesel. The 7,500 barrels per day plant including upgrading to products, with some used equipment, would cost $149 million.

Project Cost: $149 million for 7,500 barrels per day facility

SYNCO SUNNYSIDE PROJECT - Synco Energy Corporation (T-220)

Synco Energy Corporation of Orem, Utah is seeking to raise capital to construct a plant at Sunnyside in Utah's Carbon County to produce oil and electricity from coal and tar sands.

The Synco process to extract oil from tar sands uses coal gasification to make a synthetic gas. The gas is cooled to 2,000 degrees F by making steam and then mixed with the tar sands in a variable speed rotary kiln. The hot synthetic gas vaporizes the oil out of the tar sands and this is then fractionated into a mixture of kerosene (jet fuel), diesel fuel, gasoline, other gases, and heavy ends.

The syngas from the gasifier is separated from the oil product, the sulfur and CO₂ removed and the gas burned in a gas turbine to produce electricity. The hot exhaust gases are then used to make steam and cogenerated electricity.

Testing indicates that the hydrogen-rich syngas from the gasified coal lends to good cracking and hydrogen upgrading in the kiln. Synco holds process patents in the U.S., Canada and Venezuela and is looking for a company to joint venture with on this project.

The plant would be built at Sunnyside, Utah, near the city of Price.

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STATUS OF OIL SANDS PROJECTS (Underline denotes changes since June 1990)

COMMERCIAL PROJECTS (Continued)

There is a reserve of four billion barrels of oil in the tar sands and 230 million tons of coal at the Sunnyside site. Both raw materials could be conveyed to the plant by conveyor belt.

The demonstration size plant would produce 8,000 barrels of refined oil, 330 megawatts of electricity, and various other products including marketable amounts of sulfur.

An application has been filed by Syncrude with the Utah Division of State Lands for an industrial special use lease containing the entire Section 36 of State land bordering the town of Sunnyside, Utah.

Project Cost: $350 million

SYNCRUDE CANADA, LTD. – Esso Resources Canada Limited (25.0 percent); Petro-Canada Inc. (17.0 percent); Alberta Oil Sands Equity (16.74 percent); Alberta Energy Company (10.0 percent); PanCanadian Petroleum Limited (10.0 percent); Gulf Canada Resources Ltd. (9.03 percent); Canadian Occidental Petroleum Ltd. (7.23 percent); LIBOG - Oil Sands Ltd. Partnership (Amoco Canada Petroleum Company Ltd) (5.0 percent) (T-230)

Located near Fort McMurray, the Syncrude surface mining and extraction plant produces 155,000 barrels per calendar day. The original plant with a capacity of 108,000 barrels was based upon: oil sand mining and ore delivery with four dragline-bucketwheel reclaimers-conveyor systems; oil extraction with hot water flotation of the ore followed by dilution centrifuging; and upgrading by fluid coking followed by hydrotreating. During 1988, a 6-year $1.5 billion investment program in plant capacity was completed to bring the production capability to over 155,000 barrels per calendar day. Included in this investment program are a 40,000 barrel per day L-C Fining hydrocracker, additional hydrotreating and sulfur recovery capacity, and auxiliary mine feed systems as well as debottlenecking of the original processes.

Project Cost: Total cost $3.8 billion

THREE STAR OIL MINING PROJECT - Three Star Drilling and Producing Corp. (T-240)

Three Star Drilling and Producing Corporation has sunk a 426 foot deep vertical shaft into the Upper Siggins sandstone of the Siggins oil field in Illinois.

Three Star has drilled over 32,000 feet of horizontal boreholes up to 1,500 feet long through the reservoir. The original drilling pattern was planned to allow the borehole to wander up and down through the producing interval in a "snake" pattern. Now, only straight upward slanting holes are being drilled. Three Star estimates the Upper Siggins still contains some 35 million barrels of oil.

The initial plans call for drilling one to four levels of horizontal boreholes. The Upper Siggins presently has 34 horizontal wells which compose the 32,000 feet of drilling.

Sixty percent of the horizontal drilling has been completed. The original plan to begin production while the rest of the drilling was completed has changed. Production has been put on hold pending an administrative hearing to determine whether the mine is to be classified as gaseous or non-gaseous. While awaiting the outcome of the hearing, the company is running production tests.

Project Cost: Three Star has budgeted $3.5 million for the first shaft.

WOLF LAKE PROJECT - BP Canada Resources Ltd. and Petro-Canada (T-260)

Located 30 miles north of Bonnyville near the Saskatchewan border, on 75,000 acres, the Wolf Lake commercial oil sands project (a joint venture between BP Canada Resources Ltd. and Petro-Canada) was completed and began production in April 1985. Production at designed capacity of 7,000 barrels per day was reached during the third quarter 1985. The oil is extracted by the "huff-and-puff" method. Nearly two hundred wells were drilled initially, then steam injected. As production from the original wells declines more wells will be drilled.

An estimated 720 wells will be needed over the expected 25-year life of the project. Because the site consists mostly of muskeg, the wells will be directionally drilled in clusters of 20 from special pads. The bitumen is heavy and viscous (10 degrees API) and thus cannot be handled by most Canadian refineries. There are no plans to upgrade the bitumen into a synthetic crude; much of it will probably be used for the manufacture of asphalt or exported to the northern United States.

By mid-1988 production had dropped 22 percent below 1987 levels. Following a change of strategy in operation of the reservoir, however, production had increased to 1,030 cubic meters per day in 1989.

In 1987, a program designed to expand production by 2,400 cubic meters per day to 3,700 cubic meters per day, total bitumen production was initiated. Wolf Lake 2 was originally expected to be completed in mid-1989.

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STATUS OF OIL SANDS PROJECTS (Underline denotes changes since June 1990)

COMMERCIAL PROJECTS (Continued)

Wolf Lake Phase 2 would be followed by Phases 3 and 4. BP’s production target is 7,000 cubic meters per day in the 1990s (44,000 barrels per day).

In early 1989, BP Canada and Petro-Canada said they will delay by one year the decision to start up the second phase. While the Wolf Lake 2 plant will be commissioned during 1989-90, full capacity utilization of the combined project is not likely before 1991, when it is expected that higher bitumen prices will support the expanded operation and further development. At the end of the commissioning period, during which BP will ensure that all the plant components are operational, BP and Petro-Canada will decide when to begin injection.

By mid 1990, the new water recycle facilities and the Wolf Lake 2 generators were commissioned and are in operation. Production levels will be maintained at 1,100 to 1,200 cubic meters per day until bitumen netbacks have improved. The Wolf Lake 2 oil processing plant and Wolf Lake 1 steam gathering facilities will be suspended.

Project Cost: Wolf Lake 1
$114 million (Canadian) initial capital
(Additional $750 million over 25 years for additional drilling)

Project Cost: Wolf Lake 2
$200 million (Canadian) initial capital

YAREGA MINE-ASSISTED PROJECT — Union of Soviet Socialist Republics (T-670)

The Yarega oilfield (Soviet Union) is the site of a large mining-assisted heavy oil recovery project. The productive formation of this field has 26 meters of quartz sandstone occurring at a depth of 200 meters. Average permeability is 3.17 mKm². Temperature ranges from 279 to 281 degrees K; porosity is 26 degrees; oil saturation is 87 percent of the pore volume or 10 percent by weight. Viscosity of oil varies from 15,000 to 20,000 mPa per second; density is 945 kilograms per cubic meter.

The field has been developed in three major stages. In a pilot development, 69 wells were drilled from the surface at 70 to 100 meters spacing. The oil recovery factor over 11 years did not exceed 1.5 percent.

Drainage through wells at very close spacing of 12 to 20 meters was tested with over 92,000 shallow wells. Development of the oilfield was said to be profitable, but the oil recovery factor for the 18 to 20 year period was approximately 3 percent.

A mining-assisted technique with steam injection was developed starting in 1968. Over the past 15 years, 10 million tons of steam have been injected into the reservoir.

Three mines have been operated for over ten years. An area of the deposit covering 225 hectares is under thermal stimulation. It includes 15 underground slant blocks, where 4,192 production wells and 11,795 steam-injection wells are operated. In two underground slant production blocks, which have been operated for about 8 years, oil recovery of 50 percent has been reached. These areas continue to produce oil. A local refinery produces lubricating oils from this crude.

Project Cost: Not Disclosed

R & D PROJECTS

ATHABASCA IN SITU PILOT PROJECT (Kearl Lake) — Alberta Oil Sands Technology and Research Authority, Husky Oil Operations Ltd., Esso Resources Canada Ltd. (T-270)

The operator of the Athabasca In Situ Pilot Project is Husky Oil Operations Ltd.

The pilot project began operation in December, 1981. Currently, three patterns are being operated: one 9-spot and two 5-spots. The central well of each pattern is an injector. The 8 observations wells are located in and around the three patterns.

The 9-spot pattern was started up in 1985. The two 5-spot patterns were started up in 1987. Results from all three patterns continue to be encouraging.

In April, 1989, a special test was initiated to increase the oil production rate. To date, the test has been very successful.

Project Cost: $139 million (estimate)
STATUS OF OIL SANDS PROJECTS (Underline denotes changes since June 1990)

R & D PROJECTS (Continued)

BATTRUM IN SITU WET COMBUSTION — Mobil Oil Canada, Unocal Canada Limited, Saskoil, 137886 Canada Ltd., Hudson’s Bay Oil and Gas (T-280)

Mobil Oil Canada initiated dry combustion in the Battrum field in the Swift Current producing area of Saskatchewan in 1965 and converted to wet combustion in 1978. The combustion scheme, which Mobil operates in three Battrum units, was expanded during 1987-88. The expansion included drilling 46 wells, adding 12 new burns, a workover program and upgrading surface production and air injection facilities.

All burns have been converted to wet combustion and air injection has increased to 25 million cubic feet per day. Studies have been initiated to determine the feasibility of oxygen enrichment for the EOR scheme.

Project Cost: Expansion $30 million

BVI COLD LAKE PILOT — Alberta Oil Sands Technology and Research Authority (AOSTRA), Bow Valley Industries Ltd., (T-290)

The project is operated by Bow Valley Industries Ltd. The process utilizes steam and additives to recover bitumen from the Clearwater formation. The project currently consists of 16 wells directionally drilled from two pad locations.

The project is located on a Gulf Canada lease in the Cold Lake area of Alberta, Canada on which Gulf operated a 6 well pilot from 1977 to 1979. Bow Valley has a farm-in arrangement with Gulf and utilizes some of the surface facilities built for the Gulf pilot.

Cyclic steam operations began in mid-January, 1985 at the original seven-well pad to test the steam and additives process. A new steam placement technique was developed during these operations with favorable results. This led to a new nine-well pad being drilled in late 1986 to further investigate the new technique developed with the original pad. Cyclic operations at both pads are continuing.

Project Cost: $13 million

CANMET HYDROCRACKING PROCESS — Petro-Canada and Partec Lavalin Inc. (T-300)

A novel hydrocracking process for the upgrading of bitumen, heavy oil and residuum has been developed at the Canada Centre for Mineral and Energy Technology (CANMET). This CANMET Hydrocracking Process is a single-stage, high conversion process effective for the conversion of 90 weight percent of the pitch in heavy feedstocks to distillate boiling below 524 degrees C. (Pitch is defined as material boiling above 524 degrees C.) An additive is used which acts as a coke preventer and a mildly active hydrogenator at moderate pressures. Hydrogen consumption and gas make are lower compared to other hydrocracking processes.

In 1979, Petro-Canada acquired an exclusive right to license the process. Petro-Canada formed a working partnership with Partec Lavalin Inc., a Canadian engineering company, for the marketing of the technology and the design and construction of a 5,000 barrels per stream day demonstration plant at the Petro-Canada refinery in Montreal.

Construction and commissioning of the extensively instrumented demonstration unit was completed in 1985. Upon startup, the unit was operated in the hydrovisbreaking mode. Without additive, 30 weight percent pitch conversion was achieved. In May 1986, introduction of additive led to the achievement of 80 weight percent pitch conversion without coking. This test proved the beneficial effect of the additive in achieving high conversions.

Further testing, in pilot plants, led to the use of a simpler additive. The plant operated from March 1987 until June 1989 using this commercial additive. During this time a number of special demonstrations were made including a high conversions (93%) run using a blend of vacuum residues from Cold Lake Heavy Oil and Western Canadian Crudes. The results of this work confirmed the capability of the process to achieve high conversion in a thermally stable, coke free, single stage reactor.

The high conversion Canmet HC process has been successfully demonstrated and is now available for commercial application. Patent protection and process guarantees are provided by the licensors.

Project Cost: Not disclosed

CARIBOU LAKE PILOT PROJECT — Husky Oil Operations Ltd. and Alberta Energy Co. (T-310)

Husky Oil Operations Ltd. (60% interest) and Alberta Energy Co. (40% interest) received ERCB approval for a 1,100 barrels per day heavy oil steam pilot in the Primrose block of the Cold Lake Air Weapons Test Range in northeastern Alberta.
STATUS OF OIL SANDS PROJECTS (Underline denotes changes since June 1990).

R & D PROJECTS (Continued)

In September, 1989, Husky and AEC Oil & Gas Company announced their intention to proceed with the development of the Caribou Lake Pilot Project. This project will test the potential commercial application of producing heavy oil using cyclic steaming technology. Husky will operate the project.

Husky and AEC have drilled 48 exploratory and development wells on the 372-section Caribou Lake block. Natural gas and bitumen discoveries have resulted, with the quality and extent of the bitumen resources justifying this pilot recovery project.

Site clearing and preparation started immediately with well drilling to follow after freeze-up and the main facility construction to occur through the second and third quarters of 1990, followed by start-up prior to year-end. The Pilot will consist of 25 cyclic steam/production wells, 25 MMBTU/hour steam generation capacity and associated oil treating and produced water clarification facilities. A comprehensive testing and analysis program to define technology for maximum reuse of produced water will be incorporated.

Project Cost: Approximately $20 Million

CELTIC HEAVY OIL PILOT PROJECT – Mobil Oil Canada (T-320)

Mobil's heavy oil project is located in T52 and R23, W3M in the Celtic Field, northeast of Lloydminster. The pilot consists of 25 wells drilled on five-acre spacing, with twenty producers and five injectors. There is one fully developed central inverted nine-spot surrounded by four partially developed nine-spots. The pilot was to field test a wet combustion recovery scheme with steam stimulation of the production wells.

Air injection, which was commenced in October 1980, was discontinued in January 1982 due to operational problems. An intermittent steam process was initiated in August 1982. The seventh steam injection cycle commenced in January, 1987 and operations are continuing.


Project Cost: $21 million (Canadian) (Capital)

C-H SYNFUELS DREDGING PROJECT - C-H Synfuels Ltd. (T-330)

C-H Synfuels Ltd. plans to construct an oil sands dredging project in Section 8, Township 89, Range 9, west of the 411% meridian. The scheme would involve dredging of a cutoff meander in the Horse River some 900 meters from the Fort Mc Murray subdivision of Abasand Heights. Extraction of the dredged bitumen would take place on a floating modular process barge employing a modified version of the Clark Hot Water Process. The resulting bitumen would be stored in tanks, allowed to cool and solidify, then transported, via truck and barge, to either Suncor or the City of Fort McMurray. Tailings treatment would employ a novel method combining the sand and sludge, thus eliminating the need for a large conventional tailings pond.

C-H proposes to add lime and a non-toxic polyacrylamide polymer to the tailings stream. This would cause the fines to attach to the sand eliminating the need for a sludge pond.

Project Cost: Not disclosed

CIRCLE CLIFFS PROJECT – Kirkwood Oil and Gas (T-340)

Kirkwood Oil and Gas is forming a combined hydrocarbon unit to include all acreage within the Circle Cliffs Special Tar Sand Area, excluding lands within Capitol Reef National Park and Glen Canyon National Recreational Area.

Work on this project is suspended until an Environmental Impact Statement can be completed.

Project Cost: Not disclosed

COLD LAKE STEAM STIMULATION PROGRAM - Mobil Oil Canada (T-350)

A stratigraphic test program conducted on Mobil's 75,000 hectares of heavy oil leases in the Cold Lake area resulted in approximately 150 holes drilled to date. Heavy oil zones with a total net thickness of 30 meters have been delineated at depths between 290 and 460 meters. This pay is found in sand zones ranging in thickness from 2 to 20 meters.
STATUS OF OIL SANDS PROJECTS (Underline denotes changes since June 1990)

R & D PROJECTS (Continued)

Single well steam stimulations began in 1982 to evaluate the production potential of these zones. Steam stimulation testing was subsequently expanded from three single wells to a total of eleven single wells in 1985. Various zones are being tested in the Upper and Lower Grand Rapids formation. The test well locations are distributed throughout Mobil's leases in Townships 63 and 64 and Ranges 6 and 7 W4M. Based on encouraging results, the Iron River Pilot was constructed with operations beginning in March, 1988. To date, steam stimulation tests have been conducted in a total of 14 vertical wells.

Three vertical wells, all multi-zone completions, are still in operation in 1990; the remaining wells were suspended at the conclusion of their testing programs. A single zone steam stimulation in a horizontal well began in mid-1989. This test is still operating.

Project Cost: Not disclosed

DONOR REFINED BITUMEN PROCESS - Gulf Canada Limited, the Alberta Oil Sands Technology and Research Authority, and L'Association pour la Valorization des Huiles Lourdes (ASVAHL) (T-360)

An international joint venture agreement has been signed to test the commercial viability of the Donor Refined Bitumen (DRB) process for upgrading heavy oil or bitumen.

About 12,000 barrels of Athabasca bitumen from the Syncrude plant were shipped to the ASVAHL facilities near Lyon, France. Beginning in October 1986 tests were conducted in a 450 barrel per day pilot plant. Engineering and economic evaluations were completed by the end of 1987.

ASVAHL is a joint venture of three French companies—Elf Aquitaine, Total-Compagnie Francaise de Raffinage, and Institut Francaise du Petrole. The ASVAHL test facility was established to study new techniques, processes and processing schemes for upgrading heavy residues and heavy oils at a demonstration scale.

The DRB process entails thermally cracking a blend of vacuum residual and a refinery-derived hydrogen-rich liquid stream at low pressure in the liquid phase. The resulting middle distillate fraction is rehydrogenated with conventional fixed bed technology and off-the-shelf catalysts.

Project Cost: Not disclosed

ESSO COLD LAKE PILOT PROJECTS - Esso Resources Canada Ltd. (T-380)

Esso operates two steam based in situ recovery projects, the May-Ethel and Leming pilot plants, using steam stimulation in the Cold Lake Deposit of Alberta. Tests have been conducted since 1964 at the May-Ethel pilot site in 27-64-3W4 on Esso's Lease No. 40. Esso has sold these data to several companies. Esso's Leming pilot is located in Sections 4 through 8-65-3W4. The Leming pilot uses several different patterns and processes to test future recovery potential. Esso expanded its Leming field and plant facilities in 1980 to increase the capacity to 14,000 barrels per day at a cost $60 million. A further expansion costing $40 million debottlenecked the existing facilities and increased the capacity to 16,000 barrels per day. By 1986, the pilots had 500 operating wells. Approved capacity for all pilot projects is currently 3,100 cubic meters per day—i.e., about 19,500 barrels per day of bitumen.

Major prototype facilities for the commercial-scale Cold Lake Project will continue to be tested including three 175,000 pounds per hour steam generators, and a water treatment plant to convert the saline water produced with the bitumen into a suitable feedwater for the steam generators. Additionally, the pilots serve as a testing area for optimizing the parameters of cyclic steam stimulation as well as on follow-up recovery methods, such as steam displacement and horizontal wells.

(See Cold Lake in commercial projects listing)

Project Cost: $260 million

EYEHILL IN SITU STEAM PROJECT - Canadian Occidental Petroleum, Ltd., Esso Resources Canada and Murphy Oil Company Ltd. (T-390)

The experimental pilot is located in the Eyehill field, Cummings Pool, at Section 16-40-28-W3 in Saskatchewan six miles north of Macklin. The pilot consists of nine five spot patterns with 9 air injection wells, 24 producers, 3 temperature observation wells, and one pressure observation well. Infill of one of the patterns to a nine-spot was completed September 1, 1984. Five of the original primary wells that are located within the project area were placed on production during 1984. The pilot covers 180 acres. Ignition of the nine injection wells was completed in February 1982. The pilot is fully on stream. Partial funding for this project was provided by the Canada-Saskatchewan Heavy Oil Agreement Fund. The pilot was given the New Oil Reference Price as of April 1, 1982.

Production in 1989 continued at 500 barrels per day and is expected to eventually peak at 1,000 barrels per day.
STATUS OF OIL SANDS PROJECTS (Underline denotes changes since June 1990)

R & D PROJECTS (Continued)

The pilot has 40 feet of pay with most of the project area pay underlain by water. Reservoir depth is 2,450 feet. Oil gravity is 14.3 degrees API, viscosity 2,750 Cp at 70 degrees F, porosity 34 percent, and permeability 6,000 md. Cumulative production reached one million barrels in 1988. This represents about 6 percent of the oil originally in place in the project area. Another four million barrels is expected to be recovered in the project's remaining 10 years of life.

Project Cost: $15.2 million

FT. KENT THERMAL PROJECT – Koch Industries and Worldwide Energy Corporation (T-400)

Canadian Worldwide Energy Ltd. and Suncor, Inc., developed heavy oil deposits on a 4,960 acre lease in the Fort Kent area of Alberta. Canadian Worldwide holds a 50 percent working interest in this project, with Koch Industries now replacing Suncor. This oil has an average gravity of 12.5 degrees API, and a sulfur content of 3.5 percent. The project utilizes huff and puff, with steamdrive as an additional recovery mechanism. The first steamdrive pattern was commenced in 1980, with additional patterns convened from 1984 through 1988. Eventually most of the project will be convened to steamdrive.

A total of 126 productive wells are included in this project, including an 8 well cluster drilled in late 1985. Five additional development well locations have been identified. Approximately 59 wells are now operating, with production averaging 1,600 barrels per day. Further development work, including tying-in the 8 wells most recently drilled, has been delayed. Ultimate recoveries are anticipated to be greater than 21 percent with recoveries in the 26 percent range in the steamflood areas expected.

Because of the experimental work being carried out, this project qualifies for a reduced royalty rate of only 5 percent. Canadian Worldwide’s share of the project costs to date is approximately $35 million (Canadian).

In January 1989, it was announced that the project would be indefinitely suspended.

Project Cost: See Above

GLISP PROJECT – Amoco Canada Petroleum Company Ltd. and AOSTRA (T-420)

The Gregoire Lake In Situ Steam Pilot (GLISP) Project is an experimental steam pilot located at Section 2-86-7-W4M. The participants are Amoco (14.29 percent), and AOSTRA (85.71 percent) (Petro-Canada participated in Phase A of the project but has declined participation in Phase B which was initiated in 1990). Other parties may participate by reducing AOSTRA’s ownership. The lease ownership is shared jointly by Amoco (85 percent) and Petro-Canada (15 percent). Amoco is the operator. The production pattern consists of a four-spot geometry with an enclosed area of 0.28 hectares (0.68 acres). Observation wells have been drilled. The process has tested the use of steam and steam additives in the recovery of highly viscous bitumen (1 x 10 million cP at virgin reservoir temperature). Special fracturing techniques have been used and sophisticated seismic methods and other techniques are being used to monitor the in situ process. Steam Foam Flooding began in October 1988.

Plans for 1990 call for optimizing surfactant and steam rates and increasing bitumen production pressure cycling of the pilot will be investigated.

The project began operation in September 1985.

Project Cost: $22.8 million (Canadian)

HANGING STONE PROJECT – Petro-Canada, Canadian Occidental Petroleum Ltd., Esso Resources Canada Limited and Japan Canadian Oil Sands (T-430)

Construction of a 13 well cyclic steam pilot with 4 observation wells was completed and operation began on July 1, 1990.

Phase 3 of the project involves operating for another two and a half years and a total expenditure of approximately $40 million.

Total land holding for the project is one-half million hectares.

Project Cost: Not formulated.

IPIATIK EAST PROJECT – Alberta Energy Company Limited, Amoco Canada and Deminex Canada (T-435)

The Ipiatik East pilot is inside the Cold Lake Air Weapons Range, otherwise known as the Primrose Block. AEC has a 60 percent interest in the project along with Amoco Canada and German Deminex Canada. The project uses cyclic steam injection to test the production potential of the Wabiskaw sands of the Lower Cretaceous Mannville Group.
STATUS OF OIL SANDS PROJECTS (Underline denotes changes since June 1990)

R & D PROJECTS (Continued)

AEC first began experimenting with cyclic steaming in the area in 1984 with seven wells drilled on 3.6 acre spacing. The initial strategy was to use the basal zone to promote reservoir heating and gravity drainage, and to minimize steam override. Initial steaming using 44,000 barrel slugs provided good performance on the first cycle but production deteriorated in later cycles. The wells had been completed with the conventional techniques of installing the production casing set through the formation and cemented to the surface.

In late 1986, AEC began testing a propped sand fracture completion prior to steam injection. The horizontal fracture provided a larger contact area for stimulation and a better chance to contain the fracture above the basal zone. To assist fracture initiation, the casing was notched to create a narrow horizontal area which would be exposed to high rate, high pressure fracture fluids. The casing was notched in the upper half of the oil sands above several of the tight calcite layers.

Results of the propped fracturing prior to steam injection were very encouraging. AEC drilled three more wells northeast of the Phase A pattern in 1987 for further testing. Again, results were very encouraging. The wells achieved daily oil production rates which were 50 percent better than cycle one, 90 percent better than cycle two and 60 percent better than cycle three on typical Phase A wells.

Encouraged by the results, AEC drilled another four wells in 1988, completing a regular seven-spot pattern on six-acre spacing. Those wells have performed better than the 1987 wells over three cycles. AEC continued testing in 1989 but the project has now been suspended.

IRON RIVER PILOT PROJECT - Mobil Oil Canada (T-440)

The Iron River Pilot Project commenced steam stimulation operations in March 1988. It consists of a four hectare pad development with 23 slant and directional wells on 3.2 and 1.6 hectare spacing within a 65 hectare drainage area. The project is 100 percent owned by Mobil Oil. It is located in the northwest quarter of Section 6-64-6W4 adjacent to the Iron River battery facility located on the southwest corner of the quarter section. The project is expected to produce up to 200 cubic meters of oil per day. The battery was expanded to handle the expected oil and water volumes. The produced oil is transported by underground pipeline to the battery. Pad facilities consist of 105 million kJ/hr steam generation facility, test separation equipment, piping for steam and produced fluids, and a flare system for casing gas.

To obtain water for the steam operation, ground water source wells were drilled on the pad site. Prior to use, the water is treated. Produced water is injected into a deep water disposal well. Fuel for steam generation is supplied from Mobil's fuel gas supply system and the treated oil is trucked to the nearby Husky facility at Tucker Lake.

The pilot project has been operating for two years and is expected to operate for one to two more years.

Project Cost: $14 million

JET LEACHING PROJECT - BP Resources Canada Ltd. (T-450)

BP Resources Canada Ltd. began in February 1988 an experimental in situ bitumen separation project at the Ells River area north of Fort McMurray, Alberta.

The process, called jet leaching, involves high-rate injection of water into a tar sand formation so that the agitation of the injected fluid cuts the tar sand and separates the bitumen. The injected water contains chemicals that cause the sand particles to agglomerate, further aiding the separation process.

The bitumen-laden fluid is brought to the surface in a typical production well while the sand particles remain in the formation. BP expects the fluid to be in the form of a froth in which the bitumen will float to the surface. Excess fluid will be discarded.

The project involves drilling four wells, in which casing will be run to the top of the formation. The jet injection device will be lowered into the uncased bottom for injection of the water. A single jet is pointed into the formation, and is rotated during injection in order to contact the entire formation exposed in the wellbore.

The fluid injection rate probably will be in the range of 15-25 barrels per hour at a fluid temperature of 175 degrees F.

The pilot targets the McMurray tar sands at a depth of 220 to 260 feet.

Project Cost: C$500,000
STATUS OF OIL SANDS PROJECTS (Underline denotes changes since June 1990)

R & D PROJECTS (Continued)

KENOCO PROJECT—Kenoco Company (T-460)

The Kenoco Company, the successor to the Kensyntar Company, is developing a heavy oil project in Western Kentucky. The principals of Kenoco acquired the interests of Pittston Synfuels, a partner in Kensyntar, in December 1984. A pilot was successfully operated from the summer 1981 through 1983 and produced over 6,400 barrels of heavy oil using a modified wet fireflood process. The operation was stopped before completion of the burn in 1983 to obtain core data on the test pattern. Sixteen core holes were drilled and analyzed.

Plans were being developed to expand to a 400 to 700 barrels per day multi-pattern operation, and over a period of 5 to 6 years to a 10,000 barrels per day operation. The commercial project is now on hold pending better market conditions.

Project Cost: Not disclosed

LINDBERGH STEAM PROJECT—Murphy Oil Company, Ltd. (T-470)

Experimental in situ recovery project located at 13-58-5 W4, Lindbergh, Alberta, Canada. The pilot produces from a 60 foot thick Lower Grand Rapids formation at a depth of 1650 feet. The pilot began with one inverted seven spot pattern enclosing 20 acres. Each well has been steam stimulated and produced roughly eleven times. A steam drive from the center well was tested from 1980 to 1983 but has been terminated. Huff-and-puff continues. Production rates from the seven-spot area have been encouraging to date, and a 9 well expansion was completed August 1, 1984, adding two more seven spots to the pilot. Oil gravity is 11 degrees API and has a viscosity of 85,000 Cp at reservoir temperature F. Porosity is 33 percent and permeability is 2500 md.

This pilot is currently suspended due to low oil prices.

(Refer to the Lindbergh Commercial Thermal Recovery Project (T-33) listed in commercial projects.)

Project Cost: $7 million to date

LINDBERGH THERMAL PROJECT—Amoco Canada Petroleum Company Ltd. (T-480)

Amoco (formerly Dome) drilled 56 wells in section 18-55-5 W4M in the Lindbergh field in order to evaluate an enriched air and air injection fire flood scheme. The project consists of nine 30 acre, inverted seven spot patterns to evaluate the combination thermal drive process. The enriched air scheme included three 10 acre patterns. Currently only one 10 acre enriched air pattern is operational.

Air was injected into one 10 acre pattern to facilitate sufficient burn volume around the wellbore prior to switching over to enriched air injection in July 1982. Oxygen breakthrough to the producing wells resulted in the shut down of oxygen injection. A concerted plan of steam stimulating the producers and injecting straight air into this pattern was undertaken during the next several years. Enriched air injection was reinitiated in this pattern in August 1985. Initial injection rate was 200,000 cubic feet per day of 100 percent pure oxygen. Early oxygen breakthrough was controlled in the first year of Combination Thermal Drive by reducing enrichment to 80% oxygen.

Project Cost: $22 million

MINE-ASSISTED PILOT PROJECT—(see Underground Test Facility Project)

MORGAN COMBINATION THERMAL DRIVE PROJECT—Amoco Canada Petroleum Company Ltd. (T-490)

Amoco (formerly Dome) completed a 46 well drilling program in Section 35-51-4 W4M in the Morgan field in order to evaluate a combination thermal drive process. The project consists of nine 30-acre seven spot patterns. All wells have been steam stimulated. The producers in these patterns have received multiple steam and air/steam stimulations to provide for production enhancements and oil depletion prior to the initiation of burning with air as the injection medium. To date, all of the nine patterns have been ignited and are being pressure cycled using air injection. Combination thermal drive is planned for one pattern during the 4th pressure cycle.

Project Cost: $20 million

FCEJ PROJECTS—Canada-Cities Service Ltd., Esso Resources Canada, Ltd., Japan Canada Oil Sands, Ltd., and Petro-Canada (T-500)

Project is designed to investigate the extraction of bitumen from Athabasca Oil Sands using an in situ recovery technique. A three phase 15 year farmout agreement has been executed with Japan Canada Oil Sands, whereby Japan Canada Oil Sands could earn an undivided 25 percent in 34 leases covering 1.2 million acres in the in situ portion of the Athabasca Oil Sands by contributing a minimum of $75 million. Japan Canada Oil Sands has completed its interest earning obligation for Phases I and II by contributing $57 million.

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SYNTHETIC FUELS REPORT, SEPTEMBER 1990
STATUS OF OIL SANDS PROJECTS (Underline denotes changes since June 1990)

R & D PROJECTS (Continued)

Phase II, designed to further test and delineate the resource, is now complete. Phase III began in December, 1988. The program includes a multi-cycle single well steam simulation test at 16-27-84-11 W4 in its eighth production cycle. A second multicycle single well steam stimulation test at 4-35-84-11 W4 is in its sixth cycle. Operation of the third single well test at 13-27 was suspended after completion of its fourth cycle. Steam injection began on May 1, 1990 in the center well of a 13 well pilot.

Project Cost: Not disclosed

PELICAN LAKE PROJECT – CS Resources Limited and Devran Petroleum Ltd. (T-510)

CS Resources has acquired from Gulf Canada, the original operator, the Pelican Lake Project comprised of some 89 sections of oil sand leases.

The Pelican Lake program is designed to initially test the applicability of horizontal production systems under primary production methods, with a view to ultimately introducing thermal recovery methods.

Eight horizontal wells have been successfully drilled at the project site in north central Alberta. The Group utilizes an innovative horizontal drilling technique which allows for the penetration of about 1,500 feet of oil sands in each well. With this technique, a much higher production rate is expected to be achieved without the use of expensive secondary recovery processes. Drilling was commenced on the first horizontal well on January 30, 1988 and drilling of the eighth well was completed in June 1988. Drilling of five more horizontal wells with horizontal sections of 3,635 feet was accomplished in December 1989 and January 1990.

Project Cost: Not disclosed

PELICAN-WABASCA PROJECT – CS Resources (T-520)

Construction of fireflood and steamflood facilities is complete in the Pelican area of the Wabasca region. Phase I of the project commenced operations in August 1981, and Phase II (fireflood) commenced operations during September 1982. The pilot consists of a 31-well centrally enclosed 7-spot pattern plus nine additional wells. Oxygen injection into two of the 7-spot patterns was initiated in November 1984. Six more wells were added in March 1985 that completed an additional two 7-spot patterns. In April 1986, the fireflood operation was shut down and the project converted to steam stimulation. Sixteen pilot wells were cyclic steamed. One pattern was converted to a steam drive, another pattern converted to a water drive. Remaining wells retained on production. In January/February 1986, 18 new wells were drilled and put on primary production. Cyclic steaming was undertaken in February 1987. The waterflood on the pilot ceased operation in April, 1987. Cyclic steaming of the producing wells on the 7-spot steamflood project south of the pilot was convened to steamflood in fall 1987.

As of early 1989 thermal operations, with the exception of the seven-spot steamflood project, have been terminated and the wells placed in a flowdown phase.

Project Cost: Not Specified

PROVOST UPPER MANNVILLE HEAVY OIL STEAM PILOT PROJECT – AOSTRA, Canadian Occidental, Esso, Murphy Oil, Norcen Energy Resources Limited (T-530)

Norcen Energy Resources Limited has applied to the Alberta Energy Resources Conservation Board to conduct an experimental cyclic steam/steam drive thermal pilot in the Provost Upper Mannville B Pool. The pilot project will consist of a single 20 acre inverted 9 spot pattern to be located approximately 20 kilometers southeast of Provost, Alberta.

An in situ combustion pilot comprising one 20 acre 5 spot was initiated in 1975. The pilot was expanded in 1982 to encompass seven 6 hectare 7 spot patterns. This pilot operation will continue under its current approval until December 31, 1986.

All nine wells in the new steam pilot pattern will initially be subject to cyclic steam with conversion to a steam drive utilizing one central injector and eight surrounding producers as soon as communication is established between each well.

All nine pattern wells were placed on primary production in February 1985.

Project Cost: Not Disclosed
STATUS OF OIL SANDS PROJECTS (Underline denotes changes since June 1990)

R & D PROJECTS (Continued)

PR SPRING PROJECT — Enercor and Solv-Ex Corporation, (T-540)

The PR Spring Tar Sand Project, a joint venture between Solv-Ex Corporation (the operator) and Enercor, was formed for the purpose of mining tar sand from leases in the PR Spring area of Utah and extracting the contained hydrocarbon for sale in the heavy oil markets.

The project's surface mine will utilize a standard box-cut advancing pit concept with a pit area of 20 acres. Approximately 1,600 acres will be mined during the life of the project. Exploratory drilling has indicated oil reserves of 58 million barrels with an average grade of 7.9 percent by weight bitumen.

The proprietary oil extraction process to be used in the project was developed by Solv-Ex in its laboratories and pilot plant and has the advantages of high recovery of bitumen, low water requirements, acceptable environmental effects and economical capital and operating costs. Process optimization and scale-up testing is currently underway for the Solv-Ex/Shell Canada Project which uses the same technology.

The extraction plant for the project has been designed to process tar sand ore at a feed rate of 500 tons per hour and produce net product oil for sale at a rate of 4,663 barrels per day over 330 operating days per year.

In August 1985 the sponsors requested loan and price guarantees totalling $230,947,000 under the United States Synthetic Fuels Corporation's (SFC's) solicitation for tar sands mining and surface processing projects. On November 19, 1985 the SFC determined that the project was qualified for assistance under the terms of the solicitation. However, the SFC was abolished by Congress on December 19, 1985 before financial assistance was awarded to the project.

The sponsors are evaluating various product options, including asphalt and combined asphalt/jet fuel. Private financing and equity participation for the project are being sought.

Project Cost: $158 million (Synthetic crude option)
$90 million (Asphalt option)

RAPAD BITUMEN UPGRADING PROJECT — Research Association for Petroleum Alternatives Development and Ministry of International Trade and Industry (T-550)

The Research Association for Petroleum Alternatives Development (RAPAD), supported by the Japanese Ministry of International Trade and Industry, adopted bitumen upgrading as one of its major research objectives. Three approaches were investigated: thermal cracking-hydrotreating, thermal cracking-solvent deasphalting-hydrotreating, and catalytic hydrotreating.

A pilot plant of the series of hydroprocessing, i.e., visbreaking-demetalization-cracking, was completed in 1984. Its capacity is 5 barrels per day, and operation has been used to evaluate catalyst performance and also to obtain engineering data. Hydroconversion catalysts with high activities for middle distillates productivity, coke suppression, and for demetalization have been developed. These catalysts made it possible to produce synthetic crude oil of high quality from tar sands bitumen under mild reaction conditions, which results in lower hydrogen consumption. Research with the 5 BPD pilot plant was finished in 1988. A 10 barrels per day pilot plant with suspended-bed reactor, designed by the M. W. Kellogg Company, was completed in 1985. A new type catalyst for the suspended bed process has been developed, and data have been obtained for process scaleup.

The original RAPAD program was an 8-year program, concluded in March 1988 at a total cost of 23.9 billion yen. Some additional research and development has been continued since April 1988.

The process developed with the aid of the 10 BPD pilot plant is called the MRH process (mild resid hydrocracking process). It is a suspended-bed process which hydrocracks, demetalizes and converts heavy oil such as vacuum resid or oil sand bitumen to middle distillates at a relatively low pressure (60-80 kilograms per square centimeter).

Project Cost: 23.9 billion yen through 1988

RTR PILOT PROJECT - RTR Oil Sands (Alberta) Ltd. (T-570)

The Oil Sands Extraction pilot plant is situated on the Suncor, Inc., property, north of Fort McMurray, Alberta. The pilot plant was operated in cooperation with Gulf Canada Resources Inc., during the second half 1981.

The evaluation of the data from the operation has demonstrated the technical viability of this closed circuit modified hot water process. The process offers good bitumen recoveries and solid waste which is environmentally advantageous due to the substantial reduction in waste volume.
STATUS OF OIL SANDS PROJECTS (Underline denotes changes since June 1990)

R & D PROJECTS (Continued)

Pilot data indicate that the total RTR/Gulf process (extraction and tailings management) offers a substantial economic advantage over conventional hot water technology. This is particularly true for a remote plant in which energy requirements must be generated.

Project Cost: Undisclosed

SANDALTA – Gulf Canada Corp., Home Oil Company, Ltd., and Mobil Oil Canada Ltd. (T-580)

Home Oil Company Limited, in October 1979, announced the farmout of its Athabasca oil sands property to Gulf Canada Corp. The property, Oil Sands Lease #0980090001 (formerly BSL #30) consists of 15,086 hectares (37,715 acres), situated 43 kilometers (26 miles) north of Fort McMurray on the east side of the Athabasca River. Under terms of the farmout agreement, Gulf, through expenditures totalling some $42 million, can earn up to an 83.75 percent interest in the lease with Home retaining 10 percent and Mobil Canada Ltd. 6.25 percent. An exploratory drilling program was carried out in the 1980 and 1981 drilling seasons, and more recently in 1985. Engineering studies on commercial feasibility are continuing.

Little progress has been reported since 1987.

Project Cost: Not Specified

SOARS LAKE HEAVY OIL PILOT - Amoco Canada Petroleum Company Ltd. (T-590)

Amoco Canada in July, 1988 officially opened the company’s 16-well heavy oil pilot facilities located on the Elizabeth Metis Settlement south of Cold Lake.

Amoco Canada has been actively evaluating the heavy oil potential of its Soars Lake leases since 1965 when the company drilled two successful wells. The company now has 57 wells at this site with most having been drilled since 1985. The heavy oil reservoir at Soars Lake is located in the Sparky formation at a depth of 1,500 feet.

In the summer of 1987, Amoco began drilling 15 slant wells for the project. One vertical well already drilled at the site was included in the plans. The wells are oriented in a square 10 acre/well pattern along NE-SW rows.

The injection scheme initially called for steaming two wells simultaneously with the project’s two 25 MMBTU/hr generators. However, severe communication developed immediately along the NE-SW direction resulting in production problems. Although this fracture trend was known to exist, communication was not expected over the 660 feet between the wells’ bottomhole locations. Steam splitters were installed to allow steaming of 4 wells simultaneously along the NE-SW direction. Four cycles of steam injection have been completed and although production problems have decreased, reservoir performance remains poor. The short-term strategy for the pilot calls for an extended production cycle to create some viodage in the reservoir prior to any further steam stimulations.

Project Cost: $26 million through 1989

TACIUK PROCESSOR PILOT - AOSTRA/The UMA Group Ltd. (T-610)

A pilot of an extraction and partial upgrading process located in southeast Calgary, Alberta. The pilot plant finished construction in March 1978 at a cost of $1 million. The process was invented by William Taciuk of The UMA Group. Development is being done by UMATAC Industrial Processes Ltd., a subsidiary of The UMA Group. Funding is by the Alberta Oil Sands Technology and Research Authority (AOSTRA). The processor consists of a rotating kiln which houses heat exchange, cracking and combustion processes. The processor yields cracked bitumen vapors and dry sand tailings. The pilot plant, which processed 5 tons of Athabasca oil sand per hour, has completed testing and demonstration.

Information agreements were made with a major oil company and with a joint-venture company between two majors. The information agreements provide, in exchange for a funding contribution to the project, full rights for evaluation purposes to the information generated by the project during the pilot phase.

A substantial increase in coke burning capacity and in the length of pilot run was demonstrated in the 1982 season. Recycle of the heaviest fraction of the extracted oil to produce an oil suitable for hydrotreating has been practiced. The oil product is similar to that of a fluid coker, so the process would replace both the extraction and primary upgrading steps of the process (hot water and coking) used at existing commercial plants.

The next stage is a "demonstration scale" ATP plant, sized at 100 tons per hour feed capacity and located in the Athabasca Oil Sands operating area. The design and proposal for this facility were completed in 1985, but the project has not proceeded because of the unfavorable economic climate for oil industry capital investment.
STATUS OF OIL SANDS PROJECTS (Underline denotes changes since June 1990)

R & D PROJECTS (Continued)

A comparable demonstration scale project is under way, however, for a semi-commercial plant to study and demonstrate the ATP System for producing oil from oil shale at a deposit in Australia. The design of this facility is well underway, and is for a throughput capacity of 6,000 tons per day of oil shale feed. Construction is not yet committed but is planned for 1991 or 1992.

A third area of application of the technology has been developed in the past five years, which is its use for remediation of oily soils and sludges. In this area the ATP has progressed to commercialization. The first ATP waste treatment was built in 1989 for Soil-Tech, Inc. which is the United States licensee for the use of the technology in waste treatment. This plant is presently being mobilized to a waste treatment project in the United States.

Project Cost To Date: $19 million (AOSTRA)

TANGLEFLAGS NORTH -- Sceptre Resources Limited and Murphy Oil Company Ltd. (T-620)

The project, located some 35 kilometers northeast of Lloydminster, Saskatchewan, near Paradise Hill, involves the first horizontal heavy oil well in Saskatchewan. Production from horizontal oil wells is expected to dramatically improve the recovery of heavy oil in the Lloydminster region.

The Tangleflags North Pilot Project is employing drilling methods similar to those used by Esso Resources Canada Ltd. in the Norman Wells oil field of the Northwest Territories and at Cold Lake, Alberta. The combination of the 500-meter horizontal production well and steamflood technology is expected to increase recovery at the Tangleflags North Pilot Project from less than one percent of the oil in place to up to 50 percent.

The governments of Canada and Saskatchewan are providing up to $3.8 million in funding under the terms of the Canada-Saskatchewan Heavy Oil Fossil Fuels Research Program.

The Tangleflags project is designed for an early production response so that expansion potential can be evaluated by 1990. Current estimates indicate sufficient reserves exist in the vicinity of the pilot to support commercial development with a peak gross production rate of 6,200 barrels of oil per day. Project life is estimated at 15 years.

The Tangleflags project has advanced to the continuous steam injection phase. With one horizontal well and four vertical steam injection wells in place, the project was producing at rates in excess of 1,000 barrels of oil per day by mid 1990. Cumulative production to the middle of 1990 was 425,000 barrels. Production is expected to continue in the range of 1,000 barrels of oil per day for at least another year. The expansion of the pilot project into a commercial operation involving 14 horizontal wells will hinge on future crude oil prices. A decision regarding pilot expansion will be made in 1991.

Project Cost: $10.2 million by 1990

TAR SAND TRIANGLE -- Kirkwood Oil and Gas (T-630)

Kirkwood Oil and Gas drilled some 16 coreholes by the end of 1982 to evaluate their leases in the Tar Sand Triangle in south central Utah. They are also evaluating pilot testing of inductive heating for recovery of bitumen. A combined hydrocarbon unit, to be called the Gunsight Butte unit, is presently being formed to include Kirkwood and surrounding leases within the Tar Sand Triangle Special Tar Sand Area (STSA).

Kirkwood is also active in three other STSAs as follows:

Raven Ridge-Rimrock -- Kirkwood Oil and Gas has received a combined hydrocarbon lease for 640 acres in the Raven Ridge-Rim Rock Special Tar Sand Area.

Hill Creek and San Rafael Swell -- Kirkwood Oil and Gas is also in the process of converting leases in the Hill Creek and San Rafael Swell Special Tar Sand Areas.

Kirkwood Oil and Gas has applied to convert over 108,000 acres of oil and gas leases to combined hydrocarbon leases. With these conversions Kirkwood will hold more acreage over tar sands in Utah than any other organization. The project is pending.

Project Cost: Unknown

TUCKER LAKE PILOT PROJECT -- Husky Oil, Ltd. (T-640)

Husky began operating a cyclic-steam pilot project at Tucker Lake in February 1984. The location of Husky's 18,000 acre lease is approximately three miles southwest of Esso's Cold Lake project. Four wells were initially put into operation and seven wells were added during 1985. To determine the most productive area the test wells are widely spaced over a 3,000 acre section of the lease.

SYNTHETIC FUELS REPORT, SEPTEMBER 1990
STATUS OF OIL SANDS PROJECTS (Underline denotes changes since June 1990)

R & D PROJECTS (Continued)

Preliminary estimates indicate that oil in place at the project area exceeds 680 million barrels. Production is from the unconsolidated Clearwater sand with a pay zone of 110 feet at a depth of 1,500 feet. Porosity of the formation is 33 percent and permeability is 1,500 md. Oil gravity is 10 degrees API with a viscosity of 100,000 cp at reservoir temperatures of 60 degrees F.

Husky has developed a 13 well pad which includes a 50 million BTU per hour steam generator along with other associated facilities. The project resumed operation during the third quarter of 1987 following a 12-month shutdown due to inadequate oil prices. The project was mothballed again in the fourth quarter of 1988 due to low oil prices. There are currently no plans or schedule for a renewal of operations.

Project Cost: Not Disclosed

UNDERGROUND TEST FACILITY PROJECT — Alberta Oil Sands Technology and Research Authority, Federal Department of Energy, Mines and Resources (CANMET), Chevron Canada Resources Limited, Esso Resources Canada Limited, Conoco Canada Limited, Mobil Oil Canada Ltd., Petro-Canada Inc., Shell Canada Ltd., Amoco Canada Petroleum Company, Ltd. (T-650)

The underground Test Facility (UTF) was constructed by AOSTRA during 1984-1987, for the purpose of testing novel in situ recovery technologies based on horizontal wells, in the Athabasca oil sands. The facility is located 70 kilometers northwest of Fort McMurray, and consists of two access/ventilation shafts, three meters in diameter and 185 meters deep, plus a network of tunnels driven in the Devonian limestone that underlies the McMurray pay. A custom drilling system has been developed to drill wells upward from the tunnels, starting at a shallow angle, and then horizontally through the pay, to lengths of up to 1,000 meters.

Two processes were selected for initial testing: steam assisted gravity drainage (SAGD), and Chevron's proprietary HASDrive process. Steaming of both test patterns commenced in December 1987 and continued up to early 1990. HASDrive was shut in April 1990 and the SAGD is expected to continue producing in a blowdown phase until the fall of 1990.

Both tests were unqualified technical successes. In the case of the Phase A SAGD test, a commercially viable combination of production rates, steam/oil ratios, and ultimate recovery was achieved. Complete sand control was demonstrated, and production flowed to surface for most of the test.

Construction of the Phase B SAGD test commenced in the spring of 1990 with the drivage of 550 meters of additional tunnel, for a total of about 1,500 meters. Phase B is a direct scale up of the Phase A test, using what is currently thought to be the economic optimum well length and spacing. The test will consist of three pairs of horizontal wells, with completed lengths of 500 meters and 70 meter spacing between pairs. Each well pair consists of a producer placed near the base of the pay, and an injector about five meters above the producer.

Phase B steaming will commence in early 1991 and is expected to continue for 4-5 years. A decision regarding expansion to commercial production will be made during this period.

Project Cost: $120 million
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PROJECT ACTIVITIES

GREAT PLAINS PHENOL PLANT NEARING COMPLETION

The phenol recovery project at the Great Plains Synfuels Plant near Beulah, North Dakota is scheduled to be completed by October 1. Construction of the $20 million plant began last April.

The phenol project will recover about 35 million pounds of phenol annually, which represents about 1 percent of the United States phenol market. The project provided about 250 construction jobs and will produce annual gross sales of $14 million.

The phenol will be sold to resin manufacturers in the Pacific Northwest for use in making plywood and chipboard.

Dakota Gasification Company (DGC) has financed its phenol recovery project with a $233 million loan to be paid back over a 10-year period. The National Rural Utilities Cooperative Finance Corporation (CFC) loaned the funds to the Dakota Funding Cooperative which then made the loan to DGC. This financial arrangement was worked out because CFC’s bylaws prohibit profit making companies such as DGC from becoming members. Only members are eligible for loans. Both Dakota Funding and DGC are subsidiaries of Basin Electric.

This is the first byproduct development at the synfuels plant to receive outside funding.

CTC EXPANDING PRODUCTION AND MARKETING

In order to meet the demand for Coal Technology Corporation’s (CTC) coal-derived fuels, the company says construction is underway on a $1.7 million expansion of its liquid coal processing facility. This new pilot plant will allow continuous processing of coal into liquid coal derivatives and into a formed coke. Construction of the facility is scheduled to be completed in November 1990.

Once the technology is tested and proven, says CTC, the process will be ready for scale-up to a commercial-size plant that would employ several hundred people. The commercial plant will process over 1,000 tons of coal per day and cost over $50 million to construct. CTC’s major interest is to prove that coal-derived transportation fuels can be an acceptable fuel in the marketplace. CTC says the technology will help reduce the need to import oil from the mid-eastern countries. The United States can use its vast coal reserves to meet both transportation and electricity energy needs.

Through “mild gasification” of coal, CTC removes the high quality liquids, refines them and blends coal-derived gasoline. The company has also developed a diesel fuel, a home heating fuel, and is conducting research on a locomotive fuel.

The mild gasification process also produces char, which can be made into metallurgical coke and sold to the steel industry. CTC researchers are working on a process to form the coke into briquettes that are stronger and burn hotter than plain coke.

CTC’s coal-derived gasoline is a blend of the high quality fluids from coal liquids and petroleum. CTC officials say the gasoline provides improved mileage and lowers exhaust emissions.

CTC recently opened its ninth outlet in southwestern Virginia offering coal-derived gasoline to the general public in six counties. Since opening its first station in September 1989, the public has driven over 16.5 million miles on coal-derived fuels, according to CTC. Combined weekly sales average 75,000 to 100,000 gallons.

The company says the fuel meets both state and federal specifications and conforms to all new car warranties. In addition, no modification in the engine or fuel supply systems is required.

The ninth outlet, opened on August 1, 1990, was the first to use the company’s own design, signs, colors, and name—“Mr. Express.” The station will market coal-derived regular unleaded and premium gasolines and diesel fuel. CTC says their diesel fuel has higher cetane, a lower gel point and cleaner emissions.

Other coal-derived products being marketed by CTC include a windshield wiper fluid and a carburetor/fuel injector cleaner.

SASOL APPROVES SIX NEW PROJECTS

The board of Sasol, South Africa’s leading coal-to-chemicals producer, has announced approval of six new projects. These represent the first phase of a 20 project program under consideration. The cost of the total program is estimated to be $1.1 billion over the next 5 years.

The six projects just approved will reportedly cost $451 million and will boost growth in operating income by
Three of the new projects will be at Sasol One in Sasolburg. They are part of the company's strategy to move from synfuel to high value-added chemical production. About half of Sasol's operating profit is currently derived from the production of synthetic fuel. All three projects, described below, are scheduled to be completed by January 1993.

- A wax expansion project is aimed at supplying the local and foreign candle wax markets and producing specialized waxes. The company's total wax producing capacity will be doubled from its current level of 64,000 tons per year to 123,000 tons per year.

- The 70,000 ton per year Sasol One ammonia plant is to be replaced by a 240,000 ton per year plant, which is expected to supply South Africa's current ammonia supply shortfall. The ammonia produced will be used to supply the fertilizer and explosive markets.

- A new facility is to be built at Sasol One to manufacture paraffinic products for detergents.

The other three newly approved projects, which will be located at Sasol's Secunda facilities, are as follows:

- An n-butanol plant to recover acetaldehyde from the Secunda facilities and to produce 17,500 tons per year of n-butanol is to be built. It is scheduled to come onstream by January 1992. The company plans to produce acetic acid and acetates from the acetaldehyde recovered from the Secunda facilities.

- The company has developed a process for producing coke from coal tar pitch and other low-value black products. The anode coke produced is suitable for use in the aluminum smelting industry, and the needle coke can be used to make high-grade anodes for arc furnace electrodes. The project will involve constructing a delayed coker to produce green coke, and a calciner to calcinate the green coke to anode and needle coke. They are scheduled to be in production by March 1993. At present, South Africa imports all anode coke and most needle coke. The proposed plant will completely replace these imports, and may also export material.

- Sasol will increase its production of ethylene by 60,000 tons per year, from its current level of 345,000 tons per year, by expanding its ethylene recovery plant at Secunda. The plant is expected to come onstream by July 1991.

The expansion should enable Sasol to supply the local ethylene demand. South Africa currently requires around 275,000 tons per year of ethylene. Further feedstock resources are said to be available to expand Sasol's total capacity to some 650,000 tons per year of the product.

###

**DGC BOARD VOTES TO CHANGE AIR QUALITY APPLICATION**

The Dakota Gasification Company (DGC) board of directors has approved a revision in the application for the air quality permit for the synfuels plant.

The change refers to the method by which sulfur dioxide \((SO_2)\) is removed from plant emissions in order to comply with state and federal air quality standards.

According to vice president and chief operating officer K. Janssen, the system proposed in the original application submitted to the North Dakota Health Department probably wouldn't bring the synfuels plant into compliance.

The application submitted in 1989 proposed increasing the efficiency of the existing sulfolin plant and building a parallel sulfolin plant. The sulfolin process is a method of removing \(SO_2\) by treating the waste gas stream before it is burned.

The board's revised application will propose other technologies as the Best Available Control Technology, or BACT, for removing the \(SO_2\). One example is a form of flue gas desulfurization, such as scrubbers like those on power plants.

Janssen estimated the cost of the new \(SO_2\)-removal system at more than $100 million. However, the exact technology, costs and method of financing have not been determined. Part of the financing is expected to come from a $30 million fund set up by the United States Department of Energy, which sold the plant to the Basin Electric subsidiary in 1988.

Since that time, staff members have been working with the Health Department to develop a plan for reducing \(SO_2\) emissions. Because the plant has been unable to meet the conditions of the original air quality provisions in the Permit to Construct, the revised application will amend the permit, reflecting the emission levels that the plant can meet.

The revised application to amend the air quality permit is to be submitted to the North Dakota Health Department in October.

####

SYNTHETIC FUELS REPORT, SEPTEMBER 1990
NEGOTIATIONS COMPLETED FOR WESTERN ENERGY PROJECT

The United States Department of Energy (DOE) has completed negotiations for a Clean Coal Technology (CCT) project to be carried out by the Western Energy Company of Butte, Montana near the company's Rosebud Coal Mine near Colstrip. Estimated to cost nearly $69 million when completed, the joint government-industry project will test an advanced technique for improving the quality of western coal by removing excess moisture from the coal, removing ash-forming impurities, and reducing its already low sulfur content.

The project is described in a DOE report sent to Congress in July. As soon as Congress completes its required 30-day "in session" review of the report, the department can sign the formal agreement to begin funding the demonstration venture.

The Western Energy project was one of the alternate projects selected in 1986 in the first round of the Clean Coal Technology program. It became a prime candidate for federal funding in December 1988 when a previous project dropped out of negotiations.

The project will upgrade low rank subbituminous coals which are becoming increasingly attractive because their low sulfur content means less air pollution. But their high moisture content—often approaching one half of their total weight—make them expensive to transport and often difficult to burn.

Western Energy will use an advanced coal beneficiation process to reduce the moisture to about 1 percent, boosting the coal's heating value from as low as 5,500 BTU per pound to 12,000 BTU per pound. The process also modifies the surface characteristics of the coal to prevent reabsorption of moisture. The sulfur content of the upgraded coal will be only 0.3 percent, enabling it to meet strict environmental standards without expensive pollution controls.

The process works by first feeding raw coal into a two-stage "thermal process system." Both stages suspend the coal in vibrating fluid-like motion. In the first stage, hot gases from a separate heating plant pass through the tumbling coal to remove loosely held water. The second stage further heats the coal to remove chemically-bound water and certain sulfur compounds. After the coal is cooled, it moves through vibrating screens and separators that remove additional sulfur and other minerals. A main advantage of the process is that it operates at low pressures.

The new plant will produce about 300,000 tons a year of improved quality coal and will be integrated with existing coal facilities at the Rosebud mine. About 150 construction and 21 operating jobs will be created during the project.

DOE expects to finalize the agreement in September. Following two and one half years of design and construction work, the plant will be operated for 3 years as a demonstration project.

If the demonstration is successful, Western Energy hopes to build a privately financed commercial-scale plant processing 1 to 3 million tons of coal per year by 1997.

DOE will provide $34.5 million, or half the project's total cost. The project will be overseen by the Energy Department's Pittsburgh Energy Technology Center.

ENCOAL COMPLETES FUNDING NEGOTIATIONS

SGI International has announced that the United States Department of Energy (DOE) has reported to Congress the successful conclusion of negotiations with ENCOAL Corporation under Round 3 of DOE's Clean Coal Technology (CCT) program to jointly fund $72.6 million for the construction and initial operation of a Liquids from Coal (LFC) Process Demonstration Plant.

Of the 13 projects selected for Round 3 CCT funding in December 1989, ENCOAL is the first to complete negotiations with DOE.

DOE announced in July that a detailed report on the project was forwarded to Congress signifying the successful completion of negotiations. Government financing is expected to begin at the conclusion of a 30-day "in session" congressional review period. DOE's share of the funding is 50 percent, or $36.3 million.

ENCOAL Corporation of Houston, Texas will demonstrate a process that converts low rank coals abundant in the western United States to two new, clean-burning, high value fuels. The demonstration plant will be built at Triton Coal Company's Buckskin Mine near Gillette, Wyoming.

When complete, the plant will process 1,000 tons per day of subbituminous coal from the Powder River Basin of northern Wyoming to form two products: a low sulfur oil, similar in quality to Number 6 fuel oil, that can be used in industrial and utility boilers; and a solid fuel, similar to bituminous coals but without the typical sulfur pollutants. Each of these fuels will meet or exceed the nation's strictest environmental requirements.

The plant will demonstrate a type of "mild gasification," an advanced version coal devolatization process. Jointly developed by SGI International of La Jolla, California and Shell Mining Company, the LFC technique is well-suited for the abundant supplies of subbituminous low rank coals located in Wyoming's Powder River Basin, North Dakota, Montana, the Gulf Coast and Alaska.

SYNTHETIC FUELS REPORT, SEPTEMBER 1990

4-3
In the LFC process, raw coal is heated under carefully controlled temperatures and operating pressures and converted to the new fuels. The coal is first heated by hot gases to remove much of the moisture. The dried solid coal is then conveyed to a pyrolyzer, where it is further heated to about 1,000 degrees. The resulting gaseous product is sent through a cyclone for cleaning, then cooled to condense out the liquid product. The remaining solid fuel is nearly free from moisture and thus has a much higher heating value.

The LFC process includes a unique computerized control system that can optimize the quality of the product fuels depending on specific market needs and the composition of the feed coal. The operating conditions can be varied to obtain a different mix of products at an individual plant.

About 500 tons of solid fuel and 500 barrels of liquid fuel per day will be produced from the plant. The fuels will then be tested in operating utility and industrial boilers. While not part of the formal agreement with the government, data from these tests will be made available to DOE.

Design and permitting for the new plant have begun with construction scheduled to begin late this fall. A 2-year operating period is expected to begin in early 1992. If ENCOAL's demonstration proves successful, a full-scale commercial plant, about 10 times the size of the ENCOAL project, could be built and operating by the mid-1990's.

Both ENCOAL and Triton Coal are wholly owned subsidiaries of Shell Mining Company. TEK-KOL, a partnership between Shell Mining and SGI International, is the owner and licensor of the LFC technology. SGI International is the licensing contractor for the TEK-KOL partnership.

The ENCOAL project will be overseen by DOE's Morgantown (West Virginia) Energy Technology Center.

###

**NEW COAL GASIFICATION/COGENERATION PROJECT PLANNED IN VIRGINIA**

Virginia Power has contracted to purchase 210 megawatts of power from a new integrated gasification combined cycle (IGCC) plant being built by Virginia Iron Industries Corporation of Winchester, Virginia. The $800 million project is scheduled to come on line in 1994 with full operation beginning in 1995.

Virginia Iron will be the first United States industry to use the COREX coal gasification technology, a German steel manufacturing process integrated with power generation. According to a company spokesman, the new plant will be very similar to the ISCOR plant installed last year in Pretoria, South Africa. The plant will be located in Hampton Roads, Virginia.

The new technology uses a closed system where the coal is burned with pure oxygen in a gasifier. The gasified coal is piped to a shaft furnace where it comes into contact with the iron ore. There the iron ore is converted to sponge iron, which settles to the bottom of the shaft and into the melter-gasifier.

The melted sponge iron passes through a limestone slag pool where the limestone draws the sulfur from the iron. The pure iron then settles to the bottom of the gasifier. The hot gas exiting the shaft furnace is cooled, cleaned and compressed for use in generating electricity.

The plant will produce a total of 340 megawatts, of which 130 megawatts will be used in the plant's gasification process and 210 megawatts will be sold to Virginia Power.

Previous attempts to introduce the COREX process to the United States were made in response to the Clean Coal Technology program, but none of these projects were able to obtain final financial commitments.

###

**DOW SYNGAS GASIFIES ONE MILLION TONS OF COAL**

At the Council of Industrial Boiler Owners held in July in Washington, D.C., M.W. Roll of Destec Energy announced that the Dow Syngas Project recently surpassed 1 million tons of coal converted to syngas. Roll noted that this is the equivalent energy of over 3.2 million barrels of oil and is enough coal to fill the Astrodome and still have 10 percent left over to spill over the side. Syngas produced at this facility is used to fuel approximately 160 megawatts of power generation capacity.

Dow Chemical's new subsidiary, Destec Energy, Inc., was formed in May 1989 as a 100 percent wholly owned subsidiary headquartered in Houston, Texas. In November 1989, Destec Energy acquired PSE Inc., an energy developer, thereby becoming the largest independent power producer in North America. A subsidiary of Destec is Louisiana Gasification Technology, Inc. (LGTI), which owns and operates the coal gasification facility at Dow's Louisiana Division in Plaquemine.

Roll says that long term strategy is to focus on power and steam generation and syngas manufacturing via coal gasification. The technical and resource base supporting this strategy include conventional natural gas fired cogeneration and coal gasification. Destec Energy owns the proprietary coal gasification process developed by Dow Chemical.
In 1984 a contract was negotiated between Dow and the United States Synthetic Fuels Corporation allowing for the construction of the present 2,400 ton per day plant which started up on April 5, 1987. The 10-year contract is now managed by the Department of the Treasury. Dow provided all of the capital to construct the plant and the Treasury guarantees the sales price of syngas produced. This plant has been in operation over 3 years and provides syngas fuel to two Westinghouse 501D combustion turbines in a fully commercial mode producing one-third of the power and steam requirements of Dow's 1,400 acre Plaquemine complex.

There are a number of applications which Destec Energy foresees for the application of its coal gasification combined cycle (CGCC) technology during the 1990s. These options include coal conversion of natural gas/oil fired plants.

New coal-fired power plants for increasing power generation capacity can be built using CGCC and can be built in phases with short construction schedules. Perhaps one of the most

important applications for CGCC will be repowering. Many coal-fired boilers in the United States are aging. Repowering of these sites with an environmentally sound CGCC technology not only allows utilization of the old steam turbine but increases the power generation capacity of the site. One recent 400 megawatt project study shows the cost to repower a site by the addition of two combustion turbines and two gasification modules with the use of the existing steam turbine to be $950 per kilowatt, with a heat rate of 8,800 BTU per kilowatt hour.

In comprehensive Electric Power Research Institute (EPRI) studies to evaluate the capital requirements of several Dow based CGCC plants, three fuels, lignite, subbituminous and bituminous coals, were evaluated. The range of capital required was $1,110 per kilowatt to $1,200 per kilowatt. These capital requirements are competitive to any coal-based power generation technology, says Roll.

####
UNIVERSITY R&D AWARDS INCLUDE COAL CONVERSION PROJECTS

More than 50 students at United States colleges and universities, while earning advanced science and engineering degrees, will also assist the United States Department of Energy (DOE) in studying cleaner, more efficient ways to use coal.

The students, along with faculty members, are part of 31 research teams selected to share $5.6 million in federal funds from DOE's annual "University Coal Research" competition. There were a total of 268 proposals sent to the federal government earlier this year. The grants were expected to be awarded by September.

In announcing the selections, Energy Secretary J.D. Watkins said that the University Coal Research program, now in its 11th year, is taking on increased significance because "scientific education is fundamentally important to a secure and environmentally clean energy future." The Interim Report on the National Energy Strategy noted that "the nation's competitive position depends on the quality of its scientists, engineers and technicians."

"At our public hearings, we heard repeated warnings that the decline in the annual production of advanced degrees in the sciences and engineering, especially among United States students, could lead to serious technological shortfalls over the next 15 years," Watkins said. "Efforts like the University Coal Research program will help prevent such shortfalls."

Each of the 31 research teams will be led by a teaching professor and will include at least one graduate student who will receive funding from the grant.

Since its inception in 1979, the University Coal Research program has provided more than $55 million to colleges and universities for fundamental studies of coal and coal processes. More than 450 students have earned their degrees while engaged in these research programs.

Shown in Table 1 on the next page is a partial list of the projects being funded and the dollar amounts awarded by DOE.

###

DOE DELAYS CCT ROUND 4

The United States Department of Energy (DOE) announced on May 14 that it would delay issuing its fourth solicitation for proposals in its $5 billion Clean Coal Technology (CCT) program until uncertainties regarding Congressional action have been resolved. The department was scheduled to issue its solicitation for nearly $600 million in federal matching funds on June 1.

The Secretary of Energy informed Congress that unresolved issues in the pending Supplemental Appropriations Act and the Clean Air Act Amendments make it premature for DOE to begin asking industry for new clean coal technology proposals.

The department has completed three of the scheduled five rounds of competition in the joint government-industry program and currently has 38 projects underway or in negotiations.

Last year's appropriations act specified a timetable for conducting the final two rounds of the program, with the fourth round to begin June 1, 1990 and the fifth round to begin September 1, 1991.

In his letter to Congress, Secretary Watkins said, "Without resolution of these [pending legislative] issues, it would be inappropriate to go forward with the issuance of the solicitation ... To do so would run the risk of having to subsequently cancel or amend it, causing unnecessary expense for both the department and the participants."

Following DOE's announcement of the delay, Congress passed the 1990 Dire Emergency Supplemental Appropriations Act which officially delayed Round 4 until September 1991.

The Clean Air Act Amendments passed in April by the House Energy and Commerce Committee also would change the scope of the final rounds of the Clean Coal Technology program by restricting eligibility to a select group of principally mid-western utilities.

The delay in the fourth round of competition will provide time for a draft of the solicitation to be issued for public comment prior to its official release. DOE had previously used public comments to obtain views from the private sector and other government agencies on specific provisions in a proposed solicitation.

The uncertainty of congressional actions and issues regarding the eventual repayment of federal funds and foreign company participation had prevented the department from issuing a draft of its fourth round solicitation document.

### 
<table>
<thead>
<tr>
<th>Grantee</th>
<th>Funding DOE</th>
<th>Grantee</th>
<th>Project Title</th>
</tr>
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<tbody>
<tr>
<td>Lowell D. Kispert, Univ. of Alabama</td>
<td>$190,117</td>
<td>$47,200</td>
<td>&quot;Molecular Accessibility in Solvent Swelled Coal&quot;</td>
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<td>Benjamin J. McCoy, Univ. of Calif. at Davis</td>
<td>$131,916</td>
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<td>&quot;Chemical Kinetics and Transport Processes in Supercritical Fluid Extraction of Coal&quot;</td>
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<td>Ronald L. Miller, Colo. School of Mines</td>
<td>$199,562</td>
<td>$0</td>
<td>&quot;Mild Coal Pretreatment to Improve Liquefaction Reactivity&quot;</td>
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<td>Henry C. Foley, Univ. of Delaware</td>
<td>$193,092</td>
<td>$0</td>
<td>&quot;Design of a High Activity and Selectivity Alcohol Catalyst&quot;</td>
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<td>Jack Winnick, Georgia Tech R&amp;H Corp.</td>
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<td>$17,272</td>
<td>&quot;High Temperature Membranes for H₂SO₄ and SO₂ Separations&quot;</td>
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<td>Joseph N. D. Dodoo, Univ. of Maryland-Eastern Shore</td>
<td>$110,000</td>
<td>$65,000</td>
<td>&quot;Structure and Thermochemical Kinetic Studies of Coal Pyrolysis&quot;</td>
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<td>Bernard Miller, Univ. of Massachusetts</td>
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<td>&quot;Catalysis and Cocatalysis of Bond Cleavage in Coal and Coal Analogs&quot;</td>
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<td>Kamalesh K. Sirkar, Stevens Institute of Technology</td>
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<td>$68,080</td>
<td>&quot;Rapid Pressure Swing Absorption Cleanup of Post-Shift Reactor Synthesis Gas&quot;</td>
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<td>Robert L. Robinson, Jr., Oklahoma State Univ.</td>
<td>$198,789</td>
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<td>&quot;Equilibrium and Volumetric Data and Model Development for Coal Fluids&quot;</td>
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<td>John W. Larsen, Lehigh University</td>
<td>$199,973</td>
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<td>&quot;The Effect of Selective Solvent Absorption on Coal Conversion&quot;</td>
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<td>Donna G. Blackmond, Univ. of Pittsburgh</td>
<td>$200,000</td>
<td>$75,581</td>
<td>&quot;Probe Molecule Studies: Active Species in Alcohol Synthesis&quot;</td>
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<td>Eric M. Suuberg, Brown University</td>
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<td>$30,000</td>
<td>&quot;A New Model of Coal-Water Interactions and Relevance for Dewatering&quot;</td>
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<td>Ates Akyurtlu, Hampton University</td>
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<td>&quot;Hot Gas Desulfurization with Sorbents Containing Oxides of Zn, Fe, V, Cu&quot;</td>
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<td>Richard M. Laine, Univ. of Washington</td>
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<td>&quot;Advanced Soluble Hydroliquefaction and Hydrotreating Catalysts&quot;</td>
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<td>Felicia F. Peng, West Virginia Univ.</td>
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<td>$0</td>
<td>&quot;Hydrocarbon-Oil Encapsulated Air Bubble Flotation of Fine Coal&quot;</td>
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THREE FIRMS WILL GET MOLTEN CARBONATE FUEL CELL FUNDING

The United States Department of Energy (DOE) has selected three firms that will take the molten carbonate fuel cell beyond the development laboratory into full-scale testing.


ERC and M-C Power will begin 3-year efforts to develop full-size fuel cell stacks—the basic "building block" of a commercial-scale power plant—along with the other components needed for a complete fuel cell power system.

The third company, IFC, will receive a 3-year contract to continue research that could improve the fuel cell stack.

The total cost for the three projects will likely top $60 million, with $15 to $20 million coming from the industrial contractors.

The construction of a full-scale stack comes after nearly a decade and a half of federal funding for the molten carbonate fuel cell concept. Key obstacles, which delayed the development effort 2 years ago, have been resolved, and the molten carbonate fuel cell is ready for full-scale stack development and testing.

Initially the fuel for the molten carbonate fuel cell is likely to be natural gas. However, the high operating temperature of the cells—in excess of 1,200°F—makes the technology attractive as a way to extract energy from hot gases made from coal in a coal gasification plant. The contractors will use natural gas and simulated coal gas in their projects.

The electrochemical process used by the molten carbonate fuel cell produces none of the pollutants associated with acid rain. In addition, the high operating efficiencies, nearly twice those of a conventional coal power plant, produce as much as 40 percent less carbon dioxide.

Federally sponsored research in molten carbonate fuel cells had previously focused on testing small "subscale stacks" and improving the life expectancy and costs of cell components.

A fuel cell "stack" is an array of individual fuel cells, each roughly the size of a large doormat. Each cell produces low voltage but the cells can be linked together to produce higher voltages. Multiple stacks would be joined to form a power plant.

Combinations of 10 to 30 cells have operated for several thousand hours. The new projects will integrate several hundred cells into a module capable of generating 100 to 300 kilowatts. The first commercial power plants are expected to link 10 to 20 stacks to produce 1 to 2 megawatts of electric power.

ERC and M-C Power have plans to construct manufacturing and testing facilities. They will also develop a commercialization plan targeting specific markets both domestically and abroad.

IFC's contract for additional research will concentrate on improving individual components of the fuel cell and on developing better engineering, manufacturing and assembly techniques.

The three contractors propose different configurations for their fuel cells. The IFC concept extracts hydrogen—the fuel for the system—from the coal gas or natural gas in a separate reformer outside the fuel cell assembly. The Energy Research Corporation process relies on an internal reforming design, while M-C Power arranges the fuel cells in a unique geometric pattern that allows heat to flow more efficiently and minimizes the tendency of the cells to shrink over time.

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SYNTHETIC FUELS REPORT, SEPTEMBER 1990
ENERGY POLICY & FORECASTS

COAL COUNCIL DELIVERS REPORT ON INDUSTRIAL USE OF COAL

Energy consumption by the industrial sector in 1988 was 21,700 trillion BTU of which coal provided 2,770 trillion BTU, nearly 13 percent. This is according to the National Coal Council's draft report, "Industrial Use of Coal and Clean Coal Technology," released this summer.

The principal consumers of industrial coal in 1988 are shown in Table 1.

TABLE 1

CONSUMERS OF INDUSTRIAL COAL - 1988

<table>
<thead>
<tr>
<th>Industry</th>
<th>Thousand Short Tons</th>
</tr>
</thead>
<tbody>
<tr>
<td>Coke Plants</td>
<td>41,910</td>
</tr>
<tr>
<td>Chemicals, Allied Products</td>
<td>14,898</td>
</tr>
<tr>
<td>Stone, Clay, Glass</td>
<td>13,792</td>
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<tr>
<td>Paper and Allied Products</td>
<td>12,437</td>
</tr>
<tr>
<td>Primary Metal Industries</td>
<td>7,691</td>
</tr>
<tr>
<td>Petroleum and Coal Products</td>
<td>7,190</td>
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<tr>
<td>Food and Kindred Products</td>
<td>6,431</td>
</tr>
<tr>
<td>Transportation Equipment</td>
<td>1,836</td>
</tr>
<tr>
<td>Textile Mill Products</td>
<td>1,497</td>
</tr>
</tbody>
</table>

The principal uses for coal in the industrial sector in decreasing order of consumption were:

- Coke Plants
- Steam Coal
- Direct Process Heat
- Manufacturing Feedstock

Electricity is used extensively in industry. According to the report, the industrial sector is the principal non-utility electricity producer with an installed capacity of 22,479 megawatts in 1987. Because electricity is 50 percent coal based, it is an indirect use of coal in industry.

The industrial sector has reacted to energy price increases with conservation and has selected fuels on the basis of economics. Some industries are heavy users of coal such as the cement industry, which uses coal for 65 percent of its fuel needs. Others, such as the glass industry, use little or no coal. Because the processes used by the industrial sector vary so much, the use of coal and clean coal technology is application specific.

The report says that clean coal technologies (CCTs) are primarily applicable to industrial boilers. Some CCTs could be adapted to direct process heat applications with further study, i.e., the glass industry.

Natural gas is the largest source of direct process heat, and points out one of the ways in which coal ultimately can be used in the industrial sector by the application of the coal gasification technology. However, the long-range availability of natural gas beyond the year 2000 at reasonable prices is a concern.

Industrial cogeneration is a viable way to utilize coal in the industrial sector. In 1988 there were 31,400 megawatts of nonutility generation capacity. Of this, 5,400 megawatts use coal as a fuel; many of these are cogenerators.

The impact of currently proposed environmental legislation (i.e., acid rain, air toxics, ozone nonattainment, greenhouse) will cause severe industrial dislocations. Many industries will seek off-shore locations where more favorable environmental regulations exist. The public may believe that industrial growth will be sacrificed in favor of environmental controls. However, says the report, the reality is that the sacrifice will not be confined to growth alone; whole industries will leave the country.

One problem for industrial users of coal is the variability of different coals, both in form and chemical analysis. A more uniform, properly sized product, deep-cleaned at the source, would be less difficult for the smaller industrial energy user, says the report.

The cost of coal handling, coal burning, and environmental controls can result in a capital cost for coal that is 2.5 to 4 times higher than for natural gas. The uncertainty of upcoming new regulations further complicates the issue. Potential users of coal face higher capital costs as well as the uncertainty of regulatory issues.

The environmental regulatory processes at both the federal and state levels are viewed as a detriment to coal use in several important respects:

- Emission standards are based on a percent reduction instead of relating emissions to unit of output.
- Best available control technology is specified without consideration of cost justification.
- The smaller size of units being brought under compliance requirements has made only the larger installation practical.
Another impediment to coal usage is that transmission line access for independent power producers and cogenerators is difficult to arrange, even though there is concern about the adequacy of the electrical transmission systems in the United States.

Recommendations

The United States Department of Energy (DOE) should continue to support and expand the development of technology for the conversion of coal into liquids, coal into gas, and synthesis gas into chemicals, says the National Coal Council.

The Secretary of Energy should encourage research and development to evaluate the best means of using coal for direct process heat in processes such as glass manufacturing. This research and development should be undertaken with the participation of the specific industry.

The council recommends that one of the clean coal technology programs be the demonstration of processes that prepare, deep-clean, and size coal for industrial use.

Industry should make use of available technologies to clean, dewater, dry, and prepare coal fines rejected by coal preparation plants.

The Secretary of Energy should encourage federal and state governments to ensure transmission line access and power markets for independent power producers and cogenerators.

The DOE should continue to support and expand the research on chemicals derived from synthesis gas from coal.

Public awareness that there is an important role for coal and that the technology exists to burn coal in an environmentally acceptable manner needs to be created.

The National Coal Council's projection of industrial coal consumption by industry type to the year 2000 is provided in Table 2.

**TABLE 2**

INDUSTRIAL COAL CONSUMPTION BY INDUSTRY TYPE
(Millions of Tons)

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Chemicals</td>
<td>17.8</td>
<td>16.6</td>
<td>16.9</td>
<td>17.0</td>
<td>17.0</td>
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<tr>
<td>Stone, Clay &amp; Glass</td>
<td>16.9</td>
<td>15.4</td>
<td>15.5</td>
<td>14.4</td>
<td>12.7</td>
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<tr>
<td>Paper</td>
<td>13.0</td>
<td>13.4</td>
<td>13.3</td>
<td>13.2</td>
<td>12.4</td>
</tr>
<tr>
<td>Primary Metal Products</td>
<td>8.5</td>
<td>8.5</td>
<td>8.6</td>
<td>8.4</td>
<td>7.6</td>
</tr>
<tr>
<td>Petroleum &amp; Coal Products</td>
<td>5.6</td>
<td>8.5</td>
<td>8.6</td>
<td>8.9</td>
<td>9.5</td>
</tr>
<tr>
<td>Food</td>
<td>5.7</td>
<td>6.9</td>
<td>7.2</td>
<td>6.5</td>
<td>5.8</td>
</tr>
<tr>
<td>Subtotal</td>
<td>67.5</td>
<td>69.3</td>
<td>70.1</td>
<td>68.4</td>
<td>65.0*</td>
</tr>
<tr>
<td>Others, Including Nonutility Generation</td>
<td>7.9</td>
<td>5.9</td>
<td>9.9</td>
<td>16.6</td>
<td>20.0</td>
</tr>
<tr>
<td>Total</td>
<td>75.4</td>
<td>79.2</td>
<td>80.0</td>
<td>85.0</td>
<td>85.0</td>
</tr>
</tbody>
</table>

*Forecast of an actual 6.7% decline, 1987-2000, in coal use by the manufacturing sector.

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IEA PREDICTS 20 PERCENT GROWTH IN COAL USE BY 2000

OECD (Organization for Economic Cooperation and Development) coal demand is expected to grow 1.7 percent per year between 1989 and 2000, according to IEA's (International Energy Agency) new edition of its annual publication, Coal Information 1990. Total coal demand will increase 20 percent to the equivalent of 1,459 million metric tons, from 1,212 million metric tons in 1989.

SYNTHETIC FUELS REPORT, SEPTEMBER 1990
Total primary energy requirements are forecast to grow 1.4 percent per year during the same period to the equivalent of 6,734 million metric tons of coal (measured in standard calorific units). IEA says it is likely that coal will increase its share of energy requirements slightly, from 21 percent in 1988 to 22 percent in 2000.

Electricity production in the OECD is forecast to grow 2.4 percent per year from 6,478 terawatt hours in 1988 to 8,591 terawatt hours in 2000, says the IEA report. The share of coal in electricity production is forecast to fall slightly from 40.5 percent in 1988 to 38.8 percent in 2000. The OECD is projected to have 1,784 gigawatts of electricity generating capacity in 2000 of which 593 gigawatts will be coal-fired.

Coal Information 1990 analyzes current world coal market trends and long-term prospects, and includes information on coal prices, demand, trade, production, productive capacity, coal ports, coal-fired power stations and coal data for non-OECD countries. Additional information provided in this year's edition includes an analysis of productive capacity and a compilation of representative export costs for steam coal and coking coal for the major coal-exporting countries.

One section of the report outlines emissions standards for coal-fired boilers in IEA countries. In many countries emissions standards are being extended to include existing facilities as well as new plants.

Highlights of 1989 Coal Activity

Coal prices in the international market continued to increase in 1989 due to the relatively tighter supply conditions experienced by coal markets since late 1987. The average value of the IEA steam coal imports rose almost 10 percent in 1989 to US$53.78 per metric ton of coal equivalent reflecting higher demand from electric utilities and constrained supply. The average value of coking coal imports into IEA countries also increased, but at lower rates of 6 percent for Japan and 3 percent for the European countries. The price of Australian steam coal to the Japanese utility market rose about 10 percent in 1989 to US$39.15 per metric ton f.o.b. Australia, compared with the previous year.
SCOTIA SYNFUELS CALCULATES 20 PERCENT RETURN POSSIBLE

Scotia Synfuels Ltd. has proposed a 12,000 barrel per day coal/oil coprocessing plant at Point Tupper, Nova Scotia, Canada. The company says that a 20 percent rate of return on investment would be possible.

An update on the project was given at the Fifteenth International Conference on Coal and Slurry Technologies held in Clearwater, Florida in April.

The overall block flow diagram is shown in Figure 1. In the coal/oil coprocessing unit coal is ground, dried and blended with oil residuum to produce a slurry. The slurry is pumped
with hydrogen into a two-stage reactor system. The coal and heavy oil are converted to lighter distillable oils. The raw distillate is processed further in hydrotreaters to improve stability and to reduce sulfur and nitrogen. This synthetic fuel is then suitable for conversion to finished products by eastern Canadian refiners.

The hydrogen required for the coprocessing unit and the hydrotreaters is produced by gasification of coal and residue from the coprocessing unit.

Total capital cost for a 12,000 barrel per day plant is estimated to be US$375 million. Net operating costs are under US$20 per barrel of synthetic fuel (Table 1).

<table>
<thead>
<tr>
<th>OPERATING COSTS ($1989)</th>
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<tr>
<td><strong>US$/Barrel</strong></td>
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<tr>
<td>Synthetic Fuel</td>
</tr>
<tr>
<td>Raw Materials</td>
</tr>
<tr>
<td>Utilities</td>
</tr>
<tr>
<td>Labor, Maintenance, Other</td>
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<tr>
<td><strong>Total Operating Costs</strong></td>
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<tr>
<td>Less: Byproduct Credits</td>
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<tr>
<td><strong>Net Operating Cost</strong></td>
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### Project Basis

The site chosen for the coprocessing project is the former refinery site at Point Tupper, Nova Scotia. An 87,000 barrel per day refinery operated at this location in the 1970s. The plant was shutdown and mothballed in 1980. The buildings, roads, storage tanks, waste water treatment ponds, and utilities systems can be made serviceable and incorporated in the design of the coprocessing facility. The previous establishment of a refinery at this site will make it easier to prepare the environmental assessment required for a project.

A wharf was constructed in association with the former refinery. This wharf is ice free the year around. Two berths are available for handling crude oil and refined products. The large berth can accommodate a Very Large Commercial Carrier (VLCC) of 360,000 tonne size.

Current mining operations in the Sydney, Nova Scotia area by DEVCO produce 4 million tonnes per year of coal for utility and metallurgical use. Proven reserves are 1 billion tonnes. One of the major seams in the coal fields is the Harbour seam. The coal is a high sulfur bituminous coal which is primarily used for thermal power production.

The Point Tupper location is situated to obtain heavy oil from a number of sources. Potential sources are heavy oils from Mexico or Venezuela or residuum from refineries in eastern Canada.

Between 1981 and 1985, Scotia Synfuels Ltd. organized a consortium to evaluate several technologies for the direct conversion of Cape Breton coal to liquid hydrocarbons. A report prepared at that time identified the then emerging technology of coal/oil coprocessing as offering potential savings.

In late 1988 Hydrocarbon Research Inc. (HRI) was commissioned by Scotia Synfuels Ltd. to perform microautoclave and bench scale tests to demonstrate the feasibility of their coprocessing technology using Harbour seam coal and several oil feedstocks. Conversions of 92 percent on coal and 86 percent on heavy oil were achieved in coprocessing bench scale tests. Overall liquid hydrocarbon yield was 77 percent of total dry feed. In early 1989, Bantrel Inc. was commissioned to develop a preliminary process design for a coal/oil coprocessing plant. The information developed in the test program and engineering study was used by Scotia Synfuels Ltd. to assess the economic viability of a project and the effects of possible government support programs. Currently, Scotia says that discussions are being held with the Canadian Government, the provincial government and private investors, to develop the next stage of the project.

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**ECONOMIC WINDOW OF OPPORTUNITY SEEN FOR COPROCESSING**

The United States Department of Energy (DOE) has been supporting several development efforts to demonstrate the technical and economic feasibility of coprocessing. As part of this effort, they requested that MITRE Corporation undertake a comparative economic analysis to identify economic conditions favorable to coprocessing.

Speaking at the SynOps 90 conference held in Bismarck, North Dakota in August, D. Gray reported on the results of this techno-economic analysis of the coprocessing of coal and petroleum resid compared to other alternative technologies of resid upgrading alone and coal liquefaction. All three of these technologies can use ebullated-bed reactors to accomplish the conversion of coal, coal-derived resid, and petroleum resid. Preliminary results of this work were reported earlier (the Pace Synthetic Fuels Report, June 1990, page 4-20).
Two of the successful, commercially proven resid hydrocracking technologies use ebullating-bed reactors. These are the H-Oil and LC-Fining processes. Both of these essentially similar technologies use high-pressure ebullating-bed reactors and hydrotreating catalysts. Feed oil and hydrogen gas enter the reactors at the bottom, and the upflow velocity expands the catalyst bed into a state of ebullation. The bed expansion is controlled by an internal recycle oil pump. H-Oil process installations are located at the Texaco refinery in Convent, Louisiana, and in Kuwait and Mexico. Husky Oil Operations is currently designing an H-Oil unit in Canada to upgrade Lloydmminster and Cold Lake heavy oils. LC-Fining units are located at the Amoco refinery in Texas City, and at Syncrude Canada's bitumen upgrading plant in Alberta.

These ebullating-bed reactors are also the key components in several technologies for the direct liquefaction of coal. Lummus-Crest used LC-Finer reactors as the second stage, together with a short-contact-time thermal first stage in their Integrated Two-Stage Liquefaction (ITSL) process. At the Wilsonville coal liquefaction test facility, H-Oil reactors are used for both first and second stages in the Close-Coupled ITSL process. Hydrocarbon Research Incorporated (HRI) uses two close-coupled H-Oil reactors in their Catalytic Two-Stage Liquefaction (CTSL) process. Two of the current development efforts in coprocessing also utilize the ebullated-bed reactor. The Lummus-Crest coprocessing concept uses LC-Finers, and the coprocessing technology being developed by HRI uses H-Oil reactors and the same configuration as used for direct coal liquefaction.

According to Gray, there are several incentives for the development of coprocessing technologies. Since coprocessing upgrades both resid and coal simultaneously, it represents an intermediate technology to produce high-value distillate from poor-quality and low-cost feedstocks. The major plant components needed for coprocessing are commercial because of the availability of ebullated-bed reactors. There is also some evidence that coal may facilitate heavy petroleum resid upgrading. It has been suggested that heavy metals from the resid may preferentially deposit onto the coal ash rather than onto the catalyst.

A comparative analysis was accomplished by developing computerized models that simulate conceptual commercial-scale plants. The conceptual plants were all scaled to produce 100,000 barrels per day of liquid products. The models calculate feedstock requirements, plant fuel, hydrogen and energy needs, and final product yields and selectivities. The raw products are of differing quality and are hydrotreated in the model to produce distillates of common quality so that fair comparison is possible.

The computer model includes all of the unit processing steps necessary to convert the feedstocks to final products. In the coal liquefaction case, this includes coal handling and preparation, coal liquefaction, product recovery, hydrogen purification, solids/liquids separation, hydrogen production via coal gasification, and all the associated off-sites. For the coprocessing case, the model is very similar and includes coal and resid preparation, coprocessing, product recovery, hydrogen purification and vacuum distillation, hydrogen production via coal gasification, and associated off-sites. In the resid-only case, the model includes the H-Oil reactor section, product recovery, hydrogen purification, hydrogen production via coal gasification or steam reforming of natural gas, and associated off-sites.

Three cases were considered in the analysis by MITRE. For case 1, the direct coal liquefaction case is based on CTSL technology. Solids/liquids separation is accomplished using the ROSE-SR critical solvent deashing (CSD) process. Case 2, coprocessing, is shown schematically in Figure 1 on the next page. Flows are based on 50 pounds of moisture-free Ohio 5/6 coal and 50 pounds of Cold Lake resid to give a total input of 100 pounds of fresh feed. Solids/liquids separation is accomplished using vacuum distillation. Case 3 is resid-only upgrading. No deashing process is needed, but vacuum distillation is required to separate unconverted bottoms for recycle.

Table 1 (on the next page) is a summary of the feedstocks and products for conceptual commercial plants. The commercial plants are sized to produce 100,000 barrels per stream day (BPSD) of raw distillate. In the CTSL plant, coal is required for liquefaction, steam generation, and gasification to produce process hydrogen. This is also the situation for the coprocessing plant, but here 58,000 barrels per day of Cold Lake resid is also processed in the coprocessing reactors. In the resid-only plant, coal is used for plant steam and for gasification to produce hydrogen. Coal gasification in this case is comparable to the other two cases that use coal for hydrogen production.

In order to compare the different quality products from the different processes, the MITRE model simulates the hydrotreatment of the raw products to a common hydrotreated product. The costs of performing this hydrotreatment and of converting the hydrotreated product to gasoline are also computed in the model. From these costs an equivalent crude value is obtained. Equivalent crude is defined as the price a refiner can afford to pay for crude oil that would allow him to produce gasoline for the same price as synthetic gasoline. Thus the differential between the equivalent crude and the raw product price is a measure of the added value of the synthetic crude to the refiner.

Table 2 (on a following page) shows a summary of the economic data for conceptual commercial plants based on the three technologies. Operating costs include the cost of coal feedstock at $1 per million BTU ($22.70 per ton) and of resid at $16 per barrel. The required selling prices are shown at the bottom of Table 2 for raw product, hydrotreated product, and gasoline. The equivalent crude
FIGURE 1

HRI COPROCESSING CASE

TABLE 1

CONCEPTUAL COMMERCIAL PLANT FEED AND PRODUCT SUMMARY
(Plants Scaled to Produce 100,000 BPSD of Raw Product)

Feedstocks

Coal Liquefaction Coprocessing Resid Upgrading Only
HRI CTSI HRI H-Oil

Coal to Liquefaction TPD (AR) 27,322 11,536 0
Coal to Steam Plant 2,669 1,461 793
Coal to Hydrogen Production 9,540 4,369 1,853
Total Coal to Plant 39,531 17,365 2,646
Oil to Upgrading TPD 0 10,406 17,206
BPD 0 57,973 95,200

Products

<table>
<thead>
<tr>
<th></th>
<th>TPD</th>
<th>BPD</th>
<th>TPD</th>
<th>BPD</th>
<th>TPD</th>
<th>BPD</th>
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<tbody>
<tr>
<td>Naphtha</td>
<td>5,076</td>
<td>36,118</td>
<td>3,454</td>
<td>25,247</td>
<td>3,149</td>
<td>24,395</td>
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<tr>
<td>Middle Distillate</td>
<td>8,575</td>
<td>53,495</td>
<td>8,135</td>
<td>52,442</td>
<td>6,505</td>
<td>43,187</td>
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<tr>
<td>Heavy Distillate</td>
<td>1,856</td>
<td>10,387</td>
<td>3,724</td>
<td>22,311</td>
<td>5,231</td>
<td>32,418</td>
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<tr>
<td>Total Raw Product</td>
<td>15,507</td>
<td>100,000</td>
<td>15,313</td>
<td>100,000</td>
<td>14,885</td>
<td>100,000</td>
</tr>
<tr>
<td>Hydrotreated Product</td>
<td>15,430</td>
<td>106,850</td>
<td>15,107</td>
<td>104,614</td>
<td>14,672</td>
<td>101,611</td>
</tr>
<tr>
<td>Gasoline</td>
<td>14,786</td>
<td>114,330</td>
<td>14,477</td>
<td>111,937</td>
<td>14,060</td>
<td>108,724</td>
</tr>
</tbody>
</table>

SYNTHETIC FUELS REPORT, SEPTEMBER 1990
TABLE 2
CONCEPTUAL COMMERCIAL PLANT ECONOMIC SUMMARY

<table>
<thead>
<tr>
<th></th>
<th>Coal Liquefaction</th>
<th>Coprocessing HRI</th>
<th>Upgrading Only H-Oil</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>HRI</td>
<td>HRI</td>
<td></td>
</tr>
</tbody>
</table>

CAPITAL AND OPERATING COSTS

<table>
<thead>
<tr>
<th></th>
<th>Liquefaction</th>
<th>Coprocessing</th>
<th>Upgrading Only</th>
</tr>
</thead>
<tbody>
<tr>
<td>Plant Construction Cost ($1,000)</td>
<td>$1,286,594</td>
<td>$924,358</td>
<td>$662,932</td>
</tr>
<tr>
<td>Solids Removal</td>
<td>172,224</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>Hydrogen Production</td>
<td>757,083</td>
<td>485,608</td>
<td>280,493</td>
</tr>
<tr>
<td>Balance of Plant</td>
<td>534,949</td>
<td>364,581</td>
<td>247,623</td>
</tr>
<tr>
<td>Total Construction Cost</td>
<td>$2,750,850</td>
<td>$1,774,546</td>
<td>$1,191,048</td>
</tr>
<tr>
<td>Total Capital</td>
<td>$4,358,360</td>
<td>$2,941,057</td>
<td>$2,098,213</td>
</tr>
</tbody>
</table>

Operating Costs ($1,000/yr)

<table>
<thead>
<tr>
<th></th>
<th>Coal ($22.70/ton)</th>
<th>Oil ($16/BBL Resid)</th>
<th>Other Operating</th>
<th>Byproduct Credit</th>
<th>Hydrotreating</th>
<th>Total Net Operating Costs</th>
</tr>
</thead>
<tbody>
<tr>
<td>Liquefaction</td>
<td>$296,130</td>
<td>0</td>
<td>371,923</td>
<td>110,472</td>
<td>127,326</td>
<td>$684,907</td>
</tr>
<tr>
<td>Solids Removal</td>
<td>$130,084</td>
<td>306,097</td>
<td>265,873</td>
<td>89,460</td>
<td>95,020</td>
<td>$707,614</td>
</tr>
<tr>
<td>Hydrogen Production</td>
<td>306,097</td>
<td>203,546</td>
<td>502,703</td>
<td>36,178</td>
<td>44,421</td>
<td>$734,311</td>
</tr>
<tr>
<td>Total Net Operating Costs</td>
<td>$684,907</td>
<td>$707,614</td>
<td>$734,311</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

PRODUCT COSTS $/BBL

<table>
<thead>
<tr>
<th></th>
<th>Raw Product</th>
<th>Hydrotreated Product</th>
<th>Gasoline</th>
<th>Equivalent Crude</th>
</tr>
</thead>
<tbody>
<tr>
<td>Liquefaction</td>
<td>38.95</td>
<td>40.07</td>
<td>42.69</td>
<td>32.90</td>
</tr>
<tr>
<td>Coprocessing HRI</td>
<td>33.45</td>
<td>34.72</td>
<td>37.81</td>
<td>28.24</td>
</tr>
<tr>
<td>Upgrading Only H-Oil</td>
<td>31.52</td>
<td>32.35</td>
<td>35.75</td>
<td>26.27</td>
</tr>
</tbody>
</table>

value is also shown, which is calculated from the gasoline price, assuming a $6 per barrel refiner's margin.

In order to investigate the favorable economic conditions for coprocessing, a series of sensitivity analyses were performed to determine the impact of feedstock costs on the required selling prices for these three technologies. Figure 2 on the next page shows the results of such an analysis for various costs of resid, assuming that the value of product gas is equal to resid on a thermal basis. Raw product selling prices are shown, and coal cost is assumed to increase at half the rate of resid on a thermal basis. This shows that coprocessing would be the preferred, lowest-cost technology for a range of resid costs from $21 to $28 per barrel. Above $28 per barrel, CTSL becomes economically preferred and below $21 per barrel, resid upgrading would be cheaper.

Figure 3 on the next page shows a plot of equivalent crude against crude oil price, assuming that resid value is two-thirds that of crude. The parity line for resid equal to two-thirds crude oil price is also shown for reference. The economically attractive regime is that area to the right of the parity line. With resid at two-thirds oil price, coprocessing is economically favorable for oil prices greater than $30 per barrel. Coprocessing appears to be economically favored compared to direct coal liquefaction and resid upgrading for crude oil prices between $33 and $42 per barrel.
YIELD AT WILSONVILLE REACHES 4 BARRELS PER TON

The Advanced Coal Liquefaction Research and Development facility at Wilsonville, Alabama has been in operation since 1974. This facility is the only operating integrated direct coal liquefaction pilot plant in the United States. It has been developing and testing new concepts in liquefaction technology for 16 years. The plant configuration has evolved from a simple single-stage process, into the present sophisticated, catalytic-catalytic close-coupled integrated two-stage liquefaction (CC-ITSL) process (Figure 1). Besides process development improvements, methods were developed to control corrosion, improve mechanical performance of pumps, valves and compressors, and biologically treat wastewater streams. Process models were developed and simulated, and good material balance procedures using elemental analysis were developed and adopted. Plant evolution and process developments at Wilsonville were recently summarized in a paper presented at the Fifteenth International Conference on Coal and Slurry Technologies.

The Wilsonville facility began operation in 1974 with a 6 ton per day pilot plant program to produce a clean solid fuel from coal that could be burned in power plants. In the original Solvent Refined Coal (SRC) process at Wilsonville, coal was dissolved and the product was filtered for solvent recovery. Over the years, the plant configuration has evolved into two-stage liquefaction with two closely coupled ebullated catalytic bed reactors followed by a ROSE-SR (Residuum Oil Super-critical Extraction—Solids Rejection) unit to remove minerals and unreacted coal from liquid products.

In the past decade, major advances in the Wilsonville test program resulted in substantial improvements to process performance and better economics for direct coal liquefaction. The first was the use of two reactors in series in place of a single reactor. In general, coal is mixed with recycle solvent and fed to the thermal first stage reactor. Heavy coal liquids are sent to the second, catalytic, stage for upgrading to distillable liquids.

In 1982, the two reactor system was first tested in the Non-integrated Two-Stage Liquefaction (NTSL) mode. The process was non-integrated in the sense that each reactor system had a separate solvent recycle system. A simplified block diagram of the NTSL and other modes that have been tried at Wilsonville is given in Figure 1. The NTSL process showed a significant improvement in liquid yields compared to the SRC process but the quality of the liquid fuels produced was not high enough to compete with premium liq-
uid fuels such as gasoline, diesel or fuel oil. To further improve product quality, research emphasis was switched to the Integrated Two-Stage Liquefaction (ITSL) process in which the vacuum resid from the thermal liquefaction stage is deashed before being fed to the hydrotreater. This process produced high yields of liquid fuels with good product quality.

The Reconfigured Integrated Two-Stage Liquefaction (RITSL) process was the next major mode of operation to be tested at Wilsonville. In this configuration, coal is slurried with a recycled process solvent and fed to the first stage under hydrogen pressure where thermal liquefaction takes place. Thermal distillate is separated by fractionation, and the vacuum bottoms along with a heavy fraction of distillate make up the feed to the hydrotreater. The vacuum-flashed bottoms from the hydrotreater are deashed, and the deashed hydrotreater resid and hydrotreated distillate formed the recycled process solvent. The major difference between RITSL and previous processes was placing the deashing unit after the hydrotreater. Catalyst performance was slightly better than with ITSL runs.

The RITSL configuration was a positive step to operate the reactors closely together, where the products from the liquefaction stage would be fed directly to the hydrotreater without any intermediate ash or distillate separation. In 1986, the process configuration was changed to the Close-Coupled Integrated Two-Stage Liquefaction (CC-ITSL) process. In this process catalyst is used in both reactors and solvent is recycled without removing all the solids. In addition, pressure let-down and heat and solvent removal between reactor stages were eliminated to improve process efficiency.

The CC-ITSL mode of operation is the most advanced two-stage liquefaction configuration that is currently available for direct coal liquefaction technology. CC-ITSL has several process advantages compared to other configurations, such as (1) reduction of fractionation unit, (2) smaller deashing unit, (3) high process efficiency, (4) improved product quality, and (5) synergistic process performance improvements in the catalytic-catalytic mode of operation. With the CC-ITSL process, 78 weight percent of a low-ash, high carbon Ohio coal was converted to high quality distillate fuel, the highest yield ever achieved by direct coal liquefaction.

In summary, coal liquefaction activities at Wilsonville have established the commercial viability of direct coal liquefaction from a technical point of view. Major breakthroughs through various tests at Wilsonville improved the liquid yields by over 40 percent. This translates to a production of over 4 barrels of liquids per ton of coal processed compared to 2.5 barrels per ton in the 1970s. The quality of liquid fuels produced also improved considerably compared to technologies developed in the 1970s and early 1980s. As a consequence of these improvements, the estimated product cost has decreased substantially to $33 per barrel.
NEW BOOK SUMMARIZES PRODUCTION OF METHANOL FROM COAL

How to Produce Methanol from Coal is the title of a new book by Emil Supp of Lurgi GmbH and published by Springer-Verlag. This book describes both the individual steps that are required for the process and the essential ancillary units and offsites associated with the process itself.

Although this relatively slim book does not go into engineering details about the process, it gives the reader an impression of how manifold a field this is, and how many process variations and combinations the designer of such plants has to consider in order to arrive at an optimum design in each particular case. Apart from the production of chemical-grade methanol, the book deals briefly also with fuel methanol production, i.e., with the production of alcohol mixes.

Comparisons of different vendor approaches to individual process steps are very brief, sometimes only a paragraph each, but the book does manage to impart a general impression of the important advantages and disadvantages of each.

Table 1 gives Supp’s comparison of overall methanol efficiencies for different coal gasification processes.

This book will provide a good introduction to the subject for those with a technical background, but who are not now involved with engineering practice in this field.

The major headings in the Table of Contents include:
- How to produce gas from coal
- How to purify and to condition methanol synthesis gas
- How to synthesize methanol and alcohol mixtures
- How to obtain pure methanol
- How to process byproducts and wastes
- How to supply utilities to a coal-to-methanol plant
- What could a methanol plant look like
- Future outlook

### TABLE 1 ###

METHANOL EFFICIENCY OF SELECTED GASIFICATION PROCESSES

<table>
<thead>
<tr>
<th>Type of Coal Gasification</th>
<th>Lurgi Dry Bottom</th>
<th>Lurgi/BG Slagger</th>
<th>Koppers-Totzek</th>
<th>Shell</th>
<th>Texaco</th>
<th>Dow</th>
</tr>
</thead>
<tbody>
<tr>
<td>Coal to Gasifier (kg/kg methanol)</td>
<td>1.028</td>
<td>0.979</td>
<td>1.248</td>
<td>1.045</td>
<td>1.109</td>
<td>1.100</td>
</tr>
<tr>
<td>Oxygen (m³/kg methanol)</td>
<td>0.526</td>
<td>0.469</td>
<td>0.88</td>
<td>0.655</td>
<td>0.743</td>
<td>0.72</td>
</tr>
<tr>
<td>Process Steam (kg/kg methanol)</td>
<td>1.380</td>
<td>0.604</td>
<td>0.496</td>
<td>0.477</td>
<td>0.430</td>
<td>0.230</td>
</tr>
<tr>
<td>Coal for Production of Oxygen and Process Steam (kg/kg methanol)</td>
<td>0.241</td>
<td>0.169</td>
<td>0.258</td>
<td>0.202</td>
<td>0.219</td>
<td>0.194</td>
</tr>
<tr>
<td>Pseudo-Methanol Efficiency (HHV Methanol/HHV Coal)</td>
<td>0.542</td>
<td>0.599</td>
<td>0.406</td>
<td>0.552</td>
<td>0.518</td>
<td>0.532</td>
</tr>
</tbody>
</table>

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aqueous slurry of sewage sludge is produced. The physical nature of the sewage sludge is changed by this shearing without heat treatment. For example, the gel structure is broken down and the water affinity of the sludge solids is reduced. When weak solid-water interfacial forces prevail, then the aqueous suspensions of sewage sludge may be easily dewatered further by conventional means. It was unexpectedly found that pumpable slurries are produced by the subject process that contain a relatively high solids content e.g., about 30 to 65 weight percent comprising coal particles in admixture with the sheared sewage sludge.

The data presented in the patent shows that applying a shearing stress alone without heating increases the amount of sewage sludge that can be included in a pumpable coal/sludge slurry as well as the amount that can be included in a slurry of sludge alone by about 33 percent. The shearing stress was applied in these runs by means of the stirring blades in a conventional blender.

Copending United States patent application 389,435 shows that subjecting sludge to a shearing stress while heating was more advantageous than heating or shearing alone. However, in spite of the fact that more sludge which has been heated/sheared can be incorporated into a slurry than sludge which was only sheared, shearing alone without heating may be the best choice in circumstances where there is no ready source of heat or heat is too expensive. Heating also introduces the need for processing that may not be required where sludge is simply sheared. For example, heating sludge produces a separable aqueous stream that cannot be recycled within a conventional treatment plant because its high BOD would overload the system.

STORAGE STABILITY OF COAL-DERIVED JET FUELS TESTED

The storage stability of coal-derived jet fuel is one component of the overall effort funded by the Aero Propulsion and Power Laboratory at Wright-Patterson Air Force Base to investigate the feasibility of making military jet fuel from the liquid byproducts of the Great Plains coal gasification plant. Recent reports have been issued by teams at Penn State University and at the National Institute for Petroleum and Energy Research.

Penn State University

Work carried out in the Department of Materials Science and Engineering at Penn State University was designed to investigate the thermal stability of a suite of alkylated phenols as typical trace contaminants in jet fuels and to determine the thermal stability of various fractions of a coal-derived and a petroleum-derived JP-8 jet fuel as well as the thermal stability of the unfractionated fuels.

The analysis of the treatment products from the alkylated phenols showed that the thermal degradation reactions involve dealkylation and rearrangement of alkyl groups on the aromatic rings and coupling of the partially dealkylated rings to form multi-ring molecules with varying degrees of alkyl substitution. It has been suggested that these high-molecular-weight complex molecules are the precursors to the solid deposits formed by thermal stressing. A comparison of the appearance and the NMR spectra of the reaction products indicated that the 2,4,6-trimethylphenol is the most stable and the 2,4,6-tri-t-butyphenol is the most reactive compound among the alkylated phenols studied.

A high-resolution GC-MS analysis of the distillate fractions of a coal-derived and a petroleum-derived JP-8 jet fuel showed that the two fuels have distinctly different chemical constitution. The petroleum-derived fuel consists mainly of long-chain paraffins mixed with low concentrations of alkylbenzenes and alkynaphthalenes, while the coal-derived fuel appeared to contain monocyclic and bicyclic alkanes and some hydroaromatic compounds as the major components.

The whole petroleum- and coal-derived JP-8 fuels were treated at 300°C for 6 hours in nitrogen and air atmospheres and at 350°C for 4 hours in a nitrogen atmosphere without the formation of visible solids. The fuels treated at 350°C showed, however, a separation of some sediments in small quantities upon storage for two days. The treatment of the petroleum- and coal-derived JP-8 at 425°C for 1 hour in a nitrogen atmosphere produced small quantities of solids.

A distinct change that was produced by thermal treatment in every case was the discoloration of the fuels, the degree of which depended upon the starting fuel and the severity of the thermal treatment. The differences in the extent of discoloration were quantified by using a spectrophotometer. Figure 1 (on the next page) shows percent transmittance of the thermal treatment products from petroleum- and coal-derived fuels at three different temperature-time combinations. Transmittance of the products from petroleum-derived JP-8 (JP-8P) is higher than that from coal-derived JP-8 (JP-8C) in every case with the difference increasing with the increasing temperature. This observation suggests that JP-8P is slightly more stable than JP-8C and that the difference in thermal stability increases with the increasing temperature.

Figure 2 (on the next page) compares percent transmittance from the products of JP-8P and JP-8C obtained in nitrogen and air atmospheres at 300°C for 6 hours. It shows that the presence of air reduces the thermal stability of both fuels, however, the coal-derived JP-8 appears to be significantly more susceptible to thermal degradation in an air atmosphere than the petroleum-derived JP-8. In addition to high temperatures, the presence of an oxidizing atmosphere is
comparatively more harmful to the thermal stability of the coal-derived JP-8. Although the coal-derived JP-8 appears to have a similar thermal stability to that of petroleum-derived JP-8 in an inert atmosphere at low temperatures, the constituents of the coal-derived JP-8 seem to be more labile at high temperatures especially in an oxidizing atmosphere.

For both petroleum-derived and coal-derived fuels, the un-fractionated JP-8 appeared to be more stable than the most stable distillate fraction indicating a synergistic effect of the coexistence of the different distillate fractions in the constitution of the whole fuels.

National Institute for Petroleum and Energy Research

Research at the National Institute for Petroleum and Energy Research (NIPER) in Bartlesville, Oklahoma also involved a study of the storage and thermal stabilities of a JP-8 fuel produced from the Great Plains gasification plant compared with similar results for a conventional petroleum-derived JP-8 fuel. Initial characterization and simulated distillation data for the two fuels indicated the coal-derived fuel contained more lower boiling material, a slight color, a high filtration time, and a high particulate content (the latter three properties being due to some suspended clay, most likely). Nevertheless, for the most part both fuels met specification tests for JP-8.

Both fuels exhibited good oxidation stability according to test ASTM D 2274 with the coal-derived fuel showing less sediment and color formation but somewhat higher peroxide content. Storage stability tests (aging at 80°C under 100 psig oxygen) gave the same results on both fuels through 3 weeks of aging. However, between the third and fourth weeks the coal-derived fuel deteriorated rapidly and exceeded the petroleum-derived reference fuel in color and sediment formation as well as peroxide content.

Both fuels easily met specifications in terms of thermal stability testing with the coal-derived fuel showing a higher breakpoint temperature. Extended JFTOT (Jet Fuel Thermal Oxidation Test) runs were conducted at temperatures slightly above the breakpoints to generate filterable sediment and tube deposit samples for analyses.

Infrared analysis of a sample of sediment from the coal-liquid derived JP-8 fuel storage stability tests was not very definitive; however, the spectrum was very similar to that of the acid fraction separated from the fresh fuel. HPLC acid subfractionation indicated the sediment was composed primarily of carboxylic acids and difunctional acids.

Mass spectra of the filterable sediments and JFTOT-tube deposits formed during extended thermal stressing runs of the coal-derived and petroleum-derived fuels were remarkably similar, indicating that the same or similar compound types were responsible for solids formation in both fuels.

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SYMPOSIUM HIGHLIGHTS PROGRESS IN BIOCONVERSION OF COAL

The First International Symposium on the Biological Processing of Coal, sponsored by the Electric Power Research Institute and the United States Department of Energy's Pittsburgh Technology Center, was held in Orlando, Florida in May. The symposium featured research reports on biological approaches to coal desulfurization and deashing, coal solubilization, coal gasification, conversion of coal gases, and cleanup of coal conversion wastes. Summaries of the projects involving direct bioconversion to liquid or gaseous products are given in the following.

Active Compounds in Biological Solubilization

In search of biologically active compounds for coal degradation, researchers at the Institute of Microbiology and Biotechnology, University of Bonn, West Germany compared a Pseudomonas strain, which was isolated from hard coal media, with a fungus (Chlamydomonas species), which was isolated from a lignite surface mining area. They found that the bacterial and fungal liquid products from lignite could clearly be distinguished by their molecular weight, polarity and duration of the process. Results suggest that the bacterial mechanism is different from the fungal one and that more than one mechanism is used. Initial investigations into the involvement of oxidative enzymes (ligninases, normal peroxidases, laccases, mono- and dioxygenases, production of \( \text{H}_2\text{O}_2 \) and hydroxyl radicals) have shown that the oxidative attack in lignite liquefaction is correlated to a peroxidase. The oxidative compound for microbial hard coal modification has not been identified yet.

Genetics of Coal Solubilization by Fungi

The Department of Biological Sciences of the University of South Carolina, has shown that Neurospora can biosolubilize coal. They described the results of work on the genetics of coal solubilization by a fungus, Neurospora crassa, whose genetics and molecular biology are well known. In this approach, the roles of specific enzymes in solubilization of coal have been confirmed by identification of mutants, which have lost the ability to solubilize coal \textit{in vivo} and \textit{in vitro}, concomitant with the loss of a specific enzyme. Researchers have identified at least four different mutants in which a missing oxidase (such as laccase and/or tyrosinase) is responsible for the lack of solubilization of coal. One such Neurospora oxidase has been purified. Antibodies against this Neurospora oxidase catalyzing coal solubilization are being raised in rabbits; these will be used for screening of a genomic library to identify the cloned gene. Results of biochemical and genetic analyses show that solubilization can be achieved without laccase.

Biotransformations of Coal by Bacteria

At the Department of Bacteriology and Biochemistry of the University of Idaho, a number of aerobic and anaerobic bacteria, isolated from natural habitats associated with coal and decomposing plant material, were characterized for their abilities to transform lignite coal and coal model compounds. Several aerobic Pseudomonas and Flavobacterium strains depolymerized a lignite coal supplied to growing cultures as a high molecular weight water-soluble polymer. The coal was solubilized by treatment with base, but had not been pre-oxidized with acid. The chemistry of depolymerization was nonoxidative as shown by comparative elemental analysis of control and depolymerized coals. A discovery of great significance was that several of these isolates produced an extracellular enzymatic activity that catalyzed rapid and substantial depolymerization of the coal polymer.

Several strictly anaerobic bacterial isolates carried out reductive chemical transformations of coal substructure model compounds, including the reduction of quinones and carbon-carbon double bonds, as well as nonoxidative decarboxylations and dehydroxylations of aromatic rings. In general, anaerobic biotransformations of the coal or coal substructure models required an extraneous source of reducing power such as hydrogen. The overall results show that potentially useful biotransformations of coal are possible using either aerobic or anaerobic microorganisms, and there is good potential for using bacteria to produce liquid or gaseous fuels from lignite coals.

Solubilization of Coal by Reducing Enzymes

Biocatalytic systems utilizing either living organisms or enzymes \textit{in vitro} have been shown to enhance the solubilization of coal. Recent research at the Chemical Technology Division, Oak Ridge National Laboratory, has included the investigation of anaerobic solubilization of coal in which a hydrogen atmosphere is used. Perhaps one of the most interesting approaches in this research is the use of enzymes dissolved in organic solvents as the solubilization medium.

Both polar and nonpolar organic solvents with several different modified reducing enzymes are being investigated for the solubilization of coal.

The most interesting results are with the use of modified hydrogenase in benzene in which it was shown that bituminous coal solubilization in excess of 20 percent could be achieved at very mild conditions. A bioprocessing concept has been developed based on a fluidized-bed reactor and the use of a process-derived solvent containing modified hydrogenase.

Bioconversion of Synthesis Gas

Liquid and gaseous fuels may be produced from coal by the biological conversion of coal synthesis gas. At the Depart-
Use of Fungi to Solubilize Low-Rank Coal

At the Department of Biology, University of Hartford, low-rank coal has been solubilized with cell-free filtrates separated from a chemically defined broth in which *Trametes versicolor* had grown. A coal solubilizing agent (CSA) has been isolated from the filtrates and shown to solubilize low-rank coal. The CSA has been recrystallized and chemically identified by FTIR and X-ray diffraction analysis. Selected fungi other than *T. versicolor* have also been investigated for coal solubilizing activity.

Biological Conversions of Coals to Methane

ARCTECH, Inc. of Alexandria, Virginia is carrying out a project on "Biogasification of Coal." Anaerobic biodegradation of several low-rank coals was evaluated using enriched bacterial cultures. These cultures, obtained from natural sources, were developed in the laboratory and demonstrated direct conversion of coals to methane. Unique bacterial consortia derived from the guts of several species of termites were studied for conversion of Texas lignite to methane. Two of these termite-derived cultures were capable of producing significant quantities of methane (up to 250 cubic centimeters of methane per gram of coal) from untreated Texas lignite. Preliminary calculations of coal carbon conversion by the best consortium indicate a coal carbon conversion of more than 60 percent. Results from ARCTECH's research projects indicate that bioconversion of low-rank coals may have commercial applications for creating environmentally clean fuel forms or chemical products from a crude feedstock. Biological processes may offer advantages over chemical coal conversion processes due to the generally low capital and equipment costs associated with biological processes.

Hyperthermophilic Archaeabacteria for Bioprocessing

The Department of Chemical Engineering at Johns Hopkins University has found that extremely thermophilic (optimum growth temperature >80°C) and hyperthermophilic (optimum growth temperature >100°C) microorganisms present many biotechnological opportunities including novel biotransformations and unusually stable enzymes. Already these bacteria have been demonstrated to rapidly remove elemental sulfur from refuse coals. Other possibilities include their use in the conversion of fossil fuels.

Microbial Gasification of Pittsburgh Seam Coal

The Bureau of Mines Pittsburgh Research Center and two other laboratories have preliminary evidence of a naturally occurring mixed microbial consortium of microorganisms capable of depolymerizing bituminous Pittsburgh seam coal. The consortium was collected from a mine site abandoned about 75 years ago. When placed on coal substrates, these microorganisms were observed to solubilize Pittsburgh seam coal.

ONLY TRACE LEVELS OF PHENOLS FOUND IN GREAT PLAINS JET FUELS

Large quantities of phenols and other oxygenated compounds are present in the liquid byproducts produced at the Great Plains coal gasification plant. Although most of these are known to be removed in hydrotreating processes, it has been suspected that trace quantities of organo-oxygenate compounds are still present in the refined jet fuels which have been made from these liquids. Such compounds could contribute to fuel stability problems.

Samples of jet fuel (JP-4, JP-8, JP-8X) produced by Amoco Oil Company were analyzed at the North Dakota Energy and Environmental Research Center (EERC) in Grand Forks, North Dakota and at the Western Research Institute (WRI) in Laramie, Wyoming.

Western Research Institute

At WRI an analytical method was developed for the determination of phenolic compounds in aviation fuels based on gas chromatography/mass spectrometry (GC/MS) analysis of the sample and acquiring the data in the selected ion mode (SIM) of data acquisition. The method has a minimum detection limit of 100 ppm.

Four product fuel samples produced by Amoco were analyzed by the method. The results from analysis of the three small-scale production samples indicated that concentration of individual phenolic species is below the detection limit of the method. This low level of phenolics in these samples probably will not have adverse effects on the stability of the fuels.

A C-3 substituted phenol was tentatively identified in the JP-8 fuel produced during the large-scale production experiment. However, this finding is believed to be in error because of possible interferences from tricycloalkanes present in the sample.
Analysis of the coal-derived jet fuels at EERC showed that:

- JP-4 is primarily cyclohexanes with some toluene and xylene.
- JP-8 is primarily more highly alkylated cyclohexanes and decalins and is a blend of different distillate cuts.
- JP-8X is primarily decalins.

EERC analyzed for four phenols, two naphthols, two benzofurans, hexanol, and hydrogenated naphthol using two methods of sample preparation. Using a method that had a detection limit of 10 ppm, only a nonquantifiable, trace amount of phenolics was detected. Using an extraction method, detectability was decreased to 1 ppm. At this detection level, the bulk sample indicated the presence of 2 ppm phenol, 3 ppm o-cresol, and 1 ppm 2,4-dimethylphenol. Trace amounts of 2,3,5-trimethylphenol and 2-naphthol were also detected in the bulk sample. No 2-methyl-1-naphthol was detected.

A total of 6 ppm of phenolics was detected in the bulk sample of coal-derived JP-8.

SIMULTANEOUS GRINDING INCREASES LIQUEFACTION RATE

Research carried out at the University of Toronto, Ontario, Canada has shown a significant enhancement of coal conversion rates when a combination grinding-liquefaction process is used, compared to liquefaction alone. A presentation by O. Trass and E.R. Vasquez at the Fifteenth International Conference on Coal and Slurry Technologies, held in Clearwater, Florida earlier this year, gave some of the results.

It is well known, say the authors, that reactivity of solids is enhanced when these materials are subjected to mechanical stress. Grinding, milling or crushing of polymers results not only in particle size reduction but also in the scission of the molecular chains with the rupture of chemical bonds yielding free radicals. The radicals resulting from mechanical scission can either recombine, react with another polymer molecule, or react with other chemical species present in the system. When coal is dry-ground, most free radicals may form carbon-carbon bonds or react with oxygen. When coal is ground under liquefaction conditions, in the presence of a hydrogen source, the newly created free radicals as well as the active sites originally present might accept hydrogen, recombine, or be preserved as such.

It appears from the very limited published literature that mechanical action during coal hydrogenation is likely to enhance the reaction rate due to the "mechano-chemical" effect. The University of Toronto study was undertaken to test this hypothesis with a grinder, the Szego Mill, which is convenient to use and can be adapted to high pressure/high temperature operation.

The Szego Mill is a planetary ring-roller mill with a stationary, cylindrical grinding surface (stator) which houses an assembly of helically grooved rollers. Crushing forces are created mainly by radial acceleration of these rollers which are radially mobile. The grooves aid material transport through the mill.

Experiments were carried out with and without grinding over a temperature range of 340°C to 380°C and hydrogen pressures up to 20 megapascal. Bituminous DEVCO coal from Nova Scotia was used for most of the work. Tetralin, a hydrogen-donor solvent, was the liquid medium under hydrogen pressure.

Conversion Results

The softening temperature of DEVCO coal, obtained from Ruhr dilatometer measurements, is reported as 341°C. Thus, considerable macromolecular mobility is expected at and above that temperature. Measurements using a differential scanning calorimeter indicated endothermic thermal activity in the range 340-380°C. Hence, the selection of the range of temperatures studied.

Figure 1 on the next page shows the total conversion results obtained on a moisture and ash-free basis (m.a.f.) as percent tetrahydrofuran solubles from both the grinding and non-grinding experiments versus reaction time in minutes. Significant differences are observed between the two processes over the temperature range investigated.

It is apparent that for shorter times, at the 10 and 30 minutes values, grinding enhances the total conversions measured. At prolonged reaction times, conversion becomes independent of the process employed; after 120 minutes, total conversions reach the same values, within experimental error. Thus, grinding increases the rate of conversion but does not influence the final level attained.

From the time reaction temperatures had been reached, the incremental conversions over the 10-minute time interval are roughly twice as large with grinding as without, suggesting a doubling of the early conversion rate caused by grinding.

Liquid Fractions

For a selected group of experiments, an analysis of the liquid product fractions was made, namely as preasphaltenes (tetrahydrofuran minus benzene solubles), asphaltenes (benzene minus n-pentane solubles) and oils (n-pentane
Grinding runs appear to produce higher total conversions initially due to the faster production of large preasphaltene molecules at all temperatures. At the lower temperature of 340°C, this preponderance of preasphaltenes persists at least through the measured period of 43 minutes, and longer. In fact, there is a relative deficiency in the asphaltene and oil fractions observed in Figure 2 compared to the non-grinding experiments. At higher temperatures, further conversion to asphaltenes and oils occurs rapidly, so that, at 360°C after 30 minutes, the higher conversion shows up in the asphaltene and oil fractions.

The authors suggest that the initial increase in heavier fractions may indicate the build-up of free radicals prior to and during the softening of the particles of coal subjected to mechanical action. Large free radicals can be stabilized by the available surrounding species depending on the free energy of stabilization, or other radicals can undergo polymerization to produce these fractions. The later evolution of increased low molecular weight volatile fractions suggests a strong chemical decomposition after the initial scission of the linkages between the aromatic structures in the coal. Therefore, this increased reactivity suggests the interaction of the physical comminution with the chemical reactions, to show the physico-chemical nature of the coal liquefaction process during grinding.

TEXACO TESTS HOT GAS DESULFURIZATION SYSTEM

Texaco Inc. is carrying out a Department of Energy (DOE) sponsored project to test various methods of hot gas desulfurization in conjunction with the Texaco coal gasification process. The experimental work is being performed at Texaco's Montebello, California research laboratory using that laboratory's process demonstration unit (PDU). At the recent Gasification Contractor's Review Meeting, Texaco reviewed the last 12 months of progress on this project. Both in situ and external hot gas desulfurization are being investigated from a technical and economical perspective. The most promising high temperature desulfurization method will then be incorporated, along with other necessary hot gas cleanup steps, into an integrated demonstration PDU.

The work, currently in its second year, is divided into five phases, with each phase originally corresponding to approximately one year. The following list summarizes the Phase II work which has been completed to date:

- The PDU was modified for one oxygen-blown gasification run to include a radiant cooled dip tube immediately downstream of the gasifier reac-
tion chamber. This was done to test the effect that increased gas-solids contact time and additional cooling of the syngas/sorbent/slag system prior to water quenching would have on sulfur capture. Unexpectedly, no increase in sulfur capture was detected.

- Five PDU test runs were conducted using Pittsburgh No. 8 coal in the air-blown gasification mode. The first run was used to develop baseline data for air gasification without any desulfurization. In the second run, a maximum of 30 percent desulfurization of the syngas was accomplished by mixing an iron oxide sorbent with the coal-water slurry feed to the gasifier. In the last three runs, a water slurry of dolomite was injected into the syngas at the entrance to the radiant syngas cooler. A maximum of 72 percent desulfurization was achieved.

- Two formulations of zinc titanate and one zinc ferrite were tested as external sulfur sorbents during air-blown gasification in the PDU. Operating as a sulfur polishing step, all three reduced the sulfur level below 99.9 percent. All of the sorbents retained their crush strength in the air-blown gasification syngas.

- Research Triangle Institute, under subcontract to Texaco, exposed two formulations of zinc titanate and one zinc ferrite to multiple cycles of sulfidation and regeneration. Simulations of both air-blown and oxygen-blown syngas were used. In all cases the sulfur level in the syngas was reduced by more than 99.9 percent. In addition, chlorides in the syngas were shown not to poison zinc titanate.

- A Westinghouse cross-flow filter was tested during two air-blown gasification tests. The ability to reduce particulate levels to as low as 6 ppm was demonstrated.

- A fiber optic alkali monitor developed by DOE was used to measure sodium and potassium levels up- and downstream of the cross-flow filter. Unfiltered syngas total alkali levels varied between 1 and 200 ppm. Filtered gas contained less than 20 ppb.

###

**METC Programs Target Methods for Making Hydrogen from Coal**

The Morgantown Energy Technology Center (METC) of the United States Department of Energy (DOE) is sponsoring several programs related to improved methods for manufacturing hydrogen from coal. In direct coal liquefaction, the production of hydrogen may account for one-half of the total capital cost of a plant. Hydrogen may also become important as a clean-burning fuel in its own right. Thus METC's contract research program covers several aspects of hydrogen production. At the Tenth Annual Gasification and Gas Stream Cleanup Systems Contractors Review Meeting held in Morgantown, West Virginia in August, the following contract efforts were reviewed.

**Hydrogen Separation by Ceramic Membranes**

The California Institute of Technology is developing ceramic membranes for hydrogen production from coal gas. The specific objectives are:

- To develop techniques for making hydrogen permselective membranes consisting of dense amorphous oxide layers deposited within the pores of support tubes
- Measure membrane permeability to various gases
- Test membrane stability at high temperatures in contact with a simulated coal gas
- Evaluate the technical and economic potential of these membranes for application to the water-gas shift reaction

Membrane synthesis was carried out by depositing thin layers of amorphous SiO₂, B₂O₃, Al₂O₃ or mixtures of these oxides within the walls of porous Vycor tubes.

Silica membranes were formed by hydrolysis of SiCl₄ at temperatures above 700°C. Formation of the membranes required deposition of 1 to 2 hours and possessed permeation rate coefficients for H₂ of about 0.07 cc per (square centimeter-atmosphere-minute) at 450°C. The H₂:N₂ selectivity was about 5,000. These membrane properties were found to be stable after exposure to simulated coal gas at 600°C for more than one week.

If sufficiently stable, the hydrogen permselective membranes developed in this project are potentially useful for simplifying the flowsheets and improving the economics of hydrogen production and sulfur recovery in coal gasification.
Catalytic Carbon Membranes for Hydrogen Production

Some of the hydrogen for direct liquefaction is expected to be produced by gasification of solid liquefaction residue. Also, production of hydrogen from gasification of mild gasification char for use in liquefaction processes can be a highly suitable end use for char. Careful integration of direct liquefaction and mild gasification processes may result in better overall plant economics due to the increased amount of hydrogen available.

Conventional coal or mild gasification char-based hydrogen plants will typically employ gasification of the solid followed by water gas shift, acid gas removal, Claus/Scot sulfur recovery, and hydrogen separation (e.g., by pressure swing adsorption). A project at Research Triangle Institute (RTI) aims to reduce the cost of hydrogen by combining the water gas shift and hydrogen separation steps using a catalytic membrane reactor. By continually separating hydrogen in the reactor, thermodynamic and kinetic limitations are reduced and maximum hydrogen is produced. The economics of the overall plant may further be made attractive by conducting the water gas shift step as well as other downstream steps at high-temperature high-pressure (HTHP) conditions.

The objective of the RTI project is to evaluate technical and economic feasibility of the development of carbon composite membrane reactors with a permselective catalytic layer for simultaneous water-gas shift reaction and hydrogen separation. The project consists of the following major components:

- Investigation of techniques for modifying commercially available carbon membrane microfilter tubes to impart catalytic activity and to improve hydrogen separation properties
- Testing of modified membranes using simulated coal gas in the HTHP environment to determine improvement in hydrogen yield due to continuous hydrogen separation in the water gas shift reaction
- Economic and technical evaluation of this process on a commercial scale

Four different polymer materials have so far been investigated by varying concentrations and pyrolysis conditions. The HTHP testing system allows conducting experiments at various controllable transmembrane pressures. Hydrogen to carbon monoxide separation factor up to 3.5 and hydrogen to carbon dioxide separation factor up to 4.5 were obtained.

Production of Low Cost Hydrogen

Manufacturing and Technology Conversion International, Inc. (MTCI) is planning to verify the ability of the MTCI indirectly heated fluid bed gasifier to economically produce hydrogen-rich gas from mild gasifier char and liquefaction residue (critical solvent deashing residue).

Amoco Corporation will be participating in the project in evaluating the results and applying it for the design of an integrated liquefaction process employing MTCI’s gasifier for hydrogen production to reduce the cost of direct liquefaction processes.

MTCI has conducted a preliminary analysis to assess the potential benefits of a pulse combustor fired, indirectly heated, steam gasification step for liquefaction residue and mild gasification char, and issued a topical report.

Liquefaction residue from Wyodak coal will be obtained from the Wilsonville Coal Liquefaction Test Facility. Char gasification tests will begin in September 1990. The liquefaction residue gasification will be done October through December 1990. After gasification tests, systems analysis including process economics will be done jointly by Amoco and MTCI.

Development of an Electrochemical Hydrogen Separation Device

Conventional hydrogen separation technologies operate at or near ambient temperatures and are not considered very effective with gases containing low concentrations of hydrogen (such as coal gas). Some of these devices are also susceptible to common impurities such as H$_2$S, H$_2$O, and NH$_3$. Energy Research Corporation is developing an alternate, versatile process for hydrogen separation from any hydrogen-containing gas. This process involves oxidation of hydrogen at a gas diffusion anode to hydrogen ions, transportation of the ions under applied electrical field to a cathode, and reduction of the hydrogen ions at the cathode to hydrogen gas. The device offers many attractive features, including operation at high temperature (approximately 200$^\circ$ C), high hydrogen recovery (> 90 percent), high product purity (> 99 percent), tolerance to a variety of impurities, flexible product pressure, efficient operation with very dilute gases, negligible pressure loss, and wide operating pressure range including atmospheric.

The electrochemical hydrogen separation device (EHSD) can also be used for recovery of H$_2$ from very dilute gas streams such as a carbonate fuel cell (CFC) anode exhaust. A 5 percentage point improvement in CFC power plant efficiency is projected through the use of the EHSD.

In the present program, the effect of design and operating parameters (e.g., pressure, temperature, H$_2$ recovery and electrochemical catalyst loading) on EHSD in single subscale (25 square centimeters) cells are being characterized and presented as a mathematical model. Process conceptual designs and economics for a potential application will be evaluated for the EHSD and a competing technology.
Production of Hydrogen and Byproducts from Coal

Advanced coal gasification technologies are probably the most promising alternative for producing large quantities of hydrogen. A project at the University of North Dakota Energy and Environmental Research Center is directed toward developing a process for producing a hydrogen-rich stream from the gasification of coal with steam. The proof-of-concept has been successfully demonstrated, market assessment has been completed, and the process has been successfully carried out on the pilot scale. Additional work on reaction kinetics, process optimization, and product characterization and cleanup are required to complete the assessment of the process.

The gasification reaction, involving coal and steam at mild conditions of 500° to 800° C and pressures of up to 150 psig, has the potential to produce hydrogen, syngas, and other products, as well as a variety of byproducts, including condensable liquids and low-volatiles char. Production of hydrogen becomes technically feasible in the range 700° to 800° C.

The objective of this research is to determine the optimum conditions for production of a gas stream enriched in hydrogen, the cleanup of that stream, and the utilization of the product. A second objective was to characterize process feed and products, evaluate catalysts and determine the kinetics of the char-steam reaction. Four calcium salts were evaluated as catalysts. Those that were most easily dispersed as a liquid phase gave the highest reactivities. Tronataconite gave excellent results in catalyst tests.

Future work will include building a bench-scale fluidized-bed reactor to screen additional coals and catalysts and test various gas stream cleanup devices.

###
COAL-WATER FUELS DRAW EMPHASIS IN JAPAN

At the 1990 Conference on Opportunities in the Synfuels Industry held in Bismarck, North Dakota in August, a paper titled "Synfuels in Japan" was presented by N. Nagata of Japan's New Energy Development Organization (NEDO).

Since the second oil shock, NEDO has been engaged in extensive research and development (R&D) and demonstrations related to increasing coal utilization in an environmentally consistent manner. Support for coal gasification and liquefaction has been an important component of this program. This includes participation in the brown coal liquefaction project in Australia, and a series of bituminous coal liquefaction and gasification projects in Japan.

Reflecting the importance of coal in the total energy mix of Japan, NEDO has also provided extensive support for a series of projects expected to make coal a more convenient fuel for a range of industrial consumers. Numerous private companies and the Japanese government have cooperated to develop coal-water mixture (CWM) technology and to promote its commercialization in Japan.

More recently, global environmental issues, and CO₂ in particular, have caused the government to deal with the coexistence of environmental protection and economic growth.

Consequently, after considering the potential for alternative energy supply sources, including atomic, geothermal, solar and other non-fossil energy, the government has recently released a revised long-term energy demand/supply forecast as shown in Table 1. According to this plan, the emission of CO₂ will be restricted to not exceed the level reached in 2008 thereafter. Subsequently, the oil ratio will be reduced below 46 percent in 2010. Coal consumption will increase from the level of 114.6 million tonnes in 1988 to 142 million tonnes in 2000, and remain at that level. In this scenario, the coal ratio will be reduced from 18.1 percent of total energy in 1988 to 15.5 percent in 2010.

Government Support for CWM Fuels

Since 1980 the Japanese government has provided active support for a number of CWM projects related to development and promotion of commercialization of CWM fuels. Most of these projects have been carried out with various private companies. The sites of Japan's major CWM related projects are shown in Figure 1 on the next page.

In fiscal year 1980, Japan's national CWM project was started at the Wakamatsu coal utilization test facility of the Electric Power Development Company, Ltd. (EPDC). This project was a 2 tonnes per day scale and included both slurry preparation techniques and associated combustion tests.

| TABLE 1 |
| LONG TERM ENERGY FORECAST FOR JAPAN |
| (May 1990) |

<table>
<thead>
<tr>
<th>Units</th>
<th>FY1988</th>
<th>FY2000</th>
<th>FY2010</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Actual</td>
<td>%</td>
<td>Projected</td>
</tr>
<tr>
<td>Petroleum (Including LPG) Mkl</td>
<td>276</td>
<td>57.3</td>
<td>308</td>
</tr>
<tr>
<td>Coal M tonnes</td>
<td>(17.4)</td>
<td>(22)</td>
<td>(23)</td>
</tr>
<tr>
<td>Natural Gas Mkl</td>
<td>114.6</td>
<td>18.1</td>
<td>142</td>
</tr>
<tr>
<td>Nuclear Mkw</td>
<td>46.1</td>
<td>9.6</td>
<td>65</td>
</tr>
<tr>
<td>(Generation) B kWh</td>
<td>(179)</td>
<td>(330)</td>
<td>(474)</td>
</tr>
<tr>
<td>Hydraulic Mkw</td>
<td>20.3</td>
<td>4.6</td>
<td>22.7</td>
</tr>
<tr>
<td>(Generation) B kWh</td>
<td>(92)</td>
<td>(91)</td>
<td>(105)</td>
</tr>
<tr>
<td>Geothermal Mkl</td>
<td>0.4</td>
<td>0.1</td>
<td>1.8</td>
</tr>
<tr>
<td>New Energy Mkl</td>
<td>6.2</td>
<td>1.3</td>
<td>17.4</td>
</tr>
<tr>
<td>Total Mkl</td>
<td>482</td>
<td>100</td>
<td>597</td>
</tr>
</tbody>
</table>

Note: Mkl = Million Kiloliter
In March 1981, on behalf of Japan, NEDO joined the IEA COM/CLM Implementing Agreement. Since then, NEDO has participated in the IEA activities currently covered by the CLM Annex II agreement, the purpose of which is "international cooperation to exchange information on the basic technology of Coal Liquid Mixtures (CLM) as an oil alternative fuel for business and industrial uses."

In fiscal year 1982, Japan initiated a further project at Wakamatsu, called "highly dense coal slurry for big boilers" in which a 1.5 tonne per hour pilot plant was built. Several tests were performed over a 4-year period beginning in fiscal year 1983, related to coal cleaning, slurry preparation, storage, ship transportation, and combustion. This project confirmed the technical feasibility of a total CWM fuel system.

A joint government/industry sponsored national CWM project was initiated in fiscal year 1985 at Wakayama, following a feasibility study. The purpose of this project was to demonstrate CWM preparation and combustion for small and medium sized boilers of general industry. Most of the funding for this project was provided by MITI with additional contributions from several companies, including Kubota, Ube, and Hitachi Shipbuilding. The Coal Mining Research Center, Japan (CMRC) managed the project on behalf of the participants.

Two other CWM projects are currently underway in Japan, with funding assistance from MITI. The first is being performed jointly between Japan COM and Idemitsu Kosan Ltd. at Tomakomai in southern Hokkaido. Ultra low ash CWM will be tested in a modified 110 tonnes per hour oil burning boiler during a 3-month combustion trial beginning in August 1990.

The second project is being performed by Ube Industries Ltd. to demonstrate both the combustion of CWM in a modified 95 tonnes per hour oil burning boiler and the preparation of CWM in a modified pre-existing 15 tonnes per hour mill. This project, with 67 percent of the funding provided by MITI, will run from September 1990 through fiscal year 1992 in order to promote the commercialization of CWM.

To further promote the commercialization of CWM, the Center for Coal Utilization, Japan (CCUJ) is performing an economic feasibility study for a domestic CWM preparation and supply system based on a conceptual 250,000 to 500,000 tonnes per year CWM preparation plant sited near Nagoya City in central Japan.

Japan COM Group

The major related activities by private businesses in Japan can be divided into three company groupings. The Japan COM Company Ltd. was established in April 1981 and it has supplied 3.1 million tonnes of coal oil mixture (COM) between the start of production in November 1984 and March 31, 1990. All of this production was sold to the Yokosuka thermal power station of Tokyo Electric Power Company. Japan COM constructed two 15 tonnes per hour CWM production plants in 1988 at their Onahama factory and has provided 150,000 tonnes of CWM between January 1988 and March 1990 to the 600 megawatt No. 8 unit of the Nakoso thermal power station of Johan Joint Thermal Power Company, Ltd.

In March 1990, a study was undertaken to determine the potential to increase the use of CWM from the current rate of 70,000 tonnes per year to 100,000 or greater tonnes per year.

Ube Industries Group

Ube Industries operates a synthetic ammonia plant based on coal gasification, provides engineering of heavy industrial facilities and imports and distributes coal. Ube has developed a proprietary high density CWM containing less than 3 percent ash (U-Coal) and has also developed an ultra-low ash CWM (less than 1 percent) in the 0.5 tonne per hour pilot plant at Wakayama as part of the national project.
addition, Ube has been testing a small scale, 0.2 tonne per hour CWM burner in its facilities.

In a long-term CWM demonstration project subsidized with funding from MITI, the company has refitted an existing grinding facility at a cement plant into a 15 tonnes per hour CWM preparation plant, and modified a 95 tonnes per hour boiler of Ube Chemicals Ltd. to burn CWM. Combustion tests are scheduled to begin in August 1990, with approximately 20,000 tonnes of CWM expected to be burned during fiscal year 1990.

JGC Group

JGC Corporation is a comprehensive engineering company based in the petrochemical industry. In 1984, JGC constructed a 4.5 tonnes per hour pilot scale CWM preparation plant based on the Carbogel process at Aioi, Hyogo Prefecture. Two years later, this plant was expanded to 20 tonnes per hour and supplied de-ashed CWM to the Himeji thermal power station of Kansai Electric Power Company. It was found from these tests that CWM was fully competitive with oil combustion for both low load and load following conditions.

Internationally, JGC is actively planning a CWM project in China. Xing L'ong Zhuang coal, with 9 percent ash, will be transported 340 kilometers by rail from the mine to the port of Shijui, where CWM will be produced and exported to Japan.

The CWM preparation plant is designed with an initial annual capacity of 250,000 tonnes per year. Construction is expected to be completed by autumn of 1990. Future plans include expanding the production capacity to 1,000,000 tonnes as overseas markets increase.

Expected Commercialization of CWM

Japan depends almost entirely on overseas energy sources except for hydro-power, particularly with the rapid increase in domestic coal production. As a result, Japan must find stable, economic and diversified supply for oil, coal, natural gas, nuclear and other new energy resources.

Japan currently imports over 100 million tonnes of coal, about one-third of the world coal trade. This will increase, sooner or later, to the range of 150 million tonnes.

According to Nagata, the source and form of supply of this coal will be important to Japan. The oil supply situation and the relative price of coal will strongly influence the rate of this increase. CWM has proved to have inherent advantages against coal; its relative price will be the most important factor influencing its success in the Japanese market. Lower price and stabilized supply, under long-term contracts, will be key for CWM to achieve a dominant share.

The "Coal Frontier Program" is a domestic initiative, which combines the efforts of both the government and private companies to promote increased coal use by the general industry.

###

SASOL PRODUCT COULD MEET REFORMULATED GASOLINE SPECS

When the United States Clean Air Act reauthorization is eventually passed, it will likely contain provisions forcing oil refineries to reformulate their gasoline products to produce lower exhaust emissions. According to J.H. Fourie of South Africa's Sasol Limited, the synthetic gasoline now produced at Sasol could probably meet the specifications for reformulated gasoline.

When synfuel technology or the production of synfuels is discussed, South Africa is invariably mentioned together with Sasol. Sasol ventured into synthetic fuels during the 50's and expanded its production capacity many times over following the energy crisis during the 70's, thereby producing a significant percentage of South Africa's total liquid fuel consumption. Until recently Sasol remained the only company in South Africa involved in the production of synthetic automotive fuels.

In 1988 the South African government approved a new project, this time for the production of synthetic fuels from offshore natural gas (see the Pace Synthetic Fuels Report, June 1990, page 1-1).

The history of the synfuels industry in South Africa has clearly shown that in isolation the production of synfuels from coal cannot compete with crude oil. This leaves two alternatives: to drop production of synfuels altogether and rely exclusively on imported crude oil or to maintain a limited synfuels activity supported by oil refining and chemicals production. In South Africa the second alternative was chosen. In South Africa the conventional Fischer-Tropsch route has been improved, but extensive work has also been done on the direct liquefaction of coal.

The successful commissioning of the two Sasol plants in Secunda in 1980 and 1982 is by now well known. In the process selection for the more recent plants, Sasol Two and Sasol Three, only commercially proven processes were selected. However, Fourie notes that over the years process optimization and improvement in equipment design continued. The competitiveness of the Sasol operations has been maintained and improved due to continued increases in plant throughputs and productivity improvements. Many of these are incremental in nature and do not attract particular attention. However, in an environment where local inflation has been running at about 15 percent for several years, and
the revenue from synfuels is coupled to the international crude oil price, special efforts were required to maintain profits.

Sasol employs 33,000 workers. In 1989 dollars, the replacement cost of the Sasol Two and Sasol Three plants is some US$12 billion.

Synthol Fischer-Tropsch Synthesis

The traditional Synthol reactors are using the circulating fluidized bed (CFB) concept. By its nature the circulation of catalyst requires significant amounts of energy and special precautions had to be taken to take care of the erosive properties of the iron based catalyst. The concept of a "fixed fluidized bed" (FFB) without external catalyst circulation was very attractive. Starting from pilot plant work and progressing through semi-commercial scale, a full commercial scale reactor using the fixed fluidized bed concept was commissioned in March 1989 at Sasol One.

Besides the obvious advantage of a much simpler and thus cheaper construction and a lower linear gas velocity, the fixed fluidized bed (FFB) reactor has much lower operating costs and maintenance is expected to be significantly cheaper than the circulating fluidized bed reactors. It is expected that the capital cost of a synthesis plant based on the FFB reactors instead of the CFB reactors could be as much as 60 percent lower.

The commercial scale fixed fluidized bed reactor still uses cyclones to separate the product gas and entrained catalyst as is the case with the circulating fluidized bed reactors. Semi-commercial scale tests are under way to prove the suitability of sintered metallic filters instead of cyclones. The successful commercialization of this technology drastically reduces the complexity of downstream processing and would lead to much better thermal efficiencies since the present quench system could be eliminated.

Similar advantages to those described above for the fixed fluidized bed reactor are in principle possible for slurry bed operation. This includes very good temperature control as well as good heat and mass transfer. The semi-commercial reactor used to commercialize the fixed fluidized bed reactor at Sasol will now be converted to a slurry bed reactor. An operating test is scheduled in approximately 6 months. One of the crucial steps to be tested is the catalyst separation from the final wax products.

If the slurry reactor development is successful, it will mean that Sasol will have four reactor systems available for Fischer-Tropsch applications. It is anticipated that the fixed fluidized bed will be the most generally applicable system for the production of a combination of gasoline, diesel fuel and chemicals. The slurry bed reactor will probably be more suitable for diesel fuel and wax products.

Chemicals Produced

Currently Sasol markets in excess of 100 different products. These are categorized in Table 1.

The main benefit of the Sasol Synthol process in olefin production is the fact that olefins have only to be recovered from the Synthol products which is a much cheaper process than obtaining the olefins from a naphtha cracker.

Further recent expansions to Sasol's activities include the erection of a fertilizer plant, an explosives plant, solvent purification and blending facilities and phenol purification facilities. These are examples of how the profitability of Sasol is being increased by expanding on the basis of existing competitive advantages.

Ethylene production at Secunda amounts to 315,000 tons per year.

A 120,000 tons per year polypropylene plant was commissioned during February 1990 at Secunda. Associated with this plant is a 150,000 tons per year propylene recovery plant. The polypropylene is aimed at replacing imported polypropylene and additionally a substantial quantity will be exported.

Further opportunities are developed based on coproducts from the Sasol processes, and also from downstream derivatives of some of these products. Areas for which such opportunities are evaluated include specialty solvents, cresylic acid derivatives, anode and electrode coke, specialty olefins and derivatives, aldehyde derivatives, wood preservatives and specialty waxes.
TABLE 1

PRODUCTS CURRENTLY MARKETED BY SASOL

<table>
<thead>
<tr>
<th>Category</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>Fuels</td>
<td>(gasoline, diesel fuel, industrial gas, fuel oils, etc.)</td>
</tr>
<tr>
<td>Solvents</td>
<td>(aromatics, alcohols, acetone, methyl ethyl ketone, etc.)</td>
</tr>
<tr>
<td>Waxes</td>
<td>(ranging from soft to very hard and including special products such as oxidized and crystallized waxes)</td>
</tr>
<tr>
<td>Nitrogenous</td>
<td>(ammonia, a full spectrum of fertilizers as well as porous ammonium nitrate for mining explosives)</td>
</tr>
<tr>
<td>Products</td>
<td>(creosotes, phenol, cresylic acids, pitch, etc.)</td>
</tr>
<tr>
<td>Coal Co-Products</td>
<td>(a polypropylene plant came on-stream in February 1990)</td>
</tr>
<tr>
<td>Polymers</td>
<td>(a wide range of mining explosives)</td>
</tr>
<tr>
<td>Explosives</td>
<td>(ethylene, propylene, paraffins, sulfur, etc.)</td>
</tr>
</tbody>
</table>

In 1987 the capacity of the tar acid refining plant was doubled and since further process improvements were made, a minimum phenol purity of 99.8 percent can be achieved consistently. This coal based phenol is now successfully competing with synthetic phenol in international markets. Also, Fourie reports that 99.85 percent pure cresylic acid can be produced, again comparable to synthetic material.

Environmental Aspects

Coal as an energy source is increasingly being labeled as dirty and environmentally unacceptable. Problems ranging from acid rain to the greenhouse effect are being ascribed to coal. These problems are mostly related to coal in its use as a feed for power generation.

Coal gasification and Fischer-Tropsch synthesis plants can be built and operated today, as shown by the Sasol Two and Sasol Three plants, in an environmentally acceptable way.

In addition it is not generally known, but the primary fuels produced by Sasol at Secunda are among the most environmentally acceptable in the world. The gasoline that is produced has zero sulfur content, is low in aromatics and the level of oxygenates means a relatively high octane number. An oxygenate-containing fuel, as a result of the lower combustion temperature, results in a generally lower level of reactive exhaust constituents.

The blending of synthetic gasoline with alcohols (ethanol as well as high fuel alcohols) presented a particular challenge to Sasol. Sasol erected sophisticated research and development facilities to optimize and characterize fuel additives. Whereas carburetor corrosion with alcohol-containing gasoline occurs with certain alloys used for carburetors, Sasol has now developed its own package of additives to the point where a formal guarantee is issued to clients who use Sasol fuel.

The diesel fuel is a zero sulfur fuel with a high cetane number and a paraffin content that will result in a lower particulate emission level than any normal refinery fuel.

Thus the fuels from Secunda could, with a minimum of refinery modification, be able to meet the specifications for the new reformulated gasoline and diesel fuels presently being proposed in the United States for the year 2000 and beyond.

###

EXTENSIVE USE OF IGCC SEEN FOR EUROPE

A paper titled "German Coals: Utilization Now and in the Future" was presented by K.R.G. Hein of the Technical University of Delft at the SynOps 90 conference held in Bismarck, North Dakota in August. Hein notes that in the Federal Republic of Germany, coal, bituminous and brown, provides 27.5 percent of the republic's primary energy needs. The significance of coals for the economy of the FRG is emphasized by the fact that the predominant portion of coal is domestically mined which reduces import dependency.

Brown coal is surface-mined from almost horizontal seams with thicknesses up to 40 meters. This allows a specific production of about 90 tons per person per shift. The production costs are low when compared with the underground mining of bituminous coals. Bituminous coals are found in sloped and tectonically heavily distorted seams of 1 to 1.8 meters thickness, at a depth of down to 1,200 meters below the ground. These geological features lead to a
specific production of only about 4 tons per person per shift, resulting in production costs which are not competitive on the world market.

The major coal application is electricity generation. The share of coal use in utility boilers is almost 60 percent and is still rising. Therefore, the future utilization of coal is strongly linked with the development of electrical power generation technology.

At present, utility boilers in Germany are under operation in single unit sizes up to 600 megawatts for brown coal and 770 megawatts for bituminous coals. During recent years, all boilers with capacities of 300 megawatts and greater had to be retrofitted with flue gas treatment plants in compliance with emission control standards. With the present techniques, efficiencies for fly ash removal of above 99.9 percent and \( \text{SO}_x \) and \( \text{NO}_x \) reduction of above 90 percent can be obtained. However, investment costs are very high. Also, the installation of these plants has led to a reduction of the overall efficiency of electricity generation by 1 to 2 percent.

Future Coal Utilization Technology

Hein points out that discussion of the harmful influence of carbon dioxide (\( \text{CO}_2 \)) on the global climate via the "greenhouse" effect has made fossil fuel combustion processes a topic of controversy in public discussion. Because of the strong growth of world population, the expected increase in industrialization, and the subsequent rise in living standards, in particular in developing countries, a further increase of fossil fuel utilization and a subsequent rise in \( \text{CO}_2 \) emissions is predicted.

Because the utilization of non-carbon fuels is either only locally accessible with small quantities available, and thus economically not attractive (regenerative energies) or suffers from limited acceptance (nuclear energy), Hein says that emphasis must be placed on the improvement of coal based processes. Thus, he says, the major task of the scientist and engineer is the design of fuel utilization systems which allow for an increase of the present conversion efficiencies. In addition, systems with a reduced impact on the environment and the most cost effective product are preferred.

Substantial improvements in fuel conversion efficiencies can only be expected by making better use of the thermodynamics, hence, by providing for energy conversion at elevated temperatures above the ones of the water/steam cycle. As one option, multiple cycle concepts using other heat transfer media (e.g., alkalines) prior to the steam cycle have been studied but proven to be uneconomical.

The most attractive solution currently offers the combination of a gas turbine with a steam turbine, due to an increase of the usable temperature difference. Depending on the gas turbine inlet temperature, efficiencies of 43 percent and higher have been reached.

With regard to coal, the discussion about \( \text{CO}_2 \) emissions caused the known principles of pressurized fuel conversion to become of renewed interest for integration into a combined cycle. Coal is gasified under pressure, cleaned and burned in a gas turbine combustion chamber. The energy of these gases is partly converted to electricity in the gas turbine. The sensible heat of the gases leaving the turbine can furthermore be used for steam raising in a waste heat boiler and subsequent electricity production in the steam turbine.

Combined cycles using only coal are in different stages of development. As an example, predictions for achievable efficiency for German brown coals are given in Figure 1 and compared to conventional coal boilers with flue gas desulfurization systems.

![FIGURE 1](image)

**FIGURE 1**

**DEVELOPMENT OF EFFICIENCY FOR BROWN COAL BASED ELECTRICITY GENERATION**

Table 1 on the next page shows the state of planning of large scale demonstration plants in Europe. As shown, the first coal combined cycles will start their demonstration operation in Europe within the next few years. Successful demonstra
TABLE I
PLANNED COMBINED CYCLES WITH INTEGRATED COAL GASIFICATION

<table>
<thead>
<tr>
<th>Company</th>
<th>Project</th>
<th>Fuel Conversion Principle</th>
<th>Location</th>
<th>Capacity</th>
<th>Status</th>
</tr>
</thead>
<tbody>
<tr>
<td>Lurgi</td>
<td>BGL</td>
<td>Fixed Bed</td>
<td>Westfield (GB)</td>
<td></td>
<td>Planning</td>
</tr>
<tr>
<td>RWE</td>
<td>KoBra (HTW)</td>
<td>Fluidized Bed</td>
<td>Go-Werk (FRG)</td>
<td>270 MW</td>
<td>Start up 1995</td>
</tr>
<tr>
<td>DBA</td>
<td>KRW</td>
<td>Fluidized Bed</td>
<td>Buggenum (B)</td>
<td>285 MW</td>
<td>Planning</td>
</tr>
<tr>
<td>Shell</td>
<td></td>
<td>Fluidized Bed</td>
<td>Freetown (USA)</td>
<td>440 MW</td>
<td>Planning</td>
</tr>
<tr>
<td>Texaco</td>
<td></td>
<td>Fluidized Bed</td>
<td>Duisburg (FRG)</td>
<td></td>
<td>Planning</td>
</tr>
<tr>
<td>Krupp Koppers</td>
<td>PRENFLO</td>
<td>Fluidized Bed</td>
<td>Werne (FRG)</td>
<td>250 MW</td>
<td>Planning</td>
</tr>
<tr>
<td>VEW</td>
<td>GDK250</td>
<td>Fluidized Bed</td>
<td>Freiberg (DDR)</td>
<td>175 MW</td>
<td>Planning</td>
</tr>
<tr>
<td>DBA</td>
<td>GSP</td>
<td>Fluidized Bed</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

The development and that might be considered for application in the APB. Three major categories of precombustion, combustion, and postcombustion are represented in these options. Included under the heading of combustion is integrated coal gasification combined cycle (IGCC). This technology, most likely to be used in the electric-utility sector, offers the potential for very efficient use of coal while providing high levels of control for atmospheric emissions commonly associated with coal utilization. Several types of gasification processes can be used in an IGCC and the technology can be used with a wide variety of coal types and sulfur contents. The basic technology can also be used in industrial applications as a cogeneration facility and/or as a producer of ammonia or chemical feedstocks.

CLEAN COAL TECHNOLOGIES SUGGESTED FOR PACIFIC RIM

Argonne National Laboratory has been studying potential markets for United States "Clean Coal Technologies" in the Asian Pacific Basin (APB). A presentation by Argonne's C.B. Szpunar at the Fifth Pacific Rim Coal Conference held in Denver, Colorado in July noted that the United States is well positioned to play an expanding role in meeting the energy-technology demands of the APB. The Clean Coal Technology (CCT) Demonstration Program, managed by the United States Department of Energy in partnership with industry, provides a proving ground for innovative coal-related technologies.

Once demonstrated, these innovative CCTs are expected to satisfy increasingly stringent environmental requirements while substantially improving power-generation efficiencies. They are also expected to be competitive with other energy options currently used in the APB. Technologies such as fluidized-bed combustion, slagging combustion, coal gasification, and coal-water slurries, many of which are expected to become commercially available soon, may help to open new markets in the APB and elsewhere.

Many coal-based technologies are undergoing R&D with the objective of making them commercially available in the near to intermediate future. For purposes of Argonne's study, 11 individual technologies were selected as representative of the variety of coal-based technology options that are under development and that might be considered for application in the APB. Three major categories of precombustion, combustion, and postcombustion are represented in these options. Included under the heading of combustion is integrated coal gasification combined cycle (IGCC). This technology, most likely to be used in the electric-utility sector, offers the potential for very efficient use of coal while providing high levels of control for atmospheric emissions commonly associated with coal utilization. Several types of gasification processes can be used in an IGCC and the technology can be used with a wide variety of coal types and sulfur contents. The basic technology can also be used in industrial applications as a cogeneration facility and/or as a producer of ammonia or chemical feedstocks.

Other options included under the category of combustion are slagging combustors, atmospheric fluid bed combustors (AFBC) and pressurized fluid bed combustors (PFBC).

Asian Pacific Basin Countries

Six countries were selected as representative of the diversity of potential markets in the APB. Japan was selected as an industrialized nation having an expressed interest in expanding current coal consumption but with few or no indigenous coal reserves. South Korea and Taiwan were selected as countries where the industrial base is relatively newly developed and is continuing to grow at a significant rate, with electricity demand and economic growth also growing rapidly. These two countries have essentially no indigenous energy resources with the exception of a small amount of low-grade anthracite in South Korea. Thailand and Indonesia are in stages of development and growth that are perhaps slightly behind those in South Korea and Taiwan. However, Thailand and Indonesia have indigenous resources that are being developed and utilized. The Peoples' Republic of China (PRC) was selected because of its early
stages of large-scale industrialization and rapid growth that can be expected to continue.

These six countries provide a wide range of electric- and industrial-sector opportunities for utilization of United States CCTs. Due to the current patterns of fuel use, expansion plans, and environmental requirements in these countries, potential CCT applications exist in each of the three major CCT categories--precombustion, combustion, and postcombustion.

A preliminary evaluation was done for each country to make an early assessment of potential country/technology matches.

Technology Assessments

As might be expected, the technologies are not likely to have the same potential applicability in all six countries. However, several technologies appear to have widespread potential. The slagging combustor and coal/water mixture (CWM) options offer the potential to convert existing oil-fired units to coal and thus decrease dependence on imported oil. Potential markets for these options appear to exist in all six countries (except for CWMs in the PRC). The AFBC and IGCC options also have potential application in all six countries as the electricity-generation capacity in each country is expected to grow rapidly. Part of this ubiquitous interest is due to the capability of these technologies to use a wide variety of fuel, including those of poor quality.

Economic assessments were performed for the country/technology niches identified above. The results of these assessments are presented in Figure 1, where the perceived potential interest is categorized as "strong," "secondary," or "little or no perceived interest at this time."

Indonesia

Indonesia is somewhat unique among the developing countries in the APB in that it has indigenous supplies of both oil and coal, along with natural gas. It has been a major exporter of both oil and liquefied natural gas. Large coal deposits have been discovered on Sumatra and Kalimantan.

Most of the installed electricity-generation capacity is oil fired. Currently, about 1,330 megawatts of coal-fired capacity exists within the total capacity of 8,530 megawatts. Between now and 2010, it is anticipated that coal capacity

![FIGURE 1: MARKETS FOR US CCT'S IN EACH STUDY COUNTRY](image-url)
will increase to 13,200 megawatts which would represent more than half of the expected 25,500 megawatts of total generation capacity.

Argonne states that at least two types of CCT would appear to be most appropriate for near-term applications in Indonesia. First, advanced coal-preparation technologies could potentially be used to upgrade the indigenous, low-quality coals. Second, Indonesia could consider the large-size generation technologies—the AFBC, the PFBC, and the IGCC. Each of these generating technologies can use the low-grade, varying quality lignite found on Sumatra and Kalimantan while providing low-cost, reliable electricity and also meeting emission standards comparable to those for new plants in the United States.

Japan

Japan is the largest importer of coal in the world. It is anticipated that coal use in the electric sector will increase from its 1987 level of about 31 million tonnes to more than 53 million tonnes in the year 2000.

Analyses for new 500-megawatt power plants suggest that the cost of electricity from either the IGCC, the PFBC, or the pulverized coal flue gas desulfurization (PC/FGD) would be significantly lower than electricity from a new oil-fired plant. Sensitivity analyses show that the cost of electricity from an IGCC plant would continue to be lower than the cost of electricity from a new oil-fired plant as long as the cost of oil is at least $1.30 per million BTU more than the cost of coal.

Peoples' Republic of China

The PRC is unique among the countries considered in Argonne's study because it currently burns a great deal of coal, but only a small amount of oil. Much of this coal is burned in very small AFBCs that abound in the countryside. It has been estimated that there are in excess of 2,000 AFBCs currently in operation in the PRC.

Economic analyses suggest that the IGCC would be the least cost option in the PRC for either high-quality imported coal or for the lower-quality coal found in the PRC. An additional advantage of the IGCC is that the sulfur removed from the coal can be recovered and used to reduce the PRC's dependence on imported, elemental sulfur.

South Korea

South Korea has a rapidly developing and expanding industrial sector. The peak electricity demand and the total annual generation demand are both expected to grow at an annual rate of about 7 percent through the remainder of the century. KEPCO (Korea Electric Power Corporation) is considering the addition of twelve 500-megawatt and four 900-megawatt coal-fired plants to be operational by 2001. These large baseload plants provide an opportunity for several of the CCTs under demonstration. The AFBC, PFBC, and IGCC all offer the potential for economic operation when compared to nuclear or oil-fired generation in Korea.

Taiwan

Taiwan is heavily dependent on imported energy with about 90 percent of its energy consumption derived from foreign sources. It is very dependent on Middle East oil supplies with about 80 percent of the imported crude being from this region. The average annual growth rate for peak power demand and total generation is projected to be in excess of 5 percent between now and the turn of the century. To meet this demand, Taipower (the state-owned electric utility) expects to add 13 new plants and coal consumption by Taipower is estimated to reach 20 million tonnes per year.

The large expansion program undertaken by Taipower provides the opportunity for several CCTs. The AFBC, PFBC, and IGCC all can be built in the sizes needed, can use a variety of coals that might be expected from a diversified supply system, and can meet the emission standards put forth by the government, says Szpunar.

Thailand

The Electricity Generating Authority of Thailand (EGAT) is the government agency responsible for electricity generation. Indigenous resources include natural gas, lignite, hydropower, and some oil.

The demand for electricity is expected to increase at an annual rate in excess of 7 percent through the mid-1990s and in excess of 5 percent through 2001. The capacity additions currently planned by EGAT are generally of the order of 50 to 300 megawatts. The Thai National Environmental Board has been established to set requirements on SO\(_2\), NO\(_x\), and particulate emissions from these new facilities.

Many of the new capacity additions are based on the desire to use the lignite reserves in Thailand. The CCT that appears to be most applicable in this situation is the AFBC. Of longer term potential interest in Thailand is the IGCC. This CCT could eventually displace the natural gas currently burned in two 386-megawatt combined-cycle units as the cost of natural gas increases.

Implications

The analyses by Argonne suggest that there is a near-term international market for the CCTs currently under development and demonstration in the United States. While this market appears to be largest for the combustion/conversion technologies, there also appears to be significant potential for the precombustion and postcombustion options.
At least three major implications with respect to the ongoing United States CCT Demonstration Program stem from this study. First, the demonstration program must continue in a timely manner so that these technologies can be demonstrated and improved in a time frame consistent with the needs of the international markets. If this continuation does not take place, these potential markets may be lost to oil or gas generation or to other countries offering similar technologies and services.

The second implication of this study deals with the coals used in the United States CCT Demonstration Program. It appears prudent that internationally traded coals be included in the United States demonstration program. By establishing performance parameters with these coals, it is possible that the role for United States CCTs in the international marketplace could be strengthened and expanded.

Third, barriers to successful commercialization abroad must be addressed and analyzed in far more detail than has been attempted to date, in order to assist United States industry in defining specific market niches where United States CCTs can be applied in the most competitive ways.

###

**UHDE AND LURGI TO COOPERATE ON DEVELOPMENT OF HTW PROCESS**

Further development of the Rheinbraun High Temperature Winkler (HTW) process for fluidized bed coal gasification is to be undertaken jointly by Uhde GmbH and Lurgi GmbH, both of Germany.

Rheinische Braunkohlenwerke AG and Uhde have been cooperating since 1975 in the development of the HTW process. Rheinbraun conducts the basic research and tests the process in pilot and demonstration plants. Uhde and now Lurgi's task is to put the know-how and experience thus gained into practice on a commercial scale.

The final development phase in the move to commercial-scale operation was completed with the commissioning of the HTW demonstration plant for the production of methanol synthesis gas from lignite. The HTW process is also said to be the low-pollution power plant of the future, consisting of a coal gasification unit in conjunction with a gas/steam turbine system.

The fluidized-bed gasification process was developed in the 1920s in Germany by Fritz Winkler. In the fluidized bed, a high material and energy transfer rate is achieved and this ensures a uniform temperature distribution throughout the gasifier. The temperature is maintained below the ash melting point. Screw conveyers are used for supplying the fresh coal and withdrawing the ash. The gasification agents, steam and air or oxygen are injected at the bottom of the gasifier (here they serve simultaneously as fluidizing agents for the fluidized bed) and they are also introduced into the fluidized bed as well as above the fluidized bed, into the post-gasification zone in order to improve the gas quality and the conversion rate due to the temperature increase.

The characteristic features of the Winkler process are summarized by Uhde as follows:

- Low consumption of oxygen and steam
- Simple feed preparation step because a broad range of grain sizes can be used
- Cocurrent gasification and complete conversion of the volatile higher hydrocarbons
- High degree of operational reliability because the coal inventory of the gasifier is very high compared with the gas generation rate
- Easy to control over a wide operational range

Numerous plants have been constructed on the basis of the Winkler process. Until 1964, two Winkler gasifiers with a capacity of 17,000 cubic meters per hour each were in operation at Union Kraftstoff, Wesseling, a subsidiary of Rheinbraun. These gasifiers were operated at atmospheric pressure and the coal conversion rate was low by present-day standards.

The experience gained with these gasifiers formed the basis for the Winkler process. The aim is to perform gasification under pressure and at an elevated temperature. Hence the name High Temperature Winkler process. This offers the following advantages:

- Higher gasification rate
- Lower energy requirement for the compression of the raw gas
- Higher capacity per gasifier unit
- Improved gas quality

A cyclone is installed at the outlet of the gasifier in order to recover unconverted carbon. Coal particles which are not sufficiently gasified are returned directly to the gasifier.

The fact that gasification takes place under pressure necessitates the use of lock hopper systems for the coal feed and ash withdrawal.

Figure 1 on the next page shows the main features of the HTW process.
On the basis of the preliminary tests in a bench-scale plant at Aachen Technical University, a pilot plant was set up in 1978 by Rheinbraun in their coal processing factory Wachtberg at Frechen near Cologne in order to test the HTW process.

In view of the good results obtained in the pilot plant, Rheinische Braunkohlenwerke AG installed a high pressure (10 bar) demonstration plant for the gasification of lignite in 1985.

The plant is located in Berrenrath on the outskirts of a densely populated region. Pollution abatement was therefore given high priority. The plant concept is such that the stringent requirements imposed by the authorities are met.

**Ammonia Synthesis**

Apart from the generation of methanol synthesis gas, the HTW process for coal gasification can be used for other applications as well. In Finland, Kemira Oy converted existing ammonia production facilities at Oulu to use peat instead of heavy oil as the feedstock. Kemira's gasification plant, in which 650 tons of peat per day are converted to synthesis gas...
The HTW process is also said to be especially suited for application in power plant engineering. Uhde has been developing a concept for a combined-cycle power plant in cooperation with Rheinbraun and Kraftwerk Union; the gasification pressure will be 25 bar, the gasification agent being air or oxygen.

High Pressure Pilot Plant

In 1989 a high pressure (20-25 bar) HTW pilot plant was started up at Wesseling, Federal Republic of Germany.

The commercial maturity of the HTW process for synthesis gas production at 10 bar has been proven, says Uhde. An essential step towards the further development of the HTW process to be used in IGCC plants is to raise the pressure to 25 bar. Raising the pressure is advantageous for synthesis gas production, too.

The new gasifier is designed for a maximum dried coal input of 6.5 tons per hour for oxygen/steam gasification and 3.4 tons per hour for air gasification. The coal is brought to gasification pressure by lock hoppers and can be fed into the gasifier by screw or by gravity pipe. The method of charging a fluidized-bed reactor by gravity pipe was proven in the Rheinbraun hydrogasification plant at pressures of up to 120 bar. It is planned to test a newly developed burner making it possible to ignite the gasifier under pressure and thus reducing its startup time.

After the pilot phase, Rheinbraun together with the Rheinisch Westfälische Elektrizitätswerk AG (RWE) are planning to build a demonstration plant for an HTW-based combined-cycle power plant. The actual work for this plant will begin in 1993 after evaluating the results of the 25 bar HTW pilot plant, and is scheduled to go on stream in mid-1995.

###

AUSTRALIAN BROWN COAL LIQUEFACTION PROJECT TO CLOSE

A significant project in Australia has been the Japanese financed Brown Coal Liquefaction (Victoria) Pty. Ltd. (BCLV) project. This project involved the construction and operation of a pilot plant at Morwell, Victoria for converting 50 tonnes per day (dry basis) of brown coal in a two stage process to naphthene and middle distillate. The project which has involved an expenditure in excess of A$700 million (US$540 million) including over A$500 million (US$390 million) in capital costs is scheduled to conclude in September 1990. The decision to construct this plant was based on the previously proven reactivity of Victorian brown coals, their low ash yield, and the extent of the resource. The technical feasibility has been established, but the current oil supply and economic considerations do not justify a move to a commercial plant at this stage.

According to R.A. Durie of the Commonwealth Scientific and Industrial Research Organization (CSIRO), there are no immediate prospects for the commercial production of gaseous or liquid fuels from brown coals in Australia. However, as the availability of non-OPEC oil declines, as it surely will, and oil prices increase significantly it should become economically feasible and strategically necessary to establish a significant synfuel industry in Australia. On the basis of the extensive work done to date on the conversion of Australian coals it seems likely that the initial focus will be on Victorian brown coals.

Brown Coal Resources

Australia's brown coal resources occur in Victoria, South Australia and Western Australia with those of Victoria dominating. The total in situ reserves in Victoria which occur within 300 meters of the surface are estimated to be 207,973 million tonnes of which 158,026 million tonnes (91 percent) occur in the Latrobe Valley Depression to the east of Melbourne. The total measured plus indicated reserves in Victoria, i.e., those yielding no more than 10 percent ash (dry basis) in seams not less than 3 meters thick within 300 meters of the surface and having an overburden to coal ratio no higher than 2:1, are estimated to be 96,300 million tonnes of which 86,200 million tonnes (89 percent) occur in the Latrobe Valley where coal seams average 137 meters in thickness over an area of 4,636 hectares (179 square miles), under very shallow overburden cover.

It is interesting to compare, on an equivalent basis, the brown coal resources of the Gippsland Basin in Victoria with those of the Fort Union Basin in the United States which underlies portions of Montana, North Dakota and South Dakota. The latter is considered to be the largest coal basin in the world. The total identified coal resources in the Fort Union Basin, down to 300 meters in seams exceeding 0.76 meters in thickness is 465,000 million tonnes. This is far greater than that for the Gippsland Basin which is 134,874 million tonnes. With regard to the reserves regarded as "strippable," however, those of the Gippsland Basin (96,300 million tonnes) exceed considerably those of the Fort Union Basin (26,300 million tonnes). The World Energy Conference (1989) figures for proved recoverable reserves of lignite (brown coals) indicate that the Australian brown coals represent 11 percent of the world's total whereas those of North America (Canada and the United States) amount to 6 percent.
Australian Research and Development

The Australian coal industry has been backed by wide ranging coal related research and development (R&D) activities commencing with the establishment by CSIRO in 1947 of the Coal Research Section (which has become the present Division of Coal and Energy Technology).

In recognition of the country’s significant dependence on imported oil, the federal government in 1977 implemented a levy of 5 cents per tonne on all salable coal produced in the country to establish a Coal R&D Trust Fund and created the National Energy Research, Development and Demonstration Council (NERDDC). NERDDC initiatives involved replacing oil by coal directly whenever practical, increasing the efficiency of energy use in all forms, the production of liquid and gaseous fuels from coals and other feedstocks and increasing the use of renewable energy sources, all in a manner that was environmentally responsible. NERDDC was charged with the responsibility of allocating funds derived from the Coal Research Trust Fund Levy together with energy research funds provided by the government.

The ready availability of crude oil at relatively low cost in recent years, however, has lulled the sense of urgency and, as elsewhere, interest in coal conversion has waned, at least for the time being, says Durie.

Although the NERDDC program has made a significant contribution to advancing the science and technology of Australian coals, the federal government, as part of its policy to replace the present government research funding organizations by industry-based R&D Boards, is in the process of replacing the NERDDC Council by an Energy R&D Corporation and a Coal R&D Corporation.

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RESOURCE

INTERIOR RE-ESTABLISHES HISTORIC COAL VALUATION FORMULA

Secretary of the Interior M. Lujan has announced that the department is returning to its historic formula for computing the value of coal extracted from federal lands.

"Re-establishing this formula will directly benefit those states that have experienced revenue losses under the current rule," said Lujan.

The Minerals Management Service (MMS) is the bureau in the Department of Interior charged with collecting revenues owed to the federal government from production of public natural resources such as coal. Modifications to the historic formula for royalty computation, which became effective on March 1, 1989, were undertaken in an effort to stimulate coal production. The 1989 modifications allowed deductions for federal black lung excise taxes, abandoned mine land fees, and state and local severance taxes from the value of coal before royalties were computed. These deductions will be disallowed under the historic valuation formula.

Investigations by the MMS have found no evidence that coal production has increased as a result of the 1989 deductions. MMS officials estimated that $32 million in royalties were foregone during the first year of that ruling.

States receive 50 percent of the revenues collected by the federal government for minerals produced on federal leases within their borders.

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The indirect economic effects of coal production in the United States are nearly four times that of the direct ones, says a Pennsylvania State University study released recently.

The report says the net contribution of the coal industry to the United States economy is about $21 billion, but when the industry's stimulation to other sectors of the economy is considered, it is responsible for $81 billion of productive activity.

The report says that while the coal industry directly employs only 166,000 workers, it is indirectly responsible for the employment of 1.1 million workers. Thus, every coal miner in America supports six additional jobs in the larger economy, according to the study's authors A. Rose and R.L. Gordon of Penn State.

"The Economic Impact of Coal" consists of two sub-reports. The first summarizes data on United States coal production, employment and consumption; the second presents data on the impacts the coal industry has on the rest of the economy.

The report says that because the operation of the coal industry results in stimulus to every other sector of the economy, any adverse effects on the coal industry and its producing regions will be felt throughout the country. "For example, if new Clean Air Act legislation displaces 35,000 coal miners and other coal industry employees, the total job losses in the United States economy would be approximately 6.8 times the direct effect, or 238,560 workers. Moreover, these job losses would affect every industry. Using the ratio of personal income to employment, the direct income loss from the 35,000 workers would be $1.7 billion and total income loss throughout the economy would be $5.7 billion." The authors note, however, that these decreases would be partially offset by increased production of coal from other regions and by higher output of other fuels.

The authors explain the "multiplier effects" that take place within major coal production regions. The United States has a highly interdependent economy where each business relies on many others for inputs into its production process. Thus the coal industry's contribution to the nation's economy extends beyond its own production to include its demand for a succession of "upstream" inputs. The extent of these many rounds of derived demands results in a large multiple of the value of coal production.

The first round demand impacts are the direct inputs to coal production, such as electricity, transportation and business services. The indirect demands, such as the successive chains of supplies to suppliers of inputs to coal production, however, thread their way through the economy and eventually stimulate every other sector. For example, refined petroleum in the form of diesel fuel is used to run railroad trains, electricity is required to power businesses serving the coal industry, transportation is needed to move goods between sectors, and iron ore is needed to produce steel used in the manufacture of mining equipment.

According to the report, the sectors of the economy most stimulated by coal are: wholesale and retail trade, $5 billion; real estate, $5 billion; petroleum and natural gas, $43 billion; health/education/social services, $2.9 billion; electric utilities, $2.9 billion; business services, $2.6 billion; transportation and equipment, $2.6 billion; food products, $2.4 billion; finance and insurance, $2.2 billion; eating and drinking places, $1.5 billion; construction and mining machinery, $0.9 billion; primary metals manufacturing, $0.9 billion; and chemical products, $0.8 billion.

In addition, the coal industry directly generates personal income of $8.1 billion, which translates into $27.1 billion in personal income throughout other sectors of the economy.

The multiplier effects of the coal industry also extend to tax revenues used to fund public expenditures. Thus, the construction of such facilities as roads, schools and hospitals and the resulting upstream inputs can also be linked to coal industry operations, say the authors.

The report also takes a look at specific regional impacts and notes that about half the states produce coal. However, the three top producing states, Wyoming, Kentucky and West Virginia, accounted for almost half of coal production in 1989, and another nine states provided about 40 percent of coal supply.

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**FINAL ECONOMIC, SOCIAL AND CULTURAL SUPPLEMENT TO POWDER RIVER I EIS ISSUED**

In June the United States Bureau of Land Management, Miles City District Office, Montana, issued the Final Economic, Social and Cultural Supplement (FSEIS) to the Powder River I Regional Coal Environmental Impact Statement. The draft SEIS was reviewed at length in the *Final Synthetic Fuels Report*, December 1989, page 4-38. The draft SEIS was prepared in response to the decisions and orders of the United States District Court for the District of Montana in *Northern Cheyenne Tribe v. Hodel* issued May 28, 1985, and October 6, 1986. The 1986 order suspended two leases issued in Montana as part of the 1982 Powder River Round I coal sale. The order allowed opera-
tions to continue on maintenance leases, pending completion of an economic, social, and cultural supplemental EIS.

The supplement corrects the deficiencies in the 1981 Final Powder River Regional Coal Environmental Impact Statement (Powder River I FEIS) by addressing the possible economic, social and cultural impacts to the Northern Cheyenne Tribe and Reservation from development of Powder River Round I federal coal leases in Montana.

The FSEIS addresses public comments made on the draft SEIS. Most of these comments concerned additional information on the unfavorable impacts to reservation culture and civil infrastructure as a result of development of adjoining coal lands.

The Northern Cheyenne and Crow belief and value systems would be affected by development of Powder River I new mine and expansion/extension tracts. In most instances, leasing of these tracts would irreversibly impact entities that are part of the Northern Cheyenne and Crow belief and value systems. These impacts include:

- **Northern Cheyenne**

  Destruction of spirits associated with springs, turning areas of the Earth Surface Dome into spiritually inert dead earth, dislocations of the Great Birds/mediators between the Northern Cheyenne and the Spirit Beings of the Blue Sky Space, loss of the isolation necessary for the keeping of the Sacred Hat at Birney Village, changes in the distribution of mammals and certain plants whose parts are essential ritual items, and loss of the privacy and seclusion necessary for religious practices.

- **Crow**

  Irreparable damage to archaeological sites with baxpe (sacred) attributes and/or ethnic significance. Site types of particular concern are burials, fasting sites (prehistoric, historic, and modern), rock art sites, Sun Dance localities, sweat lodges, offering sites, Medicine Wheels, and tipi ring sites. Reduction of the environmental setting, loss of privacy for religious activities, and resulting deemphasis of cultural values would also occur.

Certain partial mitigation actions are listed as possible. These include:

- Cultural leaders have proposed that successful lessees notify the Crow Historic and Cultural Committee and the Northern Cheyenne Cultural Protection Board regarding mine development and concerning all aspects of cultural resource impact mitigation. This would need to occur in the planning process and would include early determination of site significance, avoidance of all burial and cultural sites when possible, and respectful treatment when avoidance is not possible.

- Develop a joint task force of tribal, state, federal and county officials aimed at easing some of the cultural/ethnic stress created by the various jurisdictional disputes.

- Teach tribal language and culture at all academic levels in area schools. This would help to avoid loss of culture and language in the face of a large non-Native American population influx.

- Recognize Indian coal as a major alternative coal supply in the Powder River Basin. This could result in explicit recognition of Indian coal development plans through the setting of regional leasing targets. This could increase the revenue and development potential of Indian coal. This is important because ethnic identity would be affected by future land sales by tribal members in order to subsist. These land sales have occurred in the past, thereby weakening spiritual/cultural ties to the land and to environmental features with spiritual values contained within the lands that are sold.

- Educate mine employees (including contractors and subcontractors) to promote respect for the lifestyle, culture, and values of Native Americans who reside near the mine. Such cultural sensitivity training could include the need to respect sacred sites and activities, and to avoid confrontations with Native Americans on and adjacent to the reservation. This training would also educate mine employees to the importance of Native Americans to be able to visit the tract for religious, lifestyle, family, tradition, or subsistence reasons.

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RECENT PUBLICATIONS

The following papers were presented at the Opportunities in the Synfuels Industry Symposium held August 27-29 in Bismarck, North Dakota:

- Hein, K.R.G., "German Coals: Now and in the Future."
- Soelistijo, U.W., "Future of Coal in Southeast Asia."
- Carvani, L., "Prospects and Constraints in the Use of Coal in Italy."
- Gray, D., "Alternate Coal Products - Liquefaction Coprocessing."
- Weft, G., "U.S. DOE Clean Coal III Program."
- Janssen, K., "Coal Gasification Combined Cycle Power Generation Enhancement with Methanol."

The following papers were presented at the conference on Coal Structure and Reactivity held September 5-7 at Queen's College in Cambridge, United Kingdom:

- Azhakesan, M., et al., "Rapid Pyrolysis as a Method of Characterizing Coals."
- Snape, C., "Similarities and Differences in Coal Reactivity During Carbonization, Pyrolysis and Liquefaction."
- Field, D.J., et al., "Reactivity of Lignites."
- Stephens, H.P., "Studies of Coal Reactivity for Direct Liquefaction."
- Snape, C.E., et al., "Impact of Catalyst Precursors on Coal Reactivity in Catalytic Hydropyrolysis."
- Pugmire, R.J., et al., "Structural Evolution of Matched Tar/Char Pairs in Rapid Pyrolysis Experiments."
- Joseph, J.T., "Beneficial Effects of Preswelling on Coal Liquefaction."
- Liu, Y., "On the Defunctionalization Differences Between Coalification and Pyrolysis Processes."


Sebesta, P., et al., "Brown Coal Reactivity to Oxygen at Low Temperature."


Stavropoulos, G.S., et al., "Porosity and Reactivity in Lignite Liquefaction."

Dey, P.K., et al., "Catalytic Coal Gasification with Steam, CO₂ and Steam-CO₂ Mixture."

Hara, T., "Formation Mechanism of Pyrolysis Tar and Utilization of Tar as Chemicals."


Pajak, J., et al., "Hydrogen Transfer from Tetrahydrothiophen to Coal and Its Macerals."


Slaghuis, J.H., et al., "Increased Reactivity of Char Due to Pyrolysis in a Reactive Atmosphere."

Chomon, M.J., et al., "Comparison of the Liquefaction Behaviour of Different Coals When the Type of Catalyst and Solvent Are Varied."


Membrado, L., et al., "Influence of Zn Content Upon Coal Hydrogenation."


Gonzalez de Andres, A.I., et al., "Nature and Mechanism of Oxidation Reactions Occurring During Coal Chlorination."


Illan-Gomez, M.J., et al., "Chemical Activation by Hydroxides of Spanish Low Rank Coal."


Cebolla, V.L., et al., "Hydrogenation of Spanish Lignites and Their Derived Vitrinite Concentrates."
Martinez, M.T., et al., "Two Stage Liquefaction of Spanish Lignite."

Benito, A., et al., "Two Stage Hydrotreating of Coal Derived Distillates."


Moore, S.A., et al., "Partial Maceral Separation in Dense Medium Coal Preparation Equipment and its Effect on Coal Dissolution in Direct Liquefaction."

Wang, J., et al., "A TPD Study of Active Sites During the Gasification of Coal Chars in Carbon Dioxide."

Lee, C.W., et al., "Influence of Pressure on Structural and Reactivity Changes in a Softening Coal During Rapid Pyrolysis."


Hzenkova, T.M., et al., "Lignites Structure and Reactivity in Hydrogenation."

Gurszhiiyants, V., "Non-Isothermal Pyrolysis in Coal Processing."


Ignashin, V.P., et al., "Coal Structure and Transformation of Coals."

The following papers were presented at the International Conference: Coal and Power Technology '90 held May 21-23 in Amsterdam, The Netherlands:

Gluckman, M.J., "ICGCC - Different Technologies."

Zon, G.D., "Integration of Pressure on Structural and Reactivity Changes in a Softening Coal During Rapid Pyrolysis."


The following presentations were made at The 5th Pacific Rim Coal Conference held July 22-25 in Denver, Colorado:

Kinoshita, A., "Japanese Clean Coal Technologies."

Surles, T., "U.S. Clean Coal Technologies."

The following papers were presented at the combined 73rd Canadian Chemical Conference and 40th Canadian Chemical Engineering Conference held July 15-20 in Halifax, Nova Scotia, Canada:


Maki, E.J., "Coal/Oil Processing Development of a Project at Point Tupper, NS."

The following papers were presented at the Fourth Annual Technical Meeting of the Consortium for Fossil Fuel Liquefaction Science, held August 15-17 in Snowbird, Utah:


Shabtai, J.S., "Low-Temperature Depolymerization-Liquefaction of Blind Canyon (UT), Pittsburgh #8 (PA) and Beulah Zap (ND) Coals."
Deshpande, A.P., et al., "Dehydrogenation of Coal."

Penn, J.H., et al., "Chemical Insights into Coal Liquefaction."


Saito, I., "An Overview on Recent Progress in Coal Liquefaction Science and Technology in Japan."

Davis, B.H., "An Overview of Reactors for Coal Liquefaction."


Wang, H.P., et al., "Spectroscopic Studies of Coal Maceral Depolymerization Catalyzed by Iron Chloride."

Pradhan, V.R., et al., "Sulfate-Treated Metal Oxides as Catalysts for Direct Coal Liquefaction."


Bhattacharyya, D., et al., "Bioprocessing of Coal."

COAL - PATENTS

"Process for the Purification of Crude Gases with Simultaneous Production of Synthesis Gas and Fuel Gas," Gerhard Ranke, Horst Weiss - Inventors, Linde AG DE, United States Patent Number 4,938,783, July 3, 1990. In a process for the purification of coal gasification gases, synthesis gas and fuel gas are simultaneously produced. In order to obtain a fuel gas rich in CO2, capable of handling fluctuations in demand, and to produce at the same time a highly concentrated H2 fluid fraction, a portion of the crude gas, scrubbed to synthesis gas purity, is utilized for stripping out CO2 under pressure from scrubbing medium loaded exclusively with CO2. The partially stripped CO2-loaded scrubbing medium is employed for the concentration of sulfur compounds in an H2S/COS loaded scrubbing medium.

"Method of Refining Coal by Short Residence Time Hydrodisproportionation to Form a Novel Coal Derived Fuel System," Gerald F. Cavaliere, Lee G. Meyer, Bruce C. Sudduth - Inventors, Carbon Fuels Corporation, United States Patent Number 4,938,782, July 3, 1990. This invention generally relates to short residence time decomposition and volatilization of coal to produce liquid coproducts while minimizing production of char and gas without utilization of external hydrogen, that is, hydrogen other than that contained in the coal feedstock. The invention more particularly relates to an improved method of economically producing uniform, fluidic, oil-type transportable fuel systems and fuel compositions and a slate of "value-added" coproducts by a coal refining process employing short residence time hydrodisproportionation (SRT-HDP).

"Method of Manufacturing a Gas Suitable for the Production of Energy," Sven Eriksson, Sven Santen - Inventors, SKF Steel Engineering AB SE, United States Patent Number 4,936,874, June 26, 1990. The present invention relates to a method of manufacturing a gas suitable for the production of energy, out of coal. The coal is gasified in counterflow with air-blast in a gasifier, and the gas generated is then mixed with a gas containing oxygen, in a ratio such that the quotient CO2/CO in the resultant gas does not exceed 0.1, in order to crack tar substances occurring in the gas. The gas is thereafter introduced into a dolomite or lime shaft for removal of sulfur compounds, any remaining tar substances and to gasify any accompanying coal particles not yet gasified.

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A method of generating a de-sulfurized volatile matter and a relatively low BTU gas includes the initial step of pyrolyzing coal to sulfurizing agent. Portions of the de-sulfurizing agent are moved among the first de-sulfurizer, the second de-sulfurizer, and the sulfurizer containing the de-sulfurizing agent to remove sulfur therefrom. A regenerator is provided for removing sulfur from the de-sulfurized volatile matter and a char. The volatile matter is fed to a first de-sulfurizer containing a de-sulfurizing agent to remove sulfur from the mixture. The bypass line which is connected to the mixture inlet of an injector which is supplied with injecting gas. The supply of the injector which carries the mixture is connected back into the vessel. The flow of aspirating and injecting gas is controlled on the basis of flow measurements taken on the supply pipe from the vessel. The aspirator and injector can accurately control the flow of pneumatically transported solid particles, in particular, pulverized coal, comprises a pulverizer or vessel for containing pneumatically suspended solid particles. A supply pipe is connected to the pulverizer or vessel for removing a mixture of pneumatic gas and solid particles from the vessel. A bend is provided in the supply pipe and an aspirator is connected to the supply pipe at a distance of from one to two pipe diameters from the bend. The aspirator is provided on the outer wall of the bend and is supplied with aspirating gas to draw off an amount of mixture from the vessel. The aspirator and injector can accurately control the flow of pneumatically transported solid particles.

"Method of Capturing Sulfur in Coal During Combustion and Gasification," Herman F. Feldmann, Byung C. Kim - Inventors, United States Patent Number 4,936,047, June 26, 1990. A method of reducing the amount of gaseous sulfur compounds released during combustion of sulfur-containing fuel, comprising the steps of: (a) preparing a mixture of sulfur containing particulate fuel and a sulfur absorbent, such as calcium oxide, calcium hydroxide, calcium carbonate, lime, limestone, dolomite, or mixtures thereof; (b) exposing the mixture to a reducing atmosphere at a temperature of at least about 1,500°F, so as to convert at least a portion of the particulate fuel into a gaseous portion and a solid, char portion; and (c) combusting the char portion, thereby forming an ash containing sulfur fixed therein.

"Flash Hydropyrolysis of Bituminous Coal," Michio Ikura, Anthony J. Last - Inventors, Energy Mines and Resources Canada, United States Patent Number 4,935,036, June 19, 1990. A process is described for the flash pyrolysis of a high rank caking coal in a pyrolysis chamber in which the coal passes through a tacky state during flash pyrolysis. According to the novel feature, before entering the pyrolysis chamber, the particles of high rank caking coal are blended with a diluent comprising a finely ground non-caking coal, whereby agglomeration and caking of the high rank coal is prevented during flash pyrolysis.

"Pulverized Coal Flow Control System," Raymond K. Kim - Inventor, The Babcock & Wilcox Company, United States Patent Number 4,932,594, June 12, 1990. An apparatus for supplying a controlled flow of pneumatically transported solid particles, in particular, pulverized coal, comprises a pulverizer or vessel for containing pneumatically suspended solid particles. A supply pipe is connected to the pulverizer or vessel for removing a mixture of pneumatic gas and solid particles from the vessel. A bend is provided in the supply pipe and an aspirator is connected to the supply pipe at a distance of from one to two pipe diameters from the bend. The aspirator is provided on the outer wall of the bend and is supplied with aspirating gas to draw off an amount of mixture from the supply pipe. This controls the amount of remaining flow of mixture through the pipe. The supply of the aspirator is connected to a bypass line which is connected to the mixture inlet of an injector which is supplied with injecting gas. The supply of the injector which carries the mixture is connected back into the vessel. The flow of aspirating and injecting gas is controlled on the basis of flow measurements taken on the supply pipe from the vessel. The aspirator and injector can accurately control the flow of pneumatically suspended solid particles.

"Method for Producing and Treating Coal Gases," Albert Calderon - Inventor, United States Patent Number 4,927,430, May 22, 1990. A method of generating a de-sulfurized volatile matter and a relatively low BTU gas includes the initial step of pyrolyzing coal to produce volatile matter and a char. The volatile matter is fed to a first de-sulfurizer containing a de-sulfurizing agent to remove sulfur therefrom. At the same time, the char is gasified to produce a relatively low BTU gas. The low BTU gas is fed to a second desulfurizer containing the de-sulfurizing agent to remove sulfur therefrom. A regenerator is provided for removing sulfur from the desulfurizing agent. Portions of the de-sulfurizing agent are moved among the first desulfurizer, the second desulfurizer, and the regenerator such that the regenerator regenerates the de-sulfurizing agent. Preferably, the portions of the de-sulfurizing agent are converted at least a portion of the particulate fuel into a gaseous portion and a solid, char portion; and (c) combusting the char portion, thereby forming an ash containing sulfur fixed therein.

"Method for Capture and Treatment of Sulfur in Coal," Herman F. Feldmann, Byung C. Kim - Inventors, United States Patent Number 4,936,869, June 26, 1990. An integrated polygeneration system and process is disclosed for generating liquid hydrogen as a main energy product for use as a propellant for space vehicles. Secondary energy products and commodities for supporting a space center complex and launching of the space vehicle includes the production of electrical and thermal energy and gaseous nitrogen. The integrated process includes a coal gasification and gas cleanup system, a combined cycle power generation system, a hydrogen production and liquefaction system and an air separation system. A medium BTU gas is produced by the coal gasification system and is delivered to the power generation system and the hydrogen production and liquefaction system. Steam also produced in the coal gasification process is delivered to a steam turbine in the combined cycle power generation system which is combined with a gas turbine to which the medium BTU gas is delivered to generate electrical and thermal power in a combined cycle power generation process. Steam from the coal gasification process is also delivered to a steam turbine in the hydrogen production system to increase the hydrogen content of the medium BTU gas prior to liquefaction. An air separation system produces oxygen and gaseous nitrogen. The oxygen is utilized in the coal gasification process and the gaseous nitrogen is delivered for storage to a launch complex site where it is used as an inert gas to purge critical environments. The gaseous nitrogen is also utilized in the hydrogen production system where the nitrogen is liquefied and used to refrigerate the hydrogen.
moved from the second de-sulfurizer to the first de-sulfurizer, from the first de-sulfurizer to the regenerator, and from the regenerator to the second de-sulfurizer.

"Combined Goal Gasifier and Fuel Cell System and Method," Rodney A. Geisbrecht, Frank D. Gmeindl - Inventors, United States Department of Energy, United States Patent Number 4,921,765, May 1, 1990. A molten carbonate fuel cell is combined with a catalytic coal or coal char gasifier for providing the reactant gases comprising hydrogen, carbon monoxide and carbon dioxide used in the operation of the fuel cell. These reactant gases are stripped of sulfur compounds and particulate material and are then separated in discrete gas streams for conveyance to appropriate electrodes in the fuel cell. The gasifier is arranged to receive the reaction products generated at the anode of the fuel cell by the electricity-producing electrochemical reaction therein. These reaction products from the anode are formed primarily of high temperature steam and carbon dioxide to provide the steam, the atmosphere and the heat necessary to endothermically pyrolyze the coal or char in the presence of a catalyst. The reaction products generated at the cathode are substantially formed of carbon dioxide which is used to heat air being admixed with the carbon dioxide stream from the gasifier for providing the oxygen required for the reaction in the fuel cell and for driving an expansion device for energy recovery. A portion of this carbon dioxide from the cathode may be recycled into the fuel cell with the air-carbon dioxide mixture.
STATUS OF COAL PROJECTS

COMMERCIAL AND R&D PROJECTS (Underline denotes changes since June 1990)

ADVANCED COAL LIQUEFACTION PILOT PLANT — Electric Power Research Institute (EPRI) and United States Department of Energy (DOE) (C-10)

EPRI assumed responsibility for the 6 tons per day Wilsonville, Alabama pilot plant in 1974. This project had been initiated by Southern Company and the Edison Electric Institute in 1972. Department of Energy began cofunding Wilsonville in 1976.

The initial thrust of the program at the pilot plant was to develop the SRC-1 process. That program has evolved over the years in terms of technology and product slate objectives. Kerr-McGee Critical Solvent Dashing was identified as a replacement for filtration which was utilized initially in the plant and a Kerr-McGee owned unit was installed in 1979. The technology development at Wilsonville continued with the installation and operation of a product hydrotreating reactor that has allowed the plant to produce a No. 6 oil equivalent liquid fuel product as well as a very high distillate product yield.

The Wilsonville Pilot Plant was subsequently used to test the Integrated Two-Stage Liquefaction (ITSL) process. In the two stage approach, coal is first dissolved under heat and pressure into a heavy, viscous oil. Then, after ash and other impurities are removed in an intermediate step, the oil is sent to a second vessel where hydrogen is added to upgrade the oil into a lighter, more easily refined product. A catalyst added in the second stage aids the chemical reaction with hydrogen. Catalytic hydrotreating in the second stage accomplishes two distinct purposes: (1) higher-quality distillate products are produced by mild hydroconversion, and (2) high residuum content, donor rich solvent is produced for recycle to the coal conversion first stage reactor. Separating the process into two stages rather than one keeps the hydrogen consumption to a minimum. Also, mineral and heavy organic compounds in coal are removed between stages using Kerr-McGee's Critical Solvent Dashing unit before they can foul the catalyst.

ITSL results showed that 30 percent less hydrogen was needed to turn raw coal into a clean-burning fuel that can be used for generating electricity in combustion turbines and boilers. Distillable product yields of greater than 60 percent MAF coal were demonstrated on bituminous coal. Similar operations with sub-bituminous coal demonstrated distillate yields of about 55 percent MAF. This represents substantial improvement over single stage coal liquefaction processes.

Tests then concentrated on testing both types of coals with the deashing step relocated downstream of the catalytic hydrotreating step. Results showed that previous improvements noted for the two-stage approach were achievable (no loss in catalyst activity). Lower product cost was indicated for this reconfigured operation in that the two reactor stages may be coupled as part of one system. The results from the reconfigured operation also indicated the potential for further improvements in product quality and/ or productivity through use of the coupled-reactor approach. This was confirmed in tests which used a truly coupled, two-stage thermal-catalytic reaction system in conjunction with an improved hydrotreating catalyst. The nickel based catalyst (AMOCAT 1-C) was developed by Amoco Corporation, a program co-sponsor. In that test, coal space velocity was increased by 60 to 90 percent over previous operations, while catalyst productivity doubled. Furthermore, an improved configuration was developed and proven out, whereby only the net vacuum bottoms are deashed, thereby reducing the equipment size substantially.

The improved deashing configuration also resulted in additional product recovery attributable to recycling ashy bottoms. For bituminous coal, conversion of the incremental product was achieved by adding another catalyst (cobalt-based Amocat 1-A) to the first stage reactor, resulting in a 70 percent MAF distillate yield. For subbituminous coal, more thermal volume was used, resulting in a 61 percent MAF distillate yield. Use of the first stage catalyst also reduced the deactivation of the more active second stage catalyst.

Later results showed that nickel-based bimodal catalysts can be used in both reactions, thereby allowing the aged catalyst from one stage to be cascaded to the other. This can increase operating flexibility and reduce overall catalyst cost.

Recent work emphasized identifying potential cost benefits through advantageous feedstock selecting. This includes the use of lower ash (Ohio) coal and lower cost (Texas) lignite. The Ohio coal run results suggest that deep cleaning of the coal prior to liquefaction can increase distillate yield by 7-8 percent.

Current work using Amocat catalyst indicated the need to improve first stage stage reactor design. This led to modification of the L/D criteria which resulted in increased productivity corresponding to improved mixing. This improvement was also demonstrated with low-rank (Powder River Basin) coal. Additional efforts regarding reactor optimization are required.

Project Cost: Construction and operating costs (through calendar 1985): $97 million

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COMMERCIAL AND R&D PROJECTS (Continued)

AECI AMMONIA/METHANOL OPERATIONS – AECI LTD. (C-20)

AECI operates a 100 ton per day methanol facility and a 1,000 ton per day ammonia plant at its Modderfontein works near Johannes- burg. The plant uses six Koppers-Totzek two-headed gasifiers operating at 1,600 degrees C and atmospheric pressure to generate synthesis gas from sub-bituminous South African coal of low sulfur and high ash content. The ammonia plant, which utilizes conventional technology in the synthesis loop, has been in service since 1974 while the methanol unit, which employs ICI’s low pressure process, has been running since 1976. The plant is operating very satisfactorily at full capacity.

A fluidized bed combustion system has been commissioned at the plant to overcome problems of ash disposal. The proposed system generates additional steam, and has reduced requirements for land for ash disposal.

AECI has successfully completed the piloting of a methanol to hydrocarbons process using Mobil zeolite catalyst. The design of a commercial scale ethylene plant using this process has been completed.

AECI has also pursued development programs to promote methanol as a route to transportation fuel. Test programs include operation of a test fleet of vehicles on gasoline blends with up to 15 percent methanol, operation of other test cars on neat methanol, and operation of modified diesel trucks on methanol containing ignition promoters, trademarked “DIESANOL” by AECI. DIESANOL” has attracted worldwide interest and is currently being evaluated as a diesel fuel replacement in a number of countries.

AECI has completed a detailed study to assess the economic feasibility of a coal-based synthetic fuels project producing gasoline and diesel using methanol conversion technology. The results of this study were encouraging technically but lacked economic feasibility, with the result that further work has been suspended.

Project Cost: Not disclosed

AMAX/EMRC MILD GASIFICATION DEMONSTRATION – AMAX, University of North Dakota Energy and Minerals Research Center (EMRC) (C-31)

AMAX is considering a 1,000 ton per day plant at its Chinook Mine in Indiana. A fast fluidized-bed reactor will be used for mild gasification of this caking coal. It is planned to produce a diesel type fuel, as well as pure chemicals such as benzene and phenol.

AMAX conducted prefeasibility studies and concluded that favorable economics depend upon upgrading the mild gasification chars to a higher value product. This is because char has lower volatile matter content and higher ash content than the starting coal. These characteristics make char a low value utility fuel. The char will be cleaned by simple physical methods, then further processed into a metallurgical coke substitute (pellets or briquettes) and possibly to activated carbon for the pollution control industry. The location of this project offers distinct marketing advantages for these products.

A 100 pound per hour mild gasification process demonstration unit will start up at the Energy and Environmental Research Center in Grand Forks, North Dakota in June 1990.

BEWAG GCC PROJECT - BEWAG AG, Brown Boveri and Cie and Lurgi (C-35)

BEWAG AG of Berlin, in cooperation with Brown Boveri and Cie and Lurgi, has started to evaluate a project called "Erection and testing of a GCC based demonstration plant."

The project’s ultimate goal is the erection of a 180 megawatt pressurized CFB combined cycle power plant, with 40 megawatts obtained from the gasification, and 140 megawatts from the combustion section.

As both sections may be operated individually, the following partition can be obtained: 180 MW on operation of the total plant, 100 MW on operation of the combustion section only and 40 MW on operating the gas turbine on oil or natural gas.

The split of 40 megawatts/140 megawatts for the gasification and combustion sections is not the optimum if efficiency were to be maximized, but this split was chosen to enable meeting of special requirements of the Berlin grid, and to enable demonstration of the smallest commercial size gas turbine.

An engineering/process study to investigate the general feasibility of both pressurized CFB gasification and the coupling of pressurized CFB gasification with atmospheric CFB combustion was supported by the German Ministry of Research and Technology, and concluded in 1986.

A second phase component testing program, costing DM12 million and supported by the German Ministry of Research and Technology, is being carried out by a working group made up of BEWAG/EAB (Berlin), Ruhrkohle Oel and Gas GmbH (Bottrop), and Lurgi GmbH (Frankfurt), under the project leadership of EAB Energie-Anlagen Berlin GmbH.
STATUS OF COAL PROJECTS (Underline denotes changes since June 1990)

COMMERCIAL AND R&D PROJECTS (Continued)

BHEL COAL GASIFICATION PROJECT – Bharat Heavy Electricals Limited, Hyderabad, India (C-40)

Bharat Heavy Electricals Limited (BHEL), of Vikas Nagar, Hyderabad, India considers fluidized bed coal gasification as a long term perspective for combined cycle power generation. An 18 ton per day coal capacity pilot scale Process and Equipment Development Unit (PEDU) has been built.

BHEL as a manufacturer of power generation equipment has been involved in research and development activities related to advanced power systems. These include coal gas based combined cycles.

BHEL’s involvement in the development of coal gasification concerns the better and wider utilization of high ash, low grade Indian coals. The coals normally available for power generation are non-caking and have ash content in the range 25-45 percent by weight. The coals have high ash fusion temperature in the range 1,523-1,723 degrees K.

In the PEDU, coal is gasified by a mixture of air and steam at around 1,173 degrees K and at a pressure of 1.013 MPa.

Phase I of the Fluidized Bed Coal Gasification test program in the pilot scale plant is continuing. The plant was commissioned in the early 1989 and further test trials are in progress.

In Phase II of the Fluidized Bed Coal Gasification Program, basic engineering of a demonstration scale up 150 TPD coal capacity gasification plant has been completed. This plant is scheduled for commissioning in 1991. A demonstration plant will be integrated with the existing 6 MW electrical gas turbine/steam turbine combined cycle plant.

Project Cost: Not disclosed

BHEL COMBINED CYCLE DEMONSTRATION PLANT – Bharat Heavy Electrical Limited, India (C-50)

Bharat Heavy Electricals Limited (BHEL) of Hyderabad, India is carrying out a broad-based research program aimed at better and wider utilization of Indian coal resources. One phase of that program has involved building a small gasification combined cycle demonstration plant using a fixed bed coal gasifier.

The Combined Cycle Demonstration Plant (CCDP) is installed at the coal research and development complex of BHEL at Trichy. The net power generation capacity at full load is 6.2 megawatts. The CCDP scheme consists of an air-blown, fixed bed, pressurized coal gasifier, an industrial gas turbine firing the low-BTU coal gas, and a waste heat recovery steam generator behind the gas turbine, which supplies a conventional steam turbine/generator.

The plant was commissioned in March 1988 and has been in test operation since then.

The test program on this plant is expected to be completed by December 1990. A comprehensive test program is underway for exploiting the moving bed gasification technology for commercialization.

Project Cost: Not disclosed

BOTTROP DIRECT COAL LIQUEFACTION PILOT PLANT PROJECT— Ruhrkohle AG, Veba Oel AG, Minister of Economics, Small Business and Technology of the State of North-Rhine Westphalia, and Federal Minister of Research and Technology of the Federal Republic of Germany (C-60)

During operation of the pilot plant the process improvements and equipment components have been tested. The last improvement made was the operation of an integrated refining step in the liquefaction process. It worked successfully between late 1986 and the end of April 1987. Approximately 11,000 tons raffinate oil were produced from 20,000 tons coal in more than 2000 operating hours.

By this new mode of operation, the oil yield is increased to 58 percent. The formation of hydrocarbon gases is as low as 19 percent. The specific coal throughput was raised up to 0.6 t/m² h. Furthermore, high grade refined products are produced instead of crude oil. The integrated refining step causes the nitrogen and oxygen content in the total product oil to drop to approximately 100 ppm and the sulphur content to less than 10 ppm.

Besides an analytical testing program, the project involves upgrading of the coal-derived syncrude to marketable products such as gasoline, diesel fuel, and light heating oil. The hydrogenation residues were gasified either in solid or in liquid form in the Ruhrkohle/Ruhrchemie gasification plant at Oberhausen-Holten to produce syngas and hydrogen.

The development program of the Coal Oil Plant Bottrop was temporarily suspended in April 1987. Reconstruction work for a bivalent coal/heavy oil process was finished at the end of 1987. The plant capacity is 9 tons/hour of coal or alternatively 24 tons/hour of heavy vacuum residual oil. The first "oil-in" took place at the end of January 1988. Since then approximately 165,000 tons of heavy oil have been processed. A conversion rate over 90% and an oil yield of 85% have been confirmed.
COMMERCIAL AND R&D PROJECTS (Continued)

The project was subsidized by the Minister of Economics, Small Business and Technology of the State of North-Rhine Westphalia and since mid-1984 by the Federal Minister of Research and Development of the Federal Republic of Germany.

Project Cost: DM830 million (by end-1987)

BRICC COAL LIQUEFACTION PROGRAM – Beijing Research Institute of Coal Chemistry - BRICC (C-68)

In the early 1980s, China renewed study on direct liquefaction with emphasis on converting coal into clean liquid fuel by direct hydrogenation. Two continuous process units (CPU) were set up at the Beijing Research Institute of Coal Chemistry. The 0.1 ton per day continuous liquefaction unit set up jointly by China and NEDO (New Energy Development Organization) of Japan has been operating for more than 1,000 hours.

A five kilogram per hour CPU using "New German Technology" was introduced from the Federal Republic of Germany. To study various coal liquefaction processes and operation conditions, a 1.8 kilogram per hour slurry continuous liquefaction unit from Xytel Company of the United States was also installed.

At present, research is being carried out in the following areas: (1) evaluation of coal liquefaction characteristics; (2) suitability of coal for small-scale continuous liquefaction units; (3) selection and evaluation of catalysts; and (4) upgrading of coal liquefaction products. Tests have shown that some Chinese lignite and high-sulfur coal are ideal feedstocks for liquefaction. The high sulfur bituminous coal from Tengxian and Beisi of Shandong province have very good liquefaction behavior and the oil yield can reach 50 percent. The liquefaction behavior of lignite from Inner Mongolia and Yunan is also good. A Ni-Mo catalyst, natural iron ore powder, ferrous disulfide, red mud from several aluminum factories and some compounds containing iron have been tested successively.

Research on indirect liquefaction, i.e., modification of the F-T synthesis process is also being carried out by the Shanxi Research Institute of Coal Chemistry of the China Academy of Science. Based on laboratory study and tests in a single tube of 50 millimeter diameter, a pilot test with an output of 100 kilograms per day of synthetic oil is undergoing tests in a chemical fertilizer plant.

BRITISH COAL LIQUID SOLVENT EXTRACTION PROJECT – British Coal, British Department of Energy, European Economic Community, Ruhrkohle, Amoco (C-70)

British Coal has built a pilot plant facility utilizing its Liquid Solvent Extraction Process, a two-stage system for the production of gasoline and diesel from coal. In the process, a hot, coal-derived solvent is mixed with coal. The solvent extract is filtered to remove ash and other residue, followed by hydrogenation to produce a syncrude boiling below 300 degrees C as a precursor for transport fuels and chemical feedstocks. Studies have confirmed that the process can produce high yields of gasoline and diesel very efficiently. Work on world-wide coals has shown that it can liquefy economically most coals and lignite and can handle high ash feedstocks. British Coal is proceeding with the commissioning of a 2.5 tons per day plant at its Point of Ayr site, near Holywell in North Wales. The project is financed by the British Coal with support from the European Economic Community, Ruhrkohle A.G., Amoco, and British Department of Energy.


BROKEN HILL PROJECT – The Broken Hill Proprietary Company Ltd. (C-80)

The Broken Hill Proprietary Company Limited has been investigating the production of transport fuels from coal via continuous hydroliquefaction, since 1976 at their Melbourne Research Laboratories in Clayton, Victoria, Australia. The current continuous processing unit was built in 1980, and since 1982 it has been used to study medium severity hydroliquefaction. Routinely the primary liquefaction reactor has a throughput of 3 kg slurry per hour, with a coal to oil ratio of 40:60, and employs a H2 pressure of 25 MPa, and a temperature of 450 degrees C.

The main objective is to evaluate and develop alternative hydroliquefaction strategies and to test the efficacy of such strategies for a small indicative range of Australian coals. The unit is capable of single stage or two-stage operation, and allows for use of disposable catalyst in stage 1 and for recycle of separated solids to stage 1, if desired. Currently, oil yields of between 35% and 55% daf coal have been obtained, depending on coal feed and process type.

Batch micro-autoclaves (50 cm3) are used extensively in support of the continuous hydroliquefaction unit. Particular emphasis has been placed on matters relating to hydrogen transfer. An in-house solvent hydrogen donor index (SHDI) has been developed and has proven to be a valuable tool in process development and control, especially in non-catalytic two-stage hydroliquefaction. The research has also been concerned with the upgrading (refining) of product syncrudes to specification transport fuels. Experimental studies have included hydrotreating, hydrocracking and reforming, for the production of gasoline, jet fuel and diesel fuel. Jet and diesel fuel combustion quality requirements, as indicated by smoke point and octane number for example, have been achieved via severe hydrotreatment. Alternatively, less severe hydrotreatment and blending with suitable blendstocks has also proven effective. High octane unleaded gasolines have been readily produced via consecutive hydrotreating and reforming.
COMMERCIAL AND R&D PROJECTS (Continued)

Substantial efforts have been directed towards understanding the chemical basis of jet and diesel fuel specification properties. As a result, novel insights into the chemical prerequisites for acceptable fuel quality have been gained and are valid for petroleum derived materials and for many types of synthetic crudes. Considerable effort has also been directed towards developing specialised analytical methodology, particularly via NMR spectroscopy, to service the above process studies.

The work is supported under the National Energy Research Development and Demonstration Program (NERD&D) administered by the Australian Federal Government.

Project Cost: Not disclosed

BROOKHAVEN MILD GASIFICATION OF COAL — Brookhaven National Laboratory and United States Department of Energy (C-90)

A program is under way on mild gasification of coal to heavy oils, tars and chars under mild process conditions of near atmospheric pressure and temperatures below 750 degrees C. A test matrix has been designed to obtain the process chemistry, yields and characterization of liquid product over a wide range of temperature (500 to 750 degrees C), coal particle residence time (10 sec to 50 min), heatup rate (50 degrees C/sec to 100 degrees C/sec), coal particle size (50 to 300 microns) and additives (slaked lime, recycle ash, silica flour, recycle char). A combined entrained and moving bed reactor is being used to obtain the data. Four different types of coal have been tried, Kentucky No. 8 and Pittsburgh No. 8 bituminous coal, a Mississippi lignite and a Wyodak subbituminous. Generally the yields of oils from bituminous coals range between 20-25% (MAF), and about 15% for subbituminous coal.

Project Cost: $200,000

CALDERON ENERGY GASIFICATION PROJECT — Calderon Energy Company (C-95)

Calderon Energy Company is constructing a coal gasification process development unit. The Calderon process targets the clean production of electrical power with coproduction of fuel methanol.

Phase I activity and Phase II, detailed design, have been completed. Construction of the process development unit (PDU) is scheduled for completion by June 1990. Test operation is scheduled to begin upon completion of construction and extend for approximately six months.

The PDU will demonstrate the Calderon gasification process. In the process, run-of-mine high sulfur coal is first pyrolyzed to recover a rich gas (medium BTU), after which the resulting char is subjected to airblown gasification to yield a lean gas (low BTU gas). The process incorporates an integrated system of hot gas cleanup which removes both particulate and sulfur components of the gas products, and which cracks the rich gas to yield a syngas (CO and H2 mix) suitable for further conversion (e.g., to methanol). The lean gas is suitable to fuel the combustion turbine of a combined cycle power generation plant.

The PDU is sized to process one ton per hour of a high sulfur midwestern coal. The construction and operation of the PDU will take place on the property of Alliance Machine Company in Alliance, Ohio. The project is being aided by $5 million in government funding.

The PDU is specified for an operating pressure of 350 psig as would be required to support combined cycle power production.

Calderon Energy has obtained certification from the Federal Energy Regulatory Commission as a Qualifying Facility for a commercial site in Bowling Green, Ohio. Calderon filed a proposal under the Clean Coal Technology program Round 3 to build a cogeneration facility supplying 87 megawatts of electricity and 613 tons of methanol per day. The project did not receive funding but Calderon plans to reapply under Round 4. A preliminary design and cost estimate has been prepared by Bechtel. Calderon is negotiating with Toledo Edison to sell the electricity which would be produced.

Project Cost: $215 million
COMMERCIAL AND R&D PROJECTS (Continued)

CAN-DO PROJECT -- Continental Energy Associates (C-100)

Greater Hazleton Community Area New Development Organization, Inc. (CAN DO, Incorporated) built a facility in Hazle Township, Pennsylvania to produce low BTU gas from anthracite. Under the third general solicitation, CAN DO requested price and loan guarantees from the United States Synthetic Fuels Corporation (SFC) to enhance the facility. However, the SFC turned down the request, and the Department of Energy stopped support on April 30, 1983. The plant was shut down and CAN DO solicited for private investors to take over the facility.

The facility has been converted into a 100 megawatt cogeneration plant. Gas produced from anthracite coal in both the original facility and in new gasifiers is being used to fuel turbines to produce electricity. The electricity is purchased by the Pennsylvania Power & Light Company over a 20-year period. Steam is also produced which is available to industries within Humboldt Industrial Park at a cost well below the cost of in-house steam production.

The project cost for this expansion is over $100 million. The Pennsylvania Energy Development Authority authorized the bond placement by the Northeastern Bank of Pennsylvania and the Swiss Bank. The new facility is owned by Continental Energy Associates.

Project Cost: over $100 million

CHARFUEL PROJECT -- Wyoming Coal Refining Systems, Inc. a subsidiary of Carbon Fuels Corp. (C-110)

Wyoming Coal Refining Systems, Inc., formerly Char-Fuels of Wyoming, is attempting to secure financing to build a 1,000 ton per day Charfuel project at the Dave Johnston Power Plant near Glenrock, Wyoming. The project could cost up to $110 million. A smaller, 150 ton per day reactor would be built for process development studies. The plant would include gas processing, hydrotreating, methanol production and aromatic naphtha recovery.

The State of Wyoming has promised $163 million in assistance, contingent on WCRS raising a certain amount of private capital.

The project involves demonstrating a coal refining process. The first step is "hydrodisproportionation" which the company says is based on short residence time flash volatilization. Resulting char is mixed back with process-derived liquid hydrocarbons to make a stable, high-BTU, pipelineable slurry fuel. This compliance fuel could be burned in coal-fired or modified oil-fired burners. It would be tested in the 100 megawatt no. 1 boiler at the Dave Johnston plant.

Additional products manufactured during the refining process would include ammonia, sulfur, methanol, MTBE, BTX, and aromatic naphtha.

Project Cost: $110 million

CHEMICALS FROM COAL -- Tennessee Eastman Co. (C-120)

Tennessee Eastman Company, a manufacturing unit of the Eastman Chemical Company, continues to operate its chemicals from coal complex at Kingsport, Tennessee at design rates. The Texaco coal gasification process is used to produce the synthesis gas for manufacture of 500 million pounds per year of acetic anhydride. Methyl alcohol and methyl acetate are produced as intermediate chemicals, and sulfur is recovered and sold.

The facility has averaged 97% onstream availability for the last three years.

In January, 1989, Eastman announced that it plans a $150-million expansion of the chemicals-from-coal facility to be completed by the end of 1991. The project, which could begin as early as mid-1989, will more than double Eastman’s output of acetyl chemicals from coal and increase its flexibility in sourcing these products and in making their cellulosic derivatives.

The expansion program will include construction of two new chemicals plants and modification of the coal gasification facilities. An acetic anhydride plant will be built, with capacity of 600 million pounds per year of anhydride and 180 million pounds of acetic acid. A new methyl acetate unit will produce 490 million pounds per year.

The existing coal gasification facility will be able to handle the new anhydride demand with some debottlenecking, because the coal gas unit was built with some spare capacity.

Project Cost: Unavailable
STATUS OF COAL PROJECTS (Underline denotes changes since June 1990)

COMMERCIAL AND R&D PROJECTS (Continued)

CIGAS GASIFICATION PROCESS PROJECT – Fundacao de Ciencia e Tecnologia–CIENTEC (C-130)

The CIGAS Process for the generation of medium BTU gas is aimed at efficient technological alternatives suitable for Brazilian mineral coals of high ash content. No gasification techniques are known to be available and commercially tested for Brazilian coals.

The CIGAS Process research and development program has been planned for the interval from 1976 to 1998. In 1977 an atmospheric bench scale reactor was built, from which were obtained the first gasification data for Brazilian coals in a fluidized bed reactor. In 1978 a feasibility study was completed for the utilization of gas generated as industrial fuel. Next the first pressurized reactor in Latin America was built in bench scale, and the first results for pressurized coal gasification were obtained.

In 1979 the first atmospheric fluidized bed pilot scale unit was assembled (with a throughput of 7.2 tons per day of coal). In 1980 a project involving a pressurized unit for oxygen and steam began (20 atmospheres and 0.5 tons per day of coal). The plant was fully operational in 1982. In 1984 the pressurized plant capacity was enlarged to 2.5 tons per day of processed coal and at the same time air was replaced by oxygen in the atmospheric plant. This unit started processing 17 tons per day of coal.

In 1986 a unit was built to treat the liquid effluents generated throughout the process and studies on hot gas desulfurization were started in bench scale. By the end of 1988 pilot scale studies will be finished. As the result of this stage, a conceptual design for a prototype unit will be made. This prototype plant will be operational in 1992 and in 1994 the basic project for the demonstration unit will be started. The demonstration unit is planned to be operational in 1998.

Project Cost: US$4.7 million up to the end of 1988. The next stage of development will require US$15 million.

CIVOGAS ATMOSPHERIC GASIFICATION PILOT PLANT – Fundacao de Ciencia e Tecnologia – CIENTEC (C-133)

The CIVOGAS process pilot plant is an atmospheric coal gasification plant with air and steam in a fluidized-bed reactor with a capacity of five gigajoules per hour of low-BTU gas. It was designed to process Brazilian coals at temperatures up to 1,000 degrees C.

In the reactor, the coal is fluidized and gasified with steam and air at temperatures up to 1,000 degrees C. This pilot gasifier is about six meters high and 0.9 meters inner diameter. The bed height is usually 1.6 meters (maximum 2.0 meters). The coal is gravity-transferred to the reactor through a pipe whose end is located slightly above the operational bed height.

The steam-air mixture enters at the bottom through a gas distributor. The steam-air conical distributor consists of stainless steel pipes covered by dense castable refractory.

The bottom ash (char), removed from the reactor through a pipe connected to the orifice located at the center of the distributor, is quenched in the char bin. The slurry is next pumped to the clarifier of the wastewater treatment plant.

The CIVOGAS pilot plant has been successfully operating for approximately 10,000 hours for the past six years and has been working mainly with subbituminous coals with ash content between 35 to 55 percent weight (moisture-free).

The best operating conditions to gasify low-rank coals in the fluidized bed have been found to be 1,000 degrees C, with the steam making up around 20 percent by weight of the air-steam mixture.

Two different coals have been processed in the plant. The results obtained with Leao coal are significantly better than those for Candiota coal, the differences being mostly due to the relative contents of ash and moisture in the feedstock. Cold gas yields for both coals are typically 65 and 50 percent respectively with a carbon conversion rate of 68 and 60 weight percent respectively.

CIENTEC expects that in commercial plants or in larger gasifiers, better results will be obtained, regarding coal conversion rate and cold gas yield due to greater major residence time, and greater heat recovery from the hot raw gas.

According to the CIENTEC researchers, the fluidized-bed distributor and the bottom char withdrawal system have been their main concerns, and much progress has been made.

COALPLEX PROJECT – AECI (C-140)

The Coalplex Project is an operation of AECI Chlor-Alkali and Plastics, Ltd. The plant manufactures PVC and caustic soda from anthracite, lime, and salt. The plant is fully independent of imported oil. Because only a limited supply of ethylene was available from domestic sources, the carbide-acetylene process was selected. The plant has been operating since 1977. The five processes include calcium carbide manufacture from coal and calcium oxide; acetylene production from calcium carbide and water; brine electrolysis to make chlorine, hydrogen, and caustic; conversion of acetylene and hydrogen chloride to vinyl chloride; and vinyl chloride polymerization to PVC. Of the five plants, the carbide, acetylene, and VCM plants represent the main differences between coal-based and conventional PVC technology.
STATUS OF COAL PROJECTS (Underline denotes changes since June 1990)

COMMERCIAL AND R&D PROJECTS (Continued)

Project Cost: Not disclosed

COGA-1 PROJECT – Coal Gasification, Inc. (C-150)

The COGA-1 project has been under development since 1983. The proposed project in Macoupin County, Illinois will consume 1 million tons of coal per year and will produce 675,000 tons of urea ammonia and 840,000 tons of urea per year. It will use a high-temperature, high-pressure slagging gasification technology. When completed, the COGA-1 plant would be the largest facility of its kind in the world.

Sponsors were in the process of negotiations for loan guarantees and price supports from the United States Synthetic Fuels Corporation when the SFC was dismantled by Congressional action in late December 1985. On March 18, 1986 Illinois Governor James R. Thompson announced a $26 million state and local incentive package for COGA-1 in an attempt to move the $600 million project forward. The project sponsor is continuing with engineering and financing efforts.

Project Cost: $600 million

COLOMBIA COAL GASIFICATION PROJECT – Carbocol (C-160)

The Colombian state coal company, Carbocol plans for a coal gasification plant in the town of Amaga in the mountainous inland department of Antioquia.

Japan Consulting Institute is working on a feasibility study on the gasification plant and current plans are to build a US$10 to 20 million pilot plant initially. This plant would produce what Carbocol calls "a clean gas fuel" for certain big industries in Antioquia involved in the manufacture of food products, ceramics and glass goods. According to recommendations in the Japanese study, this plant would be expanded in the early 1990s to produce urea if financing is found.

Project Cost: $20 million initial $200 million eventual


In 1985, Montana One Partners (MOP), was formed to develop, construct, manage and maintain an LFC-Cogeneration plant in Colstrip, Rosebud County, Montana. SGI, the developer of the LFC (Liquids From Coal) process, is the sole general partner and one of two original limited partners of MOP.

In 1987, this 35 megawatt project was separated into two independent units, the 35 megawatt power unit (Colstrip Project) and the LFC Process unit. Separation of the project into two independent units required a new license from the Federal Energy Regulatory Commission, which was granted in October, 1987.

In April, 1988, MOP entered into an engineering procurement and construction contract with Bechtel Construction, Inc. for the Colstrip Project (i.e., the power unit). The project construction started in the third quarter of 1988, with completion scheduled for the second half of 1990.

In August, 1988, MOP sold all of its interest in the Colstrip Project to four individuals. These four individuals are the shareholders of Rosebud Energy Corporation, a Montana corporation.

In July, 1988 construction and long-term financing was obtained for the Colstrip Project. The investment banking firm of Ladenburg, Thalmann & Company, Inc. structured and arranged this project financing. The project lenders, Bank of New England, N.A. and Trust Company of the West are providing up to $79,734,000 of construction financing and up to $56,984,000 of long-term financing for the Colstrip Project. Equity funding of $22,750,000 is being provided by an affiliate of Bechtel Development Company, a California public utility, which are the limited partners of Colstrip Energy Limited Partnership (CELP). CELP has become the new owner of the Colstrip Project. The general partner of CELP is Rosebud.

COOL WATER COAL/MSW GASIFICATION PROGRAM – Texaco Syngas Inc. (C-170)

Original Cool Water participants built a 1,000-1,200 tons per day commercial-scale coal gasification plant using the oxygen-blown Texaco Coal Gasification Process. The gasification system which includes two Syngas Cooler vessels, was integrated with a General Electric combined cycle unit to produce approximately 122 megawatts of gross power. The California Energy Commission approved the state environmental permit in December 1979 and construction began in December 1981. Plant construction which took only 2.5 years, was completed on April 30, 1984, a month ahead of schedule and well under the projected $300 million budget. A five-year demonstration period was completed in January 1989.

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COMMERCIAL AND R&D PROJECTS (Continued)

Texaco and SCE, which have contributed equity capital of $45 million and $25 million respectively to the effort, signed the joint participation agreement on July 31, 1979. The Electric Power Research Institute (EPRI) executed an agreement to participate in the Project in February 1980 and their contribution is $69 million. Bechtel Power Corporation was selected as the prime engineering and construction contractor and also executed a participation agreement in September 1980 and have contributed $30 million to the project. General Electric signed a participation agreement in September 1980. In addition to contributing $30 million to the Project, GE supplied the combined cycle equipment. The JCWP Partnership, comprised of the Tokyo Electric Power Company, Central Research Institute of the Electric Power Industry, Toshiba CGP Corporation and III Coal Gasification Project Corp., signed a participation agreement on February 24, 1981 to commit $30 million to the Project. ESEERCO and Sohio Alternate Energy Development Company are non-equity contributors to the project, having signed contributor agreements on January 20, 1982, and April 10, 1984, respectively committing $5 million each to the Project. A $24 million project loan with a $6 million in-kind contribution by SCE of facilities at SCE’s existing generating station in Daggett, California completes the $263 million funding.

A supply agreement was executed with Airco, Inc. on February 24, 1981 for Airco to provide "over-the-fence" oxygen and nitrogen from a new on-site facility, thus reducing capital requirements of the Project.

The Project applied to the United States Synthetic Fuels Corporation for financial assistance in the form of a price guarantee in response to the SFC’s first solicitation for proposals. This was designed to reduce the risks of the existing Participants during the initial demonstration period. The Project was not accepted by the SFC because it did not pass the "credit elsewhere" test (the SFC believed sufficient private funding was available without government assistance). However, the sponsors reapplied for a price support under the SFC’s second solicitation which ended June 1, 1982. On September 17, 1982, the SFC announced that the project had passed the six-point project strength test and had been advanced into Phase II negotiations for financial assistance. On April 13, 1983 the sponsors received a letter of intent from the SFC to provide a maximum of $120 million in price supports for the project. On August 28, 1983 the Board of Directors of the SFC voted to approve the final contract awarding the price guarantees to the project.

A spare quench gasifier, which has been added to the original facility to enhance the plant capacity factor, was successfully commissioned in April 1985.

A Utah bituminous coal was utilized as "the Program" coal was burned at all times that the facility was not burning an alternate test coal. The Program could test up to 8 different coal feedstocks on behalf of its Participant companies.

A 32,000 ton Illinois No. 6 coal (nominal 3.1 percent weight sulfur) test, a 21,000 ton Pittsburgh No. 8 coal (nominal 2.9 percent weight sulfur) test, and a 20,000 ton Australian Lemington high-ash-fusion-temperature coal (nominal 0.5 percent weight sulfur) test have been completed. Energy conversion rates and environmental characteristics while running the alternate coals are essentially the same as those observed while burning the low sulfur Utah bituminous.

The gasifier was started up on May 7, 1984. On May 20, 1984 syngas was successfully fed to the gas turbine and the first combined cycle system operation was accomplished on May 31, 1984. On June 23, 1984 the ten continuous day SFC acceptance test was successfully completed and the Program was declared to be in commercial production on June 24, 1984.

At the completion of the demonstration program in January 1989 the gasifier had been on-line for more than 27,116 hours, and gasified over 1,132,000 tons of coal (dry basis). Approximately 2.8 billion gross kWh of electricity was produced.

In September, 1989 Texaco Inc. announced that Texaco Syngas Inc., its wholly owned subsidiary, had been awarded the rights to negotiate with Southern California Edison (SCE) for the purchase and operation of the Cool Water plant.

Upon acquiring the plant, Texaco intends to utilize a new application of Texaco's technology which will permit Cool Water to convert sewage sludge to useful energy by mixing it with the coal feedstock. Sewage sludge has been disposed of for many years in landfills and by ocean dumping, methods that are now becoming unacceptable for either overcapacity or environmental reasons. Texaco has demonstrated in pilot studies that sludge can be mixed with coal and, under high temperatures and pressures, gasified to produce a clean synthesis gas. Texaco officials emphasize that its gasification process results in no harmful by-products.

Acquisition of the plant is conditioned upon finalizing the terms of the purchase agreement and the completion of negotiations with SCE for the sale of electricity to be produced at Cool Water. In addition, negotiations will be required with municipalities and other governmental entities that produce and handle sewage sludge.

Upon conclusion of the necessary negotiations, Texaco will invest additional capital in the Cool Water plant for modifications aimed at reopening the facility in early 1992.

Project Cost: $263 million
COMMERCIAL AND R&D PROJECTS (Continued)

CRE SPUTTED BED GASIFIER - Coal Research Establishment, Otto-Simon Carves (C-190)

A spouted fluidized bed process for making low-BTU fuel gas from coal has been developed by British Coal at the Coal Research Establishment (CRE). A pilot plant has been built with a coal throughput of 12 tonnes per day.

This project has been sponsored by the European Economic Community (EEC) under two separate demonstration grants. Results to date have established the basis of a simple yet flexible process for making a gaseous fuel low in sulfur, tar and dust.

The CRE gasification process is based on the use of a submerged spouted bed. A significant proportion of the fluidizing gas is introduced as a jet at the apex of a conical base. This promotes rapid recirculation within the bed enabling caking coals to be processed without agglomeration problems. Coals with swelling numbers up to 8.5 have been processed successfully.

Plant construction was completed in April 1985 and cold commissioning of all aspects of the plant was successfully achieved by June 1985. As part of the contract with the EEC several extended trials were completed between April 1986 and March 1987 using char as bed material. Between April 1987 and November 1989, a further contract with the EEC investigated the use of inert bed materials and oxygen enrichment of the fluidizing air. This work enabled coal conversion efficiencies on the order of 90 percent (mass basis) to be attained, and allowed gases to be produced with calorific values up to 7.5 MJ/m³ (dry, gross).

Work on the 12 tonne per day pilot plant was directed towards providing design information for gasifiers operated at atmospheric pressure for industrial fuel gas applications. The aim was to develop a range of commercial gasifiers with a coal throughput typically of 24 to 100 tonnes per day. To this end a license agreement was signed by OSC Process Engineering Ltd. (OSC) to exploit the technology for industrial application. Designs of commercial gasifiers are available and OSC together with British Coal are actively promoting the use of the technology in the United Kingdom process industries.

Although OSC has yet to build the first commercial unit, they say considerable interest has been shown from a large number of potential clients worldwide.

The application of the process for power generation is also being investigated. Various cycles incorporating a pressurized version of the spouted bed technology have been studied and power station efficiencies up to 45 percent are predicted. A contract with the EEC to develop a pressurized version was initiated in January 1989. The proposal is to link the gasifier to a char combustor to form what is known at the British Coal topping cycle.

CRIEPI ENTRAINED FLOW GASIFIER PROJECT -- Central Research Institute of Electric Power Industry (Japan) (C-200)

Japan's CRIEPI (Central Research Institute of Electric Power Industry) has been engaged in research and development on gasification, hot gas cleanup, gas turbines, and their integration into an IGCC (Integrated Gasification Combined Cycle) system.

An air-blown pressurized two-stage entrained-flow gasifier (2.4 tons per day process development unit) adopting a dry coal feed system has been developed and successfully operated. This gasifier has been determined to be employed as the prototype of the national 200 tons per day pilot plant. The hot gas cleanup system process development unit (PDU) which employs a porous filter for dust removal and an iron oxide honeycomb fixed bed for desulfurization was constructed and has been successfully operated.

Research and development on a 200 tons per day entrained-flow coal gasification pilot plant equipped with hot gas cleanup facility and gas turbine has been carried out extensively from 1986 and will be completed in 1993.

CRIEPI executed a feasibility study of entrained-flow coal gasification combined cycle, supported by the Ministry of International Trade and Industry (MITI) and New Energy Development Organization (NEDO). They evaluated eight systems combining different methods of coal feed (dry/slurry), oxidizer (air/oxygen) and gas cleanup methods (hot-gas/cold-gas). The optimal plant system, from the standpoint of thermal efficiency, was determined to be composed of dry coal feed, airblown and hot-gas cleanup methods. This is in contrast to the Cool Water demonstration plant, which is composed of coal slurry feed, oxygen-blown and hot-gas cleanup systems.

CRIEPI constructed, in 1983, a coal gasification process development unit with a capacity of 2.4 tons per day coal using air-blown pressurized two-stage entrained-flow method, and since then has been promoting research and development jointly with Mitsubishi Heavy Industries, Ltd.

As of late 1989, the gasifier had been operated for 1,652 hours, and tested on 17 different coals.

For the project to build a 200 tons per day entrained-flow coal gasification combined cycle pilot plant, the electric utilities have organized the "Engineering Research Association for Integrated Coal Gasification Combined Cycle Power Systems (IGC)" with 10 major electric power companies and CRIEPI to carry out this project supported by MITI and NEDO.
STATUS OF COAL PROJECTS (Underline denotes changes since June 1990)

COMMERCIAL AND R&D PROJECTS (Continued)

Basic design and engineering of the pilot plant was started in 1986, and manufacturing and construction started in 1988 at the Nakoso Coal Gasification Power Generation Pilot Plant site. Tests will be beginning in 1991 for the air-blown pressurized entrained-flow gasifier connected with the hot gas cleanup system and a high temperature gas turbine of 1,300 degrees C combustor outlet temperature.

Project Cost: 53 billion yen

DANISH GASIFICATION COMBINED CYCLE PROJECT – Elkraft (C-205)

The Danish Utility, Elkraft, in response to government directives to lower pollution by using more natural gas, says that it will increase the use of natural gas to generate electricity. However, the utility says that it also plans for two power plants based on integrated coal gasification combined cycle (IGCC). The first will be a 50-megawatt demonstration unit at Masnedoe, at the site of an existing power plant that will be retired.

The Danish energy minister expects to decide during 1989 whether to approve this scheme.

If the Masnedoe demonstration is successful, Elkraft intends to move on to construct a full-scale 300-megawatt IGCC unit at Siltanæs, for service in 1997.

As yet, Elkraft has given no indication which IGCC design it favors for the Masnedoe demonstration.

Potential bidders could include Shell, Dow, Texaco and Krupp-Koppers.

DELAWARE CLEAN ENERGY PROJECT – Texaco, Star Enterprise, Delmarva Power & Light, Mission Energy (C-208)

Texaco SynGas Inc., Star Enterprise, a partnership between Texaco and Saudi Refining, Inc., Delmarva Power and Light Co. and Mission Energy have begun joint preliminary engineering and environmental studies for an integrated gasification combined cycle (IGCC) electrical generating facility. The project calls for the expansion of an existing power plant adjacent to the Star Enterprise refinery in Delaware City, Delaware. The facility would convert 2,000 tons per day of high sulfur petroleum coke, a byproduct of the Star refinery, into clean, gaseous fuel to be used to produce about 200 MW of electrical power in both existing and new power generating equipment.

Completion is planned for mid-1994 at an estimated cost of $250-300 million (1989 dollars).

The gasification process would inject a slurry composed of 60 percent coke and 40 percent water, and simultaneously inject oxygen into a refractory vessel (furnace). The vessel is operated at 2,500 degrees F and under 400 pounds of pressure.

The project has the potential to reduce substantially overall emissions at the Delaware City facilities, nearly double the current electric output and make use of the coke byproduct of the oil refinery. The Phase I studies will require approximately one year to complete (in 1991) at an estimated cost of $6 million.

The existing power plant would be upgraded and expanded and would continue to operate as a cogeneration facility.

DOW SYNGAS PROJECT – Louisiana Gasification Technology, Inc. a subsidiary of Destec Energy, Inc. (C-210)

The Dow Syngas Project began commercial operations in April, 1987, operating at rates up to 103 percent of capacity. As of July 1990 the project has completed 14,020 hours on coal. It has produced 14,409 billion Btu of on-spec syngas and supplied Dow’s Louisiana Division power plant with syngas for 13,487 hours.

At full capacity, the plant consumes 2,400 tons of coal per day providing 30 billion BTU per day of medium BTU gas. The process uses Dow-developed coal gasification technology to convert coal or lignite into medium BTU synthetic gas.

The process uses a pressurized, entrained flow, slagging, slurry-fed gasifier with a continuous slag removal system. Dow’s GAS/SPEC ST-1 acid gas removal system and Selectox sulfur conversion unit are also used at the Plaquemine, Louisiana, plant. Oxygen is supplied by Air Products.

Construction of the plant was completed in first quarter, 1987 by Dow Engineering Company. The project is owned and operated by Louisiana Gasification Technology Incorporated, a wholly owned subsidiary of Houston-based Destec Energy, Inc., a subsidiary of The Dow Chemical Company.
STATUS OF COAL PROJECTS (Underline denotes changes since June 1990)

COMMERCIAL AND R&D PROJECTS (Continued)

In this application the Dow Gasification Process and the associated process units have been optimized for the production of synthetic gas for use as a combustion gas turbine fuel. The project received a price guarantee from the United States Synthetic Fuels Corporation (now the Treasury Department) which is subject to the amount of gas produced by the project. The amount of the price guarantee is based on the market price of the natural gas and the production of the project. Maximum amount of the guarantee is $620 million.

Project Cost: $728.8 million

DUNN NOKOTA METHANOL PROJECT – The Nokota Company (C-220)

The Nokota Company is the sponsor of the Dunn-Nokota Methanol Project, Dunn County, North Dakota. Nokota plans to convert a portion of its coal reserves in Dunn County, via coal gasification, into methanol and other marketable products, including carbon dioxide for enhanced oil recovery in the Williston and Powder River Basins. Planning for the project is in an advanced position. $30 million has been spent, and 12 years have been invested in site and feasibility studies. After thorough public and regulatory review by the state of North Dakota, air quality and conditional water use permits have been approved. The Bureau of Reclamation released the final Environmental Statement on February 26, 1988. The Federal Water Service Contract is expected to be approved in 1990. Operation of Phase I of the project is scheduled to begin in 1996.

In terms of the value of the products produced, the Dunn-Nokota project is equivalent to an 800 million barrel proven oil reserve. In addition, the carbon dioxide product from the plant can be used to recover substantially more crude oil from oil fields in North Dakota, Montana, and Wyoming through carbon dioxide injection and crude oil displacement.

The Dunn-Nokota plant is designed to use the best available environmental control technology. The impacts which will occur from the construction and operation of this project will be mitigated in accordance with sound operating procedures and legal and regulatory requirements. At full capacity, the plant will use the coal under approximately 390 acres of land (about 14.7 million tons) each year. Under North Dakota law, this land is required to be reclaimed and returned to equal or better productivity following mining. Nokota will be working closely with local community leaders, informing them of the types and timing of socio-economic impact associated with this project.

Dunn-Nokota would produce approximately 81,000 barrels of chemical grade methanol, 2,400 barrels of gasoline blending stock (naphtha) and 300 million standard cubic feet of pipeline quality, compressed carbon dioxide per day from 40,000 tons of lignite (Beulah-Zap bed).

Additional market studies will determine if methanol production will be reduced and gasoline or substitute natural gas coproduced.

Existing product pipelines and rail facilities are available to provide access to eastern markets for the project’s output access to eastern markets for the project’s output. Access to western markets for methanol through a new dedicated pipeline to Bellingham, Washington, is also feasible if West Coast market demand warrants.

Construction employment during the six year construction period will average approximately 3,200 jobs per year. When complete and in commercial operation, employment will be about 1,600 personnel at the plant and 500 personnel in the adjacent coal mine.

Nokota’s schedule for the project calls for phased construction and operation, with initial construction (site preparation) beginning in 1992 and mechanical construction beginning in 1993 on a facility producing at one-half the full capacity. Commercial operation of this phase of the project is scheduled for 1996. Construction of the remainder of the facility is scheduled to begin in 1995 and to be in commercial operation in 1998. This schedule is subject to receipt of all permits, approvals, and certifications required from federal, state, and local authorities and upon appropriate market conditions for methanol and other products from the proposed facility.

Project Cost: $2.2 billion (Phase I and II)
$0.2 billion (CO2 compression)
$0.1 billion (Pipeline interconnection)
$0.3 billion (mine)

ENCOAL LFC DEMONSTRATION PLANT – ENCOAL Corporation, United States Department of Energy (C-221)

ENCOAL Corporation, a wholly owned subsidiary of Shell Mining Company of Houston, Texas, expects to receive funding from the Department of Energy’s Clean Coal Technology Round 3 Program for a 1,000 ton per day mild gasification plant at Shell’s Buckskin Mine in Northeastern Wyoming. The demonstration plant will utilize the LFC technology developed by SOI International.

The demonstration plant will be put in service by the first quarter of 1992. The plant will be designed and operated as a small commercial facility and is expected to produce sufficient quantities of process derived fuel and coal derived liquids to conduct full scale test burns of the products in industrial and utility boilers. Feed coal for the plant will be purchased from the Buckskin Mine which...
STATUS OF COAL PROJECTS (Underline denotes changes since June 1990)

COMMERCIAL AND R&D PROJECTS (Continued)

is owned and operated by Triton Coal Company (a wholly owned subsidiary of Shell Mining Company). Other United States coals may be shipped to the demonstration plant from time to time for test processing, since the process appears to work well on lignites and some Eastern bituminous coals.

A Permit to Construct has been received from the Wyoming Department of Environmental Quality, Air Quality Division for the demonstration plant. It was approved on the basis of the use of best available technology for the control of SO\textsubscript{x}, NO\textsubscript{x}, CO, hydrocarbons and particulates. There will be no waste water and source water requirements will be very small.

ENCOAL will contract for engineering, procurement and construction services from the M.W. Kellogg Company. SGI International will furnish technical services.

The plant will process 1,000 tons of coal per day and produce 150,000 barrels of liquids per year plus 180,000 tons of upgraded solid fuel.

Estimated Project Cost: $73,000,000

ESCrick CYCLONE GASIFIER TEST — Oaklands Limited (C-222)

A one megawatt cyclone gasifier system has been evaluated on a clay pipe kiln at Oaklands Ltd., Escrick, Yorkshire, United Kingdom. The clay pipe kiln at this works is heated using butane gas and on occasions when such high quality fuel has become expensive, the company has considered a number of different systems in order to achieve at least some element of coal firing. Earlier systems fired pulverized coal directly into the kiln through pulverized fuel burners. Carbon burnout was poor and unburned carbon and ash built up to such an extent in the bottom of the kiln that the car carrying the clay pipes could no longer be pushed through. The maximum continuous period of operation using this system was about seven days, when normally the kiln is operated continuously for many months.

A low cost gasifier system was needed to produce a clean low-BTU gas which could be used to fuel burners firing through the roof of the kiln. Ash/particulate retention was a very high priority while carbon burnout was not too crucial. The cyclone gasifier system was well suited for this task in that the technology enabled much of the particulate matter to be retained inside the combustion chamber.

A cyclone combustor with a maximum rating of 1.5 megawatts with two vortex collector pockets in order to improve ash retention was chosen. The unit was situated alongside the kiln. A crushed coal with an ash fusion temperature of just below 1,400 degrees C was chosen to ensure that no deposition or slagging occurred in the unit. Operation was fuel rich at a mixture ratio of 0.7 of stoichiometric for primary air.

The kiln on which these trials were conducted had four firing zones. Exhaust gases from the kiln were fed to a drier with extra heat being added to these gases by an auxiliary burner. Each firing zone required 900 kilowatts of heat, distributed through nine top fired burners. The cyclone gasifier system was designed to operate all nine such burners in a zone. To control the flowrate of gases from the cyclone gasifier to the kiln burners a fluidic, non-moving-part valve was used to regulate the gas flowrate and either divert the gas to the kiln burners or allow it to pass to a swirl burner/furnace system for incineration.

The gases from the cyclone gasifier were burnt in the kiln using simple co-axial burners with an air sheath surrounding the fuel gas. At the end of the trials there was no evidence of slag formation in the collected solids or in the cyclone combustor, while only sparse quantities of dust/grits were observed on the cured clay pipes the following day. Typically more than 80 percent of the generated ash and unburnt material were retained by the two VCP's and the central collector. Overall combustion efficiency of the cyclone combustor was about 80 percent.

FREETOWN IGCC PROJECT — Texaco Syngas Inc., Commonwealth Energy and General Electric Company (C-223)

FREETOWN IGCC PROJECT — Texaco Syngas Inc., Commonwealth Energy and General Electric Company (C-223)

The three companies have begun preliminary planning for a joint development of an electrical generating facility, using an integrated gasification combined cycle (IGCC) design, in Freetown, Massachusetts. The facility would be known as the Freetown Energy Park.

The energy park will be located on a 600 acre site along the Taunton River owned by a subsidiary of Commonwealth Energy.

Texaco Syngas will design the plant to use the Texaco Coal Gasification process and General Electric's high efficiency, gas turbines. The initial phase will produce 440 megawatts of power to be sold to New England utilities.

The plant will be one of the world's cleanest coal based power plants with emissions levels of particulates, SO\textsubscript{x} and NO\textsubscript{x} significantly less than conventional coal plants and below state and federal emissions standards.
STATUS OF COAL PROJECTS (Underline denotes changes since June 1990)

COMMERCIAL AND R&D PROJECTS (Continued)

The gasification process involves the injection of a coal-water slurry with oxygen into a pressurized vessel where partial oxidation of the coal occurs and synthesis gas is produced. The gas leaves the vessel through a water bath where ash and particulates are removed as slag. The cleaned gas is then directed to a sulfur removal system, which removes 98 percent of the sulfur prior to its use within the gas turbine.

Using the syngas, the gas turbine produces electricity while exhausting high temperature exhaust gas to heat recovery steam generators. The heat recovery steam generators produce steam for use in a steam turbine which in turn produces additional electricity. This combination of equipment is able to produce electricity in a highly efficient manner.

Project startup is scheduled for June 1995.

FRONTIER ENERGY COPROCESSING PROJECT - Canadian Energy Developments, Kilborn International (C-225)

Under the United States Department of Energy's Clean Coal Technology Round 3 Program, the Frontier Energy project is the commercial demonstration of a state-of-the-art technology for the simultaneous conversion of high sulfur coal and heavy oil (bitumen) to low sulfur, lean burning, liquid hydrocarbon fuels plus the cogeneration of electricity for export. Two main liquid hydrocarbon products are produced, a naphtha fraction which can be used as a high value petrochemical feedstock or can be processed further into high octane motor fuel and low sulfur fuel oil that can be used to replace high sulfur coal in thermal power plants. Cogenerated electricity, surplus to the requirements of the demonstration plant, is exported to the utility electrical system.

Frontier Energy is a venture involving Canadian Energy Developments of Edmonton, Alberta, Canada and Kilborn International Ltd. of Tucson, Arizona.

The technology being demonstrated is the CCLC Coprocessing technology in which a slurry of coal and heavy oil are simultaneously hydrogenated at moderate severity conditions (temperature, pressure, residence time) to yield a low boiling range (C₃-975 F) distillate product.

The CCLC Coprocessing technology is being developed by Canadian Energy Developments Inc. in association with the Alberta Office of Coal Research and Technology (AOCRT) and Gesellschaft fur Kohleverflussigung mbH (GfK) of Saarbrucken, West Germany.

The technology is in an advanced stage of development. Two integrated and computerized process development units (PDUs), 18-22 pounds per hour feed rate, are currently being operated to confirm the technology in long duration runs, to generate operating data for the design of larger scale facilities and to produce sufficient quantities of clean distillate product for secondary hydrotreating studies and market assessment studies.

Canadian Energy and GfK are planning to modify an existing 10 ton/day coal hydrogenation pilot plant to the CCLC Coprocessing configuration and to use it to confirm the coprocessing technology in large pilot scale facilities while feeding North American coals and heavy oils. Data from this large pilot scale facility will form the basis of the design specification for the Frontier Energy Demonstration Project.

The demonstration project will process 1,128 tons per day of Ohio No. 6 coal and 20,000 barrels per day of Alberta heavy oil.

GFK DIRECT LIQUEFACTION PROJECT - West German Federal Ministry for Research and Technology, Saarbergwerke AG, and GfK Gesellschaft fur Kohleverflussigung MbH (C-230)

For the hydrogenation of heavy oils, mixtures of heavy oil and coal (Co-processing) and coals with low ash contents, GfK favors a unique hydrogenation reactor concept in which the feedstock is fed at the top and passes through the reactor counter currently to the hydrogen which is fed at the reactor bottom. It has been found that this reactor is superior to the classical bubble column. At present this concept is being further tested using a variety of different coals and residual oils on the bench scale.

On the 31st of December 1989, GfK has terminated the operation of its pilot and bench-scale facilities. The further development, particularly the demonstration of the counter-flow-reactor on the pilot scale, is now pursued within a cooperation with East Germany's company Chemieanlagenbau Leipzig-Grimma where an existing hydrogenation pilot-plant is presently being modified to the new concept. Operation will begin by mid-1991.

Project Cost: Not disclosed

GREAT PLAINS GASIFICATION PROJECT - Dakota Gasification Company (C-240)

Initial design work on a coal gasification plant located near Beulah in Mercer County, North Dakota commenced in 1973. In 1975, ANG Coal Gasification Company (a subsidiary of American Natural Resources Company) was formed to construct and operate the facility and the first of many applications were filed with the Federal Power Commission (now FERC). The original plans called
STATUS OF COAL PROJECTS (Underline denotes changes since June 1990)

COMMERCIAL AND R&D PROJECTS (Continued)

for a 250 million cubic feet per day plant to be constructed by late 1981. However, problems in financing the plant delayed the project and in 1976 the plant size was reduced to 125 million cubic feet per day. A partnership named Great Plains Gasification Associates was formed by affiliates of American Natural Resources, Peoples Gas (now MidCon Corporation) Tenneco Inc., Transco Companies Inc. (now Transco Energy Company) and Columbia Gas Systems, Inc. Under the terms of the partnership agreement, Great Plains would own the facilities, ANG would act as project administrator, and the pipeline affiliates of the partners would purchase the gas.

In January 1980, FERC issued an order approving the project. However, the United States Court of Appeals overturned the FERC decision. In January 1981, the project was restructured as a non-jurisdictional project with the SNG sold on an unregulated basis. In April 1981, an agreement was reached whereby the gas would be sold under a formula that would escalate quarterly according to increases in the Producer Price Index and the price of No. 2 Fuel Oil, with limits placed on the formula by the price of other competing fuels. During these negotiations, Columbia Gas withdrew from the project. On May 13, 1982, it was announced that a subsidiary of Pacific Lighting Corporation had acquired a 10 percent interest in the partnership; 7.5 percent from ANR's interest and 2.5 percent from Transco.

Full scale construction did not commence until August 6, 1981 when DOE announced the approval of a $2.02 billion conditional commitment to guarantee loans for the project. This commitment was sufficient to cover the debt portion of the gasification plant, Great Plains' share of the coal mine associated with the plant, an SNG pipeline to connect the plant to the interstate natural gas system, and a contingency for overruns. Final approval of the loan guarantee was received on January 29, 1982. The project sponsors were generally committed to providing one dollar of funding for each three dollars received under the loan guarantee up to a maximum of $740 million of equity funds.

The project was designed to produce an average of 125 million cubic feet per day (based on a 91 percent onstream factor) of high BTU pipeline quality synthetic natural gas, 93 tons per day of ammonia, 88 tons per day of sulfur, 200 million cubic feet per day of carbon dioxide, potentially for enhanced oil recovery, and other miscellaneous by-products including tar oil, phenols, and naphtha to be used as fuels. Approximately 16,000 tons per day of North Dakota lignite is required as feedstock.

In August, 1985 the sponsors withdrew from the project and defaulted on the loan, and DOE began operating the plant under a contract with the ANG Coal Gasification Company. The plant successfully operated throughout this period and earned revenues in excess of operating costs. The gas is marketed through a 34 mile long pipeline connecting the plant with the Northern Border pipeline running into the eastern United States.

In parallel with the above events, DOE/DOJ filed suit in the United States District Court in the District of North Dakota (Southwestern Division) seeking validation of the gas purchase agreements and approval to proceed with foreclosure. On January 14, 1986 the North Dakota Court found that state law was not applicable and that plaintiffs (DOE/DOJ) were entitled to a summary judgment for foreclosure. A foreclosure sale was held on June 30, 1986, and DOE obtained legal title to the plant and its assets by a Marshall's deed dated July 16, 1986. This decision was upheld by the United States Court of Appeals for the Eighth Circuit on January 14, 1987. On November 3, 1987, the Supreme Court denied a petition for a writ of certiorari.

The North Dakota District Court also held that the defendant pipeline companies were liable to the plaintiffs (DOE/DOJ) for the difference between the contract price and the market value price. This decision was upheld by the United States Court of Appeals for the Eighth Circuit on May 19, 1987. No further opportunity for appeal exists and the decisions of the lower court stands.

In early 1987 the Department of Energy hired Shearson Lehman Bros. to help sell the Great Plains plant. In August, 1988 it was announced the Basin Electric Power Cooperative submitted the winning bid for approximately $85 million up-front plus future profit-sharing with the government. Two new Basin subsidiaries, Dakota Gasification Company and Dakota Coal Company, operate the plant and manage the mine respectively. Ownership of the plant was transferred on October 31, 1988.

For the first 15 months of operation under Dakota Gasification ownership, the plant produced gas at over 108 percent of design capacity.

The Linde Division of Union Carbide Industrial Gases Inc. has signed a 15-year agreement with Dakota Gasification Company to buy all the krypton/xenon produced at the Great Plains Synfuels Plant beginning in December 1990.

Project Cost: $2.1 billion

GSP PILOT PLANT PROJECT – German Democratic Republic (C-250)

Since 1983 a 30 tonne per day gasification complex has been in operation at Gaskombinat Schwarze Pumpe (GSP) in East Germany. It produces more than 50,000 cubic meters raw gas per hour. Practical results and experience gained during operation of this system are planned to be applied to the construction of a large-scale gas works, five to 10 times larger, with an annual output of two to four billion cubic meters raw gas.
The environmental compatibility of the GSP coal gasification process is said to meet the highest requirements even if coal that is rich in ash and sulfur and contains salt is used. The GSP process involves the gasification of pulverized coal under pressure, using the brown coal of the German Democratic Republic. Its mode of operation, however, is widely independent from the fuel, so that brown coal, hard coal, coke, high-ash coal, and so-called salt coal as well as waste products can be processed.

Project Cost: Not disclosed

HANOVER ENERGY DOSWELL PROJECT – Hanover Energy Associates (C-255)

Hanover Energy Associates is planning a 700 megawatt co-fired cogeneration plant to sell electricity to Virginia Power. The plant, to be located near Doswell, Virginia, will include 24 to 28 Wellman-Galusha gasifiers. The gas turbines will burn five-sixths natural gas and one-sixth low-BTU coal gas from the gasifiers.

The coal source will be coal wastes located in Western Virginia.

Construction is scheduled to begin on July 1 and will take two years, according to documents filed with the Federal Energy Regulatory Commission.

Other equipment includes four Westinghouse 501 D5 gas turbine generators, four waste heat recovery boilers and two steam turbine generators. Steam will be sold to National Energetics Company for manufacturing carbon dioxide and possibly to a nearby paper company.

Hanover Energy Associates, a limited partnership, was one of about 30 companies that responded to Virginia Power's solicitation in December 1986 for some 1,100 megawatts of electricity. Hanover has a similar plant planned in northeastern Pennsylvania, with a capacity of about 100 megawatts.

HUENXE CGT COAL GASIFICATION PILOT PLANT – Carbon Gas Technology (CGT) GmbH (C-260)

CGT was established in 1977, with the goal of developing a coal gasification process to the point of commercial maturity and economic utilization. The CGT coal gasification concept consists of the combination of two principal processes of coal gasification in a specially developed reactor. The characteristic feature of the CGT Process is the integrated fluidized bed and dust gasification stages. The coal is fed into the fluidization zone of the reactor, and fluidized and gasified by the addition of the gasification media (steam and oxygen) through side nozzles. The unconverted fines exit the reactor with the 1,000 degrees C hot product gas and are separated in a downstream cyclone as coke dust. The hot coke dust is cooled and stored in bunkers. The coke dust is then fed to the dust gasification stage at the top of the reactor and gasified with steam and oxygen in a cooled combustion chamber. The product gas exiting the combustor at high speed is directed to the fluid bed. The ash melted in the combustor flows down into the fluidized bed and is drawn off through the slag outlet. The coupling of a fluidized bed with entrained flow gasification under pressure leads to a higher specific throughput capacity with simultaneously higher efficiency. The production of tar-free product gas at the relatively low temperature of the reactor leads to various simplifications in gas purification.

The overall program for the development of the CGT process consists of three stages. Step 1: (1978-1981)—Planning, construction, and management of checkout tests of key components of the technical process. Step 2: (1981-1986)—Planning, construction and operation of a 4 tons per hour operating system. Step 3—Demonstration of the process at commercial scale. For the component test program, in 1979 a cold flow pressurized fluid bed facility and one for an atmospheric pressure dust gasification stage were erected. In 1981, planning began for building a 4 ton per hour test facility for a multi-stage CGT gasification process. The process design was agreed to in September 1982 and construction of the facility was completed on schedule in mid-1983. The component test facility and the 4 tons per hour pilot plant were erected at the site of the BP Ruhr refinery at Huenxe. The test work comprises a conceptual test program to the end of 1986. After bringing the facility on line and operating the combined fluidized bed with entrained flow gasification, the complete working of the test facility with a reference coal will be carried out over the entire operating range. In the following test phases the suitability of different feed coals will be checked out. In connection with the systematic test program, gasification tests with client coals for specific applications are planned.

Project Cost: Not disclosed

HYCOL HYDROGEN FROM COAL PILOT PLANT – Research Association for Hydrogen from Coal Process Development (Japan) (C-270)

In Japan, the New Energy Development Organization (NEDO) has promoted coal gasification technologies based on the fluidized bed. These include the HYBRID process for high-BTU gas making and the low-BTU gas making process for integrated combined cycle power generation. NEDO has also started to develop coal gasification technology based on a multi-purpose coal gasifier for medium-BTU gas.
The multi-purpose gasifier was evaluated as a key technology for hydrogen production, since hydrogen is the most valuable among coal gasification products. NEDO decided to start the coal-based hydrogen production program at a pilot plant beginning in fiscal year 1986. The pilot plant, with the exception of the gasification section, is being constructed at the plant site in Sodegaura, Chiba prefecture. Construction is planned to be completed in August of 1990. Operational research is scheduled to begin in 1991 after a trial run.

The key technology of this gasification process is a two-step spiral flow system. In this system, coal travels along with the spiral flow from the upper part towards the bottom because the four burner nozzles of each stage are equipped in a tangential direction to each other and generate a downward spiral flow. As a result of this spiral flow, coal can stay for a longer period of time in the chamber and be more completely gasified.

In order to obtain a higher gasification efficiency, it is necessary to optimize the oxygen/coal ratio provided to each burner. That is, the upper stage burners produce reactive char and the lower stage burners generate high temperature gas. High temperature gas keeps the bottom of the gasifier at high temperature, so molten slag falls fluently.

The specifications of the pilot plant are as follows:

- Coal feed: 50 ton per day
- Pressure: 1.0 MPa
- Temperature: 1,500 to 1,800 degrees C
- Oxidant: Oxygen
- Coal Feed: Dry
- Slag Discharge: Slag Lock Hopper
- Refractory Lining: Water-cooled slag coating
- Dimensions Outer Pressure Vessel: 2 Meters Diameter, 13.5 Meters Height
- Carbon Conversion: 98 Percent
- Cold Gas Efficiency: 78 Percent
- 1,000 Hours Continuous Operation

The execution of this project is being carried out by the Research Association for Hydrogen from Coal Process Development, a joint undertaking by nine private companies, and is organized by NEDO. Additional researches are also being conducted by several private companies to support research and development at the pilot plant. The nine member companies are:

Idemitsu Kosan Co., Ltd.
Osaka Gas Co., Ltd.
Electric Power Development Company
Tokyo Gas Co., Ltd.
Toho Gas Co., Ltd.
Nippon Mining Company
The Japan Steel Works, Ltd.
Hitachi, Ltd.
Mitsui SRC Development Co., Ltd.

IMHEX MOLTEN CARBONATE FUEL CELL DEMONSTRATION – M-C Power Corporation, Combustion Engineering, Inc., Institute of Gas Technology (C-273)

Despite being turned down for funding under the United States Department of Energy's Clean Coal Technology Round 3 Program, M-C Power Corporation is going ahead with a demonstration project to repower existing coal-fired power plants with coal gas-fired IMHEX molten carbonate fuel cells (MCFC). The proposed coal gasification/MCFC system can be used to fully or partially repower existing power plants regardless of the fossil fuel for which they were initially designed. This repowering should result in more economic plants, with greater capacity and reduced emissions of SO₂ and NOₓ.

The IMHEX configuration is a novel advanced molten carbonate fuel cell designed to eliminate many of the pumping problems experienced by previous molten carbonate fuel cell concepts.

The demonstration facility will be located at IGT's Energy Development Center in Chicago, Illinois. The demonstration will use IGT's existing U-GAS coal gasifier and will produce 500 kilowatts of electricity.

The demonstration project will begin April 1, 1991 and will be completed September 30, 1994. Total estimated cost of the project is $22,700,000.
ISCOR MELTER-GASIFIER PROCESS – ISCOR, Voest-Alpine Industrieanlagenbau (C-275)

An alternative steel process that does not use coke has been commercialized at ISCOR's Pretoria works (South Africa). Designed and built by Voest-Alpine Industrieanlagenbau GmbH (Linz, Austria), the plant converts iron ore and coal directly into 300,000 tons per year of pig iron in a melter-gasifier, referred to as the COREX process. Conventional techniques require use of a coke oven to make coke, which is then reacted with iron ore in a blast furnace.

Two separate streams of materials are gravity fed into the melter-gasifier. One stream is coal (0.5-0.7 tons of carbon per ton of pig iron produced) with ash, water and sulfur contents of up to 20 percent, 12 percent and 1.5 percent, respectively. Lime is fed together with the coal to absorb sulfur. The second stream—iron ore in lump, sinter or pellet form—is first fed to a reduction furnace at 850-900 degrees C and contacted with reducing gas (65-70 percent CO and 20-25 percent H₂) from the melter-gasifier. This step reduces the ore to 95 percent metal sponge iron. The metallization degree of the sponge iron where it comes into contact with the 850-900 degrees C hot reducing gas produced in the reduction furnace, is 95% on average.

The sponge iron proceeds to final reduction and melting in the melter-gasifier, where temperatures range from 1,100 degrees C near the top of the unit to 1,700 degrees C at the oxygen inlets near the bottom. Molten metal and slag are tapped from the bottom. As a byproduct of the hot metal production export gas is obtained, which is a high quality gas with a caloric value of approximately 2000 kcal/Nm³. Voest-Alpine says the pig iron quality matches that from blast furnaces, and that costs are $150 per ton.

Voest-Alpine has also recently patented several schemes involving a fluidized bed meltdown-gasifier (United States Patents 4,725,306, 4,728,360, 4,729,786, issued in 1988). Typically a fluidized bed of coke particles is maintained on top of the molten iron bath by blowing in oxygen-containing gas just at the surface of the molten metal.

Voest-Alpine has been collaborating with Geneva Steel to demonstrate the technology in the United States, however, Geneva has shelved further action on the project after failing to receive funding in the DOE Clean Coal Technology Round 3. In 1990 Virginia Iron Industries Corporation announced plans to build a COREX plant in Hampton Roads, Virginia. The $800 million project is scheduled to come on line in 1994.

KANSK-ACHINSK BASIN COAL LIQUEFACTION PILOT PLANTS – Union of Soviet Socialist Republics (C-280)

The Soviet Union is building a large coal-based project referred to as the Kansk-Achinsk Fuel and Energy Complex (KATEK). The project consists of a very large open pit mine (the Berezovskiy-1 mine), a 6,400 megawatt power plant, and a coal liquefaction facility. Additionally, the small town of Sharypovo is being converted into a city with new schools, stores, housing, and transportation.

A pilot plant referred to as an ST-75 installation is being built at KATEK to test a catalytic hydrogenation process. Construction of the unit began in 1982. Start up of the unit was originally planned for 1984, however, the plant has still not been completed. Preliminary tests indicate that five tons of Kansk-Achinsk brown coal can produce one ton of liquid products at a cost that is 25 to 30 percent less than products that are refined from crude oil from remote Siberian regions.

Additionally, a second unit referred to as the ETKh-175 is being built at KATEK to test a catalytic hydrogenation process. Construction of the unit began in 1982. Start up of the unit was originally planned for 1984, however, the plant has still not been completed. Preliminary tests indicate that five tons of Kansk-Achinsk brown coal can produce one ton of liquid products at a cost that is 25 to 30 percent less than products that are refined from crude oil from remote Siberian regions.

Additionally, a second unit referred to as the ETKh-175 is being built at a power station in Krasnoyarsk to test rapid pyrolysis of brown coal from the Borodinskoye deposit and is said to be nearing completion. The test unit will have a capacity of 175 tons of coal per hour. The plant is designed to crush the Kansk-Achinsk run of mine coal with 40 percent moisture in hammer mills and simultaneously dry the resulting coal dust with the flue gas from a special-type self-contained furnace. In the thermal reaction (pyrolysis) chamber, the dried coal dust heats up quickly to 550-700 degrees C as it mixes with a solid transfer agent (pulverized coke) circulating in the system and preheated to 850-950 degrees C in a process furnace. As the two mix during pyrolysis, the coal forms coke breeze and a mixture of combustible gas, resinous and pyrogenous water vapors. Upon dedusting in cyclone separators, the mixture is subjected to fast cooling whereupon it is fed to the gas cleaning and condensation plant.

The excess coke breeze formed during pyrolysis is cooled down to 75-80 degrees C and is used as a commercial product.

The ETKh-175 energy efficiency is said to be about 83 percent, with account for the energy losses and auxiliary power. The plant will be supplemented with facilities for obtaining liquid tar resins, motor fuel and coal tar, various chemical products and for making coke breeze briquettes from a mixture of brown coal and coal tar.

A third experimental coal liquefaction unit, ST-5, is under construction at the Belkovskaya mine of the Novomoskovsk Coal Association. The unit is intended to demonstrate a relatively low pressure hydrogenation process that reportedly operates at approximately 1,500 psig and 400 degrees C. A catalyst is used in the process to enhance the hydrogenation of coal into high octane gasoline. The liquid and solid are separated, and the solids are combusted to recover the catalyst. Startup of ST-5 was to occur in 1984.

Project Cost: Not disclosed
STATUS OF COAL PROJECTS (Underline denotes changes since June 1990)

COMMERCIAL AND R&D PROJECTS (Continued)

K-FUEL COMMERCIAL FACILITY — Energy Brothers Inc. (C-290)

Energy Brothers, licensee of the K-Fuel process, is building a plant located next to the Fort Union Mine near Gillette, Wyoming. The plant will use the process invented by Edward Koppelman and developed further by SRI International. In the K-Fuel process, low-grade coal or peat is dried and mildly pyrolyzed in two coupled reactors that operate at elevated temperatures and at a pressure of 600 psi. The process produces a pelletized, low-moisture, low-sulfur coal with a BTU value of 12,000, and by-product water and fuel gas. K-Fuel pellets contain 60 percent more energy (approximately 27 million BTU per ton) and 40 percent less sulfur than the raw coal. The fuel gas from the process is utilized on site to provide the needed heat for the process. The proposed facility will utilize 4 modules each capable of producing 350,000 tons per year of K-Fuel. Wisconsin Power and Light has agreed to a 10-year purchase agreement for "a substantial portion" of the output of the plant. The K-Fuel will be tested at Wisconsin Power and Light's Rock River generating station near Beloit in south-central Wisconsin. For the test Wisconsin Power and Light will purchase the fuel at the cost of production, which has yet to be determined but is estimated to be over $30 per ton. If the test is successful, Wisconsin Power and Light has the option to invest in the process.

Wisconsin Power and Light is interested in burning K-Fuel to eliminate the need to install expensive equipment to reduce sulfur emissions from the power plant. The upgraded coal is also less expensive to ship and store due to its improved heating value.

Construction of the plant will begin during the fourth quarter, 1989. Fru-Con Construction Corporation of St. Louis, Missouri is building the facility, and the plant will begin commercial operation by March, 1991. EA-K Energy, Inc., which is jointly owned by Energy America Incorporated of San Diego and K-Fuel Partnership of Denver, will build and operate the facility.

A new company, Smith Powerfuels, a partnership of K-Fuel Partnership and Energy America, has been established to develop an international market for K-Fuel.

Project Cost: $62 Million

KRW ENERGY SYSTEMS INC. ADVANCED COAL GASIFICATION SYSTEM FOR ELECTRIC POWER GENERATION — The M.W. Kellogg Co., United States Department of Energy, and Westinghouse Electric (C-310)

In April 1984 Westinghouse sold its coal gasification technology to Kellogg Rust and the new organization was named KRW Energy Systems Inc., owned 20% by Westinghouse and 80% by the M.W. Kellogg Company. The major activities of KRW Energy Systems has been to complete development of a fluidized bed coal gasification technology and to develop a commercial demonstration project.

The major development facility for KRW is a coal gasification pilot plant located at the Waltz Mill site near Pittsburgh, Pennsylvania. This facility started operation in 1975 and accumulated more than 12,000 hours of hot operation utilizing a broad range of coals. These coals include high caking Eastern bituminous, Western bituminous, and lignites with high and low ash contents and high and low moisture contents. A number of German brown coals have also been successfully gasified. The pilot plant program was completed in September 1988, and the facility has been decommissioned.

The pilot plant utilized a single stage fluidized bed gasifier with ash agglomeration and hot fines recycle. The pilot gasifier is operated at temperatures between 1,550 degrees F and 1,950 degrees F and pressures between 130 psig and 230 psig, with air feed to produce low-BTU gas and oxygen feed to produce medium-BTU gas. Pilot plant coal capacity ranged between 20 and 25 tons per day, depending on coal type.

The DOE hot gas cleanup program that was initiated in late 1984 was also completed in fiscal year 1988. The results from this development program have provided significant cost and efficiency improvements for the KRW gasification technology as applied to gasification combined cycle electric power generation. Operations at the Waltz Mill pilot plant with an air blown gasifier using a high sulfur (2-4.5%) and highly caking Eastern bituminous coal, have achieved the following significant demonstrations:

- A simplified process to deliver a hot and clean low BTU fuel gas to a combustion turbine.
- Gasifier in-bed desulfurization to meet NSPS requirements by removing over 90% of feed sulfur utilizing limestone or dolomite sorbents.
- Utilization of a regenerable zinc ferrite sorbent in a sulfur polishing mode to reduce fuel gas sulfur levels to less than 20 ppm.
- Demonstrated use of sintered silicon carbide candle filters at 1,100-1,200 degrees F and 16 atm pressure to reduce fuel gas solid particulates to less than 10 ppm.
- Delivery of final product fuel gas at high temperature and pressure containing less than 1 ppm combined alkali and heavy metals.

Commercial scale process performance systems studies show the KRW hot gas combined cycle power system to have net heat rates less than 8,000 BTU/kWh and capital costs less than 1,250$/kWh for 300-400 MW sized plants. A significant feature of these systems is the modularity of design which provides much planning and construction flexibility.
STATUS OF COAL PROJECTS (Underline denotes changes since June 1990)

COMMERCIAL AND R&D PROJECTS (Continued)

Kelloan is interested in applying the KRW gasification technology to a commercial size demonstration plant of about 60 MWe capacity.

Project Cost: Not disclosed

LAKEsIDE REPOWERING GASIFICATION PROJECT — Combustion Engineering, Inc. (C-320)

The project will demonstrate Combustion Engineering's pressurized, airblown, entrained-flow coal gasification repowering technology on a commercial scale. The syngas will be cleaned of sulfur and particulates and then combusted in a gas turbine (40 MWe) from which heat will be recovered in a heat recovery steam generator (HRSG). Steam from the gasification process and the HRSG will be used to power an existing steam turbine (25 MWe).

The proposed project is selected for demonstration at the Lakeside Generating Station of City Water, Light and Power, Springfield, Illinois. The selected site with associated characteristics and costs includes repowering an existing steam turbine to produce 65 MWe via the combined cycle mode.

The project is funded under Round 2 of the Department of Energy's Clean Coal Technology Program.

LAPORTE LIQUID PHASE METHANOL SYNTHESIS — Air Products & Chemicals, Chem Systems Inc., Electric Power Research Institute, and United States Department of Energy (C-330)

Air Products is testing a 5 tons per day PDU located near LaPorte, Texas. The unit is being run as part of a program sponsored by the DOE and will be used to evaluate the liquid phase methanol synthesis technology developed by Chem Systems. In the process, synthesis gas is injected in the bottom of a reactor filled with light oil in which a methanol synthesis catalyst is suspended. The oil acts as a large heat sink, thus improving temperature control and allowing the use of more active catalysts and/or a more concentrated synthesis gas.

Additionally, a wider range of synthesis gas compositions can be used, thereby allowing the use of low hydrogen/carbon ratio gases without the need for synthesis gas shift to produce more hydrogen. The technology is particularly suitable to syngas derived from coal in modern, efficient coal gasifiers which produce a high CO content syngas.

In spring 1985, the liquid phase methanol PDU located near LaPorte, Texas was started, with the initial objective of a 40 day continuous run. During the run, the LaPorte unit was operated under steady-state conditions using carbon monoxide-rich gas representative of that produced by advanced coal gasifiers. During the run, the plant achieved a production rate of up to 8 tons per day with a total production of approximately 165 tons of methanol (50,000 gallons). The plant, including the slurry pump and a specially designed pump seal system, operated very reliably during the run.

In a four-month test lasting from September 1, 1988 to January 8, 1989, the unit produced methanol from simulated coal gas at a rate more than twice the original design rate of the test facility.

The LaPorte run lasted 124 days and was interrupted only briefly when Hurricane Gilbert threatened the Gulf Coast early in the test program. During the marathon operation, the experimental facility produced just over 8,000 barrels of fuel-grade methanol. Production rates averaged 60 to 70 barrels per day — roughly twice the facility's original 35-barrel per day design rate. Methanol from the test run was of high enough quality to be used directly as a motor fuel without further upgrading.

The 124-day run also demonstrated the effectiveness of improvements in the facility's reaction vessel which had been modified last year to incorporate an internal heat exchanger and vapor/liquid separation process. Synthesis gas was provided by Air Products from its adjacent H2CO production plant. Operation of the PDU was again successfully tested from September 1989 through March 1990. The PDU operated extremely well with excellent productivity.

The 48-month, $10.2 million contract will expire in March 1991.

Project Cost:
- DOE: $26.4 million
- Private participants: $3.8 million

LIQUID PHASE METHANOL DEMONSTRATION PLANT — Air Products and Chemicals, Dakota Gasification (C-345)

Air Products and Chemicals, Inc. and Dakota Gasification Company (DGC) have been selected by the United States Department of Energy (DOE) to negotiate for an estimated $93 million from the federal government to help underwrite the costs of a 500 ton-per-day liquid phase methanol unit the two companies jointly plan to construct at DGC's Great Plains Synfuels Plant in Beulah, North Dakota. The novel project, which is designed to lower power costs and reduce acid rain emissions, was one of 13 selected by the DOE under the third round of the nation's Clean Coal Technology Demonstration Program.
COMMERCIAL AND R&D PROJECTS (Continued)

Coal Gasification Combined Cycle (CGCC) is the cleanest technology for generating electric power from coal. The liquid phase methanol technology that will be demonstrated at the Great Plains facility has been developed specifically to lower the cost of electricity produced in Coal Gasification Combined Cycle (CGCC) power plants by efficiently storing energy in the form of methanol for use during periods of peak power demand. These types of facilities could also sell any excess quantities of the clean-burning fuel for other applications. CGCC can effectively repower coal-fired facilities and meet stringent environmental limits for sulfur dioxide and nitrogen oxide emissions. Thus, on a commercial scale, the liquid phase methanol technology could reduce electric power costs by allowing utilities to rely less on imported liquid fuels or natural gas and still meet the nation's clean air requirements.

Fuel-grade methanol produced at Great Plains by the LPMEOH process will be used in tests to demonstrate its suitability for boilers, turbine and transportation fuel applications.

About 10 percent of the synthesis gas currently produced at the Great Plains plant will be converted to make 500 tons per day of methanol, while the remaining synthesis gas will continue to be used in making substitute natural gas.

The Great Plains project is expected to be on stream by 1993. Air Products and Dakota Gasification will contribute about $121 million of the total estimated cost of $213 million. If the technology is successful on a commercial scale, Air Products could build conversion plants for other companies as soon as 1995.

LULEA MOLTEN IRON COAL GASIFICATION PILOT PLANT - KHD Humboldt Wedag AG and Sumitomo Metal Industries, Ltd (C-350)

KHD and Sumitomo agreed to jointly build and operate a 240 tonnes per day pilot plant to test the molten iron coal gasification processes independently developed by both companies. Construction of the pilot plant was completed in Lulea, Sweden at the country's steel research center in mid-1985, with operation scheduled to last through 1987.

The pilot plant was designed for operation at pressures up to 5 atmospheres. In the process, pulverized coal and oxygen are injected into a bath of molten iron at temperatures of 1,400 to 1,600 degrees C. Potential advantages of the technology include simple coal and oxygen feed controls and low carbon dioxide production.

Project Cost: Not Disclosed

LU NAN AMMONIA-FROM-COAL PROJECT – China National Technical Import Corporation (C-360)

The China National Technical Import Corporation awarded a contract to Bechtel for consulting services on a commercial coal gasification project in the People's Republic of China. Bechtel will provide assistance in process design, design engineering, detailed engineering, procurement, construction, startup, and operator training for the installation of a Texaco gasifier at the 200 metric tons per day Lu Nan Ammonia Complex in Tengxian, Shandong Province. When completed in December, 1990, the Lu Nan modification will replace an obsolete coal gasification facility with the more efficient Texaco process.

Project Cost: Not Disclosed

MILD GASIFICATION PROCESS DEMONSTRATION UNIT – Coal Technology Corporation and United States Department of Energy (C-370)

Coal Technology Corporation, formerly United Coal Company's Research Division, UCC Research Corporation has built a Mild Gasification Process Demonstration Unit at its research center in Bristol, Virginia. The unit is capable of processing 1 ton per day of coal or coal waste. Under the sponsorship of the United States Department of Energy (DOE), UCC has developed a process that is primarily aimed at recovering the energy value contained in wastes from coal cleaning plants. To utilize this waste, UCC developed a mild gasification/coal liquid extraction process.

Work under Phase I of the Mild Gasification Process Demonstration program is now complete in all areas. Phase II continues under the sponsorship of the U.S. Department of Energy/Morgantown Energy Technology Center involving further development of the process with concentration on a variety of coal feedstocks rather than coal waste. The two year program as completed the following:

Developed a detailed test plan for conducting in-depth optimization tests of the Mild Gasification Process.

Conducted a extensive test program to optimize the operation of the Mild Gasification Process and producing significant quantities of coal liquids and char.

Tests of char and char/coal blends for use in industrial/utility boilers, 100 percent char in stoker boilers, and for use to replace or extend coke in blast furnaces are ongoing.
STATUS OF COAL PROJECTS (Underline denotes changes since June 1990)

COMMERCIAL AND R&D PROJECTS (Continued)

Evaluation of the coal liquids as a home heating fuel.

Distillation of the coal liquids into fractions with boiling ranges approximately those for gasoline, diesel oil, and heavy oil to
determine which fractions may be best suited for commercial applications.

The process demonstration unit underwent a modification phase initially to enhance the overall unit performance. Modifications to
the condensing system, reactor tubes, furnace, and coal feed system were made.

Work is now concentrated on a 0.5 ton per hour continuous mild gasification process demonstration unit for the production of
coproducts. The work is oriented toward production of transportation fuels and metallurgical coke for blast furnaces.

Project Cost: Not disclosed

MILD GASIFICATION OF WESTERN COAL DEMONSTRATION -- AMAX, Western Research Institute (C-372)

AMAX is planning a 1,000 ton per day commercial demonstration plant at its Eagle Butte Mine near Gillette, Wyoming. Inclined
fluid-bed reactors will be used for drying and mild gasification.

The first liquid product, dirty pitch, will be used to spray the dry coal. Clean pitch will be used as a binder for carbon anodes used
in aluminum production. The oil product will be used to run the heavy mine equipment.

Prefeasibility studies concluded that favorable economics depend upon upgrading the mild gasification chars to a higher value
product. This is because char has lower volatile matter content and higher ash content than the starting coal. These characteristics
make char a low value utility fuel. Therefore, char will be converted to pure carbon to be used for the manufacture of carbon
anodes in aluminum production or sold as carbon black. Its use as a premium fuel for gas turbines and heat engines offers the
largest long-term market. The waste streams will be incinerated in an atmospheric fluidized-bed combustor which, in addition to
supplying process heat, will produce electric power for export.

A 100 pound per hour inclined fluid bed mild gasification process development unit has been operating at Western Research In-
stitute since January 1990. A 50 pound per hour char to carbon process demonstration unit will start up at Amax Research and

MINNESOTA P&L ELFUEL PROJECT -- Minnesota Power and Light Company, BNI Coal, Institute of Gas Technology, Electric
Power Research Institute and Bechtel Corporation (C-373)

Minnesota Power and Light submitted a proposal to DOE's Clean Coal Technology Program Round Three for a project in which
2,000 tons per day of raw North Dakota lignite would be reformed at temperatures of 600 degrees F and 1,850 psi, creating a
product that resembles bituminous coal. In the final ELFUEL product, moisture would be reduced to eight percent by weight and
the energy content increased from 7,250 BTU per pound to 11,100 BTU per pound.

The project was not selected for funding. However, the proposers are considering submitting it to the next round of the Clean Coal
Technology Program. Testing is still continuing to try to reduce sulfur levels in the final product. If these tests are promising Min-
nesota P&L may decide to continue the project without DOE funding.

Project Cost: $146 million

MONASH HYDROLIQUEFACTION PROJECT -- Coal Corporation of Victoria and Monash University (C-380)

The Chemistry, Chemical Engineering, and Physics Departments at Monash University at Clayton, Victoria are conducting a major
investigation into the structure and hydroliquefaction of Victorian brown coal. Batch autoclave and other studies are being con-
ducted.

The work is largely supported by the Coal Corporation of Victoria and NERDDC.

Earlier studies on the hydroliquefaction of brown coal have led to a more detailed study of its structure and reactivity and are
based on extensive collaborations with a number of other laboratories in Australia. These lead to the proposal of a guest/host
model for brown coal which more recent results suggest may represent an oversimplification of coal structure. The nature of the
bonding, chemical and/or physical, by which aliphatic material is retained in the lignocellulosic polymer has yet to be defined.

The use of sodium aluminate as a promoter for the reaction of brown coal with carbon monoxide and water, leading to high yields
of low molecular weight products under relatively mild conditions without the use of a recycle solvent, has been established. Some
success has been achieved in characterising the aluminum species responsible for promoting these reactions but further work is re-
quired.
STATUS OF COAL PROJECTS (Underline denotes changes since June 1990)

COMMERCIAL AND R&D PROJECTS (Continued)

Partial oxidation of brown coal is thought to be adventitious for hydroliquefaction, particularly in the carbon monoxide/water/aluminate system.

A wide range of collaborative projects are currently in progress. Investigations are underway into the isolation and characterization of potentially useful products which can be extracted from brown coal.

Project Cost: $2.0 million (Australian) since commencement

MONGOLIAN ENERGY CENTER — People’s Republic of China (C-390)

One of China’s largest energy and chemical materials centers is under construction in the southwestern part of Inner Mongolia. The first-phase construction of the Jungar Coal Mine, China’s potential largest open-pit coal mine with a reserve of 25.9 billion tons, is in full swing and will have an annual capacity of 15 million tons by 1995.

The Ih Je League (Prefecture) authorities have made a comprehensive development plan including a 1.1 billion yuan complex which will use coal to produce chemical fertilizers. A Japanese company has completed a feasibility report.

The region may be China’s most important center of the coal-chemical industry and the ceramic industry in the next century.

MRS COAL HYDROGENATOR PROCESS PROJECT — British Gas plc and Osaka Gas Company Ltd. (C-400)

Work is being carried out jointly by British Gas plc and the Osaka Gas Company Ltd. of Japan, to produce methane and valuable liquid hydrocarbon coproducts by the direct thermal reaction of hydrogen with coal. A novel reactor, the MRS (for Midlands Research Station) coal hydrogenator incorporating internal gas recirculation in an entrained flow system has been developed to provide a means of carrying out the process without the problems of coal agglomeration, having to deal with excessive coal fines, or excessive hydrogenation gas preheat as found in earlier work.

A 200 kilogram per hour pilot plant was built to prove the reactor concept and to determine the overall process economics. The process uses an entrained flow reactor with internal gas recirculation based on the Gas Recycle Hydrogenator (GRH) reactor that British Gas developed to full commercial application for oil gasification.

Following commissioning of the plant in October 1987, a test program designed to establish the operability of the reactor and to obtain process data was successfully completed. An Engineering and Costing Study of the commercial process concept confirmed overall technical feasibility and exceptionally high overall efficiency giving attractive economics.

In December 1988, the sponsors went ahead with the second stage of the joint research program to carry out a further two year development program of runs at more extended conditions and to expand the pilot plant facilities to enable more advanced testing to be carried out.

Through 1989, performance tests have been conducted at over 43 different operating conditions. Four different coals have been tested, and a total of 10 tonnes have been gasified at temperatures of between 700 degrees centigrade and 1,000 degrees centigrade. The initial plant design only allowed tests of up to a few hours duration to be carried out. The plant was modified in early 1990 to provide continuous feeding of powdered coal and continuous cooling and discharge of the char byproduct. It will be operated in this mode in the second half of 1990.

Project Cost:  
Phase I $6 million  
Phase II $7.4 million

NEDOL BITUMINOUS COAL LIQUEFACTION PROCESS - New Energy Development Organization (NEDO) (C-410)

Basic research on coal liquefaction was started in Japan when the Sunshine project was inaugurated in 1974, just after the first oil crisis in 1973. NEDO assumed the responsibility for development and commercialization of coal liquefaction and gasification technology. NEDO plans a continuing high level of investment for coal liquefaction R&D, involving two large pilot plants. The construction of a 50 tons per day brown coal liquefaction plant was completed in December 1986 in Australia, and a 150 tons per day bituminous coal liquefaction plant is planned in Japan.

The pilot plant in Australia is described in the project entitled “Victoria Brown Coal Liquefaction Project.” The properties of brown coal and bituminous coal are so different that different processes must be developed for each to achieve optimal utilization. Therefore, NEDO has also been developing a process to liquefy sub-bituminous and low grade bituminous coals. NEDO had been operating three process development units utilizing three different concepts for bituminous coal liquefaction: solvent extraction, direct liquefaction, and solvolysis liquefaction. These three processes have been integrated into a single new process, so called NEDOL Process, and NEDO has intended to construct a 150 tons per day pilot plant.
COMMERCIAL AND R&D PROJECTS (Continued)

In the proposed pilot plant, bituminous coal will be liquefied in the presence of activated iron catalysts. Synthetic iron sulfide or iron dust will be used as catalysts. The heavy fraction (-538 degrees C) from the vacuum tower will be hydrotreated at about 350 degrees C and 100-150 atm in the presence of catalysts to produce hydrotreated solvent for recycle. Consequently, the major products will be light oil. Residue-containing ash will be separated by vacuum distillation.

Detailed design of the new pilot plant has been completed. It is expected that the pilot plant will start operation in 1991.

In 1988, 5 different coals were processed in the bench scale unit with encouraging results.

Project Cost: 100 billion yen, not including the three existing PDU

NYNAS ENERGY CHEMICALS COMPLEX - AGA, A. Johnson & Company, and the Swedish Investment Bank (C-420)

A group of Swedish companies are planning to build a gasification plant in Sweden. The Nynas Energy Chemicals Complex (NEX) will utilize the Texaco coal gasification process to produce fuel gas for a combined cycle unit and synthesis gas for ammonia production. Initially, the facility will produce 280 megawatts of electricity, 200,000 tons of ammonia per year, hot water for the Southern Stockholm district heating system, and industrial gases (oxygen, nitrogen, and argon). Also, Nynas Petroleum's refinery in Nynashamn will switch to fuel gas from NEX. The plant is scheduled to go on stream in 1991.

Participants in the project are: AGA, the Swedish industrial gas group; A. Johnson and Company, a privately-owned Swedish trading and industrial group; and the state-owned Swedish Investment Bank.

The Investment Bank, AGA, and Johnson are equal partners in a new company, Nynas Kombinate AB, which owns 100 percent of NEX. AGA will build on their own the air separation plant for the facility.

Project Cost: US$500 million


This project is a prototype commercial coal/oil co-processing plant to be located in Warren, Ohio. This plant will convert high sulfur, high nitrogen, Ohio bituminous coal and poor-quality petroleum to produce clean liquid fuels. The process to be utilized is HRI, Inc.'s proprietary commercial ebullated-bed reactor technology. In this process coal is blended with residual oil and both are simultaneously converted to clean distillate fuels. A "typical" C_C_975 degrees F distillate fuel will contain 0.3 percent sulfur and 0.3 percent nitrogen. The prototype plant will process 800 tons per day of coal, plus residual oil sufficient to yield 11,750 barrels per day of distillate product. Startup of the plant was slated for 1994, however, it will likely be delayed to 1996 because of problems with permits.

The products were originally slated for transportation fuels, however, emphasis has switched to finding an alternative market such as a host utility that would burn the fuel for electricity generation.

The project was selected by DOE for financial assistance in the Clean Coal Technology Program Round One. Continued funding by DOE, however, hinges on Ohio's ability to find an alternative market for the fuel.

Project Cost: Estimated $226 million

OULU AMMONIA FROM PEAT PROJECT - Kemira Oy (C-450)

Kemira of Finland is building a pressurized fluidized bed peat gasification system for producing synthesis gas. The gas will be used for ammonia and other chemicals. Ammonia production is to be 80,000 tons per year.

Currently Kemira operates in Oulu a minor ammonia plant based on the gasification of heavy fuel oil. However, peat is the only realistic domestic raw material for synthesis gas in Finland. Therefore, a research program aiming at the gasification of peat was started in the middle of the 1970s.

The gasification plant includes as integrated individual processes: peat transfer, screening, crushing, drying, pressurized HTW fluidized bed gasification, soot removal, raw gas compression and three-stage gas purification. The existing Pyroflow boiler plant serves for energy supply and a waste incinerator. The gasification plant was placed in operation in June 1988. It has a capacity of 150 megawatts, thermal.

Project Cost: Investment costs are expected to be FIM225 million.
STATUS OF COAL PROJECTS (Underline denotes changes since June 1990)

COMMERCIAL AND R&D PROJECTS (Continued)

P-CIG PROCESS – Interproject Service AB, Sweden and Nippon Steel Corporation, Japan (C-455)

The Pressurized-Coal Iron Gasification process (P-CIG) is based on the injection of pulverized coal and oxygen into an iron melt at overatmospheric pressure. The development started at the Royal Institute of Technology in Stockholm in the beginning of the 1970s with the nonpressurized CIG Process. Over the years work had been done on ironmaking, coal gasification and ferroalloy production in laboratory and pilot plant scale.

In 1984, Interproject Service AB of Sweden and Nippon Steel Corporation of Japan signed an agreement to develop the P-CIG Process in pilot plant scale. The pilot plant system was built up at the Metallurgical Research Station (MEFOS) in Lulea, Sweden. The P-CIG Process utilizes the bottom blowing process for injection of coal and oxygen in the iron melt. The first tests started in 1985 and several test campaigns were carried out through 1986. The results were then used for the design of a demonstration plant with a gasification capacity of 500 tons of coal per day.

According to project sponsors, the P-CIG Process is highly suitable for integration with combined cycle electric power generation. This application might be of special interest for the future in Sweden.

For the 500 tons of coal per day demonstration plant design, the gasification system consisted of a reactor with a charge weight of iron of 40 tons. Twenty-two tons of raw coal per hour would be crushed, dried and mixed with five tons of flux and injected together with 9,000 cubic meters of oxygen gas.

POLISH DIRECT LIQUEFACTION PROCESS – Coal Conversion Institute, Poland (C-460)

In 1975, Polish research on efficient coal liquefaction technology was advanced to a rank of Government Program PR-1 “Complex Coal Processing,” and in 1986 to a Central Research and Development Program under the same title.

The leading and coordinating unit for the coal liquefaction research has been the Coal Conversion Institute, part of the Central Mining Institute.

Initial work was concentrated on the two-stage extraction method of coal liquefaction. The investigations were carried out up to the bench scale unit (120 kilograms of coal per day). The next step—tests on a Process Development Unit (PDU)—met serious problems with the mechanical separation of solids (unreacted coal and ash) from the coal extract, and continuous operation was not achieved. In the early eighties a decision was made to start investigations on direct coal hydrogenation under medium pressure.

Investigations of the new technology were first carried out on a bench-scale unit of five kilograms of coal per hour. The coal conversion and liquid products yields obtained as well as the operational reliability of the unit made it possible to design and construct a PDU scaled for two tonnes of coal per day.

The construction of the direct hydrogenation PDU at the Central Mining Institute was finished in the middle of 1986. In November 1986 the first integrated run of the entire unit was carried out.

The significant, original feature of this direct, non-catalytic, middle-pressure coal hydrogenation process is the recycle of part of the heavy product from the hot separator through the preheater to the reaction zone without pressure release. Thanks to that, a good distribution of residence times for different fractions of products is obtained, the proper hydrodynamics of a three-phase reactor is provided and the content of mineral matter (which acts as a catalyst) in the reactants is increased. From 1987 systematic tests on low rank coal type 31 have been carried out, with over 100 tons of coal processed in steady-state parameters.

The results from the operation of the PDU will be used in the design of a pilot plant with a capacity of 200 tonnes coal per day which is expected to be completed by the end of the eighties.

PFBC/GCC COMBINED SYSTEM – British Coal Corporation, United Kingdom Department of Energy, European Commission, PowerGen, (C-465)

British Coal Corporation has proposed a research project utilizing the pressurized fluidized bed combustion process (PFBC) developed at Grimethorpe, South Yorkshire.

The project is intended to increase the output of the power station by incorporating a turbine which runs on a combination of gasified coal and exhaust from the pressurized fluidized bed combustor.

In conventional PFBC, coal is burned in a fluidized bed under pressure, and the hot pressurized combustion gases are fed directly into a gas turbine. However, the operating temperature in a PFBC unit is usually only about 850°C to avoid softening the ash and impeding fluidization. This comparatively low temperature limits efficiency.

To overcome this, British Coal engineers proposed a topping cycle. It would entail injecting a fuel gas into the hot PFBC combustion gas and burning the combination in the gas turbine inlet, raising the hot gas temperature to 1,100°C or more.
COMMERCIAL AND R&D PROJECTS (Continued)

At first, the fuel gas would be natural gas. In due course the intention would be to couple a coal gasifier and a PFBC unit.

Coal would be partially gasified, and the solid residue burned in the PFBC unit, or on another version of a CFBC unit; the fuel gas
from the gasifier would be burned in the hot combustion gas in a fully coal-fired topping cycle.

The gas turbine is due to start operation at Grimethorne in early 1991; the novel, pressured spouted bed gasifier, developed at the

The gas turbine operation is funded by British Coal, UK Department of Energy, PowerGen, and EPRI. The gasifier work is
funded by British Coal and the European Community.

PRENFLO GASIFICATION PILOT PLANT - Krupp Koppers GmbH (KK) (C-470)

Krupp Koppers, of Essen, West Germany (in United States known under the name of Owl Gesellschaft fuer Kohle-Technologie)
are presently operating a 48 tons per day demonstration plant and designing a 1,000 tons per day demonstration module for the
PRENFLO (pressurized entrained flow) process. The PRENFLO process is KK’s pressurized version of the Koppers-Totzek (KT)
gasifier.

In 1973, KK started experiments using a pilot KT gasifier with elevated pressure. In 1974, an agreement was signed between Shell
Internationale Petroleum Maatschappij BV and KK for a cooperation in the development of the pressurized version of the KT
process. A demonstration plant with a throughput of 150 tons per day bituminous coal and an operating pressure of 435 psia was
built and operated for a period of 30 months. After completion of the test program, Shell and KK agreed to continue further
development separately, with each partner having access to the data gained up to that date. KK’s work has led to the PRENFLO
process.

Krupp Koppers has decided to continue development with a test facility of 48 tons per day coal throughput at an operating pressure
of 30 bar. The plant is located at Fuerstenhausen, West Germany. By September 1988, more than 6,200 hours of operation had
been accumulated.

Krupp Koppers and Siemens, KWU Group, are planning a demonstration IGCC plant based on the PRENFLO process. This
demonstration plant will have a capacity of 160 megawatts, based on one PRENFLOW module with 1,200 tonnes per day coal
throughput and two Siemens V64 gas turbines. The detailed engineering is expected to be finished in 1989, so that a contract can
be awarded in the second half of the year. The startup of the plant is planned for 1992.

Project Cost: Not disclosed

PRESSURIZED FLUID BED COMBUSTION ADVANCED CONCEPTS – M. W. Kellogg Company (C-473)

In September of 1988, Kellogg was awarded a contract by the DOE to study the application of transport mode gasification and
combustion of coal in an Advanced Hybrid power cycle. The study was completed in 1990 and demonstrated that the cycle can
reduce the cost of electricity by 20-30 percent (compared to a PC/FGD system) and raise plant efficiency to 45 percent or more.

The Hybrid system combines the advantages of a pressurized coal gasifier and a pressurized combustor which are used to drive a
high efficiency gas turbine generator to produce electricity. The proprietary Kellogg system processes pulverized coal and lime-
stone and relies on high velocity transport reactors to achieve high conversion and low emissions.

The gasifier converts part of the coal to a low-BTU gas that is filtered and sent to the gas turbine. The remaining char is comb-
busted and the flue gas is filtered and also goes to the gas turbine. The advantages of the system in addition to high efficiency are
lower capital cost and greatly reduced SO₂ and NOₓ emissions.

Kellogg is currently building a bench scale test unit to verify the kinetic data. A pilot plant of 1-2 ton per hour capacity is planned
for the near future.

RIEHNABRAUN HIGH-TEMPERATURE WINKLER PROJECT - Rheinische Braunkohlenwerke AG, Uhde GmbH, Lurgi
GmbH, West German Federal Ministry for Research & Technology (C-480)

Rheinbraun and Uhde have been cooperating since 1975 on development of the High Temperature Winkler fluidized bed gasifica-
tion process. In 1990 Lurgi joined the commercialization effort.

Based on operational experience with various coal gasification processes, especially with ambient pressure Winkler gasifiers,
Rheinische Braunkohlenwerke AG (Rheinbraun) in the 1960s decided to develop pressurized fluidized bed gasification, the High-
Temperature Winkler (HTW) process. The engineering contractor for this process is Uhde GmbH.

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STATUS OF COAL PROJECTS (Underline denotes changes since June 1990)

COMMERCIAL AND R&D PROJECTS (Continued)

The development was started at the "Institut fur Eisenhuttenkunde" of Aachen Technical University in an ambient pressure process development unit (PDU) of about 50 kilograms per hour coal throughput.

Based on the results of pre-tests with this PDU a pilot plant operating at pressure of 10 bar was built in July 1978 at the Wachtberg plant site near Cologne. Following an expansion in 1980/1981, feed rate was doubled to 1.3 tons per hour dry lignite. By end of June 1985 the test program was finished and the plant was shut down. From 1978 until June 1985 about 21,000 tonnes of dried brown coal were processed in about 38,000 hours of operation. The specific synthesis gas yield reached 1,580 standard cubic meters per tonne of brown coal, MAF, corresponding to 96 percent of the thermodynamically calculated value. At feed rates of about 1,800 kilograms per hour coal, the synthesis gas output of more than 7,700 standard cubic meters per hour per square meter of gasifier area was more than threefold the values of atmospheric Winkler gasifiers.

After gasification tests with Finnish peat in the HTW pilot plant in the spring of 1984 the Kemira Oy Company, Finland decided to convert an existing ammonia production plant at Oulu from heavy oil to peat gasification according to the HTW process. The plant was designed to gasify approximately 650 tons per day of peat at 10 bar and process it to 280 tons per day of ammonia. This plant started up in 1988 and was operated with success until January 1990.

Rheinbraun constructed a 30 ton per hour demonstration plant for the production of 300 million cubic meters syngas per year. All engineering for gasifier and gas after-treatment including water scrubber, shift conversion, gas clean up and sulfur recovery was performed by Uhde; Linde AG is contractor for the Rectisol gas cleanup. The synthesis gas produced at the site of Rheinbraun's Ville/Berrenrath briquetting plant was pipelined to DEA - Union Kraftstoff for methanol production testing periods. From start-up in January 1986 until end of April 1990 about 510,000 tonnes of dried brown coal were processed within about 21,650 hours of operation. During this time about 655 million cubic meters of synthesis gas were produced.

Studies for further development of the HTW process for higher pressures up to about 25 bar are being performed including optimization of the processing system as well as operation in a recycling fluidized bed especially in respect to utilization for combined power production.

A new pilot plant for pressures up to 25 bar and throughputs up to 6.5 tonnes per hour was erected on the site of the former pilot plant of hydrogasification and started up in November 1989. Up to now the design throughput of 6.5 tonnes per hour was reached operating with oxygen/steam as gasification agents. From mid 1990 onwards corresponding tests with air as gasification agent will follow.

This work is performed in close co-ordination with Rheinbraun's parent company, the Rheinisch-Westfalishes Elektrizitatswerk (RWE), which operates a power station of a capacity of some 9,300 megawatts on the basis of lignite. Since this generating capacity will have to be renewed after the turn of the century, it is intended to develop the IGCC technology so as to have a process available for the new power plants. Based on the results of these tests and on the operating experience gained with the HTW synthesis gas plant, a demonstration plant for integrated HTW gasification combined cycle (HTW-IGCC) power generation is planned which will go on stream in 1995 and will have a capacity of 265 MW of electric power.

Project Cost: Not disclosed

SASOL - Sasol Limited (C-490)

Sasol Limited is the holding company of the multi divisional Sasol Group of Companies. Sasol is a world leader in the commercial production of coal based synthetic fuels. The Synthol oil-from-coal process was developed by Sasol in South Africa in the count of more then 30 years. A unique process in the field, its commercial-scale viability has been fully proven and its economic viability conclusively demonstrated.

The first Sasol plant was established in Sasolburg in the early fifties. The much larger Sasol Two and Three plants, at Secunda - situated on the Eastern Highveld of Transvaal, came on-stream in 1980 and 1982, respectively.

The two Secunda plants are virtually identical and both are much larger than Sasol One, which served as their prototype. Enormous quantities of feedstock are processed at these plants. At full production, their daily consumption of coal is almost 100,000 tons, of oxygen, 26,000 tons; and of water, 160 megaliters. Sasol's facilities at Secunda for the production of oxygen are by far the largest in the world.

Facilities at the fuel plants include boiler houses, Lurgi gasifiers, oxygen plants, Rectisol gas purification units, synthol reactors, gas reformers and refineries. Hydrocarbon synthesis takes place by means of the Sasol developed Synthol process.

The products of Sasol Two and Three, other than liquid fuels, include ethylene, alcohols, acetone, methyl ethyl ketone, pitch, tar acids, and sulphur, produced for Sasol's Chemical Division, ammonia for the group's Fertilizer and Explosives Divisions, and propylene for the Polypropylene Division.

SYNTHETIC FUELS REPORT, SEPTEMBER 1990
STATUS OF COAL PROJECTS (Underline denotes changes since June 1990)

COMMERCIAL AND R&D PROJECTS (Continued)

Sasol’s Mining Division manages the five Sasol-owned collieries, which have an annual production of 35-million tons of coal. The collieries comprised of the four Secunda Collieries, which form the largest single underground coal mining complex in the world, and the Sigma Colliery in Sasolburg.

A technology company, Sastech, is responsible for the Group’s entire research and development programme, process design, engineering, project management, and transfer of technology.

Project Cost*:
- SASOL Two $2.9 Billion
- SASOL Three $3.8 Billion

*At exchange rates ruling at construction

SCOTIA COAL SYNFUELS PROJECT – DEVCO (A Federal Crown Corporation); Alastair Gillespie & Associates Limited; Gulf Canada Products Company (a subsidiary of Gulf Canada Limited); NOVA, an Alberta Corporation; Nova Scotia Resources Limited (a Provincial Crown Corporation); and Petro-Canada (a Federal Crown Corporation) (C-500)

The consortium conducted a feasibility study of a coal liquefaction plant in Cape Breton, Nova Scotia using local coal to produce gasoline and diesel fuel. The plant would be built either in the area of the Point Tupper Refinery or near the coal mines. The 25,000 barrels per day production goal would require approximately 2.5 million tonnes of coal per year. A contract was completed with Chevron Research Inc. to test the coals in their two-stage direct liquefaction process (CCLP). A feasibility report was completed and financeability options discussed with governments concerned and other parties.

Scotia Synfuels Limited has been incorporated to carry on the work of the consortium. Scotia Synfuels has down sized the project to 12,500 barrels per day based on a coprocessing concept and purchased the Point Tupper site from Ultramar Canada Inc. Recent developments in co-processing technology have reduced the capital cost estimates to US$375 million. Net operating costs are estimated at less than US$20 per barrel.

Scotia Synfuels and partners have concluded an agreement with the Nova Scotia government supported by the federal government for financial assistance on a $23 million coprocessing feasibility study. The study is expected to be completed by June, 1990.

Project Cost:
- Approximately $23 million for the feasibility study
- Approximately C$500 million for the plant

SCRUBGRASS — Scrubgrass Associates (C-510)

Scrubgrass Associates (SGA) planned to build a 2,890 barrels per day coal-to-methanol-to-gasoline (and other products) plant, to be located in Scrubgrass Township, Venango County, Pennsylvania. The sponsors submitted a request for loan and price guarantees from the United States Synthetic Fuels Corporation under the solicitation for Eastern Province or Eastern Region of the Interior Province Bituminous Coal Gasification Projects. The technology consists of three basic processes: high pressure GKT entrained-flow coal gasification, ICI methanol synthesis, and the Mobil methanol-to-gasoline (MTO) process. On November 19, 1985, the SFC dropped the project from further consideration.

Scrubgrass Power Corporation has converted the project from production of liquid fuels to the production of electric power, at the same location. Environmental work has largely been completed for the previous plan. The capacity of the plant is 80 MEG. The plan is to use circulating fluidized bed technology, fueled with up to 6 percent sulfur coal.

No federal assistance of any kind is sought.

The estimated total project costs, including start-up, commissioning, engineering, procurement, and construction, and financing costs, are $145,000,000.

Project Cost: See above
STATUS OF COAL PROJECTS (Underline denotes changes since June 1990)

COMMERCIAL AND R&D PROJECTS (Continued)

SEP GASIFICATION POWER PLANT PROJECT – SEP (C-520)

Samenwerkende Elektriciteits-Productiebedrijven (SEP), the Central Dutch electricity generating company, has submitted to the government a plan to build a 250 megawatt coal gasification plant, to be ready in 1993. SEP's previous electricity plan, approved early in 1987, contained a project to build a 600 megawatt coal gasification unit at Maasvlakte, near Rotterdam, but construction for startup in 1997 will now be based on experience gained from the smaller plant.

SEP gave Comipro Engineering Consultants in Amsterdam an order to study the gasification technologies or Shell, Texaco and British Gas/Lurgi. In April, 1989 it was announced that the Shell process had been chosen.

The location or the gasification/combined cycle demonstration station is likely to be in Buggenum, in the province or Limburg.

After two years of experimentation, the plant may be expanded to 600 megawatts capacity.

Project Cost: DF1,700 million

SHANGHAI CHEMICALS FROM COAL PLANT – People's Republic or China (C-525)

The Chinese government has approved construction of a new methanol complex. Using coal as raw material, the Shanghai-based plant is expected to produce 100,000 tons per year or methanol and 15,000 tons per year of acetate fiber. Completion is due in 1992.

SHELL COAL GASIFICATION PROJECT – Royal Dutch/Shell Group and Shell Oil Company (U.S.) (C-530)

Shell Oil Company (U.S.) and the Royal Dutch/Shell Group are continuing joint development of the pressurized, entrained bed, Shell Coal Gasification Process. A 6 tons per day pilot plant has been in operation at Shell's Amsterdam laboratory since December 1976. A number or different coals and petroleum cokes have been successfully gasified at 300 to 600 psi. This pilot plant has now operated for over 10,000 hours.

A 150 tons per day prototype plant has been operating at the German Shell Hamburg/Harburg refinery since 1978 with over 6,000 hours of operation logged. Its experimental program now complete, the plant has successfully gasified different types of coal in runs as long as 1,000 hours and has demonstrated the technical viability of the process. Further development of the Shell process is continuing through active pursuit at other Shell facilities.

Shell Oil Company has constructed a demonstration unit for making medium-BTU gas, using the Shell Coal Gasification Process, at its Deer Park Manufacturing Complex near Houston, TX. The facility's gasifier uses high-purity oxygen to process a wide range of coals, including about 250 tons per day of high sulfur bituminous coal or about 400 tons per day of lignite. The medium-BTU gas and steam produced are consumed in Shell's adjacent manufacturing complex. The Electric Power Research Institute is also a participant in the program.

Shell's demonstration unit started up in July 1987 and reached design capacity within the first 50 hours of operation. During the five month period from December 1987 to May 1988, the unit operated at design conditions 82 percent of the time. Additionally, the unit has successfully completed a planned demonstration run of 1500 hours – or more than two months – of continuous operation. The plant operated smoothly and met design conditions. During the demonstration the unit consumed about 230 tons daily of Illinois No. 5 coal containing 3 percent sulfur. The smooth plant operation during this long run indicates the reliability of the process and mechanical features of the Shell Coal Gasification technology.

The long run also validated the environmental acceptability of the Shell process. The plant's emissions were well below the limits of the company's Texas air quality permit, while the wastewater was treated at the plant's bio-treater and posed no significant operating problems. The product gas contained the required low level of sulfur compounds and no detectable solids. The slag produced was used locally in a variety of construction applications.

Since achievement of the long demonstration run, the plant has focused on evaluation of additional coals, plant runs aimed at optimizing design rules and technology improvements. Eleven different coals have been run in the demonstration unit including those from the Illinois Basin, Northern and Central Appalachia, Powder River Basin, Texas lignite, and Australian coals.

Project Cost: Not disclosed

SLAAGING GASIFIER PROJECT – British Gas Corporation (C-540)

The British Gas Corporation (BGC) constructed a prototype high pressure slagging fixed bed gasifier in 1974 at Westfield, Scotland. (This gasifier has a six foot diameter and a throughput of 300 tons per day.) The plant successfully operated on a wide range of British and American coals, including strongly caking and highly swelling coals. The ability to use a considerable proportion of
fine coal in the feed to the top of the gasifier has been demonstrated as well as the injection of further quantities of fine coal through the tuyeres into the base of the gasifier. By-product hydrocarbon oils and tars can be recycled and gasified to extinction. The coal is gasified in steam and oxygen. The slag produced is removed from the gasifier in the form of granular frit. Gasification is substantially complete with a high thermal efficiency. A long term proving run on the gasifier has been carried out successfully between 1975 and 1983. Total operating time was over one year and over 100,000 tons of coal were gasified.

A new phase, started in November 1984, is the demonstration of a 500 tons per day (equivalent to 70 megawatts) gasifier with a nominal I.D. of 7.5 feet. Integrated combined cycle tests will be carried out with an SK 30 Rolls Royce Olympus turbine to generate power for the grid. The turbine is supplied with product gas from the plant. It has a combustor temperature of 1,950 degrees F, a compression ratio of 10, and a thermal efficiency of 31 percent. Currently, this gasifier has operated for approximately 1,300 hours and has gasified over 26,000 tons of U.K. and U.S. (Pittsburgh No. 8) coals.

In addition to the current 500 ton per day gasifier, an experimental gasifier designed to operate in the fixed bed slagger mode at pressure up to 70 atmospheres was constructed in 1988. It is designed for a throughput of 200 tons per day. The unit is to be used to study the effect of pressure on methane production and gasifier performance.

Project Cost: Not available

SOUTH AUSTRALIAN COAL GASIFICATION PROJECT – Government of South Australia (C-550)

The South Australian Government is continuing to assess the feasibility of building a coal gasification plant utilizing the low rank brown coal of the Northern St. Vincent Basin deposits, north of Adelaide. The plant being studied would be integrated with two 300 MW combined cycle power station modules and is one possible option for meeting additional power station capacity requirements in the mid-1990s.

Coal has been tested in a number of processes including the Sumitomo CGS (molten iron bath), Westinghouse, Shell-Koppers and Texaco, and studies are continuing in conjunction with Sumitomo, Uhde-Steag, and Krupp-Koppers. Heads of Agreement have been signed with a consortium headed by Uhde GmbH to test coal from the Bowmans deposit in the Rheinbraun HTW gasifier and perform a detailed design and feasibility study for a 600 MW gasification combined cycle power station. Ten tonnes of coal were satisfactorily gasified in the small scale Process Development Unit at Aachen, FRG, in August 1985. Testing Bowmans coal in the 40 ton per day Rheinbraun pilot plant at Frechen-Wachtberg, FRG has been completed.

The third phase, the detailed costing and feasibility study, was deferred in 1988 for at least three years due to deferred need for new electric capacity with significant reduced electricity load growth.

Project Cost: DM 7.5 million

SYNTHESGASANLAGE RUHR (SAR) – Ruhrkohle Oel and Gas GmbH and Hoechst (C-560)

Based on the results of the pressurized coal-dust gasification pilot plant using the Texaco process, which has been in operation from 1978 to 1985, the industrial gasification plant Synthesgasanlage Ruhr has been completed on Ruhrchemie's site at Oberhausen-Holten.

The coal gasification plant has been in operation since August 1986. The coal gases produced have the quality to be fed into the Ruhrchemie's oxosynthesis plants. As of 1989 the gasification plant is to be modified to allow for input of either hard coal or heavy oil residues. The initial investment was subsidized by the Federal Minister of Economics of the Federal Republic of Germany. The Minister of Economics, Small Business and Technology of the State of North-Rhine Westphalia participates in the coal costs.

Project Costs: DM220 million (Investment)

TEXACO COAL GASIFICATION PROCESS – Texaco Inc. (C-570)

The Texaco Coal Gasification Process reached a milestone in January, 1989 with the successful completion of the five year demonstration of commercial operation by the Cool Water Coal Gasification Program. After production of more than 2.5 billion kilowatt hours of electricity from gasification of more than one million tons of coal, the Cool Water Program completed operation in late January to permit full documentation of the results. As the first fully integrated commercial scale gasification combined cycle power plant in the world, Cool Water demonstrated the ability of the texaco process to efficiently use a wide range of coals in an environmentally superior manner. Emissions of sulfur dioxide, oxides of nitrogen and particulates from even high sulfur coals were far below the stringent Federal New Source Performance Standards requirements for coal fired plants.

The Texaco Coal Gasification Process can be used for the commercial production of electric power and a variety of products, and has application for a wide range of chemicals which can be manufactured from synthesis gas. Commercial projects currently in operation utilizing the Texaco Coal Gasification Process include the 900 tons per day Tennessee Eastman plant which manufactures...
methanol and acetic anhydride, the 1,650 tons per day Ube Ammonia plant which manufactures ammonia, and the 800 tons per day SAR plant in Oberhausen, West Germany for the manufacture of oxo-chemicals. Commercial projects currently in detailed design and/or construction include the 400 ton per day LuNan Coal Gasification Plant in China to manufacture ammonia, and the 1,100 tons per day Shoudu Coal Gasification Plant in Beijing, China, which will produce town gas. Many United States utilities are actively considering coal gasification for future electric power capacity additions, and are working with Texaco on detailed site-specific studies of the Texaco process. Outside the U.S. many projects using Texaco's technology are in the evaluation stage and include plants to be located in the Netherlands, Sweden, Denmark, Italy and China.

Project Cost: Not applicable

UBE AMMONIA-FROM-COAL PLANT – Ube Industries, Ltd. (C-590)

Ube Industries, Ltd., of Tokyo recently completed the world's first large scale ammonia plant based on the Texaco coal gasification process (TCGP). There are four complete trains of quench mode gasifiers in the plant. In normal operation three trains are used with one for stand-by. Ube began with a comparative study of available coal gasification processes in 1980. In October of that year, the Texaco process was selected. 1981 saw pilot tests run at Texaco's Montebello Research Laboratory, and a process design package was prepared in 1982. Detailed design started in early 1983, and site preparation in the middle of that year. Construction was completed in just over one year. The plant was commissioned in July 1984, and a first drop of liquid ammonia from coal was obtained in early August 1984. Those engineering and construction works and commissioning were executed by Ube's Plant Engineering Division. Ube installed the new coal gasification process as an alternative "front end" of the existing steam reforming process, retaining the original synthesis gas compression and ammonia synthesis facility. The plant thus has a wide range of flexibility in selection of raw material depending on any future energy shift. It can now produce ammonia from coals, naphtha and LPG as required.

The gasification plant has operated using four kinds of coal—Canadian, Australian, Chinese, and South African. The overall cost of ammonia is said by Ube to be reduced by more than 20 percent by using coal gasification. Furthermore, the coal gasification plant is expected to be even more advantageous if the price difference between crude oil and coal increases.

Project Cost - Not disclosed

VEW GASIFICATION PROCESS – Vereinigte Elektrizitätswerke Westfalen AG, Dortmund (C-600)

A gasification process being specially developed for application in power plants is the VEW Coal Conversion Process of Vereinigte Elektrizitätswerke Westfalen AG, a German utility. The process works on the principle of entrained flow. Coal is partly gasified with air and the remaining coke is burned separately in a fluidized bed combustion unit. Because the coal is only partly gasified, it is not necessary to use oxygen. A prototype 10 tons coal per hour plant has been operated in Gersteinwerk near Dortmund since 1985. Superheated steam of 530 degrees C and 180 bar is generated in the waste heat boiler. Three variants are being tested for gas cleaning, whereby both wet and dry gas cleaning are being applied. These consist of:

- Wet gas-cleaning with prescrubbing to remove NH4Cl, and amisol washing plus a Claus plant to remove sulfur.
- Prescrubbing to remove NH4Cl, with combustion of gases free of chlorine and alkalies in the gas turbine, followed by sulfur separation in the fluidized bed combustion unit.
- Dry removal of chlorine and alkalies in a circulating fluidized bed in which lime is used as a reagent, with sulfur removal in the fluidized bed combustion unit.

VEW is presently planning the conversion of one of its six gas-fired power stations to the new technology. The coal gasification process is expected to be fully developed by 1990.

Project Cost: Not disclosed

VICTORIA BROWN COAL LIQUEFACTION PROJECT – Brown Coal Liquefaction (Victoria) Pty. Ltd. (C-610)

BCLV is operating a pilot plant at Morwell in southeastern Victoria to process the equivalent of 50 tons per day of dry ash free coal. BCLV is a subsidiary of the Japanese-owned Nippon Brown Coal Liquefaction Company (NBCL), a consortium involving Kobe Steel, Mitsubishi Kasei Corporation, Nissho Iwai, Idemitsu Kosan, and Asia Oil.

The project is being run as an inter-governmental cooperative project, involving the Federal Government of Australia, the State Government of Victoria, and the Government of Japan. The program is being fully funded by the Japanese government through the New Energy and Industrial Technology Development Organization (NEDO). NBCL is entrusted with implementation of the entire program, and BCLV is carrying out the Australian components. The Victorian government is providing the plant site, the coal, and some personnel.

Project Cost: Not applicable
STATUS OF COAL PROJECTS (Underline denotes changes since June 1990)

COMMERCIAL AND R&D PROJECTS (Continued)

Construction of the drying, slurning, and primary hydrogenation sections comprising the first phase of the project began in November 1981. The remaining sections, consisting of solvent deashing and secondary hydrogenation, were completed during 1986. Both sections are now operating. The pilot plant is planned to operate until October 1990, and shut down at that point.

The aim of the pilot plant is to provide data on the BCL Process developed since 1971 by members of the consortium. Tentative plans call for construction of a demonstration plant consuming about 5,000 tons per day of dry coal equivalent, this being the first unit of a six unit commercial plant.

The pilot plant is located adjacent to the Morwell open cut brown coal mine. Davy McKee Pacific Pty. Ltd., provided the Australian portion of engineering design procurement and construction management of the pilot plant.

Project Cost: Undisclosed

WESTERN ENERGY ADVANCED COAL CONVERSION PROCESS DEMONSTRATION – Western Energy Company, United States Department of Energy (C-616)

The United States Department of Energy has completed negotiations with Western Energy Company for funding as a replacement project in Round One of the Department's Clean Coal Technology Program. The project has gone to the report to Congress waiting period.

The Western proposal is a novel coal cleaning process to improve the heating value and reduce the sulfur content of western coals. Typical western coals may contain moisture as much as 25 to 35 percent of their weight. The high moisture and mineral content of the coals reduces their heating value to less than 9,000 BTU per pound.

The Western Energy process would upgrade the coals, reducing their moisture content to as low as one percent and produce a heating value of up to 12,000 BTU per pound. The process also reduces sulfur content of the coals, which can be as high as 1.5 percent, to as low as 0.3 percent. The project will be conducted at a 50 ton per hour unit adjacent to a Western Energy subbituminous coal mine in Colstrip, Montana.

Project Cost: Not disclosed

WUJING TRIGENERATION PROJECT – Shanghai Coking and Chemical Plant (C-620)

Shanghai Coking and Chemical Plant is considering a trigeneration project to produce coal-derived fuel gas, electricity, and steam. The proposed plant will be constructed near the Shanghai Coking and Chemical plant in Wujing, a suburb south of Shanghai. SWCC contracted with Bechtel on June 6, 1986 to conduct a technical and economic feasibility study of the project.

The proposed project will consist of coal gasification facilities and other processing units to be installed and operated with the existing coke ovens in the Shanghai Coking and Chemical Plant. The facility will produce 3 million cubic meters per day of 3,800 Kcal per cubic meter of town gas (106 million cubic feet per day of 427 BTU per cubic foot); 50 to 60 megawatts of electricity; 100 metric tons per hour of low pressure steam; and 300,000 metric tons per year of 99.85 percent purity chemical grade methanol, 100,000 metric tons per year of acetic anhydride, and 50,000 metric tons per year of cellulose acetate. The project will be constructed in stages.

The study was completed and evaluated. Bechtel was paid from a $600,000 grant to SCCP from the United States trade and development program (TDP), International Development Cooperation Agency.

Phase I, designed to produce one million cubic meters per day of town gas, 100,000 tons per year of methanol, and 15,000 tons per year of cellulose acetate was submitted to the Chinese National Planning Board for approval by Shanghai municipality in April, 1988. It was approved by the Chinese National Planning Board at the end of September, 1989.

Project Cost: Not disclosed

YUNNAN LURGI CHEMICAL FERTILIZERS PLANT – Yunnan Province, China (C-625)

In the 1970s, a chemical fertilizer plant was set up in Yunnan province by using Lurgi pressurized gasifiers of 2.7 meter diameter. The pressurized gasification of a coal water slurry has completed a model test with a coal throughput of 20 kilograms per hour and achieved success in a pilot unit of 1.5 tons per hour. The carbon conversion reached 95 percent, with a cold gas efficiency of 66 percent.

For water-gas generation, coke was first used as feedstock. In the 1950s, experiments of using anthracite to replace coke were successful, thus reducing the production cost of ammonia by 25-30 percent. In order to substitute coal briquettes for lump anthracite, BRICC developed a coal briquetting process in which humate was used as a binder to produce synthetic gas for chemical fertilizer production. This process has been applied to production.

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STATUS OF COAL PROJECTS (Underline denotes changes since June 1990)

COMMERCIAL AND R&D PROJECTS (Continued)

UNDERGROUND COAL CONVERSION PROJECTS

UNDERGROUND COAL GASIFICATION, INDIA — Oil and Natural Gas Commission (C-630)

The government of India has appropriated $40 million to test the potential of underground coal gasification (UCG) for domestic coal. The proposed site for the test in western India contains large reserves of subbituminous coal that could be amenable to UCG. However, experts from the United States, France, Netherlands, Belgium, and West Germany concluded that the depth of the coal—approximately 2,750 feet—may cause some challenges, but have agreed with the strategy adopted by India for detailed geological, geophysical and hydrological studies prior to gasification and proposed horizontal drilling, completion policy and surface design. Therefore, they recommended that the Indian researchers utilize the Controlled Retracting Injection Point (CRIP) technology developed by the Lawrence Livermore National Laboratory.

The first information well (UCG-1) has been drilled in Mehsana City structure located in North Gujarat. Detailed hydrological, geological and geophysical studies have been completed. Detailed 3-D seismic work has been done. Another well is proposed to be drilled for more data gathering before actual gasification in 1989-90.

Project Cost: $40 million appropriated

UNDERGROUND COAL GASIFICATION, LLNL STUDIES — Lawrence Livermore National Laboratory (C-650)

Initial LLNL work involved development of the packed bed process for UCG, using explosive fracturing to link injection and production wells. A field test, Hoe Creek No. 1, was conducted during FY1976-77, to test the concept. The second experiment, carried out during FY1977-78, Hoe Creek No.2, was linked using reverse combustion and produced 100-150 BTU per standard cubic foot gas using air injection, and 250-300 BTU per standard cubic foot gas during a two day steam-oxygen injection test. The next experiment, Hoe Creek No. 3, was carried out during the FY1978-79, using a drilled channel to provide the link. The test ran for 57 days, 47 consecutive days using steam and oxygen during which 3,800 tons of coal were gasified with an average heating value of 215 BTU per standard cubic foot. The test showed that long term use of steam oxygen for UCG is technically feasible, operationally simple and safe.

As a result of the experience at Hoe Creek LLNL developed the Controlled Retracting Injection Point (CRIP) concept for UCG. The development of this gasification method was a result of recognition of the importance of maintaining oxygen injection in a UCG reactor low in the seam. The CRIP concept insures a low injection point by using a horizontally drilled injection well placed at the bottom of the seam, in which a steel liner is inserted the full length of the hole. In addition, the technique also allows multiple cavities to be developed from a single injection well. This is accomplished through the use of an igniter/cutter assembly in the injection well capable of burning through the injection well liner and igniting the coal. This new concept was first tested in the "Large Block Tests" carried out in FY1982 at the WIDCO mine site. In addition to testing the new CRIP concept for the first time, these tests were designed to be midway between laboratory and full field scale. This mid-scale size allowed the burn cavities to be excavated yielding valuable information about UCG cavity growth.

The results of the "Large Block Tests" led to the design of the Centralia Partial Seam CRIP test which was carried out in FY1983-84. This test which used the upper half of the Big Dirty seam demonstrated the technical feasibility of the CRIP method on a full-scale system. Two cavities were developed and over 2,000 tons of coal were gasified with steam and oxygen, producing an average heating value of 240 BTU per standard cubic foot. Because of routine mining operations at the WIDCO mine site where the test was performed, LLNL had the opportunity to excavate this large scale burn during FY1983. This excavation was extremely valuable in helping to refine the UCG process model as well as providing data for model validation.

The CRIP concept was carried to an even larger scale in the Rocky Mountain I (RM-I) UCG test performed in FY1988. The RM-I test was a nominal 100 day test of two technologies for UCG performed near Hanna, Wyoming at the site of previous DOE UCG tests. In addition to the CRIP module a second module called the Extended Linked Well (ELW) module was also operated. The CRIP module performed extremely well. Approximately 10,000 tons of coal were gasified over the course of 93 days of forward gasification. The 287 BTU per standard cubic foot average gas heating value was the highest level ever obtained in a flat lying coal seam. The process also demonstrated efficiencies equal to that of surface gasification units. During operation of the CRIP module four separate cavities were generated demonstrating the ability of the CRIP technology to reliably generate multiple cavities from a single injection well.

The RM-I test was jointly sponsored by the DOE and private industry. LLNL involvement in the test included supply and operation of data acquisition hardware and software, supply and operation of gas analysis equipment, technical input to test design and operation, and supply of personnel for technical operation of the test.

In addition to involvement in field work, LLNL has over the course of the last several years developed a state-of-the-art computer model of the UCG process. This model, called CAVSIM, addresses both gas composition and resource recovery questions associated with UCG. The model successfully predicted the shape of the cavity uncovered during the excavation of the Centralia
STATUS OF COAL PROJECTS (Underline denotes changes since June 1990)

Underground Gasification Projects (Continued)

Partial Seam CRIP test. In addition, model computations of coal consumption and gas production rates in a simulation of the RM-I test have been shown to agree very well with the field data.

Project Cost: Not disclosed
## COMPLETED AND SUSPENDED PROJECTS

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